

**Bonneville Power Administration
Transmission Services**

2008 INITIAL TRANSMISSION PROPOSAL

**DIRECT TESTIMONY AND
QUALIFICATION STATEMENTS**

DIRECT TESTIMONY

<u>BPA Exhibit No.</u>	<u>Subject</u>	<u>Witness</u>
TR-08-E-BPA-03	Overview of Rate Proposal	Metcalf, Parker
TR-08-E-BPA-04	Revenue Forecast	Knudsen, Woerner
TR-08-E-BPA-05	Revenue Requirement Study and Risk Analysis	Homenick, Jensen, Russell and Taylor

QUALIFICATION STATEMENTS

TR-08-Q-BPA-01	Ronald J. Homenick
TR-08-Q-BPA-02	Dana M. Jensen
TR-08-Q-BPA-03	Randy B. Russell
TR-08-Q-BPA-04	F. Steven Knudsen
TR-08-Q-BPA-05	Nancy Parker
TR-08-Q-BPA-06	Eric K. Taylor
TR-08-Q-BPA-07	John R. Woerner
TR-08-Q-BPA-08	Dennis E. Metcalf

February 2007

INDEX

TESTIMONY OF DENNIS E. METCALF AND NANCY PARKER

Witnesses for Bonneville Power Administration Transmission Services

SUBJECT: OVERVIEW OF RATE PROPOSAL

	Page
SECTION 1. Introduction and Purpose	1
SECTION 2. Settlement Agreement.....	2
SECTION 3. Rate Proposal	4
SECTION 3.A. Formula Rates	6
SECTION 3.B. Point-to-Point Service Rates	7
SECTION 3.C. Ancillary and Control Area Service (ACS) Rates.....	9
SECTION 4. Redispatch.....	10
SECTION 5. Equitable Allocation	11

ATTACHMENT A. Settlement Agreement

ATTACHMENT B. Signatories

1 **TESTIMONY OF**

2 **DENNIS E. METCALF and NANCY PARKER**

3 Witnesses for Bonneville Power Administration Transmission Services

4 **SUBJECT: OVERVIEW OF RATE PROPOSAL**

5 **SECTION 1. INTRODUCTION AND PURPOSE**

6 *Q. Please state your names and qualifications.*

7 A. My name is Dennis E. Metcalf and my qualifications are stated at TR-08-Q-BPA-08.

8 A. My name is Nancy Parker and my qualifications are stated at TR-08-Q-BPA-05.

9 *Q. What is the purpose of your testimony?*

10 A. BPA Transmission Services (TS) is proposing transmission and ancillary service rates to
11 be effective for Fiscal Years (FY's) 2008 and 2009 (Rate Period). The purpose of this
12 testimony is to provide an overview of the 2008 Initial Proposal, which is based on the
13 attached 2008 Transmission Rate Case Settlement Agreement (Settlement Agreement).
14 This testimony also sponsors the 2008 Transmission and Ancillary Service Rate Schedules
15 (Rate Schedules), TR-08-E-BPA-02.

16 *Q. How is your testimony organized?*

17 A. This testimony is organized in 5 sections. Section 1 is this Introduction. Section 2
18 provides an overview of the Settlement Agreement. Section 3 describes the proposed
19 revisions to the transmission and ancillary service rates and other proposed rate schedule
20 revisions provided for in the Settlement Agreement. Section 4 discusses redispatch.
21 Finally, section 5 addresses the equitable allocation standard in relation to the rate
22 proposal.

1 **SECTION 2. SETTLEMENT AGREEMENT**

2 *Q. Please describe the process that led to the development of the Settlement Agreement for the*
3 *2008 Transmission Rate Case.*

4 A. In order to establish transmission and ancillary service rates to be effective October 1,
5 2007, when current transmission and ancillary service rates expire, TS held three public
6 workshops during the period July 2006 through October 2006. The workshops were used
7 to discuss potential changes in the rate schedules as well as to the Open Access
8 Transmission Tariff (OATT), Attachment K, regarding procedures for redispatch. At the
9 customers' suggestion, TS and the customers met to explore the possibility of a negotiated
10 settlement of the rate case. During October and November 2006, TS published notice of
11 the settlement discussions and related documents, and met with customers and interested
12 parties to negotiate a settlement of transmission and ancillary service rate levels and
13 resolution of other significant issues. The discussions resulted in the Settlement
14 Agreement, which was offered by TS on November 30, 2006, signed by most customers on
15 or before January 5, 2007, and signed by TS on January 12, 2007.

16 *Q. What issues were resolved in the Settlement Agreement?*

17 The Settlement Agreement includes agreement on the transmission and ancillary service
18 rate levels to be submitted as the Initial Proposal, and addresses a limited set of other
19 issues. The Settlement Agreement is shown in Attachment A to this testimony;
20 Attachment B is a list of the entities that have signed the Settlement Agreement. This
21 Initial Proposal reflects the terms of the Settlement Agreement.

22 *Q. Please provide an overview of the Initial Proposal.*

23 A. TS proposes to revise to the rate charges as specified in the Settlement Agreement.
24 Attachment A, at 1 and 9-10. Revisions to the transmission and ancillary services rate
25 schedules also include: elimination of the Reservation Fee for deferred PTP service;

1 inclusion of a formula rate in the Formula Power Transmission FPT-08.3 rate schedule to
2 capture any changes over the Rate Period in the Reactive and Voltage Control From
3 Generation Sources Service (GSR) rate level; updating certain values in the FPT-08.1
4 formula rate and the Integration of Resources IR-08 Short Distance Discount formula rate;
5 elimination of the GSR formula rate components to recover GSR payments to BPA Power
6 Services (PS) and transmission costs; addition of Conditional Firm Transmission Service
7 under Section I of the PTP rate schedule; inclusion of a Operating Reserves rate applicable
8 to customers who elect to self-supply or third-party supply Operating Reserves for the Rate
9 Period and who default on such obligations back to TS; clarification in the rate schedules
10 for PTP transmission service of the non-firm hourly billing determinant during an
11 interruption; clarification of applicability of the two required Ancillary Services to
12 transmission service subject to an Unauthorized Increase Charge; and removal of formula
13 rates for the ancillary and control area services of Regulation and Frequency Response and
14 Operating Reserves. Attachment A, at 1-3 and 11-13.

15 *Q. Are there other issues agreed to in the Settlement Agreement that are reflected in the Initial*
16 *Proposal?*

17 *A.* The Settlement Agreement includes revisions to and clarifications of Attachment K of the
18 OATT, which concerns procedures for redispatch of the federal hydro system. Attachment
19 A, at 5-6 and 17-18. The revised Attachment K clarifies the circumstances under which TS
20 may request redispatch from BPA's merchant, PS, and distinguishes between those cases
21 in which PS must provide redispatch in response to a request and those in which PS has the
22 discretion whether to provide redispatch or not. In addition, instead of paying PS a flat
23 amount for redispatch service for each year of the rate period, TS will compensate PS for
24 redispatch provided on a per-event basis. For the Rate Period, TS has also agreed to
25 provide customers detailed information on redispatch and curtailments. *See* Section 4,

1 below, for further discussion on redispatch. Finally, the Settlement Agreement provides
2 that TS will include in the transmission revenue requirement \$4.5 million per year for
3 projected payments to Federal and nonfederal entities for redispatch. Attachment A, at 6;
4 Revenue Requirement Study, TR-08-E-BPA- 01, Appendix B at B-4 and B-5.

5 *Q. What other issues are addressed in the Settlement Agreement?*

6 A. The Settlement Agreement provides for reserve financing. Attachment A, at 3; Homenick,
7 et al., TR-08-E-BPA-05, Section 2B. In addition, the Settlement Agreement includes a
8 process satisfying BPA's procedural and public process requirements regarding Debt
9 Optimization Program (DOP) and Debt Service Reassignment (DSR) demonstration under
10 the Slice Settlement Agreement. The Settlement Agreement details the process by which
11 the Transmission Rate DOP Demonstration is included in this 2008 Transmission Rate
12 Case. Attachment A, at 3-5 and 14-16.

13 *Q. What is the Transmission Rate DOP Demonstration under the Slice Settlement Agreement?*

14 A. BPA must demonstrate that transmission rates are no higher with the DOP, including DSR,
15 than they would otherwise be. Homenick, et al., TR-08-E-BPA-05, Section 4.

16 *Q. Are other issues addressed in the Settlement Agreement?*

17 A. The Settlement Agreement provides notice that during the Rate Period BPA may conduct a
18 separate rate case to establish a rate for generation regulation service and generation
19 following service. Attachment A, at 3. Finally, the Settlement Agreement provides that
20 BPA will post notice of potential Spill Conditions. *Id.* at 7.

21 **SECTION 3. RATE PROPOSAL**

22 *Q. Is BPA proposing significant changes to the rate levels for the Rate Period?*

23 A. No. Based on the projected costs for the Rate Period and transmission sales projections,
24 revenues at *current* rates are sufficient to recover transmission costs for the Rate Period.
25 Knudsen and Woerner, TR-08-E-BPA-04, Section 3. However, given that the proposed

1 GSR rate is forecasted to be zero during the Rate Period, the proposed 2008 transmission
2 rates are set at levels that are higher than current rates by \$0.082/kWmo., the forecasted
3 2006 GSR rate, to allow the recovery of higher transmission costs. Therefore, the increase
4 in transmission rates is balanced by a forecasted decrease in the GSR rate, resulting in no
5 expected net increase in total rates.

6 *Q. Why is the proposed GSR rate forecasted to be zero during the Rate Period?*

7 A. The current 2006 GSR formula rate recovers payments to PS and nonfederal generators for
8 GSR, as well as certain transmission costs. As of October 1, 2007, TS will no longer pay
9 BPA PS for GSR. In addition, transmission costs previously recovered under the GSR rate
10 will be recovered in transmission rates. Therefore, the proposed 2008 GSR formula rate is
11 revised to eliminate the rate components that currently recover the cost of GSR payments
12 to PS and transmission costs. The remaining GSR formula rate components are designed
13 to pass through to customers the payments to non-federal generators for GSR, and self-
14 supply credits, if any. BPA intends to submit filings with the Federal Energy Regulatory
15 Commission (Commission) to end GSR payments to each non-federal generator as of
16 October 1, 2007. If BPA is successful, payments for GSR to non-federal generators will
17 cease, and the resulting GSR formula rate for this component will be zero. Therefore, TS
18 is projecting no payments to non-federal generators for GSR for the Rate Period resulting
19 in a GSR rate of zero. In that case, the reduction in the GSR rate will offset the increase in
20 transmission rates, resulting in no change in customers' total bills for transmission and
21 ancillary services. See section 3.A, below, for further discussion of the GSR formula rate.

22 *Q. Please explain the increase in the FPT-08.3 rate level.*

23 A. The FPT-08.3 rate is increasing to match the FPT-08.1 rate levels. Certain FPT contracts
24 contain provisions that the rate cannot be adjusted more frequently than once every three
25 years. The current FPT-06.3 rate was set at the same level as the FPT-04.3 rate established

1 for the second year of the FY2004-2005 rate period. Since the FPT-06.3 rate was not
2 adjusted for the current rate period (FY2006-2007), the proposed FPT-08.3 rate associated
3 with these FPT contracts is adjusted to bring it in line with the FPT-08.1 rate.

4 **SECTION 3.A. FORMULA RATES**

5 *Q. Which rate schedules are proposed as formula rates?*

6 A. A formula rate is proposed for the Reactive Supply and Voltage Control from Generation
7 sources (GSR) Service rate under the Ancillary Service and Control Area Service (ACS)
8 Rate Schedule. Rate Schedules, TR-08-E-BPA-02, at 40-44. In addition, the FPT-08.1,
9 FPT-08.3 and IR-08 transmission rates are formula rates. These transmission rates include
10 a GSR cost component, which may need to be adjusted during the Rate Period to reflect
11 changes in the GSR rate. Id, at 3-12.

12 *Q. Please explain the need for formula rates.*

13 A. Formula rates will allow TS to pass through costs as they become known during the Rate
14 Period. The cost component that drives the need for formula rates is potential
15 compensation for GSR from non-Federal generation through payment of a Commission-
16 approved rate or self-supply credits.

17 *Q. Please explain the GSR rate formula.*

18 A. The proposed GSR rate will be calculated quarterly to account for two factors: TS expense
19 associated with compensating non-Federal generators for GSR under a Commission-
20 approved rate; and to account for self-supply of GSR. Thus, the quarterly adjustment of
21 the GSR rate allows TS to ensure that it fully recovers its costs as they become known
22 during the Rate Period. The GSR formula rate is designed to recover TS's cost of GSR
23 from non-Federal generators in a timely manner, while not changing the rate level
24 dramatically each quarter.

25 *Q. How does the proposed GSR rate differ from the current GSR formula rate?*

1 A. As previously described, consistent with the Settlement Agreement, two components in the
2 current GSR formula rate are eliminated in the proposed GSR rate: the transmission
3 component (“t”), and the BPA PS generation input component (“P”). See Section 3,
4 above, regarding the elimination of these two GSR formula rate components.

5 *Q. Please discuss the credit for self-supply of GSR.*

6 A. The GSR rate schedule permits transmission customers to apply for a reduction in the
7 billing factor to the extent the transmission customer demonstrates it can self-supply this
8 service. TS is not expecting any self-supply of GSR by customers during the Rate Period
9 based on the forecasted GSR rate, which is zero.

10 *Q. Please describe the changes to the FPT-08.1, FPT-08.3 and IR-08 transmission rates.*

11 A. The proposed FPT-08.1, FPT-08.3 and IR-08 rates recover costs associated with the
12 Integrated Network plus the two required ancillary services, Scheduling, System Control,
13 and Dispatch (SCD) Service and GSR Service. To the extent that the ACS-08 GSR rate
14 changes quarterly, as discussed above, that change will be factored into the FPT-08.1, FPT-
15 08.3 and IR-08 rates quarterly according to the formulas in those rate schedules. The
16 transmission and SCD cost components are not adjusted and so remain constant over the
17 Rate Period. The charges in the proposed FPT-08.1 and IR-08 rate schedules have been
18 updated. The FPT-08.3 rate schedule is now a formula rate, identical to the FPT-08.1 rate
19 schedule, as explained in section 3, above.

20
21 **SECTION 3.B. POINT-TO-POINT SERVICE RATES**

22 *Q. What changes are proposed for the rate schedules for PTP Service?*

23 A. TS is proposing to revise the Hourly Nonfirm Billing Factor applicable during interruption
24 of non-firm transmission service; the applicability of the Reservation Fee; and adds the
25 availability of the PTP-08 Rate Schedule for Conditional Firm Service.

1 Q. *Please describe the revision to the Hourly Nonfirm Billing Factor.*

2 A. The billing factor for Hourly Nonfirm service when service is curtailed or interrupted is
3 proposed to be Reserved Capacity minus curtailed capacity if the service is curtailed or
4 interrupted before the close of the hourly non-firm scheduling window; and is proposed to
5 remain the actual schedule if the service is curtailed or interrupted after the close of the
6 scheduling window. This proposed change reflects the rights customers have to use their
7 Reserved Capacity up to the close of the scheduling window. Regardless of when the
8 curtailment occurs, if the curtailment originates from conditions on another transmission
9 provider's transmission system, the billing factor is the Reserved Capacity. The change in
10 the Billing Factor for Hourly Nonfirm service during an interruption or curtailment of non-
11 firm service is reflected in the PTP-08, IS-08 and IM-08 rate schedules. Rate Schedules,
12 TR-08-E-BPA-02, at 19, 24, 28.

13 Q. *Please describe the rate schedule revision for the Reservation Fee.*

14 A. TS is proposing to remove the applicability of the Reservation Fee to deferred service
15 under the PTP-08, IM-08 and IS-08 rate schedules. *Id.* The Reservation Fee for an
16 extension of the Service Commencement Date will remain. The current Reservation Fee
17 rate schedule defines "deferred service" as any advanced reservation with a Service
18 Commencement Date greater than one year from the request date. While TS encourages
19 customers to request transmission service with as much advanced notice as possible,
20 applying the Reservation Fee to deferred service discourages customers from requesting
21 transmission service until they are within a year of the Service Commencement Date.

22 Q. *Please describe the revision to the PTP rate schedule for Conditional Firm Service.*

23 A. Conditional Firm (CF) Transmission Service has been added under the Availability section
24 of the proposed PTP-08 rate schedule. *Id.* at 17. TS is working to develop a CF product
25 with costs to be recovered under the PTP rate schedule.

1 **SECTION 3.C. ANCILLARY AND CONTROL AREA SERVICE (ACS) RATES**

2 *Q. What changes are proposed for the ACS rate schedule?*

3 A. TS is proposing to modify the Billing Factors for the ACS-08 rates for Scheduling, System
4 Control and Dispatch Service and Reactive Supply and Voltage Control from Generation
5 Sources Service to include the Unauthorized Increase Charge (UIC) billing factor. These
6 revisions are made to clarify that the unauthorized transmission use charged for under the
7 UIC rate will also be charged the two required ancillary services. Rate Schedules, TR-08-
8 E-BPA-02, at 39, 43-44.

9 *Q. What changes are proposed for the Operating Reserve rates for Spinning Reserve Service
10 and Supplemental Reserve Service?*

11 A. The formula rate structure of the Operating Reserve rate is replaced with a fixed rate for
12 the entire Rate Period. *Id.* at 49-52, 57-60. The current formula rate was required because
13 the cost of generation input from PS was not known at the time the ASC-06 Operating
14 Reserve (OR) rates were proposed. In contrast, the generation input costs associated with
15 OR for the Rate Period were determined in the 2007 Power Rate Case so a formula rate is
16 no longer needed. In addition, TS has added a rate to the OR rate schedules that is
17 applicable to customers who have chosen to self-supply or third-party supply OR for the
18 Rate Period and then default on their self-supply or third-party supply obligations. This
19 “default” rate is 15% higher than the regular Operating Reserve rate. *Id.*

20 *Q. What changes were made to the Regulation and Frequency Response Rate?*

21 A. The formula rate for Regulation and Frequency Response Service (RFR) was removed and
22 replaced with a fixed rate for the Rate Period. *Id.* at 45, 53. The generation input cost
23 associated with RFR for the Rate Period was determined in the 2007 Power Rate Case, so a
24 formula rate is no longer needed.

1 **SECTION 4. REDISPATCH**

2 *Q. Please explain the Settlement Agreement provisions concerning redispatch service.*

3 A. BPA will submit to the Commission a revised Attachment K to the OATT defining the
4 redispatch services to be provided by PS in fiscal years 2008 and 2009. Attachment A, at
5 17-18. Attachment K has been revised to clarify that there are three types of reliability
6 redispatch: Emergency Redispatch, which applies when TS has declared a system
7 emergency; NT Firm Redispatch, which applies when a transmission constraint may impair
8 reliability and TS has curtailed nonfirm PTP schedules and secondary NT schedules; and
9 Discretionary Redispatch, which applies when a transmission constraint may impair
10 reliability but TS has not curtailed nonfirm PTP and secondary NT schedules. PS must
11 provide redispatch when TS makes a request under either of the first two categories. The
12 third category is labeled “discretionary” because PS has the discretion whether to offer
13 redispatch in this case. TS requests redispatch from PS under all of these circumstances
14 today. The revision clarifies the distinctions between the categories and makes the third
15 category of redispatch discretionary with PS.

16 *Q. Please explain the change in how TS will compensate PS for redispatch.*

17 A. Currently, TS pays PS \$1.5 million per year for redispatch regardless of the amount of
18 redispatch that PS provides. Under the Settlement Agreement, TS will pay PS for
19 redispatch provided on a per-event basis.

20 *Q. What amount will TS pay PS for redispatch under Attachment K?*

21 A. For each request for redispatch, PS will submit a bid price to TS (unless the request is for
22 Discretionary Redispatch and PS decides not to offer redispatch). TS will decide whether
23 to accept the bid price or to take other actions to preserve reliability instead. We are
24 making this change so that the amount TS pays PS for redispatch more accurately reflects
25 the actual amount of redispatch provided, instead of being based on a projection.

1 Q. *What is TS forecasting for costs associated with redispatch in the Revenue Requirement?*

2 A. As part of the Settlement Agreement, TS is including \$4.5 million per year in the Revenue
3 Requirement for expected payments for redispatch of generation under Attachment K and
4 under any reliability redispatch programs that may be in effect during the Rate Period.
5 Revenue Requirement Study, TR-08-E-BPA- 01, Appendix B at B-4 and B-5. TS is
6 developing a redispatch pilot program scheduled for the summer of 2007 and expects to
7 have additional programs during the Rate Period. The pilot program and any additional
8 programs are expected to include both federal and non-Federal generation.

9
10 **SECTION 5. EQUITABLE ALLOCATION**

11 Q. *Do the proposed transmission and ancillary services rates represent an equitable*
12 *allocation of costs between Federal and non-Federal power?*

13 A. Yes. TS is not presenting segmentation and cost allocation studies to support the proposed
14 rates; the rates are a product of the Settlement Agreement. Nevertheless, equitable
15 allocation is demonstrated in two important ways. First, equitable allocation between
16 Federal and non-Federal power is achieved through adherence to the principle of
17 comparability. Prior to 1996, when most transmission for Federal power was provided for
18 in bundled power sales contracts, an allocation of costs in the rate case was needed to
19 demonstrate equitable allocation of transmission costs between Federal and non-Federal
20 power. Under BPA's OATT, purchasers of transmission for Federal power, including both
21 BPA PS and PS's customers, receive the same service and pay the same rates as purchasers
22 of transmission for non-Federal power. BPA draws no distinction between Federal and
23 non-Federal power using the system. An equitable allocation of transmission costs
24 between Federal and non-Federal power is achieved through application of the same rates
25 to the two classes of service. A separate rate case allocation is unnecessary.

1 Second, equitable allocation is demonstrated by the breadth of the settlement and
2 the diversity among the settling parties. The settling parties include the PS and PS full
3 requirements customers; large partial requirements customers that both buy Federal power
4 and wheel large amounts of non-Federal power; large wheeling customers, such as the
5 region's Investor Owned Utilities, which purchase little Federal power; power marketers
6 and independent power producers. The TS would not have been able to obtain the
7 agreement of such a large group of customers with such diverse interests unless the
8 proposed allocation of costs was equitable.

9 *Q. Does this conclude your testimony?*

10 *A. Yes.*

SETTLEMENT AGREEMENT
Bonneville Power Administration 2008 Transmission Rate Case

The undersigned signatories to this Settlement Agreement hereby agree to the following:

1. In the Bonneville Power Administration (BPA) 2008 Transmission Rate Case (Rate Case), BPA Transmission Services (TS) will submit a proposal (Initial Proposal) to establish rates for FYs 2008-2009 (Rate Period) as shown in Attachment 1.
2. The Initial Proposal will also include the following changes to existing rate schedules and no other changes:
 - a. Formula rates for Formula Power Transmission Rate FPT-08.1 and FPT-08.3, Integration of Resources (IR) Rate, Reactive Supply and Voltage Control from Generation Sources Service, and the Short Distance Discount Rate in the IR rate schedule, as shown in Attachment 2.
 - b. The deletion of “a. FY 2006 (October 2005 through September 2006)” in section 1 of the Regulation and Frequency Response Service rate schedules in both the Ancillary Services Rates and the Control Area Services Rates, and the deletion of section 1.b of such rate schedules.
 - c. The deletion of section II.E.1.a. from the Operating Reserve – Spinning Reserve Service rate schedule in the Ancillary Services Rates and section III.C.1.a from the Operating Reserve – Spinning Reserve Service rate schedule in the Control Area Services Rates, and their replacement with the following language:
 - a. Spinning Reserve Service**
 - (i) For customers that elect to purchase Operating Reserve – Spinning Reserve Service from BPA Transmission Services, the rate shall not exceed 7.93 mills per kilowatthour.
 - (ii) For customers that are required to purchase Operating Reserve – Spinning Reserve Service from BPA Transmission Services because they defaulted on their self-supply or third-party supply obligations, the rate shall be 9.12 mills per kilowatthour.
 - d. The deletion of section II.F.1.a from the Operating Reserve – Supplemental Reserve Service rate schedule in the Ancillary Services Rates and section III.D.1.a from the Operating Reserve – Supplemental Reserve Service rate schedule in the Control Area Services Rates, and their replacement with the following language:

a. Supplemental Reserve Service

(i) For customers that elect to purchase Operating Reserve – Supplemental Reserve Service from BPA Transmission Services, the rate shall not exceed 7.93 mills per kilowatthour.

(ii) For customers that are required to purchase Operating Reserve – Supplemental Reserve Service from BPA Transmission Services because they defaulted on their self-supply or third-party supply obligations, the rate shall be 9.12 mills per kilowatthour.

e. The deletion of the reservation fee for deferred service in the PTP, Southern Intertie (IS), and Montana Intertie (IM) rate schedules and in section II.E of the General Rate Schedule Provisions. The reservation fee for an extension of the Service Commencement Date will be retained.

f. The deletion of the following language in section IV.D. of the PTP rate schedule; section IV.C of the IS rate schedule; section IV.C of the IM rate schedule; section A.2.a. of the Scheduling, System Control and Dispatch Service rate schedule; and section B.2.a. of the Reactive Supply and Voltage Control From Generation Sources Service rate schedule:

If Hourly Non-Firm PTP Transmission Service is Curtailed or Interrupted, the Transmission Customer will be charged for actual use during the hour, and not Reserved Capacity. If the Curtailment originates from conditions on another Transmission Provider's Transmission System, no adjustment will be made to the Reserved Capacity billing factor.

and its replacement by the following language:

i. If the need for Curtailment is caused by conditions on the Federal Columbia River Transmission System, the Billing Factor will be as follows:

a. If Hourly Non-Firm PTP Transmission Service is Curtailed or Interrupted before the close of the hourly non-firm scheduling window, the Billing Factor will be the Reserved Capacity minus the curtailed capacity.

b. If Hourly Non-Firm PTP Transmission Service is Curtailed or Interrupted after the close of the hourly non-firm scheduling window, the Billing Factor will be the Transmission Customer's actual schedule in the hour.

ii. If the need for Curtailment is caused by conditions on another transmission provider's transmission system, the Billing Factor will be the Reserved Capacity.

g. The addition of the following language to section 2 of the Scheduling, System Control and Dispatch Service rate schedule and the Reactive Supply and Voltage Control From Generation Sources Service rate schedule:

For Transmission Customers taking Point-to-Point Transmission Service (PTP, IS, and IM rate schedules) that are subject to a UIC in a billing month, the Billing Factor for the billing month shall be the Billing Factor calculated above plus the UIC Billing Factor calculated under section II.G.2.a. of the GRSPs.

For Transmission Customers taking Network Integration Transmission Service that are subject to a UIC in a billing month, the Billing Factor for the billing month shall be the Billing Factor calculated above plus the UIC Billing Factor calculated under section II.G.2.b. of the GRSPs.

h. The addition of the following language at the end of the second sentence of section I of the PTP rate schedule:

and to customers taking Conditional Firm (CF) Transmission Service, if BPA adopts CF Transmission Service.

3. During the Rate Period, TS does not intend to compensate BPA Power Services (PS) or third parties for generation-supplied reactive power (GSR). Notwithstanding any provision of the Initial Proposal terminating such compensation and notwithstanding paragraph 7 of this Settlement Agreement, this Settlement Agreement is not intended to, and does not, resolve the dispute between BPA and certain signatories regarding such signatories' right to compensation for GSR. By executing this Settlement Agreement, no signatory shall be deemed to have waived or relinquished its position on any issue relating to compensation for GSR that is raised in Docket No. WP-07, including but not limited to the treatment of costs related to GSR provided by synchronous condensers.

4. The signatories recognize that during the Rate Period BPA may conduct a rate case for the purpose of adopting a rate for generation regulation service and/or generation following service.

5. Financial Reserves

a. BPA expects to use, and the signatories will not object to or otherwise challenge BPA's use of, \$15 million recorded as Transmission reserves in each year of the Rate Period (for a total of \$30 million) as a funding source for transmission capital programs. Nothing in this Settlement Agreement prohibits the signatories from objecting to or otherwise challenging, in a forum other than the Rate Case, the level of Transmission capital programs, the specific projects included in capital programs, or the level of expenditures for any project(s); and

b. In the calculation and presentation of the revenue requirement in the Rate Case, BPA will model the use of Transmission reserves as a funding source for transmission capital programs as described in paragraph 5.a.

6. BPA, BPA's Slice customers and Northwest Requirements Utilities ("NRU") executed an agreement settling litigation and other disputes relating to certain Slice true-up adjustments, Agreement No. 07PB-12273 (the "Slice Settlement Agreement"), effective November 22, 2006. BPA, BPA's Slice customers and NRU agree that the following process satisfies BPA's procedural and public process requirements regarding the Debt Optimization Program (DOP) and Debt Service Reassignment (DSR) demonstration under the Slice Settlement Agreement: (1) for transmission rates at the 2007 annual meeting and (2) for the Rate Case:

a. At the annual DOP and DSR meeting planned for January 2007, the demonstration for transmission rates will be addressed separately from the demonstration for power rates. BPA will demonstrate that transmission rates are no higher with the DOP than they would have been in the absence of the DOP (which includes DSR). BPA will demonstrate achievement of this principle by running and presenting results from repayment studies that compare a base transmission repayment study that includes all debt management activities completed as of September 30, 2006, with a transmission repayment study that includes new DOP and DSR projections for the current and upcoming fiscal years ("Transmission Rate DOP Demonstration"). Time will be made available at the January 2007 meeting for the BPA Slice customers, NRU and other interested parties to discuss with BPA the information presented at the meeting, to ask questions about such information and to state their concerns and information needs. Any requests for information from BPA shall be limited to the facts of the Transmission Rate DOP Demonstration, such as how it was constructed, the sources of data, assumptions and bases for assumptions, how conclusions were derived, description of methods used in the repayment studies or affirmative reasons for using these methods. BPA will not provide information to requests that seek privileged or proprietary information, information that is unduly burdensome to produce, or that requires BPA to perform any new studies or perform or run any different analysis. A follow up meeting may be scheduled, if necessary, no later than 8 days following the January 2007 DOP Demonstration meeting to respond to requests for information made at the first meeting, and to further address concerns regarding the Transmission Rate DOP Demonstration. No later than 15 days after the first meeting in January 2007, each of BPA's Slice customers and NRU shall notify BPA, in writing, that it either has no objections and is satisfied with the Transmission Rate DOP Demonstration and agrees to the stipulation described below, or has concerns about the Transmission Rate DOP Demonstration that remain unresolved.

b. For purposes of the Rate Case, BPA's Initial Proposal shall include (1) the Transmission Rate DOP Demonstration made available at the January, 2007 meeting(s); (2) language in the Transmission Revenue Requirement Study in accordance with the Slice Settlement Agreement, Exhibit D, Section B (Attachment 3), that clearly and transparently describes the DOP-related costs for which transmission rates are being set; and (3) testimony that draws attention to that language.

- i. If each of BPA's Slice customers and NRU have no objections and are satisfied with the Transmission Rate DOP Demonstration, then all of BPA's Slice customers and NRU agree to (1) stipulate to such conclusion, (2) move to enter the stipulation into the Rate Case record at the prehearing conference, and (3) request an order from the Hearing Officer directing that no party direct case testimony be submitted on the Transmission Rate DOP Demonstration during the Rate Case by any rate case party, or
- ii. If any of BPA's Slice customers or NRU have concerns that remain unresolved ("Objecting Party(ies)"), then the Objecting Party shall have the opportunity to submit direct case testimony on the Transmission Rate DOP Demonstration. If an Objecting Party submits direct case testimony, then other rate case parties will also be afforded the opportunity to submit direct case testimony on the Transmission Rate DOP Demonstration. BPA and all rate case parties shall have the right to submit rebuttal testimony on any party direct case testimony on

the Transmission Rate DOP Demonstration, and BPA and all rate case parties will have the opportunity to cross examine the BPA, Objecting Party or other rate case party witnesses on that topic, and all rate case parties may submit briefs and participate in oral argument. The rate case parties agree to limit any direct case testimony, rebuttal testimony, cross examination of witnesses, and briefs and oral arguments to the Transmission Rate DOP Demonstration issue, and will not contest any other aspects of the Initial Proposal presenting testimony on any other provisions agreed to under this Settlement Agreement unless such contest is otherwise permitted pursuant to the other paragraphs of this Settlement Agreement.

c. In the application to the Federal Energy Regulatory Commission (FERC) seeking confirmation and approval of the proposed 2008 Transmission Rates, BPA will draw FERC's attention to the Revenue Requirement Study language regarding the Transmission Rate DOP Demonstration.

d. Compliance by BPA with the foregoing provisions of this paragraph 6 shall satisfy the procedural and public process requirements of BPA under the Slice Settlement Agreement regarding BPA's Transmission Rate DOP Demonstration for the 2007 annual meeting and the Rate Case and FERC filing obligations, and does not establish any precedent for BPA's demonstration obligation in any subsequent year or BPA transmission rate case.

e. All other signatories to this Settlement Agreement agree to not oppose this paragraph 6 or any actions by BPA, any Slice customer, NRU or any other rate case party taken in accordance with this paragraph 6. BPA will undertake all necessary and appropriate actions to defend the commitments made under this paragraph, before FERC and elsewhere.

7. Except as provided in paragraph 6, the signatories agree not to contest any aspect of the Initial Proposal, including but not limited to the level of any transmission or ancillary services or control area services rate or any of the elements thereof, the methodologies and principles used to derive such rates, or any aspect of the rate schedules or general rate schedule provisions, or any other issue that is included in this Settlement Agreement, and further agree to waive their rights to cross-examination and discovery with respect thereto. If, however, TS does not submit an Initial Proposal consistent with the terms of this Settlement Agreement, the signatories may contest any aspect of the Initial Proposal.

8. Revised Attachment K (Attachment 4 to this Settlement Agreement) is intended to replace the existing Attachment K in BPA's Open Access Transmission Tariff. The signatories agree not to contest any aspect of the revised Attachment K and waive their rights in the Rate Case to cross-examination and discovery with respect thereto. If no party in the Rate Case contests any aspect of the revised Attachment K, BPA will submit such revised Attachment K to the FERC for approval as an amendment to BPA's Open Access Transmission Tariff. Nothing in this Settlement Agreement limits a signatory's right to argue in an appropriate forum that, when making curtailments, BPA has not curtailed on a non-discriminatory basis the transaction(s) that effectively relieve the constraint.

9. BPA expects to implement a "Within Hour Reliability Redispatch Pilot Program," (Pilot Program) in coordination with the Congestion Management Steering Committee, to acquire redispatch from federal and non-federal generators in the summer of 2007. As soon as

practicable after the conclusion of the Pilot Program, BPA will hold a public meeting or meetings to evaluate the Pilot Program and redispatch under Attachment K. If BPA concludes, based upon the evaluation of the Pilot Program, that the continued participation of non-federal entities is appropriate, BPA will include non-federal generators in any follow-on redispatch program, and will consider including non-federal entities other than generators. BPA will also consider whether it is appropriate to revise Attachment K, including whether to include non-federal entities.

10. For redispatch and curtailment during the Rate Period:

- a. TS will include in its revenue requirement for the Rate Period \$4.5 million per year for expected payments for redispatch of generation under Attachment K or its successor and under any reliability redispatch program.
- b. For each request for redispatch that TS makes under Attachment K, PS will provide TS a bid price for providing the redispatch. If TS accepts the bid price and PS provides the redispatch, TS will pay PS the bid price.
- c. For all requests for redispatch or curtailment made on or after June 1, 2007, TS will track and post on its website the following information:
 - (i) For redispatch provided by PS or a non-federal entity: type of redispatch (Discretionary, Emergency, NT Firm, Pilot Program or other program), date, hour starting and hour ending, megawatts, source of increase, source of decrease, and reason triggering the redispatch request including constrained flowgate, as soon as practicable after the end of each month. In addition:
 - (a) For the quarter beginning October 1, 2007, and for each quarter thereafter, TS will post, no later than 30 days after the end of such quarter, the inc and dec price for each redispatch provided under Attachment K; provided *however*, BPA shall not be required to explain the basis of the price for any redispatch under Attachment K.
 - (b) For requests for redispatch on or after June 1, 2007, under the Pilot Program or any other redispatch programs other than Attachment K, TS will post pricing information as required by such program.
 - (ii) For curtailments requested by TS of any transmission customer: date, hour starting and hour ending, megawatts curtailed, curtailment location (Network Flowgates, external interconnections and/or Interties), summary of Curtailment Calculator if applicable, and reason(s) for triggering the curtailment including constrained flowgate, as soon as practicable after the end of each month.
- d. If, during FY 2008, the cumulative costs paid by TS for redispatch reach \$2.25 million, within 30 days TS will schedule a public meeting or meetings to review TS's implementation of redispatch including the data listed in paragraph 10.c.i.; provided *however*, BPA shall not be required to explain the basis of the price for any redispatch under Attachment K. Workshops for the transmission rate case for the FY 2010 -11 period will include a review of redispatch events, payment methodologies and payments subject to the provisions of paragraph 10.c.i.a. above.

11. On or before October 1, 2007, BPA will post notice of a potential Spill Condition on the TS website no later than 11am PT on preschedule day. BPA will have no liability for the failure of the potential spill condition to materialize or for the materialization of spill conditions that are not forecasted at preschedule. BPA will continue to use the declared spill posted after the fact for billing purposes.

12. The signatories will move the Hearing Officer to specify a date within a reasonable time of the prehearing conference by which (a) any party to the Rate Case that has not executed this Settlement Agreement must object to the settlement proposed in this Settlement Agreement and identify each issue such rate case party chooses to preserve for hearing, or (b) NRU or any Slice customer that has objected to the Transmission Rate DOP Demonstration pursuant to paragraph 6 and that is a party to the Rate Case must identify each issue on which such rate case party will file direct testimony or be deemed to have waived any right to object to the settlement proposal or to the Transmission Rate DOP Demonstration or preserve issues for hearing. If no rate case party objects to the settlement proposal and preserves issues for hearing, and neither NRU nor any Slice customer has preserved an issue for hearing, TS shall propose to the Administrator that he adopt the Initial Proposal in its entirety and BPA shall submit the revised Attachment K to FERC as a proposed amendment to BPA's Open Access Transmission Tariff. In the event that any rate case party does so object to the settlement proposal, TS may, but shall not be required to, revise the Initial Proposal as it believes appropriate and BPA may, but shall not be required to, revise Attachment K as it believes appropriate, either after such rate case party states its objection or after parties file their direct testimony. If TS decides to revise the Initial Proposal, or if BPA decides to revise Attachment K, the parties will meet promptly to discuss a new procedural schedule that they will propose to the Hearing Officer, allowing TS or BPA, as the case may be, a reasonable time in which to present a revised proposal and the parties a reasonable time to respond to such revised proposal. In that event, the signatories may contest any aspect of the revised proposal.

In the event that no rate case party objects to the settlement proposal, but either NRU or any Slice customer has preserved an issue for hearing, TS may, but shall not be required to, revise the Initial Proposal as it believes appropriate, either after such rate case party states its objection or after such rate case party files its direct testimony. If TS decides to revise the Initial Proposal, the rate case parties will meet promptly to discuss a new procedural schedule that they will propose to the Hearing Officer, allowing TS a reasonable time in which to present a revised proposal and the parties a reasonable time to respond to such revised proposal. In such event, the signatories may contest any aspect of the revised proposal related to the Transmission Rate DOP Demonstration. If TS does not revise its Initial Proposal, the parties will propose to the Hearing Officer a procedural schedule that will allow the objecting party and other rate case parties to file testimony on the Transmission Rate DOP Demonstration.

13. If TS submits an Initial Proposal consistent with the terms of this Settlement Agreement, and does not submit a revised proposal pursuant to paragraph 12, the signatories agree not to enter any evidence into the Rate Case or make any argument in the Rate Case contesting any provision of section 36 of BPA's current Open Access Transmission Tariff. If the Administrator establishes transmission rates consistent with the Initial Proposal and submits such rates to FERC for confirmation and approval, the signatories agree not to make any such argument regarding section 36 of BPA's Open Access Transmission Tariff before FERC or any judicial forum during the Rate Period.

14. Nothing in this Settlement Agreement is intended in any way to alter the Administrator's authority and responsibility to periodically review and revise the Administrator's transmission rates or the signatories' rights to challenge such revisions.

15. If the Administrator establishes transmission rates consistent with the Initial Proposal and submits such rates to FERC for confirmation and approval under the applicable standards of the Northwest Power Act or as a reciprocity filing, the signatories agree not to challenge such confirmation and approval of such rates or any element thereof, including the methodologies and principles used to establish such rates, or support or join any such challenge, and agree not to challenge such rates or any element thereof, including the methodologies and principles used to establish such rates, in any judicial forum. The signatories further agree not to contest the approval by FERC of the revised Attachment K, and if FERC approves the revised Attachment K without change, the signatories agree not to challenge such approval or any element of Attachment K in any judicial forum.

The signatories agree that in the usual course any rate case party has the right to argue to FERC, based on BPA's Transmission Rate DOP Demonstration, that FERC should deny confirmation and approval of BPA's transmission rates on the ground that the rates violate one or more of the statutory ratemaking standards in section 7(a) of the Northwest Power Act, and to challenge such rates in any appropriate judicial forum. If, however, the Administrator adopts the rates proposed in the Initial Proposal, the signatories agree not to bring any such contest or challenge to such rates.

16. The signatories agree that they will not assert in any forum that anything in this Settlement Agreement or any action with regard to this Settlement Agreement taken or not taken by any signatory, the Hearing Officer, the Administrator, FERC, or a court, creates or implies any procedural or substantive precedent or creates or implies agreement to any underlying principle or methodology, or creates any precedent under any contract between BPA and any signatory.

17. By executing this Settlement Agreement, no signatory waives any right to pursue BPA Open Access Transmission Tariff (OATT) dispute resolution procedures consistent with BPA's OATT (including without limitation any complaint concerning implementation of BPA's OATT) or any claim that a particular charge, methodology, practice or rate schedule has been improperly applied.

18. Nothing in this Settlement Agreement amends any contract or modifies rights or obligations or limits the remedies available thereunder.

This Settlement Agreement may be executed in counterparts.

_____ for

Party

Date _____

Attachment 1

Summary of Rate Levels

	Units	Proposed 2008 Rates	
		FPT-08.1	FPT-08.3
FPT-08.1 and FPT-08.3			
M-G Distance.....	\$/kW-mi-yr	0.0587	0.0587
M-G Miscellaneous Facilities.....	\$/kW-yr	3.35	3.35
M-G Terminal.....	\$/kW-yr	0.68	0.68
M-G Interconnection Terminal.....	\$/kW-yr	0.61	0.61
S-S Transformation.....	\$/kW-yr	6.31	6.31
S-S Interconnection Terminal.....	\$/kW-yr	1.73	1.73
S-S Intermediate Terminal.....	\$/kW-yr	2.44	2.44
S-S Distance.....	\$/kW-mi-yr	0.5772	0.5772
Overall FPT Rate.....	\$/kW-yr	15.93	15.93
Overall FPT Rate.....	\$/kW-mo	1.327	1.327
 IR-08			
Demand.....	\$/kW-mo	1.498	
 NT-08			
Base Rate (\$/kW-mo).....	\$/kW-mo	1.298	
Load Shaping (\$/kW-mo).....	\$/kW-mo	0.367	
Base plus Load Shaping.....	\$/kW-mo	1.665	
 PTP-08			
Demand.....	\$/kW-mo	1.298	
Daily Block 1 (day 1 thru 5).....	\$/kW-day	0.060	
Daily Block 2 (day 6 and beyond).....	\$/kW-day	0.046	
Hourly.....	mills/kWh	3.74	
 Utility Delivery			
Demand.....	\$/kW-mo	1.119	
 IS-08			
Demand.....	\$/kW-mo	1.293	
Daily Block 1 (day 1 thru 5).....	\$/kW-day	0.060	
Daily Block 2 (day 6 and beyond).....	\$/kW-day	0.045	
Hourly.....	mills/kWh	3.72	
 IM-06			
Demand.....	\$/kW-mo	1.312	
Daily Block 1 (day 1 thru 5).....	\$/kW-day	0.061	
Daily Block 2 (day 6 and beyond).....	\$/kW-day	0.043	
Hourly.....	mills/kWh	3.78	
 Intertie East			
IE-06.....	mills/kWh	1.13	

Attachment 1

Summary of Rate Levels

	Units	Proposed 2008 Rates
Power Factor Penalty Charge		
Demand -- Lagging.....	\$/kVAr-mo	0.28
Demand -- Leading.....	\$/kVAr-mo	0.24
Scheduling Control and Dispatch ('08)		
Demand.....	\$/kW-mo	0.203
Daily Block 1 (day 1 thru 5)....	\$/kW-day	0.010
Daily Block 2 (day 6 and beyond).	\$/kW-day	0.006
Hourly.....	mills/kWh	0.59
Generation Supplied Reactive ('08)		
Demand.....	\$/kW-mo	0.000
Daily Block 1 (day 1 thru 5)....	\$/kW-day	0.000
Daily Block 2 (day 6 and beyond).	\$/kW-day	0.000
Hourly.....	mills/kWh	0.00
Regulation and Frequency Response		
Hourly.....	mills/kWh	0.33
Energy Imbalance		
Hourly.....	mills/kWh	100.00
Operating Reserves		
Spinning.....	mills/kWh	7.93
Supplemental.....	mills/kWh	7.93
Operating Reserves -Default Rate		
Spinning.....	mills/kWh	9.12
Supplemental.....	mills/kWh	9.12

Attachment 2

Formula Rates

FPT-08.1 Formula Power Transmission Rate

*** Updated the denominator of the formula rate which is the average FPT rate based on FY08-09 data

The Main Grid and Secondary System charges are calculated each quarter beginning October 2007 according to the following formula:

$$\left(1 + \frac{\text{GSR}_q}{\$1.327/\text{kW}/\text{mo}}\right) * \text{FPT Base Charges}$$

Where:

- GSR_q = The ACS-08 Reactive Supply and Voltage Control From Generation Sources Service Rate for Long-Term Firm PTP Transmission Service and NT Service, section II.B.1.a., that is effective for the quarter for which the FPT rate is being calculated, in \$/kW/mo.
- FPT Base Charges = The following annual Main Grid and Secondary System charges:

FPT-08.3 Formula Power Transmission Rate

***Included formula rate for Main Grid and Secondary System charges for FPT X.3

The Main Grid and Secondary System charges are calculated each quarter beginning October 2007 according to the following formula:

$$\left(1 + \frac{\text{GSR}_q}{\$1.327/\text{kW}/\text{mo}}\right) * \text{FPT Base Charges}$$

Where:

- GSR_q = The ACS-08 Reactive Supply and Voltage Control From Generation Sources Service Rate for Long-Term Firm PTP Transmission Service and NT Service, section II.B.1.a., that is effective for the quarter for which the FPT rate is being calculated, in \$/kW/mo.
- FPT Base Charges = The following annual Main Grid and Secondary System charges:

Attachment 2

Formula Rates

IR-08 Integration of Resources Rate

***Updated the denominator of the formula rate which is the sum of the base IR rate minus the SCD rate

B. SHORT DISTANCE DISCOUNT (SDD) RATE

For Points of Integration (POI) specified in the IR agreement as being short-distance POIs, for which Network facilities are used for a distance of less than 75 circuit miles, the monthly rate shall be the sum of:

1. \$0.203/kW/mo; and
2. ACS-08 Reactive Supply and Voltage Control From Generation Sources Service Rate for Long-Term Firm PTP Transmission Service and NT Service, section II.B.1.a., effective for the quarter for which the IR rate is being calculated, in \$/kW/mo; and
3. $(0.6 + (0.4 \times \text{transmission distance}/75)) \times \$1.295/\text{kW/mo}$

Where:

The transmission distance is the circuit miles between a designated POI for a generating resource of the customer and a designated Point of Delivery serving load of the customer. Short-distance POIs are determined by BPA-TBL after considering factors in addition to transmission distance.

REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES SERVICE

***Removed payments to PS in formula and updated bd

a. Long-Term Firm PTP Transmission Service and NT Service

The rate, in dollars per kilowatt per month (\$/kW/mo), shall not exceed:

$$\frac{4(N_q + U_{q-1} + Z_{q-1})}{bd - 4S_q}$$

Where:

- bd = 407,916 MW-mo = Average of forecasted FY 2008 and FY 2009 GSR Service billing determinants. Each annual billing determinant is the sum of the 12 monthly billing determinants.
- N_q = Non-federal GSR cost to be paid by BPA-TBL under a FERC-approved rate during the relevant quarter, as anticipated prior to the quarter. (\$)
- U_{q-1} = Payments of non-federal GSR cost made in the preceding quarter(s) that were not included in the effective rate for the

preceding quarter(s). Any refunds received by BPA-TBL would reduce this cost. U_{q-1} is a true-up for any deviation of non-federal GSR costs from the amount used in a previous quarter's GSR rate calculation. For calculating the GSR rate effective October 1, 2007, U_{q-1} is zero. (\$)

S_q = Reduction in effective billing demand for approved self-supply of reactive during the relevant quarter, as anticipated prior to the quarter. (MW-mo)

Z_{q-1} = A dollar true-up for under- or overstatement of reactive self-supply in rate calculations for the preceding quarter(s). For calculating the GSR rate effective October 1, 2007, Z_{q-1} is zero. Z_{q-1} will be calculated by multiplying the under- or overstated megawatt amount of self-supply by the GSR rate that was effective during the quarter of self-supply deviation. (\$)

“Relevant quarter” refers to the 3-month period for which the rate is being determined.

Attachment 3

Slice Settlement Agreement, Exhibit D, Section B

B. BPA Commitments Concerning the Debt Optimization Program

1. BPA, working with Energy Northwest (“EN”), has developed the DOP to increase its available borrowing authority from the United States Treasury using proceeds accomplished as a result of EN bond refinancings.

2. One of the fundamental principles of the DOP, created at the time Debt Service Reassignment (DSR) (described more fully in Section B.4 below) was developed, is that the rates of each of BPA’s business lines (Transmission Business Line (“TBL”) and Power Business Line (“PBL”)) are no higher with the DOP than they would have been in the absence of the DOP. BPA will manage the DOP in conformance with, and to achieve realization of, this principle, notwithstanding that the mechanics of recording the DOP transactions and understanding their impact on rates are complex. BPA annually demonstrates achievement of this principle by running repayment studies that compare a base repayment study that includes all debt management activities completed to date with a DOP repayment study that includes new DOP projections for the upcoming years, the results of which comply with such principle. BPA will continue to so demonstrate achievement of this principle annually and in the next and subsequent general wholesale power and transmission rate proceedings so long as new DOP refinancings occur. The demonstration for power rates will be made in the power rate case, and for the transmission rates in the transmission rate case. The Participants agree that for purposes of making its demonstration in the next general transmission rate proceeding, BPA will introduce the information for the first time in its rebuttal case, and the Administrator will direct the hearing officer in writing to provide parties a reasonable period of time to respond to such information with surrebuttal testimony and, if requested by any party (including BPA), a further reasonable period of time to respond to such surrebuttal with sur-surrebuttal testimony. Furthermore, BPA will adhere to this principle and will not move away from adherence to this principle without a public review and comment period, consistent with Section C of this MOU and any requirements of law.

3. In a letter to the EN Executive Board on December 11, 2000, BPA's Administrator stated that the success of the DOP in achieving its objectives depends both on the successful completion of the extension of the Columbia Generating Station debt and on the disciplined application of the proceeds from that action by BPA to amortize more Federal debt than would otherwise be scheduled for amortization. The Administrator gave the EN Executive Board BPA's commitment that this increased amortization would equal the reduction in BPA's net billing obligation resulting from debt management actions under this program on an annual basis and that only under extreme financial pressure would BPA consider deviating from the actions required to implement this program. These assurances also apply to extensions of Projects 1 and 3 debt. BPA will adhere to this principle and will not move away from adherence to this principle without a public review and comment period, consistent with Section C of this MOU and any requirements of law.

4. Customers have expressed a desire for assurance that BPA match, by business line, the benefit received (prepayment of Federal debt) with the obligation incurred (issuance of new EN debt). BPA has researched and believes it has implemented the appropriate accounting treatment and rate case methodologies to ensure that costs are recovered (per the repayment study) and debt service expense is attributed accurately as reflected in BPA's PBL and TBL income statements, thereby matching, by business line, the benefit received (prepayment of Federal debt allocated to a business line) with the obligation incurred (issuance of new EN debt) under DOP. When EN debt is issued and there is a resulting benefit to TBL, the original EN debt that was due in that particular year (and refinanced) is considered "paid" by the PBL. The original debt is no longer in existence due to the refinancing and the TBL responsibility for paying the debt service on the new debt is reflected in the accounting and rate case methodologies mentioned above. This all describes DSR, which is a component of DOP. References in this MOU to DOP shall include DSR, unless the context clearly requires otherwise.

BPA intends and will act to ensure that any EN debt service assigned to TBL through DSR cannot be later reassigned or reallocated to PBL customers during the term of such debt, consistent with law and contract. While net billing constraints, priority of payment requirements, and BPA ratemaking requirements to assure total cost recovery make it possible—though a very remote possibility—that BPA could find itself in a position unable to fulfill this commitment, BPA will seek to prevent that and, if it cannot, will inform the Participants consistent with Section C of this MOU. BPA does not now see any reason why it could or would not continue to set transmission rates to recover transmission costs and power rates to recover power costs, *i.e.*, it does not anticipate being in the situation where a transmission cost (*e.g.*, in this context, obligations resulting from DSR) would need to be reallocated or reassigned to PBL for recovery, but in any event BPA will utilize the Communication Protocols set forth in Section C of this MOU to keep customers apprized of any change in circumstances.

Under BPA's priority of payment requirements, obligations resulting from DSR must be repaid before BPA repays Federal interest and amortization. That priority of payments makes it even more unlikely that obligations resulting from

DSR would ever need to be allocated or assigned from TBL to PBL in order to assure total BPA cost recovery. However, in the event BPA did find itself in the situation where obligations resulting from DSR needed to be allocated or assigned back from TBL to PBL in order to assure total BPA cost recovery, BPA commits to treat the allocation or assignment in a manner where the costs would be tracked and the PBL would be fully compensated for its recovery of the TBL cost. The means of compensation would be proposed in a rate case and would be subject to review and comment by parties in that rate case, as addressed below.

5. In each general BPA PBL and TBL wholesale rate proceeding conducted while EN bonds refinanced under DOP, including EN debt service reassigned under DSR to TBL, are still outstanding, BPA will include the language of Sections B.1, B.2, B.3 and B.4 above in its Revenue Requirement Study, will clearly and transparently describe the DOP-related costs for the business line (PBL or TBL) for which rates are then being set, and will draw attention to that language in its testimony, except that the references to "Section C of this MOU" will be changed to give a complete citation to this MOU. After BPA's rate proceeding, and when BPA files its proposed rates with the Federal Energy Regulatory Commission (FERC), BPA will draw FERC's attention to such Revenue Requirement Study language in its cover letter. BPA will take all necessary and appropriate actions to defend the commitments made in this Section B, before FERC and elsewhere. In the event BPA were to propose to allocate or assign obligations resulting from DSR from TBL to PBL for recovery, BPA agrees that allocation or assignment must be implemented through a section 7(i) hearing and that it will not argue or otherwise assert that the Participant(s) are precluded from arguing or otherwise asserting in any such section 7(i) rate proceeding and thereafter in any proceeding before the FERC for approval of BPA wholesale rates, and thereafter in any proceeding for judicial review of BPA's rates, that BPA's proposal violates the equitable allocation standard or other standard of law.

Attachment 4

Attachment K: Procedures for redispatch of the federal hydro system

This attachment establishes parameters and procedures for the period October 1, 2007, through September 30, 2009, for redispatch of the federal hydro system by BPA's Power Services (PS) at the request of BPA's Transmission Services (TS). TS may request redispatch during any period when TS determines that a transmission constraint exists on the Transmission System and such constraint may impair the reliability of the system. TS may not request redispatch under this Attachment K to make additional firm or non-firm transmission sales.

Definitions

Under this Attachment K, redispatch is the intentional incrementing or decrementing of generating units or projects by PS, or the limitation of generation at specific locations by PS, at the request of TS. There are three types of redispatch under this Attachment K:

- A. Emergency Redispatch is redispatch requested by TS upon declaration of a "system emergency" as that term is defined by the North American Electric Reliability Council (NERC).
- B. NT Firm Redispatch is redispatch requested by TS for the purpose of maintaining firm network transmission (NT) schedules after TS has curtailed non-firm point-to-point (PTP) schedules and secondary network schedules in a sequence consistent with the NERC curtailment priority. For NT Firm Redispatch, TS shall request redispatch from PS and shall curtail firm PTP schedules in amounts proportionate to the non-secondary NT and firm PTP flows on the affected transmission flowgates at the time of the request.
- C. Discretionary Redispatch is redispatch requested by TS prior to its curtailment of any firm or non-firm PTP schedules or secondary NT schedules for the purpose of avoiding or ameliorating curtailments.

Provisions

1. PS must comply with requests for Emergency Redispatch even if PS must violate non-power constraints.
2. PS must comply with requests for NT Firm Redispatch to the extent that it can do so without violating non-power constraints.
3. PS may respond to requests for Discretionary Redispatch by offering, at each generating unit or project, either no redispatch or any amount of redispatch up to the amount requested at each generating unit or project.
4. TS may request redispatch for the following maximum time periods:
 - a) If TS requests redispatch before twenty minutes after the hour, TS may request redispatch only for the remainder of the hour.
 - b) If TS requests redispatch at or after twenty minutes after the hour, TS may request redispatch for the remainder of the hour and the next hour.
 - c) If TS requests Discretionary Redispatch and, before the expiration of the period for which it has requested Discretionary Redispatch, requests NT Firm Redispatch at the same generating units or projects, the amount of Discretionary Redispatch, if any, that PS provided shall be treated as having been provided in response to the request for NT Firm Redispatch for purposes of calculating the proportionate amounts of non-secondary NT Redispatch and firm PTP

curtailments that must take place in response to the OTC violation that resulted in the need for redispatch.

5. In response to any redispatch request, PS may provide redispatch through purchases and/or sales rather than by changing federal generation levels. PS will inform TS at the time of the request if it intends to implement the redispatch through purchases.
6. PS may respond to a TS request for redispatch specific to Network Load located in other control areas through transmission purchases, federal redispatch and/or power purchases.

Attachment B

Entities That Have Signed the 2008 Transmission Rate Case Settlement Agreement as of February 1, 2007

PUBLICS

Individual:

Ashland, City of – see also NRU
Benton PUD
Clark Public Utilities
Consolidated Irrigation District, Greenacres, WA
Cowlitz Co. PUD
Emerald People's Utility District
Franklin Co PUD
Grant County Public Utility District
Ohop Mutual
Pend Oreille County, PUD No. 1 of
Richland, City of
Seattle City Light
Seattle, Port of
Snohomish PUD
Springfield Utility Board
Tacoma Power
Wahkiakum PUD

Reps

Idaho Energy Authority, Inc. (IDEA)

NRU representing

Ashland, City of,
Benton REA,
Big Bend Electric Co-Operative, Inc.,
Bonners Ferry, City of,
Burley, City of,
Cascade Locks, City,
Central Lincoln PUD
Cheney, City of,
Columbia Basin Electric Co-op,
Columbia Power Cooperative,
Columbia REA
Columbia River PUD,
East End Mutual Electric Col, LTD,
Ferry County PUD #1,
Flathead Electric Cooperative,
Forest Grove, City of,
Glacier Electric Cooperative, Inc.,

Harney Electric Cooperative,
Hermiston Energy Services,
Heyburn, City of,
Hood River Electric Co-op,
Idaho County Light & Power,
Inland Power & Light,
Klickitat County PUD,
Kootenai Electric Cooperative, Inc.,
Lincoln Electric Cooperative, Inc.,
Lower Valley Energy,
McMinnville Water & Light,
Midstate Electric Cooperative,
Mission Valley Power,
Missoula Electric Coop
Modern Electric Water Company,
Monmouth, City of,
Nespelem Valley Cooperative,
Northern Wasco County PUD,
Orcas Power & Light Coop,
Oregon Trail Electric Co-Op,
Peninsula Light,
Ravalli County Electric Coop,
Richland, City of,
Rupert, City of,
Salem Electric,
Skamania County PUD
Surprise Valley Electrification Corp.,
Tanner Electric Cooperative,
Tillamook PUD
United Electric Cooperative,
Vera Water & Power,
Vigilante Electric Cooperative, Inc.,
Wasco Electric Cooperative, and
Wells Rural Electric.
PNGC, representing
Blachly-Lane Electric Coop
Central Electric Coop
Clearwater Power Company
Consumers Power Inc.
Coos Curry Electric
Douglas Electric Coop
Fall River REA Coop
Lane Electric Coop
Lost River Electric Coop
Northern Lights, Inc.
Okanogan Co. Electric Coop

Raft River Rural Electric, Inc.
Salmon River Electric Coop
Umatilla electric Coop
West Oregon Electric Coop.
Public Power Council

WPAG representing

Benton REA,
Clallam County PUD No. 1
The City of Ellensburg,
Grays Harbor PUD No. 1,
Kittitas County PUD No. 1,
Lewis County PUD No. 1,
Mason County PUD No. 1
Mason County PUD No. 3,
Pacific County PUD No. 2,
Peninsula Light Company,
The City of Port Angeles, and
Pierce County Cooperative Power Association, which includes
Alder Mutual Light Co.,
The Town of Eatonville,
Elmhurst Mutual Power & Light Company,
Lakeview Light and Power Co.,
The City of Milton,
Ohop Mutual Light Co
Parkland Light and Water Co., and
The Town of Steilacoom.

Western Montana Electric Generating & Transmission Cooperative, Inc., signing for:

Flathead Electric Coop
Glacier Electric Coop
Lincoln Electric Coop
Missoula Electric Coop
Mission Valley Power
Ravalli County Electric Coop; and
Vigilante Electric Coop
BPA Power Services
BPA Transmission Services

IOUs

Avista Corp
PacifiCorp
Portland General Electric Company
Puget Sound Energy

IPPs/Marketers

Powerex
NIPPC representing
Chehalis Power Generating, LLC
TransAlta Centralia Generation LLC
Calpine Corporation.

INDEX

TESTIMONY OF F. STEVEN KNUDSEN AND JOHN R. WOERNER

Witnesses for Bonneville Power Administration Transmission Services

SUBJECT: REVENUE FORECAST

	Page
SECTION 1. Introduction and Purpose of Testimony.....	1
SECTION 2. Sales Forecast.....	2
SECTION 3. Revenue Forecast.....	8

1 TESTIMONY OF

2 F. STEVEN KNUDSEN AND JOHN R. WOERNER

3 Witnesses for Bonneville Power Administration Transmission Services

4 **SUBJECT: REVENUE FORECAST**

5 **SECTION 1. INTRODUCTION AND PURPOSE**

6 *Q. Please state your name and qualifications.*

7 A. My name is F. Steven Knudsen. My qualifications are stated in TR-08-Q-BPA-
8 04.

9 A. My name is John R. Woerner. My qualifications are stated in TR-08-Q-BPA-07.

10 *Q. What is the purpose of your testimony?*

11 A. The purpose of this testimony is to sponsor and describe Bonneville Power
12 Administration (BPA) Transmission Service's (TS) revenue forecast for Fiscal
13 Years (FYs) 2007-2009.

14 *Q. How is your testimony organized?*

15 A. This testimony is organized in three sections. Section 1 is this introduction.
16 Section 2 describes the development of the sales forecast that is summarized in
17 the Revenue Requirement Study Documentation (Documentation), TR-08-E-
18 BPA-01A, Table 13-1. Section 3 describes the revenue forecast and presents a
19 summary of revenues under current and proposed rates. *Id.* at Table 13-2 and
20 Table 13-3.

1 **SECTION 2. SALES FORECAST**

2 *Q. As a general matter, how is the sales forecast structured?*

3 A. Sales are forecasted for each transmission service TS offers. Sales over the
4 Network segment of the federal transmission system are distinguished from those
5 over the Southern Intertie segment and the Montana Intertie. BPA separately
6 forecasts long-term and short-term sales; and within long-term, contract-demand
7 and load-based sales.

8 *Q. Has use of the transmission system changed since the revenues were forecast for*
9 *the 2006 transmission rate case?*

10 A. Yes. TS has seen an increase in the execution of new, long-term Point-to-Point
11 (PTP) Service Agreements since the revenue forecast was developed for the 2006
12 transmission rate case. The most significant increases have been new PTP
13 agreements delivering power to the Southern Interties for delivery into California.
14 The addition of new generation in BPA's control area has also fueled the increase
15 in long-term transmission service contracts. In addition, customers have been
16 rolling over existing long term transmission service agreements as those
17 agreements expire, effectively renewing or extending service.

18 *Q. What categories of sales are forecast?*

19 A. The categories of sales forecast for services provided under BPA's Open Access
20 Transmission Tariff (OATT) are load-based Network Integration (NT) service
21 and contract-demand PTP service. PTP sales can be long-term, for one or more
22 years of service, or short-term, for less than one year. TS offers PTP service on
23 the Network, Southern Intertie, and Montana Intertie segments of the federal

1 transmission system. Sales are also forecast for long-term service on the Network
2 segment of the transmission system that is provided under legacy, contract-
3 demand based Formula Power Transmission (FPT) and Integration of Resources
4 (IR) contracts. We expect that these legacy contracts will convert to PTP service
5 when they expire. Utility Delivery Charge and ancillary services sales are also
6 forecasted.

7 *Q. How is the NT sales forecast developed?*

8 A. NT sales are forecast from point of delivery (POD) load forecasts. The aggregate
9 of these forecasts comprises BPA's NT Network Load. The POD load forecasts
10 are based on an average of NT customers' historical POD billing data for the
11 period FY02-FY06. These historical data are escalated using 2004 BPA White
12 Book expected growth rates from 2006 to 2011 by customer class. Peak load
13 forecasts for federal agencies, non-generating publics, and generating publics
14 from the White Book Capacity Table A.1 ("Total Retail Loads") were used.
15 Overall, peak loads of customers purchasing NT service are expected to increase
16 1.13% per year. Customer-Served Load (CSL) declared in NT contracts is
17 subtracted from the forecast of NT Network Load to produce the NT Base billing
18 determinant shown in Documentation, TR-08-E-BPA-01A, Table 13-1, line 3.
19 The forecast of NT Network Load is used to produce the NT Load Shaping billing
20 determinant and is shown in Documentation, TR-08-E-BPA-01A, Table 13-1, line
21 20.

1 *Q. How is the Utility Delivery Charge sales forecast developed?*

2 A. Utility Delivery Charge sales are those sales served through low-voltage PODs
3 that are assessed the Utility Delivery Charge. The sales forecast is based on the
4 historical POD billing data at low voltage PODs for the period FY02-06. Low-
5 voltage PODs in this context are those PODs where TS owns the transformer and
6 the transformer's low-side voltage is less than 34.5kV. The forecast is shown in
7 Documentation, TR-08-E-BPA-01A, Table 13-1, line 21.

8 *Q. What long-term, contract-demand products does TS sell on the Network segment?*

9 A. FPT, IR, and PTP contracts provide long-term TS Network service that is billed
10 based on transmission demand.

11 *Q. How is the forecast of long-term transmission demand for these products
12 developed?*

13 A. First, we develop a base forecast by summing the transmission demands of each
14 executed PTP, FPT and IR contract that commences service before or during the
15 rate period. These transmission demands are summed for each month of the
16 forecast period extending through the end of the rate period. The transmission
17 demand of each contract with an expiration date prior to the end of the rate period
18 is specified as zero beginning the month after expiration. Thus, the forecast of
19 executed contracts is the base level of future sales secured by contract, assuming
20 no expiring contract is renewed. Documentation, TR-08-E-BPA-01A, Table 13-
21 1, line 5.

22 Second, the base forecast reflects the assumption that all FPT and IR
23 contracts expiring during the rate period will convert to PTP service. The

1 transmission demands of those converted contracts are summed and added to the
2 forecast. *Id.* at Table 13-1, lines 6 and 7. Third, for each expiring PTP contract
3 that is eligible to rollover its service pursuant to section 2.2 of the OATT, we
4 assume that all of these contracts will be rolled over and that service will continue
5 through the rate period. The transmission demands of those PTP contracts
6 forecasted to exercise rollover rights are summed and added to the forecast. *Id.* at
7 Table 13-1, line 8. Fourth, for each PTP contract whose holder has exercised its
8 right to extend the commencement date of the PTP contract pursuant to section
9 17.7 of the OATT, we forecast the contract holder will continue to exercise its
10 section 17.7 rights for the full five years permitted by the OATT. We sum up and
11 subtract from the forecast the transmission demands of those contracts whose
12 commencement of service dates are extended. *Id.* at Table 13-1, line 9. Fifth, we
13 forecast new, long-term PTP sales to be made before or during the rate period. In
14 developing that forecast, we assume that only those requests for long-term PTP
15 transmission service to deliver power from resources that are in TS's Large
16 Generation Integration (LGI) queue will become long-term sales during the rate
17 period. *Id.* at Table 13-1, line 10.

18 *Q. Why does the forecast limit new PTP sales to requests from resources in the LGI*
19 *queue?*

20 *A. In our experience many parties that request long-term PTP transmission service*
21 *do not accept TS's offer of service. The assumption that new PTP sales will be*
22 *made only for those transmission service requests that have associated requests*
23 *for generation interconnections identifies a group of transmission service requests*

1 for which there is a vested interest in accepting a TS transmission contract offer.
2 This group is more likely to accept an offer of service. Of course, not all
3 transmission offers tied to a resource in the LGI queue may be accepted. If a
4 transmission offer associated with a resource in the LGI queue is not accepted, the
5 transmission capacity offered to that party will be offered to and potentially
6 accepted by another party that is seeking transmission to move power from other
7 resources or markets.

8 *Q. How is the forecast of long-term transmission demand for the Southern Intertie*
9 *(IS) developed?*

10 A. First, we establish a base forecast of executed long-term IS contracts that
11 commence before or during the Rate Period by summing those contracts'
12 transmission demands and assuming that no expiring contract is renewed.
13 Documentation, TR-08-E-BPA-01A, Table 13-1, line 14. Second, we prepare a
14 forecast of IS contract renewals by parties whose contracts expire during the
15 forecast period and who have Section 2.2 rollover rights. *Id.* at Table 13-1,
16 line 15. In the forecast we assume that approximately 75% of the expiring
17 contracts will be renewed. Third, we forecast new long-term IS sales that require
18 construction of transmission facilities and will be funded in a manner similar to
19 LGIA Network Upgrades. *Id.* at Table 13-1, line 16; Homenick, et al., TR-08-E-
20 BPA-05, section 2A.

21 *Q. How is the forecast of long-term transmission demand for the Montana Intertie*
22 *(IM) developed?*

1 A. The IM sales forecast includes one PTP service reservation for 16 megawatts on
2 the Montana Intertie. Documentation, TR-08-E-BPA-01A, Table 13-1, line 22.

3 No other IM service is forecasted.

4 *Q. What are short-term PTP sales and how are they forecast?*

5 A. Short-term PTP sales are PTP transmission service sales of less than one year in
6 duration. They consist of monthly, weekly, and daily firm PTP service as well as
7 hourly firm and non-firm PTP service. We based the forecast of these short-term
8 sales on historical sales data for the period FY04-FY06. For Short-term sales on
9 the Network the historical sales for FY06 were given a 0.5 weighting factor to
10 account for the extremely high level of short-term sales we saw as a result of
11 above-average water year in the Northwest. FY04 and FY 05 were both given a
12 1.0 weighting factor. The weighted sum of the historical sales for FY04-FY06
13 were reduced by 260 MW in FY 2008 and 200MW in FY 2009 to account for an
14 increase in long term sales which are expected to result in a reduction of short-
15 term PTP during sales during the Rate Period. For short-term sales on the
16 Southern Intertie the historical sales for FY04 and FY06 were given a 1.0
17 weighting factor and FY05 was given a 0.5 weighting factor to account for
18 uncharacteristically low short-term sales on the Southern Intertie. The weighted
19 sum of the historical sales is the IS short-term sales forecast. Documentation, TR-
20 08-E-BPA-01A, Table 13-1, line 18.

1 **SECTION 3. REVENUE FORECAST**

2 *Q. Please describe the revenue forecast.*

3 A. A summary of the revenue forecast by product by year is shown in
4 Documentation, TR-08-E-BPA-01A, Tables 13-2 and 13-3. Revenues are
5 forecast assuming current rates (Table 13-2) and proposed rates (Table 13-3).
6 The revenues from FPT, IR, PTP, NT, IS, IM and Utility Delivery sales are
7 calculated by applying the current and proposed rates to the billing determinants
8 of the forecasted sales shown in Documentation, TR-08-E-BPA-01A, Table 13-1.
9 The proposed rates used are those set out in the Settlement Agreement. Metcalf
10 and Parker, TR-08-E-BPA-03, Attachment A, at 9-10.

11 *Q. How were revenues for Ancillary and Control Area Services estimated?*

12 A. The billing factors for the two required Ancillary Services, Scheduling, System
13 Control, and Dispatch Service and Reactive Supply and Voltage Control from
14 Generation Sources Service, are the same as the billing factors for transmission
15 service. Thus, the sales forecast generated for the Network, Southern Intertie, and
16 Montana Intertie transmission sales were also used for the revenue forecast of the
17 two required Ancillary Services.

18 Forecasted sales of Operating Reserve services are an average of BPA's
19 historical operating reserve requirement, net of self- and 3rd party-supplied
20 reserves totaling 380MW. Sales of Regulation and Frequency Response service
21 were forecast using FY 2005 actual billing determinants, escalated by 1.7% per
22 year and adjusted for known changes in loads in the control area before or during

1 the rate period. No net revenue was assumed from Energy and Generation
2 Imbalance Services.

3 *Q. Are all sources of revenue affected by the proposed rates?*

4 A. No. Some revenues are recovered from sources other than the general
5 transmission rates associated with the transmission services described above. We
6 treat this revenue as revenue credits because in rate setting they would be used to
7 credit costs prior to calculating the general rates. This includes revenue from
8 certain rates such as the Townsend Garrison Transmission (TGT) and Southern
9 Intertie Annual Cost (AC) rates, as well as revenue from various services that TS
10 provides such as Operation and Maintenance and other use of facility (UFT)
11 charges.

12 *Q. How are these revenue credits forecast?*

13 A. Revenue credits are forecast at actual FY 2005 levels with adjustments for known
14 changes. These revenues amount to less than 7% of TS revenues.
15 Documentation, TR-08-E-BPA-01A, Tables 13-2 and 13-3, lines 18-31.

16 *Q. Will any changes be made to the revenue forecasts for the final rate proposal?*

17 A. TS does not expect to revise the revenue forecasts.

18 *Q. Does this conclude your testimony?*

19 A. Yes.

INDEX

TESTIMONY OF

RONALD J. HOMENICK, DANA M. JENSEN, RANDY B. RUSSELL,
AND ERIC K. TAYLOR

Witnesses for Bonneville Power Administration Transmission Services

SUBJECT: REVENUE REQUIREMENT STUDY AND RISK ANALYSIS

	Page
SECTION 1. Introduction and Purpose of Testimony	1
SECTION 2. Revenue Requirements	2
SECTION 2A. Large Generator Interconnection Agreements (LGIA).....	3
SECTION 2B. Other Changes to Obligations and Assumptions.....	7
SECTION 3. Risk Analysis	8
SECTION 4. Slice/Debt Optimization Debt Service Reassignment Demonstration	10
SECTION 5. Additional Modifications and Adjustments	12

1 TESTIMONY OF

2 RONALD J. HOMENICK, DANA M. JENSEN, RANDY B. RUSSELL,

3 AND ERIC K. TAYLOR

4 Witnesses for Bonneville Power Administration Transmission Services

5 **SUBJECT: REVENUE REQUIREMENT STUDY AND RISK ANALYSIS**

6 **SECTION 1. INTRODUCTION AND PURPOSE**

7 *Q. Please state your names and qualifications.*

8 A. My name is Ronald J. Homenick and my qualifications are contained in TR-08-Q-
9 BPA-01.

10 A. My name is Dana M. Jensen and my qualifications are contained in TR-08-Q-
11 BPA-02.

12 A. My name is Randy B. Russell and my qualifications are contained in TR-08-Q-
13 BPA-03.

14 A. My name is Eric K. Taylor and my qualifications are contained in TR-08-Q-BPA-
15 06.

16 *Q. Please state the purpose of your testimony.*

17 A. The purpose of this testimony is to explain and support the development of the
18 transmission revenue requirements for fiscal years 2008 and 2009 (Rate Period)
19 and the accompanying risk analysis. This testimony also sponsors the 2008
20 Revenue Requirement Study (Study), TR-08-E-BPA-01, and the 2008 Revenue
21 Requirement Study Documentation (Documentation), TR-08-E-BPA-01A, except
22 for the sales and revenue forecasts in the Documentation, Chapter 14, which are
23 sponsored separately. *See* Knudsen and Woerner, TR-08-E-BPA-04.

1 *Q. How is your testimony organized?*

2 A. Our testimony addresses assumptions used in the development of the transmission
3 revenue requirements for the rate period and in the demonstration of cost recovery
4 and repayment of the Federal investment. First, in Section 2, we identify payment
5 obligations and capital funding assumptions used in the transmission revenue
6 requirement study, including customer up-front payments under Large Generator
7 Interconnection Agreements (LGIA) and the use of cash reserves to fund capital
8 expenditures. In Section 3, we address the risk analysis. In Section 4, we address
9 the demonstration that rates are no higher with the Debt Optimization Program
10 than without it as called for in the Slice Settlement Agreement. In Section 5, we
11 discuss the potential for adjustments and updates that may be made in the Final
12 Rate Proposal.

13 **SECTION 2. REVENUE REQUIREMENTS**

14 *Q. Have any changes been made to the way Bonneville Power Administration (BPA)*
15 *determines the transmission revenue requirements?*

16 A. No. We are using the same methodology as in the TR-06 rate proceeding.

17 *Q. Are non-Federal payment obligations incorporated in the rate proposal?*

18 A. Yes. As in the TR-06 rate proceeding, this proposal includes two financial
19 obligations involving non-Federal funding sources that benefit the transmission
20 system during the Rate Period and beyond. These are the obligation for annual
21 payments associated with a third-party lease-purchase arrangement for a long-
22 term capitalized transmission asset purchase (lease-purchase), and the
23 reassignment to transmission of a portion of refinanced Energy Northwest (EN)

1 non-Federal bond debt service obligations under BPA's Debt Optimization
2 Program (Debt Service Reassignment). These obligations are treated in the same
3 manner as in the TR-06 rate proceeding. The obligations incurred under Debt
4 Service Reassignment have been updated to reflect additional transactions that
5 have occurred since the conclusion of the TR-06 rate proceeding.

6 *Q. Have additional non-Federal payment obligations been incorporated in the rate
7 proposal?*

8 A. Yes. This proposal includes new payment obligations associated with customer-
9 financed Network Upgrades under provisions of BPA's Open Access
10 Transmission Tariff for large generator interconnection, which are described
11 below in Section 2A.

12 *Q. Are there other assumptions or changes that affect the determination of
13 transmission revenue requirements?*

14 A. Yes. As in the TR-06 rate proceeding, the transmission revenue requirements for
15 the Rate Period reflect the 2008 Transmission Rate Case Settlement Agreement
16 (Settlement Agreement) assumption that BPA will use \$15 million per year of
17 transmission cash reserves instead of Treasury borrowing as a funding source for
18 transmission capital. This assumption is described in Section 2B below. In
19 addition, the depreciation expense calculated for the transmission revenue
20 requirement incorporates the results of an updated depreciation study which did
21 not alter the average service life of transmission facilities.

22 **SECTION 2A. Large Generator Interconnection Agreements (LGIA)**

23 *Q. Please describe the Open Access Transmission Tariff LGIA transmission credits.*

1 A. The LGIA requires interconnection customers to finance the cost of Network
2 Upgrades needed to interconnect their generating facilities to BPA's transmission
3 system if BPA, as the transmission provider/owner, does not provide funding.
4 BPA requires interconnection customers to provide up-front payments in an
5 amount sufficient to cover the cost of construction. The interconnection customer
6 is entitled to transmission credits, which are used to offset charges for eligible
7 transmission service on their bill.

8 *Q. What determines the amount of an interconnection customer's LGIA credit*
9 *balance?*

10 A. The initial credit balance is based on the sum of the funds advanced by an
11 interconnection customer to BPA for the cost of constructing the Network
12 Upgrades. Interest begins to accrue on the funds advanced for the construction of
13 LGIA Network Upgrades at the rate specified by the Federal Energy Regulatory
14 Commission (Commission) at the time BPA receives the funds. The interest that
15 accrues on those funds is included as part of the credit balance. *See*
16 *Documentation, TR-08-E-BPA-01A, Chapter 13, Table 13-6, for the forecasted*
17 *rates used to calculate interest expense that accrues on credit balances. Interest*
18 *continues to accrue on the credit balance on a monthly basis until such time that*
19 *the credit balance has been exhausted or twenty years from the date the generator*
20 *commences operation. The LGIA requires that if the credit balance is not fully*
21 *depleted within twenty years from the date the generator commences operation,*
22 *BPA will refund the balance in a single payment, including any accrued and*
23 *unpaid interest.*

1 Q. *How are the transmission credits applied?*

2 A. Transmission credits are applied to charges for Network Integration (NT) or
3 Point-to-Point (PTP) transmission service associated with the interconnected
4 generator, excluding charges for Ancillary Services. For NT service, the rate at
5 which credits are repaid is based on a ratio of 1) a customer's share of the
6 generator over 2) the customer's maximum Network Load on the hour of the
7 Monthly Transmission Peak Load over the previous 12 months. For PTP service,
8 the rate of credit application is based on the amount of transmission capacity
9 reserved from the generator Point of Receipt. The credits are applied on a dollar-
10 for-dollar basis using the transmission rates that are in effect when service is
11 taken.

12 Q. *How was the forecast of LGIA transmission credits developed?*

13 A. The LGIA transmission credit forecast was based on the generating facilities that
14 have been, or are expected to be, energized prior to or during the Rate Period. To
15 the extent possible, each facility was associated with transmission service requests
16 in the long-term transmission request queue to determine the rate at which
17 transmission credits are applied. The transmission charges on which credits are
18 applied was capped at the maximum megawatt capacity of each facility. The date
19 on which BPA begins applying transmission credits was determined by each
20 facility's proposed energization date. *See* Documentation, TR-08-E-BPA-01A,
21 Chapter 13, Tables 13-4 and 13-5, for the forecast of credit balances and accruing
22 interest.

1 Q. *Is BPA TS forecasting transmission credits for Network Upgrades that are not*
2 *generator interconnections?*

3 A. Yes. TS is forecasting one project that is expected to be funded by transmission
4 customers requesting service on the Southern Intertie. The credits for the
5 amounts funded are forecasted to be made in a manner similar to the LGIA
6 transmission credits.

7 Q. *How are LGIAs reflected in the revenue requirement expense categories for the*
8 *Rate Period?*

9 A. BPA has added a new expense category to the revenue requirement. It is an
10 Operating Expense which is also reflected in the Statement of Cash Flows. “Non-
11 Federal Projects Debt Service” is composed of both the interest earned by
12 customers on their upfront payment balances as well as the Allowance for Funds
13 Used During Construction (AFUDC) accrued by customer-funded Network
14 Upgrade projects. Consequently, the Depreciation and Amortization expense
15 category now includes the depreciation of the investment in customer-funded
16 upgrades that are projected to be in service during the Rate Period. These
17 components are non-cash elements of the revenue requirements.

18 Q. *How else does the LGIA affect the revenue requirements in this proceeding?*

19 A. As part of its rate directives, BPA must demonstrate cost recovery on a cash basis.
20 However, these agreements produce non-cash (accrual) revenues in the revenue
21 forecast. BPA would not necessarily demonstrate full recovery of cash
22 requirements if the forecasted Revenues from Proposed Rates, including these
23 non-cash revenues, were simply equal to the Revenue Requirement. In order to

1 account for the non-cash impact of the LGIA, the Revenue Requirement is
2 adjusted to include the sum of both the Cash Requirements as well as the Non-
3 Cash Revenues.

4 *Q. How is that reflected on the Income Statement?*

5 A. As shown in the Study, TR-08-E-BPA-01, Tables 3 and 4, the calculation of the
6 Minimum Required Net Revenues compensates for the effect of the accrual
7 revenues. This component ensures that cash requirements will be sufficiently
8 covered by cash-bearing revenues.

9 **SECTION 2B. Other Changes to Obligations and Assumptions**

10 *Q. Are there other assumptions that affect the determination of the revenue*
11 *requirements?*

12 A. Yes. As part of the 2008 Transmission Rate Case Settlement Agreement, BPA is
13 proposing to use \$15 million per year of transmission-generated cash reserves to
14 fund transmission capital programs. Metcalf and Parker, TR-08-E-BPA-03,
15 Attachment A, at 4. As in the TR-06 rate proceeding, this use of reserves is
16 assumed instead of including the \$15 million as a cash requirement factored into
17 the calculation of the Minimum Required Net Revenues.

18 *Q. How is the proposed use of cash reserves reflected in the revenue requirement for*
19 *the Rate Period?*

20 A. In the Statement of Cash Flows, the projected Treasury borrowing is \$15 million
21 less than the cash used for capital investments each year. The Revenue
22 Requirement is generally unaffected because a draw-down of cash reserves is
23 included as a source of funds in Cash from Current Operations to cover that

1 difference. Study, TR-08-E-BPA-01, Table 4. However, as a direct result, the
2 interest income calculation reflects this draw-down, showing the decrease in
3 available cash reserves during the rate period. Documentation, TR-08-E-BPA-
4 01A, Chapter 4.

5 *Q. Have there been other updates?*

6 A. In FY 2006, BPA implemented the results of an updated depreciation study
7 pertaining to transmission plant service life characteristics. This has been
8 incorporated in the current proposal for calculation of depreciation expense.
9 Documentation, TR-08-E-BPA-01A, Chapter 3. The average service life of the
10 system as a whole was not affected by the study.

11 **SECTION 3. RISK ANALYSIS**

12 *Q. Has BPA made any changes to its risk analysis methodology?*

13 A. With one major exception, BPA used the same method and spreadsheet model for
14 the risk analysis used in the 2002 Final Transmission Proposal as well as the 2004
15 and the 2006 Final Transmission Proposals. *See* 2002 Final Revenue
16 Requirement Study, TR-02-FS-BPA-01, Section 2.2; 2002 Final Revenue
17 Requirement Documentation, TR-02-FS-BPA-01A, Chapter 9; Westman and
18 Sapp, TR-02-E-BPA-07; 2004 Final Revenue Requirement Study, TR-04-FS-
19 BPA-01; 2004 Final Revenue Requirement Documentation, TR-04-FS-BPA-01A,
20 Chapter 9; 2006 Final Revenue Requirement Study, TR-06-FS-BPA-01; 2006
21 Final Revenue Requirement Documentation, TR-06-FS-BPA-01A, Chapter 9.

22 *Q. What is the one exception to the risk analysis methodology?*

1 A. Previously, BPA used a statistical technique known as the ‘bootstrap’ to estimate
2 sampling distributions for Network and Southern Intertie annual revenues. *See*
3 TR-04-FS-BPA-01A for a description of the ‘bootstrap’ method. For this risk
4 analysis, BPA used data and information gathered from subject matter experts to
5 develop the probability distributions for these variables.

6 *Q. Why did BPA make this change?*

7 A. For two reasons. First, the original data used to develop the sampling
8 distributions were from monthly transmission bills from FY 1998 through FY
9 2002. BPA believes that this data is no longer representative of future
10 transmission billing or revenues. Second, the Region has experienced below-
11 normal water conditions for much of the past five years, with subsequently lower
12 transmission loads and revenues. Therefore, BPA believes using more recent
13 billing data to estimate the sampling distributions with the ‘bootstrap’ method
14 would not be representative of future loads and revenues.

15 *Q. What are the results of the risk analysis for this Rate Period?*

16 A. In this rate proposal, BPA has identified and quantified transmission risks and
17 designed risk mitigation tools that achieve BPA’s policy standard of at least a 95
18 percent U.S. Treasury payment probability. Simulations of BPA’s financial
19 reserves attributable to the transmission function have a most-likely value of \$287
20 million at the beginning of FY 2008. These reserves and the cash flow
21 anticipated from the proposed rates for FY 2008 and FY 2009 meet BPA’s TPP
22 standard of 95 percent for a two-year period without the need to include any

1 | planned net revenue for risk in the revenue requirement. *See* Study, TR-08-E-
2 | BPA-01, Section 2.2

3 | **SECTION 4. SLICE/DEBT OPTIMIZATION DEBT SERVICE**

4 | **REASSIGNMENT DEMONSTRATION**

5 | *Q. What is the Slice/Debt Optimization and Debt Service Reassignment*
6 | *Demonstration?*

7 | A. BPA, Slice purchasers and Northwest Requirements Utilities (NRU) have been
8 | involved in litigation regarding the BPA’s Slice Product, which is a particular
9 | power sale product. In late November, the parties signed a Memorandum of
10 | Understanding of the Slice Settlement Agreement that provided in part that BPA
11 | would make a demonstration showing that “rates of each of BPA’s business lines
12 | (Transmission Business Line (“TBL”) and Power Business Line (“PBL”)) are no
13 | higher with the DOP than they would have been in the absence of the DOP.” The
14 | MOU further provided:

15 | The Participants agree that for purposes of making its
16 | demonstration in the next general transmission rate proceeding,
17 | BPA will introduce the information for the first time in its rebuttal
18 | case, and the Administrator will direct the hearing officer in writing
19 | to provide parties a reasonable period of time to respond to such
20 | information with surrebuttal testimony and, if requested by any
21 | party (including BPA), a further reasonable period of time to
22 | respond to such surrebuttal with sur-surrebuttal testimony. Metcalf
23 | and Parker, TR-08-E-BPA-03, Attachment A, at 4 (Attachment 3
24 | to the 2008 Transmission Rate Case Settlement Agreement).

25 |
26 | *Q. What was the process for satisfying the demonstration required by the Slice*
27 | *Settlement Agreement?*

28 | A. As part of the 2008 Transmission Rate Case Settlement Agreement, BPA, BPA’s
29 | Slice customers and NRU agreed that the following process satisfies BPA’s

1 procedural and public process requirements regarding the Debt Optimization
2 Program (DOP) and Debt Service Reassignment (DSR) demonstration under the
3 MOU. The Settlement Agreement provides:

4 At the annual DOP and DSR meeting planned for January 2007,
5 the ‘demonstration for transmission rates will be addressed
6 separately from the demonstration for power rates. BPA will
7 demonstrate that transmission rates are no higher with the DOP
8 than they would have been in the absence of the DOP (which
9 includes DSR). Metcalf and Parker, TR-08-E-BPA-03, Attachment
10 A, at 4.

11 The Settlement Agreement further provides that:

12 For purposes of the Rate Case, BPA's Initial Proposal shall include
13 (1) the Transmission Rate DOP Demonstration made available at
14 the January, 2007 meeting(s); (2) language in the Transmission
15 Revenue Requirement Study in accordance with the Slice
16 Settlement Agreement, Exhibit D, Section B (Attachment 3), that
17 clearly and transparently describes the DOP-related costs for which
18 transmission rates are being set; and (3) testimony that draws
19 attention to that language. *Id.*

20 *Q. Please describe the DOP Demonstration provided at the January 23, 2007*
21 *meeting.*

22 *A.* The DOP demonstration described the results of two repayment studies. One
23 study, consistent with the Initial Proposal, assumed that no additional DOP
24 actions occurred after FY 2006. The second study included forecasted DOP
25 actions beyond FY 2006. The results showed that over a twenty-year horizon the
26 total capital costs (Federal amortization, interest, and third-party debt service)
27 were on average no different in the two studies, which means that rates would be
28 no higher with DOP than without such actions, including rates for this rate period.
29 Documentation, TR-08-E-BPA-01A, Chapter 14.

1 Q. Please explain the DOP-related costs that are included in the transmission rates
2 established in this proceeding.

3 A. The revenue requirement income statement includes “Debt Service Reassignment
4 Interest” which includes the interest expense associated with DOP actions. Study,
5 TR-08-E-BPA-01, Table 3. The statement of cash flows includes “Debt Service
6 Reassignment Principal” which represents non-Federal principal that is repaid. *Id*
7 at Table 4. The development of these costs, which incorporate all DSR
8 transactions made to date, are explained and detailed in Chapter 7 of the
9 Documentation, TR-08-E-BPA-01A.

10 **SECTION 5. ADDITIONAL MODIFICATIONS AND ADJUSTMENTS**

11 Q. What additional changes could affect the Revenue Requirement Study in the Final
12 Rate Proposal?

13 A. We do not expect any changes to the expense and capital program levels reflected
14 in revenue requirements for the Rate Period. The repayment study currently
15 includes the most recent historical data, FY 2006 actual financial data. BPA does
16 not anticipate changing the revenue forecasts. Knudsen and Woerner, TR-08-E-
17 BPA-04. However, if any changes are made, they will be incorporated in the
18 Final Proposal.

19 Q. Does that conclude your testimony?

20 A. Yes.

QUALIFICATION STATEMENT OF
RONALD J. HOMENICK

Witness for the Bonneville Power Administration

Q. Please state your name, employer, and business address.

A. My name is Ronald J. Homenick. I am employed by the Bonneville Power Administration (BPA), 905 NE 11th Avenue, Portland, Oregon.

Q. In what capacity are you employed?

A. I am a Financial Analyst in the Financial Analysis and Requirements group of Corporate Finance.

Q. Please state your educational background.

A. I received a Bachelor of Arts degree in English from Kent State University in 1973.

Q. Please summarize your professional experience.

A. From 1982 to 1985, I was employed as a Computer Programmer/Analyst for Electronic Data Systems under contract with BPA. In that capacity, I worked with the group that is now part of Financial Analysis & Requirements, designing and implementing numerous BPA revenue requirement/cost of service computer applications and performing various financial analyses related to BPA's 1983 and 1985 rate cases.

In 1984, I researched historical costs and performed various financial analyses that formed the financial basis of BPA's compliance report to the Federal Energy Regulatory Commission on separate accounting for power and transmission functions.

In 1985, I became a BPA employee and worked for the group that is now Financial Analysis & Requirements. I have been employed as a Financial Analyst since 1986. In this capacity, I have been responsible for various financial analyses related to power and transmission revenue requirement development, such as preparation of the

projected investment bases, depreciation forecasts, inter-business unit costs, and segmentation of the transmission revenue requirements.

I have been the primary analyst in Corporate Finance responsible for the annual preparation of the separate accounting analysis. I am also one of BPA's primary analysts in the area of repayment policy.

Q. Please state your experience as a witness in previous proceedings.

A. I have appeared as a witness on Revenue Requirement issues in BPA's 1991, 1993, 1995, and 1996 general rate proceedings, BPA's 3rd AC Intertie Non-Federal Participation rate case, BPA's 2002 and 2007 wholesale power rate proceedings and the 2002, 2004 and 2006 transmission rate proceedings.

1 QUALIFICATION STATEMENT OF

2 DANA M. JENSEN

3 Witness for the Bonneville Power Administration

4 *Q. Please state your name, employer, and business address.*

5 A. My name is Dana M. Jensen. I am employed by the Bonneville Power Administration
6 (BPA), 905 NE 11th Avenue, Portland, Oregon.

7 *Q. In what capacity are you employed?*

8 A. I am a Financial Analyst in the Treasury and Debt Management group in Corporate
9 Finance.

10 *Q. Please state your educational background.*

11 A. I received an Associates degree in Humanities and General Studies from Lane
12 Community College, Eugene, Oregon in 1987; a Bachelor of Science degree in Finance
13 and Management from the University of Oregon in 1989; and a Master in Business
14 Administration from Portland State University in 1995. My field of concentration was
15 public finance.

16 *Q. Please summarize your professional experience.*

17 A. I am currently employed as a Financial Analyst at BPA. I provide economic and
18 financial analytical support for rate case and regulatory proceedings. I serve as a senior
19 technical analyst in developing cost, revenue, and financial forecasts and related analyses
20 with the financial and operating condition of BPA, its business lines, customers, and
21 competitors. I participate in preparing, analyzing, and implementing BPA's financial
22 business strategy; measure financial performance against strategic goals; analyze industry
23 and marketplace developments including potential State and Federal legislation that may
24 affect BPA's future financial integrity; and develop and maintain financial data, forecast
25 systems, and analytical tools.

1 In my previous position with BPA, I developed a credit review function to assess
2 creditworthiness and determine credit limits for new customers (wholesale). I developed
3 the procedures and a procedure manual, programmed rating criteria into our model, and
4 developed a model to pull records from a data base program into Excel for manipulation
5 and calculation and then to compile a user report. I performed credit analyses and review
6 on potential hazardous waste contractors. I conducted ad hoc analysis including financial
7 profiles, ratio analyses, net present value project analyses, revenue and profit forecasts,
8 cost-effectiveness, buy vs. lease, and various other analyses. I developed current and pro
9 forma business line financial statements and developed and used financial models (using
10 Excel) to identify and assess the financial effects of alternative capital spending and
11 expense levels and financing alternatives. I served as an in-house management
12 consultant, performing studies on efficiency, cost analysis, and feasibility. I also assisted
13 staff end-users in computer troubleshooting and loading software.

14 Prior to my employment with BPA, I worked for two years as a residential
15 mortgage loan processor and substitute loan officer at a savings bank. I conducted
16 extensive credit and financial analyses of the borrowers and builders, reviewing private
17 and corporate (mainly sub S) financial statements and other records. I compiled
18 summary reports based on my analyses for the underwriters and loan committee.

19 From September 1994 to October 1996, I was a Reserve Police Officer for the
20 City of Hillsboro.

21 *Q. Have you ever been a witness in a rate case?*

22 *A. Yes. I was on the Revenue Requirements Panel in the 2002 and 2007 Generation Rate*
23 *Cases, and on the same panel in the 2004 and 2006 Transmission Rate Cases.*

1 QUALIFICATION STATEMENT OF

2 RANDY B. RUSSELL

3 Witness for the Bonneville Power Administration

4 *Q. Please state your name, employer, and business address.*

5 A. My name is Randy B. Russell. I am employed by the Bonneville Power Administration
6 (BPA), 905 NE 11th Avenue, Portland, Oregon.

7 *Q. In what capacity are you employed?*

8 A. I am a Risk Analyst in the Enterprise Risk Management group under the Chief Risk
9 Officer.

10 *Q. Please state your educational background.*

11 A. I received a Bachelor of Arts degree in Economics from the University of Utah in 1976
12 and a Master of Science degree in Economics from the University of Utah in 1984.

13 *Q. Please summarize your professional experience.*

14 A. In May 1982, I began work at BPA as a Public Utilities Specialist in the Cost and
15 Analysis Section of the Division of Rates. In 1983, I transferred to the Division of
16 Financial Requirements as a Financial Analyst. My major duties included forecasting the
17 costs of the Residential Exchange Program for BPA rate cases, budget submittals, and
18 Residential Exchange contract buyouts.

19 In 1994, I was promoted to the position of Manager of Financial Analysis and
20 Consulting in the Financial Services Group. In this position, my major duties included
21 managing the development of a new Agency-wide capital budget process, corporate risk
22 analysis, and forecasting Agency net revenues and reserves for planning and setting
23 Agency financial targets.

24 In August, 2000 I transferred to the Capital and Risk Management group under
25 the Chief Financial Officer. My major duties included analyzing Agency-wide financial
26 risk and related financial analyses.

TR-08-Q-BPA-03

Page 1

Witness: Randy B. Russell

1 I assumed my current position in October 2003. My major duties include
2 providing staff support to the Enterprise Risk Management Committee, performing risk
3 analysis on Agency strategic risks, and developing tools for analyzing global financial
4 risk to the Agency.

5 *Q. Please state your experience as a witness in previous proceedings.*

6 A. I was a witness for the forecast of the costs of the Residential Exchange Program in
7 previous BPA rate proceedings, most recently in the 1993 Wholesale Power rate
8 proceeding. I was a witness in the SN CRAC 7(i) process, sponsoring testimony and
9 analysis for the Accrual-to-Cash adjustments used by ToolKit to convert net revenues
10 into cash. Most recently, I was a witness in the 2007 Wholesale Power rate proceeding,
11 sponsoring testimony on the Non-Operating Risk Model (NORM). In general, operating
12 risks include variations in prices, loads and generation resource capability related to
13 operating the hydro system. NORM modeled the non-operating risks for the Risk
14 Analysis Study.

1 QUALIFICATION STATEMENT OF

2 F. STEVEN KNUDSEN

3 Witness for the Bonneville Power Administration

4 *Q. Please state your name, employer, and business address.*

5 A. My name is F. Steven Knudsen. I am employed by the Bonneville Power Administration
6 (BPA), 7500 NE 41st St. Vancouver, WA. 98662

7 *Q. In what capacity are you employed?*

8 A. I am a senior policy analyst in the Policy, Rates and Strategy section of the Transmission
9 Marketing and Sales group.

10 *Q. Please state your educational background.*

11 A. I graduated from University of Oregon in 1976 with a Bachelor of Science degree in
12 Economics. I earned an MBA from the Northwestern University Kellogg School in 1979.

13 *Q. Please summarize your professional experience.*

14 A. I have been employed at BPA for approximately 15 out of the last 22 years. I first came to
15 BPA in 1983 after five years with the US General Accounting Office as a management
16 analyst. From 1983 to 1986, I was Section Chief of the Utility Load Section in the Office of
17 Financial Management where I was responsible for financial modeling and analysis,
18 financial policy development, and official agency projections as well as assessments of
19 future financial position and revenue requirements. From 1986 to 1988, I was Branch Chief
20 of the Revenue Requirements Branch where I supervised the development of Treasury
21 repayment policies and preparation of the Revenue Requirement Study and associated
22 Functionalization and Segmentation Studies for BPA's 1987 Rate Case.

1 From 1988 to 1990, I was Section Chief of the Utility Load Section in the Office of Energy
2 Resources where I was responsible for developing monthly and hourly load forecasts for
3 specific utilities to support BPA system planning, hydro-system operations, revenue
4 forecasting and power marketing. In that capacity, I supervised the development of load
5 forecasts used in developing BPA's 1990 Rate Case.

6 From 1990 until 1994, I was both a Section Chief and Branch Chief in BPA's
7 Resource Planning Division where I developed and implemented resource planning and
8 demand or supply side acquisition policies and strategies, risk management policies, and
9 financial hedging strategies.

10 From 1994 through 1995, I was a BPA Account Executive responsible for sales of
11 electric power and transmission products to electric power marketers and independent power
12 producers.

13 From 1996 through 1999, I was employed by Pacific Gas Transmission Company as
14 an Account Manager. In that position, I conducted gas transmission market development
15 and account management activity focusing primarily on utilities in the Pacific Northwest
16 and Independent Power Producers. I formulated market and regulatory strategies to support
17 pipeline capacity marketing and the development and pricing of new products and services.

18 From 2000 through 2002, I was employed by PG&E Energy Trading as Director of
19 Market Development where I was responsible for gas and power marketing and long-term
20 commodity sales and purchases transactions throughout the western United States. I also
21 was responsible for generating resource development in the Rocky Mountain West and was
22 lead developer for the 113 MW Plains End Generating Project currently operating in
23 Arvada, Colorado. In my capacity developing generating resources, I responded to utility

1 Requests for Proposals for power supply and negotiated subsequent agreements, such as
2 Power Purchase Agreements. To successfully develop generating projects, I negotiated
3 Engineering, Procurement, Construction and powerplant Operation and Maintenance
4 contracts as well as Interconnection Agreements with the local Transmission Service
5 Provider.

6 Since January of 2003, I have been employed by BPA in my current position where I
7 work primarily on ATC management, revenue forecasting, policy development, and tariff
8 implementation. In this capacity, I direct a staff of revenue forecasters and revenue analysts
9 responsible for developing the revenue forecast used to develop rates. I am responsible for
10 revenue analysis and forecast performance reporting to senior management, and for
11 directing the evaluation and development of enhancements to agency revenue forecasting
12 methodologies and models.

13 *Q. Please state your experience as a witness in previous proceedings.*

14 *A.* I have helped prepare material for previous rate cases back to 1983, and was a witness in the
15 Transmission 2006 Rate Case.

1 QUALIFICATION STATEMENT OF

2 NANCY PARKER

3 Witness for the Bonneville Power Administration

4 *Q. Please state your name, employer, and business address.*

5 A. My name is Nancy Parker. I am employed by the Bonneville Power Administration (BPA),
6 7500 NE 41st St. Vancouver, WA. 98662.

7 *Q. In what capacity are you employed?*

8 A. I am a Public Utilities Specialist in Transmission Services.

9 *Q. Please state your educational background.*

10 A. I received a B.S. degree in microbiology from the University of Michigan in 1975. I have
11 completed a portion of the Master's degree program in Business Administration at Portland
12 State University.

13 *Q. Please summarize your professional experience at BPA.*

14 A. Since September 1979 I have been a Public Utilities Specialist specializing in rate
15 development. For BPA's 1981 rate filing, I prepared studies in support of BPA's wholesale
16 power rates, particularly the Nonfirm Energy rate.

17 For BPA's 1982 and 1983 rate filings, I was responsible for preparing BPA's
18 Wholesale Power Rate Design Study. I also prepared studies in support of BPA's Surplus
19 Firm Power and Nonfirm Energy rates. I prepared major portions of testimony on rate
20 design issues for each of these rate filings as well as for the Federal Energy Regulatory
21 Commission's Section 7(k) hearings on BPA's NF-1 and NF-2 Nonfirm Energy rates.

22 In 1986 I prepared testimony for BPA's rate hearing on the Southern California Edison
23 Contract (SC-86) rate, and in 1988 I was in charge of the Modified SC-86 rate process.

TR-08-Q-BPA-05

Page 1

Witness: Nancy Parker

1 I was responsible for the implementation of the Section 7(b)(2) methodology in BPA's
2 1987 rate case and supervised the development of wholesale power rate projections.

3 From 1990 through the beginning of 1991, I oversaw the process in which BPA decided
4 to continue the Variable Industrial (VI) rate after the first 5 years of implementation, and to
5 extend the rate for an additional 3 years.

6 During 8 months of 1991, I was temporarily assigned to the Power Management staff
7 of the Lower Columbia Area office.

8 In 1992 I joined the transmission rates staff. I have worked on transmission rate and
9 terms and conditions issues since that time.

10 *Q. Please state your experience as a witness in previous proceedings.*

11 *A. I appeared as a witness in the following BPA rate cases: the 1985 and 1987 general rate*
12 *cases, testifying on power rate issues; the Modified SC-86 rate case; the 1990 VI rate case;*
13 *and the 1993, 1996, 2002, 2004 and 2006 rate cases, testifying on transmission rate issues.*

1 QUALIFICATION STATEMENT OF

2 ERIC K. TAYLOR

3 Witness for the Bonneville Power Administration

4 *Q. Please state your name, employer, and business address.*

5 A. My name is Eric K. Taylor. I am employed by the Bonneville Power Administration (BPA),
6 7500 NE 41st St. Vancouver, WA. 98662

7 *Q. In what capacity are you employed?*

8 A. I am a Public Utilities Specialist in BPA's Transmission Services (TS) organization,
9 Transmission Policy, Rates and Revenues.

10 *Q. Please state your educational background.*

11 A. I received a Bachelor of Arts degree from Claremont McKenna College in 1999 where I
12 dual majored in Economics and Government. I then received a Masters of Business
13 Administration from the University of Oregon in 2001.

14 *Q. Please state your professional experience.*

15 A. I was hired into BPA in July 2000 through a cooperative student program. From July 2000
16 to May 2005, I worked as a financial analyst where my duties were centered on managing
17 the BPA Transmission capital program. In May 2005, I was hired into my current position
18 as a Public Utilities Specialist where my responsibilities are centered on revenue forecasting
19 and business practice/policy development. For the 2006 rate case, I developed a forecast of
20 Large Generation Interconnection transmission credits, which was factored into both the
21 BPA TS rate case sales forecast and revenue requirement.

22 *Q. Please state your experience as a witness in previous proceedings.*

23 A. I have had no prior experience with regard to rate case proceedings.

TR-08-Q-BPA-06

Page 1

Witness: Eric K. Taylor

1 QUALIFICATION STATEMENT OF

2 JOHN R. WOERNER

3 Witness for the Bonneville Power Administration

4 *Q. Please state your name, employer, and business address.*

5 A. My name is John R. Woerner. I am employed by the Bonneville Power Administration
6 (BPA), 7500 NE 41st Street, Vancouver, Washington, 98662.

7 *Q. In what capacity are you employed?*

8 A. I am an Industry Economist in BPA's Transmission Services (TS), Transmission Policy, Rates,
9 and Revenue Forecasting group.

10 *Q. Please state your educational background.*

11 A. I received a B.A. and M.A. degrees in Economics from the University of Montana in 1970
12 and 1975, respectively. I minored in philosophy and math as an undergraduate and
13 emphasized econometrics during graduate school. Following this, I worked for 1 year in a
14 Ph.D. program in geography at the University of Washington, where I studied regional
15 economics and quantitative methods.

16 *Q. Please state your professional experience.*

17 A. I was employed as a research assistant for the Bureau of Business and Economic Research,
18 University of Montana in 1974-1975. Since March 1980, I have worked for BPA
19 specializing in rate development and forecasting. In BPA's 1981 and 1982 rate cases, I
20 worked on the time-differentiation of power rates. I ran the Wholesale Power Rate Design
21 computer program in BPA's 1983 rate case. From 1984 to 1993, I was responsible for the
22 Transmission Rate Design model. I developed a statistical wheeling energy forecast model

1 for BPA's 1987 transmission rate case as a front-end model to the Transmission Rate Design
2 Study (TRDS). This model was used to forecast energy sales for rate-setting purposes
3 through the 1993 case. I designed and populated the 1996 Transmission Rate Design Study,
4 with similar responsibilities in the 2002, 2004, and 2006 Transmission Rate Cases. My
5 current responsibilities include forecasting TS revenue.

6 *Q. Please state your experience as a witness in previous proceedings.*

7 A. In BPA's 1987 rate case, I sponsored the above-mentioned statistical wheeling forecasting
8 model as an exhibit to the TRDS. I was a member of the transmission rates panel
9 sponsoring the TRDS in the 1993, 1996, 2002, 2004 and 2006 rate cases.

1 QUALIFICATION STATEMENT OF

2 DENNIS E. METCALF

3 Witness for the Bonneville Power Administration

4 *Q. Please state your name, employer, and business address.*

5 A. My name is Dennis E. Metcalf. I am employed by the Bonneville Power Administration
6 (BPA), 7500 N.E. 41st Street, Vancouver, Washington, 98663.

7 *Q. In what capacity are you employed?*

8 A. I am the Manager Transmission Policy and Strategy in the Transmission Services (TS). I have
9 lead responsibility for the development and implementation of BPA's Transmission Rates and
10 Tariffs.

11 *Q. Please state your educational background.*

12 A. I received a B.S. degree in Economics from Portland State University in 1973.

13 *Q. Please summarize your professional experience.*

14 A. I was initially employed at BPA in 1977 in the Division of Rates as an Industry Economist.
15 For over 13 years I worked in the Division of Rates and the Division of Contracts and Rates.
16 During this period, I worked on all aspects of BPA ratemaking, including retail rate review,
17 transmission rates, cost allocation, nonfirm energy rates, power rate design, and rate case
18 planning. I held several positions including Chief of the Rate Design Section, Chief of the
19 Wholesale Rates Branch, and Deputy Director of the Divisions of Rates and of the Division
20 of Contracts and Rates.

21 From 1991 to 1994 I was the Lower Columbia Area Power Manager. In that
22 position I managed BPA's Power Sales business with its customers in Western Oregon and

1 Southwest Washington. My management functions included primarily load forecasting and
2 contract negotiation and administration.

3 In 1994, I briefly served as a Direct Service Industry Account Executive.

4 From 1995 to 1996 I worked in Pricing, Marginal Cost and Ratemaking in a position
5 similar to my current position. During that time I managed the development of BPA's 1995
6 and 1996 Transmission Rates and Transmission Terms and Conditions cases. In my current
7 position, I managed development of BPA's 1995 and 1996 Transmission Rates and
8 Transmission Terms and Conditions cases. In addition, I was BPA's lead representative on
9 the IndeGo pricing team during 1996-1998. I was also a member of BPA's core team to
10 work on the formation of RTO West, focusing on pricing issues.

11 *Q. Please state your experience as a witness in previous proceedings.*

12 *A.* I filed written testimony and appeared as a witness in BPA's 1981, 1982, 1983, 1985, and
13 1987, 1995, 1996, 2002, 2004 and rate cases. In 1984, I testified before the Federal Energy
14 Regulatory Commission on BPA's 1981 nonfirm energy rates. In 1986, I testified in BPA's
15 Variable Industrial Rate Case.