Service Agreement No. 02TX-10791

AUTHENTICATED

AMENDED AND RESTATED SERVICE AGREEMENT

for

POINT-TO-POINT

TRANSMISSION SERVICE

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

EUGENE WATER & ELECTRIC BOARD

1. This Service Agreement is entered into, by and between the Bonneville Power Administration Transmission Services (Transmission Provider) and Eugene Water & Electric Board (Transmission Customer).

2. The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Point-to-Point (PTP) Transmission Service under the Transmission Provider's Open Access Transmission Tariff (Tariff).

3. The Transmission Customer has provided to the Transmission Provider a deposit, if applicable, unless such deposit has been waived by the Transmission Provider, for Firm Point-to-Point Transmission Service in accordance with the provisions of Section 17.3 of the Tariff.

4. Service under this Service Agreement for a transaction shall commence on the later of (1) the Service Commencement Date as specified by the Transmission Customer in a subsequent request for transmission service or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed. This Service Agreement shall terminate on such date as mutually agreed upon by the Parties.

5. The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Point-to-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6. Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated in Exhibit D.

7. The Tariff, Exhibit A (Transmission Service Request), Exhibit B (Direct Assignment and Use-of-Facilities Charges), Exhibit C (Ancillary Service Charges), Exhibit D (Notices), and Exhibit E (Creditworthiness and Prepayment) are incorporated herein and made a part hereof. Capitalized terms not defined in this Service Agreement are defined in the Tariff.

8. This Service Agreement shall be interpreted, construed, and enforced in accordance with Federal law.

9. This Service Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and assigns.

10. The Transmission Customer and the Transmission Provider agree that provisions of Section 3201(i) of Public Law 104-134 (Bonneville Power Administration Refinancing Act) are incorporated in their entirety and hereby made a part of this Service Agreement.

11. Section 202 of Executive Order No. 11246, 30 Fed. Reg. 12319 (1965), as amended by Executive Order No. 12086, 43 Fed. Reg. 46501 (1978), as amended or supplemented, which provides, among other things, that the Transmission Customer will not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin, is incorporated by reference in the Service Agreement the same as if the specific language had been written into the Service Agreement, except that Indian Tribes and tribal organizations may apply Indian preference to the extent permitted by Federal law.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

EUGENE WATER & ELECTRIC BOARD		UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration	
By:	**/S/ KEVIN CARDOZA**	By:	**/S/ G. DOUG JOHNSON**
Name:	**Kevin Cardoza** *(Print/Type)*	Name:	G. Doug Johnson *(Print/Type)*
Title:	**Real Time Supervisor**	Title:	Transmission Account Executive
Date:	**9/28/16**	Date:	**10/18/16**

EXHIBIT A
SPECIFICATIONS FOR LONG-TERM
FIRM POINT-TO-POINT TRANSMISSION SERVICE

This Exhibit A is not applicable at this time.

EXHIBIT B
DIRECT ASSIGNMENT AND USE-OF-FACILITIES CHARGES

This Exhibit B is not applicable at this time.

EXHIBIT C
ANCILLARY SERVICE CHARGES

This Exhibit C accomplishes the following: (1) updates the Ancillary Service Charges to reference the current Rate Schedule; and (2) updates format in Section 3 in the "Provided By" column by adding "As Applicable" as well as associated footnote.

This Exhibit C is subject to the Ancillary Service Rate Schedule, or its successor, in effect at the time of service.

		Provided By	Contract No.
1.	**SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE**	Transmission Provider – As Applicable[1]	02TX-10791
2.	**REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION OR OTHER SOURCES SERVICE**	Transmission Provider – As Applicable[1]	02TX-10791
3.	**REGULATION & FREQUENCY RESPONSE SERVICE**	Transmission Provider – As Applicable[1]	02TX-10791
4.	**ENERGY IMBALANCE SERVICE**	Transmission Provider – As Applicable[1]	02TX-10791
5.	**OPERATING RESERVE – SPINNING RESERVE SERVICE**	Transmission Provider[1]	02TX-10791
6.	**OPERATING RESERVE – SUPPLEMENTAL RESERVE SERVICE**	Transmission Provider[1]	02TX-10791

[1] Refer to the Transmission, Ancillary, and Control Area Service Rate Schedules and General Rate Schedule Provisions to determine which Ancillary Service Charges are applicable.

EXHIBIT D
NOTICES

1. NOTICES RELATING TO PROVISIONS OF THE SERVICE AGREEMENT

Any notice or other communication related to this Service Agreement, other than notices of an operating nature (Section 2 below), shall be in writing and shall be deemed to have been received if delivered in person, by First Class mail, by facsimile or sent by overnight delivery service.

If to the Transmission Customer:

Eugene Water & Electric Board
4200 Roosevelt Boulevard
Eugene OR, 97402
Attention: Kevin Cardoza
Title: Real-Time Supervisor
Phone: (541) 685-7338
Fax: (541) 685-7598
E-mail: kevin.cardoza@eweb.org

If to the Transmission Provider:

Attention: Transmission Account Executive for Eugene Water & Electric Board – TSE/TPP-2
Phone: (360) 619-6016
Fax: (360) 619-6940

If by First Class Mail:
Bonneville Power Administration
P.O. Box 61409
Vancouver, WA 98666

If by Overnight Delivery Service:
Bonneville Power Administration – TSE/TPP-2
905 NE 11th Avenue
Portland, OR 97232

2. NOTICES OF AN OPERATING NATURE

Any notice, request, or demand of an operating nature by the Transmission Provider or the Transmission Customer shall be made either orally or in writing by First Class mail or by facsimile.

If to the Transmission Customer:

Eugene Water & Electric Board
4200 Roosevelt Boulevard
Eugene, OR 97402
Attention: EWEB Real-Time
Phone: (541) 685-7555
Fax: (541) 685-7555
E-mail: realtime.realtime@eweb.org

If to the Transmission Provider:

Bonneville Power Administration
P.O. Box 491
Vancouver, WA 98666
Attention: Real-Time Scheduling
Phone: **EMERGENCY ONLY**
(360) 695-2650
Fax: (360) 418-8740

3. SCHEDULING AGENT

Transmission Customer performs its own scheduling.

EXHIBIT E
CREDITWORTHINESS AND PREPAYMENT

This Exhibit E is not applicable at this time.

Rec'd 10/31/11 0855 Vea Fedex 8V

Service Agreement No. 02TX-10793

AMENDED SERVICE AGREEMENT

for

NETWORK INTEGRATION

TRANSMISSION SERVICE

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

EUGENE WATER & ELECTRIC BOARD

1. This Service Agreement is entered into, by and between the Bonneville Power Administration Transmission Services (Transmission Provider) and Eugene Water & Electric Board (Transmission Customer).

2. The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Network Integration Transmission Service under the Transmission Provider's Open Access Transmission Tariff (Tariff).

3. The Transmission Customer has provided to the Transmission Provider a deposit, unless such deposit has been waived by the Transmission Provider, for Transmission Service in accordance with the provisions of Section 29.2 of the Tariff.

4. Service under this agreement shall commence on the later of (1) the requested Service Commencement Date, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed. Service under this agreement shall terminate on such date as mutually agreed upon by the parties.

5. The Transmission Provider agrees to provide and the Transmission Customer agrees to pay for Network Integration Transmission Service in accordance with the provisions of Part III of the Tariff and this Service Agreement.

6. Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated in Exhibit D.

7. The Tariff, Exhibit A (Specifications for Network Integration Transmission Service), Exhibit B (Direct Assignment and Use-of-Facilities Charges), Exhibit C (Ancillary Services), and Exhibit D (Notices) are incorporated herein and made a part hereof. Capitalized terms not defined in this agreement are defined in the Tariff.

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8. This Service Agreement shall be interpreted, construed, and enforced in accordance with Federal law.

9. This Service Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors.

10. The Transmission Customer and the Transmission Provider agree that provisions of Section 3201(i) of Public Law 104-134 (Bonneville Power Administration Refinancing Act) are incorporated in their entirety and hereby made a part of this Service Agreement.

11. Section 202 of Executive Order No. 11246, 30 Fed. Reg. 12319 (1965), as amended by Executive Order No. 12086, 43 Fed. Reg. 46501 (1978), as amended or supplemented, which provides, among other things, that the Transmission Customer will not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin, is incorporated by reference in the Service Agreement the same as if the specific language had been written into the Service Agreement, except that Indian Tribes and tribal organizations may apply Indian preference to the extent permitted by Federal law.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

EUGENE WATER & ELECTRIC BOARD

(b) (6)

By: [redacted]

Name: Clay Norris
(Print/Type)

Title: Director, Power Resources

Date: 10·28·2011

UNITED STATES OF AMERICA
Department of Energy
Bonneville Power Administration

(b) (6)

By: [redacted]

Name: J. Diego Ochoa
(Print/Type)

Title: Transmission Account Executive

Date: 11/2/2011

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EXHIBIT A
SPECIFICATIONS FOR
NETWORK INTEGRATION TRANSMISSION SERVICE

TRANSMISSION SERVICES REQUEST
Assign Ref(s): 1800692 & 76179306

This Exhibit A accomplishes the following: (1) adds renewal Assign Refs 76179260, 76179263, 76179265, & 76179270 under Section 2, (2) adds Leaburg Hydroelectric, Walterville Hydroelectric, and International Paper as Behind the Meter Network Resources in Section 2(c), (3) adds Short Distance Discount and eligible Network Resources under Section 8.1, (4) removes Declared Customer Served Load from Section 9, (5) removes EWEB Cogen (U of O) as a designated Network Resource, and (6) updates rate schedule references to reflect the current Service Agreement Charges.

1. TERM OF TRANSACTION

For Assign Ref(s): 1800692
Service Agreement Start Date: at 0000 hours on December 1, 2006.
Service Agreement Termination Date: at 0000 hours on December 1, 2011.

For Assign Ref(s): 76179306
Service Agreement Start Date: at 0000 hours on December 1, 2011.
Service Agreement Termination Date: at 0000 hours on October 1, 2028.

2. NETWORK RESOURCES

Pursuant to section 29.2 and 30.2 of Transmission Provider's Tariff, Transmission Customer has designated the following Network Resources:

(a) **Generation Owned by the Transmission Customer**

Resource Name	Start Date	Stop Date	Designated Capacity (MW)	Point of Receipt & Source	Balancing Authority	Associated Assign Ref
Carmen-Smith/ Trail Bridge[1]	12/1/06	12/1/11	100	EWEB/ CARMNSMTHTP115	BPAT[2]	1800695
Carmen-Smith/ Trail Bridge[1]	12/1/11	10/1/28	100	EWEB/ CARMNSMTHTP115	BPAT[2]	76179260
Smith Creek	12/1/06	12/1/11	37	SMITHCREEK/ SMITHCRKTP115	BPAT[2]	1800694
Smith Creek	12/1/11	10/1/28	37	SMITHCREEK/ SMITHCRKTP115	BPAT[2]	76179263

[1] Generation output from Carmen-Smith and Trail Bridge resources is associated with Transmission Assign Ref, 1800695, for 100 MW of Designated Capacity. The Carmen-Smith resource is 95 MW of the 100 MW of Designated Capacity, and Trail Bridge is 5 MW.

[2] Bonneville Power Administration Transmission.

(b) **Generation Purchased by the Transmission Customer**

Source (Contract No.) or Resource Name	Start Date	Stop Date	Designated Capacity (MW)	Point of Receipt & Source	Balancing Authority	Associated Assign Ref
BPA-PBL 00PB-12041 (10/1/01 – 10/1/11)	12/1/06	12/1/11	Block Product/ Slice Output Energy	FCRPS[3]	BPAT[2]	1800692
BPA-PBL 09PB-13041 (10/1/11 – 10/1/28)	12/1/11	10/1/28	Block Product/ Slice Output Energy	FCRPS[3]	BPAT[2]	76179306
Klondike III	1/1/08	1/1/28	25	KLONDIKESH/ KLONDIKESH230	BPAT[2]	71774599
Priest Rapids	12/1/06	12/1/11	16	BPAT.GCPD/ MIDWAY230GCPD	GCPD[4]	71349648
Priest Rapids	12/1/11	10/1/28	16	BPAT.GCPD/ MIDWAY230GCPD	GCPD[4]	76179270
Wanapum	12/1/06	12/1/11	21	BPAT.GCPD/ VANTAGE230	GCPD[4]	1800693
Wanapum	12/1/11	10/1/28	21	BPAT.GCPD/ VANTAGE230	GCPD[4]	76179265

(c) **Local Resource Behind the Meter (owned or purchased)**

Resource Name	Start Date	Stop Date	Designated Capacity (MW)	Balancing Authority	Associated Assign Ref
Metro Wastewater	06/30/2010	09/30/2019	0.800	BPAT[2]	N/A[5]
Seneca Sustainable Energy	03/1/2011	03/1/2016	19.877	BPAT[2]	N/A[5]
Leaburg Hydroelectric	10/1/2011	10/1/2028	16.72	BPAT[2]	N/A[5]
Walterville Hydroelectric	10/1/2011	10/1/2028	8	BPAT[2]	N/A[5]
International Paper	10/1/2011	10/1/2028	12.7	BPAT[2]	N/A[5]

3. POINT(S) OF RECEIPT

(a) Federal Generation Point(s) of Receipt

Transmission Customer Point of Receipt: Federal Columbia River Power System (FCRPS);

POR Number: 3453;

Balancing Authority: BPAT;

[3] Federal Columbia River Power System.

[4] Grant County PUD No. 2.

[5] There is no Associated Assign Ref for this Network Resource.

Location: FCRPS;

Voltage: 500 kV;

Metering: Scheduled quantity;

Exceptions: none.

(b) **Non-Federal Resource Point(s) of Receipt**

(1) **Transmission Customer Point of Receipt:** Carmen-Smith Tap 115 kV;

POR Number: 3324;

Balancing Authority: BPAT;

Location: the points near structure 2/5 in the Transmission Provider's Cougar - Thurston No. 1 115 kV Transmission Line where the 115 kV facilities of the Transmission Provider and Eugene Water & Electric Board are connected;

Voltage: 115 kV;

Metering: at the Carmen-Smith Project, in the 115 kV circuit over which such electric power flows;

Metering Loss Adjustment: none;

Exceptions: none.

(2) **Transmission Customer Point of Receipt:** Klondike SH 230 kV;

POR Number: 4026;

Balancing Authority: BPAT;

Location: the point at Iberdrola Renewables, Inc.'s Klondike Schoolhouse Substation, where the 230 kV facilities of the Transmission Provider and Iberdrola Renewables, Inc. are connected;

Voltage: 230 kV;

Metering: at the Klondike SH Substation in the 230 kV circuit over which such electric power flows;

Metering Loss Adjustment: none;

Exceptions: none.

(3) **Transmission Customer Point of Receipt:** Midway 230 kV - GCPD;

POR Number: 3669;

Balancing Authority: GCPD;

Location: the points in the Transmission Provider's Midway Substation where the 230 kV facilities of the Transmission Provider and the Public Utility District No. 2 of Grant County are connected;

Voltage: 230 kV;

Metering: metered quantity for deliveries from Priest Rapids Hydro Project [6];

Metering Loss Adjustment: none;

Exceptions: none.

(4) **Transmission Customer Point of Receipt:** Smith Creek Tap 115 kV;

POR Number: 3877;

Balancing Authority: BPAT;

Location: the point near the Transmission Provider's Bonner's Ferry Substation where the 115 kV facilities of the Transmission Provider and Eugene Water & Electric Board are connected;

Voltage: 115 kV;

Metering: at Smith Falls Hydro Project, in the 13.8 kV circuit over which such electric power flows;

Metering Loss Adjustment: none;

Exceptions: none.

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[6] Eugene Water & Electric Board has long-term rights to shares of generation from the Priest Rapids and Wanapum Dams. Within each hour, Eugene Water & Electric Board controls its share of instantaneous generation. At the end of each hour, Eugene Water & Electric Board's share of actual total generation is calculated from Grant County PUD metering -- net of transfers, losses and other schedules -- and the resulting net generation is deemed delivered to Eugene Water & Electric Board at the Point of Receipt. This net generation is divided between Wanapum and Priest Rapids for power accounting and transmission purposes based on the respective shares of generation at the Dams.

(5) **Transmission Customer Point of Receipt:** Vantage 230 kV;

POR Number: 3977;

Balancing Authority: GCPD;

Location: the points in the Transmission Provider's Vantage Substation where the 230 kV facilities of the Transmission Provider and the Public Utility District No. 2 of Grant County are connected;

Voltage: 230 kV;

Metering: metered quantity for deliveries from Wanapum Hydro Project[6];

Metering Loss Adjustment: none;

Exceptions: none.

4. POINT(S) OF DELIVERY

(a) **Description of Network Points of Delivery:** EWEBNTDP

(1) **Transmission Customer Point of Delivery:** Alvey 115 kV - EWEB;

BPA POD Name: EWEB;

BPA POD Number: 25;

Balancing Authority: BPAT;

Location: the point in the Transmission Provider's J.P. Alvey substation where the 115 kV facilities of the Transmission Provider and Eugene Water & Electric Board are connected;

Voltage: 115 kV;

Metering: in the Transmission Provider's J.P. Alvey Substation in the Alvey-Currin 115 kV circuit over which such electric power flows;

(A) **BPA Meter Point Name:** Alvey Out;

BPA Meter Point Number: 1245;

Direction for Billing Purposes: positive;

Manner of Service: direct, Transmission Provider to Eugene Water & Electric Board;

(B) **BPA Meter Point Name:** Alvey In;

BPA Meter Point Number: 1246;

Direction for Billing Purposes: negative;

Manner of Service: direct, Eugene Water & Electric Board to Transmission Provider;

Metering Loss Adjustment: not applicable;

Exceptions: subtract deliveries to Springfield Utility Board at Thurston 12.5 kV [MP 609], and Weyerhaeuser No. 2 Substation 115 kV (metered at 12.5 kV) [MP2958 – Sierra Pine] metering locations. Apply published network and delivery loss factors.

(2) **Transmission Customer Point of Delivery:** Alvey 230 kV - PACW;

BPA POD Name: BPAT.PACW;

BPA POD Number: 3226;

Balancing Authority: PACW;

Location: the point in the Transmission Provider's J. P. Alvey Substation, where the 230 kV facilities of the Transmission Provider and PacifiCorp are connected;

Voltage: 230 kV;

Metering:

(A) in Eugene Water & Electric Board's McKenzie Substation, the 115 kV circuit over which such electric power flows;

(i) **BPA Meter Point Name:** SUB McKenzie - In;

BPA Meter Point Number: 2152;

Direction for Billing Purposes: positive;

Manner of Service: direct, Transmission Provider to Eugene Water & Electric Board;

(ii) **BPA Meter Point Name:** SUB McKenzie - Out;

BPA Meter Point Number: 2153;

Direction for Billing Purposes: negative;

Manner of Service: direct, Eugene Water & Electric Board to Transmission Provider;

(iii) **BPA Meter Point Name:** 69kV EWEB to PPL;

BPA Meter Point Number: 2646;

Direction for Billing Purposes: negative;

Manner of Service: direct, Eugene Water & Electric Board to Transmission Provider;

(iv) **BPA Meter Point Name:** 69kV PPL to EWEB;

BPA Meter Point Number: 2647;

Direction for Billing Purposes: positive;

Manner of Service: direct, Transmission Provider to Eugene Water & Electric Board;

(B) in the Transmission Provider's Alvey Substation in the 230 kV circuit over which such electric power flows;

(i) **BPA Meter Point Name:** 230kV EWEB to PPL;

BPA Meter Point Number: 2644;

Direction for Billing Purposes: negative;

Manner of Service: direct, Eugene Water & Electric Board to Transmission Provider;

(ii) **BPA Meter Point Name:** 230kV PPL to EWEB;

BPA Meter Point Number: 2645;

Direction for Billing Purposes: positive;

Manner of Service: direct, Transmission Provider to Eugene Water & Electric Board;

Metering Loss Adjustment: the Transmission Provider will adjust for losses between Eugene Water & Electric Board's Point of Delivery and Point(s) of Metering. Such adjustments shall be specified in written correspondence between the Transmission Provider and Eugene Water & Electric Board;

Exceptions:

(i) Eugene Water & Electric Board is responsible for arranging transmission service over the path between J. P. Alvey Substation and McKenzie Substation;

(ii) subtract PacifiCorp's 69 kV meter location [MP 2646] at McKenzie Substation.

(3) **Transmission Customer Point of Delivery:** Bertelsen 115 kV;

BPA POD Name: EWEB;

BPA POD Number: 59;

Balancing Authority: BPAT;

Location: the point between structures 3/3 and 3/4 in the Eugene-Bertelsen section of the Transmission Provider's Eugene-Alvey 115 kV line No. 1 where the facilities of the Transmission Provider and Eugene Water & Electric Board are connected;

Voltage: 115 kV;

Metering: in Eugene Water & Electric Board's Bertelsen Substation, in the 115 kV circuit over which such electric power and energy flows;

(A) **BPA Meter Point Name:** Bertelsen Out;

BPA Meter Point Number: 390;

Direction for Billing Purposes: positive;

Manner of Service: direct, the Transmission Provider to Eugene Water & Electric Board;

(B) **BPA Meter Point Name:** Bertelsen-Seneca 115 Out;

BPA Meter Point Number: 3480;

Direction for Billing Purposes: positive;

Manner of Service: direct, Transmission Provider to Eugene Water & Electric Board;

(C) **BPA Meter Point Name:** Bertelsen-Seneca 115 In;

BPA Meter Point Number: 3481;

Direction for Billing Purposes: negative;

Manner of Service: direct, Eugene Water & Electric Board to Transmission Provider;

Metering Loss Adjustment: not applicable;

Exceptions: Bertelsen-Seneca 115 Out and Bertelsen-Seneca 115 In meter points not yet energized. Expected energization is Fall 2011.

(4) **Transmission Customer Point of Delivery:** Dillard Tap 115 kV;

BPA POD Name: EWEB;

BPA POD Number: 180;

Balancing Authority: BPAT;

Location: the point at structure No. 10/3 in the Transmission Provider's Eugene-Alvey 115 kV line No. 2 where the facilities of the Transmission Provider and Eugene Water & Electric Board are connected;

Voltage: 115 kV;

Metering: in Eugene Water & Electric Board's Dillard Substation in the 115 kV circuit over which such electric power flows;

(A) **BPA Meter Point Name:** Dillard Out;

BPA Meter Point Number: 555;

Direction for Billing Purposes: positive;

Manner of Service: direct, Transmission Provider to Eugene Water & Electric Board;

(B) **BPA Meter Point Name:** Dillard In;

BPA Meter Point Number: 556;

Direction for Billing Purposes: negative;

Manner of Service: direct, Eugene Water & Electric Board to Transmission Provider;

Metering Loss Adjustment: not applicable;

Exceptions: none.

(5) **Transmission Customer Point of Delivery:** Eugene 115 kV;

BPA POD Name: EWEB;

BPA POD Number: 221;

Balancing Authority: BPAT;

Location: the point in the Transmission Provider's Eugene Substation where the 115 kV facilities of the Transmission Provider and Eugene Water & Electric Board are connected;

Voltage: 115 kV;

Metering: in the Transmission Provider's Eugene Substation, in the 115 kV circuits over which such electric power flows;

(A) **BPA Meter Point Name:** Eugene 115 Out;

BPA Meter Point Number: 1249;

Direction for Billing Purposes: positive;

Manner of Service: direct, Transmission Provider to Eugene Water & Electric Board;

(B) **BPA Meter Point Name:** Eugene 115 In;

BPA Meter Point Number: 1250;

Direction for Billing Purposes: negative;

Manner of Service: direct, Eugene Water & Electric Board to Transmission Provider;

(C) **BPA Meter Point Name:** Eugene 115 kV Bethel In;

BPA Meter Point Number: 2142;

Direction for Billing Purposes: negative;

Manner of Service: direct, Eugene Water & Electric Board to Transmission Provider;

(D) **BPA Meter Point Name:** Eugene 115 kV Bethel Out;

BPA Meter Point Number: 2143;

Direction for Billing Purposes: positive;

Manner of Service: direct, Transmission Provider to Eugene Water & Electric Board;

Metering Loss Adjustment: not applicable;

Exceptions: none.

(6) **Transmission Customer Point of Delivery:** Hawkins 115 kV;

BPA POD Name: EWEB;

BPA POD Number: 313;

Balancing Authority: BPAT;

Location: the point at structure 6/6 in the Bertelsen-Hawkins section of the Transmission Provider's Eugene-Alvey 115 kV line No. 1 where the facilities of the Transmission Provider and Eugene Water & Electric Board are connected;

Voltage: 115 kV;

Metering: in Eugene Water & Electric Board Hawkins Substation, in the 12.5 kV circuit over which such electric power flows;

BPA Meter Point Name: Hawkins Out;

BPA Meter Point Number: 357;

Direction for Billing Purposes: positive;

Manner of Service: direct, Transmission Provider to Eugene Water & Electric Board;

Metering Loss Adjustment: the Transmission Provider will adjust for losses between Eugene Water & Electric Board's Point of Delivery and Point(s) of Metering. Such adjustments shall be specified in written correspondence between the Transmission Provider and Eugene Water & Electric Board;

Exceptions: none.

(7) **Transmission Customer Point of Delivery:** Lane 115 kV;

BPA POD Name: EWEB;

BPA POD Number: 385;

Balancing Authority: BPAT;

Location: the points in the Transmission Provider's Lane Substation where the 115 kV facilities of the Transmission Provider and Eugene Water & Electric Board are connected;

Voltage: 115 kV;

Metering: in the Transmission Provider's Lane Substation in the 115 kV circuits over which such electric power flows;

(A) **BPA Meter Point Name:** Lane #1 Out;

BPA Meter Point Number: 1247;

Direction for Billing Purposes: positive;

Manner of Service: direct, Transmission Provider to Eugene Water & Electric Board;

(B) **BPA Meter Point Name:** Lane #1 In;

BPA Meter Point Number: 1248;

Direction for Billing Purposes: negative;

Manner of Service: direct, Eugene Water & Electric Board to Transmission Provider;

(C) **BPA Meter Point Name:** Lane #2 Out;

BPA Meter Point Number: 974;

Direction for Billing Purposes: positive;

Manner of Service: direct, Transmission Provider to Eugene Water & Electric Board;

(D) **BPA Meter Point Name:** Lane #2 In;

BPA Meter Point Number: 975;

Direction for Billing Purposes: negative;

Manner of Service: direct, Eugene Water & Electric Board to Transmission Provider;

Metering Loss Adjustment: not applicable;

Exceptions: none.

(8) **Transmission Customer Point of Delivery:** McKenzie 115 kV-EWEB;

BPA POD Name: EWEB;

BPA POD Number: 4114;

Balancing Authority: BPAT;

Location: the point in Eugene Water & Electric Board's McKenzie Substation where the 115 kV facilities of the Transmission Provider and Eugene Water & Electric Board are connected;

Voltage: 115 kV;

Metering:

(A) in Eugene Water & Electric Board's Thurston Substation in the 115 kV circuits over which such electric power flows;

(i) **BPA Meter Point Name:** Thurston/Willakenzie In;

BPA Meter Point Number: 1812;

Direction for Billing Purposes: negative;

Manner of Service: direct, Eugene Water & Electric Board to Transmission Provider;

(ii) **BPA Meter Point Name:** Thurston/Willakenzie Out;

BPA Meter Point Number: 1813;

Direction for Billing Purposes: positive;

Manner of Service: direct, Transmission Provider to Eugene Water & Electric Board;

(B) in Eugene Water & Electric Board's McKenzie Substation in the 115 kV circuit over which such electric power flows;

(i) **BPA Meter Point Name:** EWEB McKenzie Thurston Line In;

BPA Meter Point Number: 3071;

Direction for Billing Purposes: negative;

Manner of Service: direct, Eugene Water & Electric Board to Transmission Provider;

(ii) **BPA Meter Point Name:** EWEB McKenzie Thurston Line Out;

BPA Meter Point Number: 3072;

Direction for Billing Purposes: positive;

Manner of Service: direct, Transmission Provider to Eugene Water & Electric Board;

Metering Loss Adjustment: not applicable;

Exceptions: subtract the deliveries to the Springfield Utility Board at the McKenzie (Gateway) 115 kV metering location [MP 2153]. Apply published network and delivery loss factors.

(9) **Transmission Customer Point of Delivery:** Thurston 115 kV;

BPA POD Name: EWEB;

BPA POD Number: 3930;

Balancing Authority: BPAT;

Location: the point at structure No. 39/4 in the Transmission Provider's Cougar - McKenzie No. 1 transmission line where the facilities of the Transmission Provider and Eugene Water & Electric Board are connected;

Voltage: 115 kV;

Metering:

(A) in Eugene Water & Electric Board's Thurston Substation in the 115 kV circuits over which such electric power flows;

(i) **BPA Meter Point Name:** Thurston Out;

BPA Meter Point Number: 504;

Direction for Billing Purposes: positive;

Manner of Service: direct, Transmission Provider to Eugene Water & Electric Board;

(ii) **BPA Meter Point Name:** Thurston In;

BPA Meter Point Number: 505;

Direction for Billing Purposes: negative;

Manner of Service: direct, Eugene Water & Electric Board to Transmission Provider;

(B) in Eugene Water & Electric Board's Thurston Substation in the 12.5 kV circuits over which such electric power flows;

BPA Meter Point Name: Thurston/Springfield Out;

BPA Meter Point Number: 609;

Direction for Billing Purposes: negative;

Manner of Service: direct, Eugene Water & Electric Board to Transmission Provider;

(C) in Eugene Water & Electric Board's Weyerhauser #2 Substation in the 12.5 kV circuit over which such electric power flows;

BPA Meter Point Name: Sierra Pine Out;

BPA Meter Point Number: 2958;

Direction for Billing Purposes: negative;

Manner of Service: direct, Eugene Water & Electric Board to Transmission Provider;

Metering Loss Adjustment: the Transmission Provider will adjust for losses between Eugene Water & Electric Board's Point of Delivery and Point(s) of Metering. Such adjustments shall be specified in written correspondence between the Transmission Provider and Eugene Water & Electric Board;

Exceptions: deliveries to Springfield Utility Board at 12.5 kV at Thurston/Springfield Out [MP 609] and 12.5 kV at Sierra Pine Out [MP 2958] are already subtracted from the total metered quantities and adjusted for losses at the Alvey 115 kV - EWEB POD No. 25.

(10) **Transmission Customer Point of Delivery:** Willow Creek 115-EWEB;

BPA POD Name: EWEB;

BPA POD Number: 2040;

Balancing Authority: BPAT;

Location: the point at structure 2/3 in the Bertelsen - Willow Creek section of the Transmission Provider's Eugene - Alvey 115 kV line No. 1 where the facilities of the Transmission Provider and Eugene Water & Electric Board are connected;

Voltage: 115 kV;

Metering: in Eugene Water & Electric Board's Willow Creek Substation in the 115 kV circuit over which such electric power flows;

(A) **BPA Meter Point Name:** Willow Creek N. Bus In;

BPA Meter Point Number: 2040;

Direction for Billing Purposes: negative;

Manner of Service: direct, Eugene Water & Electric Board to Transmission Provider;

(B) **BPA Meter Point Name:** Willow Creek N. Bus Out;

BPA Meter Point Number: 2041;

Direction for Billing Purposes: positive;

Manner of Service: direct, Transmission Provider to Eugene Water & Electric Board;

(C) **BPA Meter Point Name:** Willow Creek S. Bus In;

BPA Meter Point Number: 2042;

Direction for Billing Purposes: negative;

Manner of Service: direct, Eugene Water & Electric Board to Transmission Provider;

(D) **BPA Meter Point Name:** Willow Creek S. Bus Out;

BPA Meter Point Number: 2043;

Direction for Billing Purposes: positive;

Manner of Service: direct, Transmission Provider to Eugene Water & Electric Board;

Metering Loss Adjustment: not applicable;

Exceptions: none.

(b) **Description of Transfer Points of Delivery**
Not applicable. See section 4(a).

5. NETWORK LOAD

The Application provides the Transmission Customer's initial annual load and resource information. Annual load and resource information updates shall be submitted to the Transmission Provider at the address specified in Exhibit D (Notices), by September 30th of each year, unless otherwise agreed to by the Transmission Provider and the Transmission Customer.

6. DESIGNATION OF PARTY(IES) SUBJECT TO RECIPROCAL SERVICE OBLIGATION

Transmission Customer and its affiliates (if they own or control transmission facilities).

7. NAMES OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE

PacifiCorp.

8. SERVICE AGREEMENT CHARGES

Service under this Service Agreement shall be subject to some combination of the charges detailed below. (The appropriate charges for transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 **Transmission Charge:**
2012 Transmission and Ancillary Service Rate Schedules (or, if not in effect, the applicable Rate Schedule) or successor Rate Schedules.

Short Distance Discount (SDD):
The following Designated Network Resource(s) are eligible for the Short Distance Discount pursuant to the 2012 Transmission and Ancillary Service Rate Schedules (or, if not yet in effect, the applicable Rate Schedules) or successor Rate Schedules.

(1) **Carmen-Smith/Trail Bridge**

(A) **Point of Delivery:** Thurston 115 kV;

Transmission Distance: 37.01 Circuit Miles;

(B) **Point of Delivery:** McKenzie 115 kV-EWEB;

Transmission Distance: 43.44 Circuit Miles.

(2) **International Paper**

Transmission Distance: 0 Circuit Miles[7].

[7] For a resource that is designated as a Network Resource that is eligible for the Short Distance Discount (DNR SD) directly connected to the Transmission Customer's system (including Behind the Meter Resources) or a DNR SD that does not use BPA's network facilities, the Transmission Distance shall be zero.

(3) **Leaburg Hydroelectric**

Transmission Distance: 0 Circuit Miles[7].

(4) **Metro Wastewater**

Transmission Distance: 0 Circuit Miles[7].

(5) **Seneca Sustainable Energy**

Transmission Distance: 0 Circuit Miles[7].

(6) **Walterville Hydroelectric**

Transmission Distance: 0 Circuit Miles[7].

8.2 **System Impact and/or Facilities Study Charge:**
System Impact and/or Facilities Study Charges are not required for service under this Service Agreement.

8.3 **Direct Assignment Facilities Charges:**
Facilities Charges are not required at this time for the service under this Service Agreement.

8.4 **Ancillary Service Charges:**
Described in Exhibit C (Ancillary Service Charges) of this Service Agreement.

9. OTHER PROVISIONS SPECIFIC TO THIS SERVICE AGREEMENT
None.

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Boehle,Jennifer M (BPA) - TSES-TPP-2

From: Commercial Business Support Application

Sent: Monday, October 31, 2011 1:28 PM

To: Charbonneau,Ray (BPA) - NJCD-DITT-2; TSR Status; Robertson,Angela D (CONTR) - TSES-TPP-2; Ochoa,J. Diego (BPA) - TSE-TPP-2

Subject: [CBSA] Eugene Water & Electric Board has a Reservation that has been CONFIRMED TSR 76179270

A Long Term Reservation (TSR 76179270) has been CONFIRMED for Eugene Water & Electric Board

Click here to see Transmission Request in CBSA

Boehle,Jennifer M (BPA) - TSES-TPP-2

From: Commercial Business Support Application

Sent: Monday, October 31, 2011 1:28 PM

To: Charbonneau,Ray (BPA) - NJCD-DITT-2; TSR Status; Robertson,Angela D (CONTR) - TSES-TPP-2; Ochoa,J. Diego (BPA) - TSE-TPP-2

Subject: [CBSA] Eugene Water & Electric Board has a Reservation that has been CONFIRMED TSR 76179265

A Long Term Reservation (TSR 76179265) has been CONFIRMED for Eugene Water & Electric Board

Click here to see Transmission Request in CBSA

Boehle,Jennifer M (BPA) - TSES-TPP-2

From: Commercial Business Support Application

Sent: Monday, October 31, 2011 1:28 PM

To: Charbonneau,Ray (BPA) - NJCD-DITT-2; TSR Status; Robertson,Angela D (CONTR) - TSES-TPP-2; Ochoa,J. Diego (BPA) - TSE-TPP-2

Subject: [CBSA] Eugene Water & Electric Board has a Reservation that has been CONFIRMED TSR 76179263

A Long Term Reservation (TSR 76179263) has been CONFIRMED for Eugene Water & Electric Board

Click here to see Transmission Request in CBSA

Boehle,Jennifer M (BPA) - TSES-TPP-2

From: Commercial Business Support Application

Sent: Monday, October 31, 2011 1:28 PM

To: Charbonneau,Ray (BPA) - NJCD-DITT-2; TSR Status; Robertson,Angela D (CONTR) - TSES-TPP-2; Ochoa,J. Diego (BPA) - TSE-TPP-2

Subject: [CBSA] Eugene Water & Electric Board has a Reservation that has been CONFIRMED TSR 76179260

A Long Term Reservation (TSR 76179260) has been CONFIRMED for Eugene Water & Electric Board

Click here to see Transmission Request in CBSA

EXHIBIT B
DIRECT ASSIGNMENT AND USE-OF-FACILITIES CHARGES

Facilities Charges are not required at this time for the service under this Service Agreement.

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EXHIBIT C
ANCILLARY SERVICE CHARGES

This Exhibit C is subject to the ACS-12 Rate Schedule (or, if not in effect, the applicable ACS Rate Schedule), or successor Rate Schedule.

		Provided By	Contract No.
1.	**SCHEDULING, SYSTEM CONTROL AND DISPATCH**	Transmission Provider	02TX-10793
2.	**REACTIVE SUPPLY AND VOLTAGE CONTROL**	Transmission Provider	02TX-10793
3.	**REGULATION & FREQUENCY RESPONSE**	Transmission Provider	02TX-10793
4.	**ENERGY IMBALANCE SERVICE**	Transmission Provider	02TX-10793
5.	**OPERATING RESERVE – SPINNING RESERVE**	Transmission Provider	02TX-10793
6.	**OPERATING RESERVE – SUPPLEMENTAL RESERVE**	Transmission Provider	02TX-10793

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EXHIBIT D
NOTICES

1. NOTICES RELATING TO PROVISIONS OF THE SERVICE AGREEMENT

Any notice or other communication related to this Service Agreement, other than notices of an operating nature (section 2 below), shall be in writing and shall be deemed to have been received if delivered in person, by First Class mail, by facsimile or sent by overnight delivery service.

If to the Transmission Customer:

Eugene Water & Electric Board
P.O. Box 10148
Eugene, OR 97440
Attention: Ms. Megan Capper
Title: Sr. Regional and
Regulatory Analyst
Phone: (541) 685-7363
Fax: (541) 685-7363
E-mail: megan.capper@eweb.org

If to the Transmission Provider:

Attention: Transmission Account Executive for Eugene Water & Electric Board – TSE/TPP-2
Phone: (360) 619-6016
Fax: (360) 619-6940

If by First Class Mail:
Bonneville Power Administration
P.O. Box 61409
Vancouver, WA 98666-1409

If by Overnight Delivery Service:
Bonneville Power Administration – TSE/TPP-2
7500 NE 41st Street, Suite 130
Vancouver, WA 98662

2. NOTICES OF AN OPERATING NATURE

Any notice, request, or demand of an operating nature by the Transmission Provider or the Transmission Customer shall be made either orally or in writing by First Class mail or by facsimile.

If to the Transmission Customer:

Eugene Water & Electric Board
P.O. Box 10148
Eugene, OR 97440
Attention: Mr. Dave Churchman
Title: Power Operations Manager
Phone: (541) 685-7598
Fax: (541) 685-7598
E-mail: dave.churchman@eweb.org

If to the Transmission Provider:

Bonneville Power Administration
Alvey Substation
86000 Highway 99 S.
Eugene, OR 97405
Attention: Chief Operator III
Phone: (541) 988-7011
Fax: (541) 988-7028

EMERGENCY ONLY

Primary: Munro Dispatch
Phone: (509) 465-1820

Alternate: Dittmer Dispatch
Phone: (360) 418-2281
Fax: (360) 418-2938

3. SCHEDULING AGENT

Transmission Customer has no designated scheduling agent.

(W:\TMC\CT\E W E B (Eugene Water & Electric Board)\Amendments\10793_NT_Amended Service Agreement.doc)

Contract No. 09PB-13041

POWER SALES AGREEMENT

executed by the

BONNEVILLE POWER ADMINISTRATION

and

THE CITY OF EUGENE, OREGON

acting by and through the

EUGENE WATER & ELECTRIC BOARD

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Exhibit A	**Net Requirements and Resources**
Exhibit B	**High Water Marks and Contract Demand Quantities**
Exhibit C	**Purchase Obligations**
Exhibit D	**Additional Products and Special Provisions**
Exhibit E	**Metering**
Exhibit F	**Scheduling**
Exhibit G	**This Exhibit Intentionally Left Blank**
Exhibit H	**Renewable Energy Certificates and Carbon Attributes**
Exhibit I	**Critical Slice Amounts**
Exhibit J	**Preliminary Slice Percentage and Initial Slice Percentage**
Exhibit K	**Annual Determination of Slice Percentage**
Exhibit L	**RHWM Augmentation**
Exhibit M	**Slice Computer Application**
Exhibit N	**Slice Implementation Procedures**
Exhibit O	**Interim Slice Implementation Procedures**
Exhibit P	**Slice Computer Application Development Schedule**
Exhibit Q	**Determination of Initial Slice Percentage**

This POWER SALES AGREEMENT (Agreement) is executed by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (BPA), and THE CITY OF EUGENE, OREGON, acting by and through the EUGENE WATER & ELECTRIC BOARD (EWEB), hereinafter individually referred to as "Party" and collectively referred to as the "Parties". EWEB is a municipal corporation, organized and authorized under the laws of the State of Oregon, to purchase and distribute electric power to serve retail consumers from its distribution system within its service area.

RECITALS

EWEB's current power sales agreement (Contract No. 00PB-12041) continues through September 30, 2011, and will be replaced by this Agreement on October 1, 2011.

BPA has functionally separated its organization in order to separate the administration and decision-making activities of BPA's power and transmission functions. References in this Agreement to Power Services or Transmission Services are solely for the purpose of clarifying which BPA function is responsible for administrative activities that are jointly performed.

BPA is authorized to market federal power to qualified entities that are eligible to purchase such power. Under section 5(b)(1) of the Northwest Power Act, BPA is obligated to offer a power sales agreement to eligible customers for the sale and purchase of federal power to serve their retail consumer load in the Region that is not met by the customer's use of its non-federal resources.

BPA has proposed the adoption of a tiered rate pricing methodology for federal power sold to meet BPA's obligations under section 5(b) of the Northwest Power Act to eligible customers, in order to provide more efficient pricing signals and encourage the timely development of regional power resource infrastructure to meet regional consumer loads under this Agreement.

To effect that purpose, in this Agreement BPA establishes a Contract High Water Mark for EWEB that will define the amounts of power EWEB may purchase from BPA at the Tier 1 Rate, as defined in BPA's Tiered Rate Methodology.

The Parties agree:

1. TERM

This Agreement takes effect on the date signed by the Parties and expires on September 30, 2028. Performance by BPA and EWEB shall commence on October 1, 2011, with the exception of those actions required prior to that date that are included in:

(1) sections 3.3 through 3.6 of section 3, Power Purchase Obligation;

(2) section 4, Block Product;

(3) section 5, Slice Product;

(4) section 7, High Water Marks and Contract Demand Quantities;

(5) section 9, Elections to Purchase Power Priced at Tier 2 Rates;

(6) section 10, Tier 2 Remarketing and Resource Removal;

(7) section 11, Right to Change Purchase Obligation;

(8) Intentionally Left Blank;

(9) section 17, Information Exchange and Confidentiality;

(10) section 18, Conservation and Renewables;

(11) section 19, Resource Adequacy;

(12) section 22, Governing Law and Dispute Resolution;

(13) section 25, Termination;

(14) Exhibit A, Net Requirements and Resources;

(15) Exhibit B, High Water Marks and Contract Demand Quantities;

(16) Exhibit C, Purchase Obligations;

(17) Exhibit D, Additional Products and Special Provisions;

(18) Intentionally Left Blank;

(19) Exhibit H, Renewable Energy Certificates and Carbon Attributes;

(20) Exhibit I, Critical Slice Amounts;

(21) Exhibit J, Preliminary Slice Percentage and Initial Slice Percentage;

(22) Exhibit K, Annual Determination of Slice Percentage;

(23) Exhibit L, RHWM Augmentation;

(24) Exhibit N, Slice Implementation Procedures;

(25) Exhibit O, Interim Slice Implementation Procedures;

(26) Exhibit P, Slice Computer Application Development Schedule; and

(27) Exhibit Q, Determination of Initial Slice Percentage.

Until October 1, 2011, section 22, Governing Law and Dispute Resolution will only apply to the extent there is a dispute regarding actions required in the above referenced sections and exhibits.

2. DEFINITIONS

Capitalized terms below shall have the meaning stated. Capitalized terms that are not listed below are either defined within the section or exhibit in which the term is used, or if not so defined, shall have the meaning stated in BPA's applicable Wholesale Power Rate Schedules, including the General Rate Schedule Provisions (GRSPs). Definitions in **bold** indicate terms that are defined in the TRM and that the Parties agree should conform to the TRM as it may be revised. The Parties agree that if such definitions are revised pursuant to the TRM, they shall promptly amend this Agreement to incorporate such revised definitions from the TRM, to the extent they are applicable.

2.1 "5(b)/9(c) Policy" means BPA's Policy on Determining Net Requirements of Pacific Northwest Utility Customers Under sections 5(b)(1) and 9(c) of the Northwest Power Act issued May 23, 2000, and its revisions or successors.

2.2 "**7(i) Process**" means a public process conducted by BPA to establish rates for the sale of power and other products pursuant to section 7(i) of the Northwest Power Act or its successor.

2.3 "**Above-RHWM Load**" means the forecast annual Total Retail Load, less Existing Resources, NLSLs, and the customer's RHWM, as determined in the RHWM Process.

2.4 "Absolute Operating Constraint" means an Operating Constraint that cannot be exceeded under any condition.

2.5 "Actual BOS Generation" means the actual generation produced by the BOS Complex, as adjusted for actual Tier 1 System Obligations and RHWM Augmentation.

2.6 "Actual Slice Output Energy" or "ASOE" means the actual amount of EWEB's Slice Output Energy BPA makes available to EWEB at the Scheduling Points of Receipt.

2.7 "Actual Tier 1 System Generation" or "ATSG" means the actual generation produced by the Tier 1 System plus the RHWM Augmentation.

2.8 "**Additional CHWM**" means the CHWMs established for DOE-Richland, New Publics formed in whole or in part out of loads previously served by an entity other than an Existing Public, and load growth for New Tribal Utilities. Additional CHWM will not include CHWMs for New Publics formed out of Existing Publics or other Initial CHWMs.

2.9 "Additional Energy" shall have the meaning as defined in section 5.8.1.

2.10 "Additional Slice Amount" shall have the meaning as defined in section 1 of Exhibit Q.

2.11 "Adjusted Annual RHWM Tier 1 System Capability" or "AART1SC" means the annual RHWM Tier 1 System Capability amount, as such amount may be adjusted by BPA pursuant to Exhibit I.

2.12 "Algorithm Tuning Parameters" shall have the meaning as defined in section 2 of Exhibit M.

2.13 "Annexed Load" means existing load, distribution system, or service territory EWEB acquires after the Effective Date from another utility, by means of annexation, merger, purchase, trade, or other acquisition of rights, the acquisition of which has been authorized by a final state, regulatory or court action. The Annexed Load must be served from distribution facilities that are owned or acquired by EWEB.

2.14 "Annual Net Requirement" means BPA's forecast of EWEB's Net Requirement for each Fiscal Year that results from the process established in section 1 of Exhibit A and is shown in the table in section 1.2 of Exhibit A.

2.15 "**Augmentation for Additional CHWM**" means the amount of annual average firm energy BPA forecasts, calculated in accordance with sections 3.2.1.1 and 3.2.1.2 of the TRM during the RHWM Process, that is equal to the amount of Additional CHWMs used in the calculation of RHWM Augmentation.

2.16 "**Augmentation for Initial CHWM**" means the amount of annual average firm energy BPA forecasts, during the RWHM Process, that will be needed (in addition to the Tier 1 System Firm Critical Output) to meet the Initial CHWM. The amount of energy is restricted by the Augmentation Limit.

2.17 "**Augmentation Limit**" means the amount of augmentation calculated by BPA in accordance with section 3.2.1 of the TRM, which establishes the maximum level of Augmentation for Initial CHWM.

2.18 "Average Megawatts" or "aMW" means the amount of electric energy in megawatt-hours (MWh) during a specified period of time divided by the number of hours in such period.

2.19 "**Balancing Authority**" means the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time.

2.20 "**Balancing Authority Area**" means the collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority.

2.21 "Base Critical Slice Amount" shall have the meaning as defined in section 1 of Exhibit Q.

2.22 "Base Slice Percentage" shall have the meaning as defined in section 1 of Exhibit Q.

2.23 "Base Tier 1 System Capability" shall have the meaning as defined in section 1 of Exhibit Q.

2.24 "Block Product" means a planned amount of Firm Requirements Power sold to EWEB to meet a portion of its regional consumer load pursuant to the terms set forth in section 4 of this Agreement.

2.25 "BOS Base" means the forecast generation amounts available from the BOS Complex, as adjusted by BPA for forecast Tier 1 System Obligations and RHWM Augmentation.

2.26 "BOS Complex" or "Balance of System Complex" means the Tier 1 System Resources, except those resources that comprise the Coulee-Chief Complex and Lower Columbia Complex.

2.27 "BOS Deviation Account" means the account BPA maintains that quantifies the cumulative amount, expressed in MWd, by which EWEB's hourly BOS Base schedules deviate from the amount determined by multiplying EWEB's Slice Percentage by the hourly Actual BOS Generation.

2.28 "BOS Deviation Return" means the energy amounts associated with the reduction of EWEB's BOS Deviation Account balance.

2.29 "BOS Flex" means the amount by which the BOS Base can reasonably be reshaped within a given calendar day by utilizing the flexibility available from the Lower Snake Complex.

2.30 "BOS Module" means the Slice Computer Application module that is used to determine EWEB's Slice Output Energy and Delivery Limits available from the BOS Complex.

2.31 "**Business Days**" means every Monday through Friday except Federal holidays.

2.32 "Bypass Spill" shall have the meaning as defined in section 2 of Exhibit M.

2.33 "Calibrated Simulator Discharge" means, for each Simulator Project, EWEB's simulated discharge as adjusted to reflect such project's actual H/K, actual Bypass Spill, and actual required Fish Spill, pursuant to section 3.6 of Exhibit M.

2.34 "Carbon Credit" shall have the meaning as defined in section 1 of Exhibit H.

2.35 "Columbia Generating Station" or "CGS" shall have the meaning as defined in section 5.8.1.

2.36 "CGS Displacement" shall have the meaning as defined in section 5.8.1.

2.37 "**CHWM Contract**" means the power sales contract between a customer and BPA that contains a Contract High Water Mark (CHWM), and under which the customer purchases power from BPA at rates established by BPA in accordance with the TRM.

2.38 "**CHWM Process**" means the FY 2011 process, as set forth in section 4.1 of the TRM, through which BPA establishes CHWMs for Existing Customers.

2.39 “Combined Maximum Additional Slice Amount” shall have the meaning as defined in section 1 of Exhibit Q.

2.40 “Consumer-Owned Resource” means a Generating Resource connected to EWEB’s distribution system that is owned by a retail consumer, has a nameplate capability greater than 200 kilowatts, is operated or applied to load, and is not operated occasionally or intermittently as a back-up energy source at times of maintenance or forced outage. Consumer-Owned Resource does not include a resource where the owner of the resource is a retail consumer that exists solely for the purpose of selling wholesale power and for which EWEB only provides incidental service to provide energy for local use at the retail consumer’s generating plant for lighting, heat and the operation of auxiliary equipment.

2.41 “Contract Demand Quantity” or “CDQ” shall have the meaning as defined in the TRM, the definition of which is recited in section 6.6.1.

2.42 “Contract High Water Mark” or “CHWM” shall have the meaning as defined in the TRM, the definition of which is recited in section 6.6.1.

2.43 “Contract Resource” means any source or amount of electric power that EWEB acquires from an identified or unidentified electricity-producing unit or units by contract purchase, and for which the amount received by EWEB does not depend on the actual production from an identified Generating Resource.

2.44 “Coulee-Chief Complex” means the two hydroelectric projects located in the middle reach of the Columbia River, consisting of Grand Coulee and Chief Joseph.

2.45 “Creditworthiness Agreement” means Contract No. 09PB-13254 between BPA and EWEB.

2.46 “Critical Slice Amount” means the forecasted amount of Slice Output Energy that EWEB is expected to receive in a Fiscal Year, and is equal to the product of EWEB’s Slice Percentage and the Adjusted Annual RHWM Tier 1 System Capability. The annual Critical Slice Amount and associated monthly Critical Slice Amounts for each FY are as set forth in Exhibit I.

2.47 “Customer Inputs” means the Simulator Project discharge, elevation, or generation requests EWEB develops as inputs to the Simulator pursuant to section 3.3 of Exhibit M.

2.48 “Dedicated Resource” means a Specified Resource or an Unspecified Resource Amount listed in Exhibit A that EWEB is required by statute to provide or obligates itself to provide under this Agreement for use to serve its Total Retail Load.

2.49 "Default User Interface" or "DUI" shall have the meaning as defined in section 5.10.1.

2.50 "Delivery Limits" means the limits that govern the availability of Slice Output and the scheduling of Slice Output Energy by EWEB as determined by BPA, and implemented through the Slice Computer Application.

2.51 "Delivery Request" means the amount of Slice Output Energy EWEB requests that BPA make available for delivery for any given hour as established per section 7 of Exhibit M.

2.52 "**Designated BPA System Obligations**" means the set of obligations specified in Table 3.4 of the TRM, imposed on BPA by statutes, regulations, court order, treaties, executive orders, memoranda of agreement, and contracts that require the generation or delivery of power, forbearance from generating power, or receipt of power, in order to support the operation of the FCRPS, including any obligations to the BPA Balancing Authority (Transmission Services).

2.53 "Diurnal" means the division of hours within a month between Heavy Load Hours (HLH) and Light Load Hours (LLH).

2.54 "**Diurnal Flattening Service**" or "DFS" means a service that makes a resource that is variable or intermittent, or that portion of such resource that is variable or intermittent, equivalent to a resource that is flat within each of the 24 HLH and LLH periods of a year.

2.55 "Due Date" shall have the meaning as described in section 16.2.

2.56 "Effective Date" means the date on which this Agreement has been signed by EWEB and BPA.

2.57 "Election Year" shall have the meaning as defined in section 5.8.1.

2.58 "Elective Spill" means Spill other than Bypass Spill or Fish Spill that occurs at a hydroelectric project and is within such project's available turbine capacity such that the Spill may otherwise be utilized to produce energy.

2.59 "Eligible Slice Customers" shall have the meaning as defined in section 1 of Exhibit Q.

2.60 "Environmental Attributes" shall have the meaning as defined in section 1 of Exhibit H.

2.61 "Environmentally Preferred Power RECS" or "EPP RECs" shall have the meaning as defined in section 1 of Exhibit H.

2.62 "Existing Customer" means a municipal, tribal, public or cooperative utility that is entitled to preference and priority under the Bonneville Project Act, P.L. 75-329 and that was eligible on December 1, 2008, to purchase requirements power at a PF rate or that would be eligible on December 1, 2008, to purchase requirements power at a PF rate.

2.63 "Existing Resource" means a Specified Resource listed in section 2 of Exhibit A that EWEB was obligated by contract or statute to use to serve EWEB's Total Retail Load prior to October 1, 2006.

2.64 "**Federal Columbia River Power System**" or "FCRPS" means the integrated power system that includes, but is not limited to, the transmission system constructed and operated by BPA and the hydroelectric dams constructed and operated by the U.S. Army Corps of Engineers and the Bureau of Reclamation in the Pacific Northwest.

2.65 "Federal Operating Decision" means a decision made by the Corps, Reclamation, BPA, or the United States Entity of the Columbia River Treaty, in accordance with the authority of each such entity, and as needed to meet Tier 1 System Obligations not already reflected in the Simulator or BOS Module, that establishes the permissible range of operations for any project or projects that comprise the FCRPS.

2.66 "FERC" means the Federal Energy Regulatory Commission, or its successor.

2.67 "**Firm Critical Output**" means the forecast output from Tier 1 System Resources that is determined in accordance with sections 3.1.3.1, 3.1.3.3, and 3.1.3.4 of the TRM.

2.68 "Firm Requirements Power" means federal power that BPA sells under this Agreement and makes continuously available to EWEB to meet BPA's obligations to EWEB under section 5(b) of the Northwest Power Act.

2.69 "**Fiscal Year**" or "FY" means the period beginning each October 1 and ending the following September 30.

2.70 "Fish Spill" means Spill that occurs at a hydroelectric project in order to maintain compliance with established fish passage criteria, such as those criteria set forth in biological opinions.

2.71 "Flat Annual Shape" means a distribution of energy having the same value of energy in all hours of the year.

2.72 "Flat Within-Month Shape" means a distribution of energy having the same average megawatt value of energy in each hour of the month.

2.73 "**Forced Outage Reserve Service**" or "FORS" means a service that provides an agreed-to amount of capacity and energy to load during the forced outages of a qualifying resource.

2.74 **"Forecast Net Requirement"** means a forecast of EWEB's Annual Net Requirement that BPA performs in each RHWM Process.

2.75 **"Forecast Year"** means the Fiscal Year ending one full year prior to the commencement of a Rate Period.

2.76 "Forced Spill" shall have the meaning as defined in section 2 of Exhibit M.

2.77 "Generating Resource" means any source or amount of electric power from an identified electricity-producing unit, and for which the amount of power received by EWEB or EWEB's retail consumer is determined by the power produced from such identified electricity-producing unit. Such unit may be owned by EWEB or EWEB's retail consumer in whole or in part, or all or any part of the output from such unit may be owned for a defined period by contract.

2.78 "Generation Benchmark" shall have the meaning as defined in section 5.8.1.

2.79 "H/K" means, prospectively, a hydroelectric project's water-to-energy conversion factor used to forecast such project's potential energy production per unit of turbine discharge, expressed as MW per kcfs, or retrospectively, for any given period of time, the value equal to a hydroelectric project's average Net Generation divided by such project's average turbine discharge, expressed as MW per kcfs.

2.80 "Hard Operating Constraint" means an Operating Constraint that may not be exceeded without express consent from project operators, owners, or other federal agencies responsible for establishing such Operating Constraints.

2.81 "Heavy Load Hours (HLH)" means hours ending 0700 through 2200 hours Pacific Prevailing Time (PPT), Monday through Saturday, excluding holidays as designated by the North American Electric Reliability Corporation (NERC). BPA may update this definition as necessary to conform to standards of the Western Electricity Coordinating Council (WECC), North American Energy Standards Board (NAESB), or NERC.

2.82 "Hydraulic Link Adjustment" means the adjustment to EWEB's simulated McNary inflow that is equal to the difference between EWEB's Calibrated Simulator Discharge for Chief Joseph and the measured Chief Joseph discharge, pursuant to section 3.7 of Exhibit M.

2.83 "Incremental Cost" shall have the meaning as defined in section 5.8.1.

2.84 "Incremental Side Flows" shall have the meaning as defined in section 2 of Exhibit M.

2.85 "Initial Slice Customers" shall have the meaning as defined in section 1 of Exhibit Q.

2.86 “Initial Slice Percentage” or “ISP” means the percentage that is determined pursuant to section 5.3.2 after January 1, 2009, and prior to May 1, 2011, and is the basis for determining EWEB’s Slice Percentage for each Fiscal Year pursuant to section 5.3.3.

2.87 “**Initial CHWM**” means the sum of all Existing Customers’ CHWMs determined in the CHWM Process pursuant to section 4.1 of the TRM.

2.88 “Integrated Network Segment” shall have the meaning as defined in section 14.1.

2.89 “Interchange Points” means the points where Balancing Authority Areas interconnect and at which the interchange of energy between Balancing Authority Areas is monitored and measured.

2.90 “Interim Slice Implementation Procedures” shall have the meaning as defined in section 5.10.1.

2.91 “Issue Date” shall have the meaning as described in section 16.1.

2.92 “Light Load Hours (LLH)” means: (1) hours ending 0100 through 0600 and 2300 through 2400 hours PPT, Monday through Saturday, and (2) all hours on Sundays and holidays as designated by NERC. BPA may update this definition as necessary to conform to standards of the WECC, NAESB, or NERC.

2.93 “Logic Control Parameters” shall have the meaning as defined in section 2 of Exhibit M.

2.94 “Lower Columbia Complex” or “LCOL Complex” means the four hydroelectric projects located on the lower reach of the Columbia River, consisting of McNary, John Day, The Dalles, and Bonneville.

2.95 “Lower Snake Complex” or “LSN Complex” means the four hydroelectric projects located on the lower reach of the Snake River, consisting of Lower Granite, Little Goose, Lower Monumental, and Ice Harbor.

2.96 “Majority” shall have the meaning as defined in section 5.12.1.

2.97 “Maximum Additional Slice Amount” shall have the meaning as defined in section 1 of Exhibit Q.

2.98 “Maximum Slice Amount” shall have the meaning as defined in section 1 of Exhibit Q.

2.99 “Megawatt-day” or “MWd” means a unit of electrical energy equal to 24 megawatt-hours.

2.100 "Monthly Reimbursement Value" means the value determined by dividing the amount EWEB is billed for a month under the applicable Customer Charges, as described pursuant to section 5.1 of the TRM, by the sum of: (1) EWEB's ASOE for such month and (2) the amount of EWEB's Surplus Slice Output energy that is curtailed during such month.

2.101 "Monthly Shaping Factors" means the monthly factors, as specified in section 1.2 of Exhibit C, that are multiplied by EWEB's annual Tier 1 Block Amount in order to determine EWEB's monthly Tier 1 Block Amounts for each month of a Fiscal Year.

2.102 "Multiyear Hydroregulation Study" shall have the meaning as defined in section 2 of Exhibit N.

2.103 "Net Generation" means the total electric energy produced at a hydroelectric project as reduced by the electric energy consumed by such project for station service purposes.

2.104 "Net Requirement" means the amount of federal power that EWEB is entitled to purchase from BPA to serve its Total Retail Load minus amounts of EWEB's Dedicated Resources shown in Exhibit A, as determined consistent with section 5(b)(1) of the Northwest Power Act.

2.105 "New Large Single Load" or "NLSL" has the meaning specified in section 3(13) of the Northwest Power Act and in BPA's NLSL policy.

2.106 "New Resource" means: (1) a Specified Resource listed in section 2 of Exhibit A that EWEB was or is first obligated by contract, or was or is obligated by statute, to use to serve EWEB's Total Retail Load after September 30, 2006, and (2) any Unspecified Resource Amounts listed in Exhibit A.

2.107 "**Northwest Power Act**" means the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. §839, Public Law No. 96-501, as amended.

2.108 "Notice Deadlines" means the dates established in section 9.1.1.

2.109 "Onsite Consumer Load" means the electric load of an identified retail consumer of EWEB that is directly interconnected or electrically interconnected on the same portion of EWEB's distribution system with a Consumer-Owned Resource of that same identified retail consumer such that no transmission schedule is needed to deliver the generation from the Consumer-Owned Resource to the consumer load.

2.110 "Operating Constraints" means the operating limits, project operating requirements, and non-power constraints that are the result of implementing Federal Operating Decisions or Prudent Operating Decisions.

2.111 "Operating Plan" shall have the meaning as defined in section 5.8.1.

2.112 "Operating Rule Curves" or "ORC" means the forebay operating limits established for a reservoir pursuant to operating agreements in effect, and as modified to reflect Operating Constraints, that are used to determine such reservoir's upper forebay operating limit (upper ORC) or lower forebay operating limit (lower ORC).

2.113 "Operating Year" means the period, beginning each August 1 and ending the following July 31, that is designated under the Pacific Northwest Coordination Agreement (PNCA) for resource planning and operational purposes.

2.114 "Pacific Northwest Coordination Agreement" or "PNCA" means Contract No. 97PB-10130, as such agreement may be amended or replaced, among BPA, the U.S. Army Corps of Engineers, the Bureau of Reclamation, and certain generating utilities in the Region that sets forth the terms and conditions for the coordinated operation of generating resources in the Region.

2.115 "Point of Delivery" or "POD" means the point where power is transferred from a transmission provider to EWEB.

2.116 "Point of Metering" or "POM" means the point at which power is measured.

2.117 "Power Services" means the organization, or its successor organization, within BPA that is responsible for the management and sale of Federal power.

2.118 "Preliminary Net Requirement" shall have the meaning as defined in section 10.1.

2.119 "Preliminary Slice Amount" shall have the meaning as defined in section 1 of Exhibit Q.

2.120 "Preliminary Slice Percentage" means a preliminary Slice Percentage that is established and set forth in Exhibit J as of the Effective Date.

2.121 "Primary Points of Receipt" shall have the meaning as defined in section 14.1.

2.122 "Project Storage Bounds" or "PSB" means the Storage Content amounts associated with the upper ORC and lower ORC in effect at a project.

2.123 "Prudent Operating Decision" means a decision made by Power Services operations staff, in their exercise of reasonable judgment, that modifies the operating range applied to any project or projects that comprise the FCRPS for the purpose of meeting any BPA obligation, including but not limited to Federal Operating Decisions, except actions taken by Power Services solely to sell surplus power to loads BPA is not contractually obligated to serve under section 5 of the Northwest Power Act. Prudent Operating Decisions are applied for a finite period of time and in a manner that proportionally affects the amount of power from such project or projects that is available to BPA, to EWEB under this Agreement, and to other Slice Customers under their respective Slice/Block Power Sales Agreements.

2.124 "Purchase Periods" means the time periods established in section 9.1.1.

2.125 "Quorum" shall have the meaning as defined in section 5.12.1.

2.126 "Rate Case Year" means the Fiscal Year ending prior to the commencement of a Rate Period. The Rate Case Year immediately follows the Forecast Year and is the year in which the 7(i) Process for the next Rate Period is conducted.

2.127 "**Rate Period**" means the period of time during which a specific set of rates established by BPA pursuant to the TRM is intended to remain in effect.

2.128 "Rate Period High Water Mark" or "RHWM" shall have the meaning as defined in the TRM, the definition of which is recited in section 6.6.1.

2.129 "Region" means the Pacific Northwest as defined in section 3(14) of the Northwest Power Act.

2.130 "Renewable Energy Certificates" or "RECs" shall have the meaning as defined in section 1 of Exhibit H.

2.131 "Requirements Slice Output" or "RSO" means, for each month, the portion of EWEB's Slice Output Energy that is equal to the lesser of: (1) EWEB's Critical Slice Amount for such month; (2) EWEB's Annual Net Requirement for such month, less monthly amounts purchased under the Block Product, as specified in Exhibit C; or (3) EWEB's actual Net Requirement for such month, less monthly amounts purchased under the Block Product, as specified in Exhibit C.

2.132 "Resource Support Services" or "RSS" means the Diurnal Flattening Service and Forced Outage Reserve Service BPA provides to support resources that are renewable resources and are Specified Resources used to serve Total Retail Load after September 30, 2006, and may in the future include other related services that are priced in the applicable 7(i) Process consistent with the TRM.

2.133 "**RHWM Augmentation**" means the amount of augmentation to the Tier 1 System Firm Critical Output BPA calculates in each RHWM Process that is needed to meet the total of all RHWMs. This calculation assumes every customer is able to purchase at Tier 1 Rates up to its full RHWM and is determined by adding Augmentation for Initial CHWM and Augmentation for Additional CHWM.

2.134 “**RHWM Process**” means a public process BPA conducts, during the Forecast Year prior to each 7(i) Process (beginning with the WP-14 7(i) Process), in which BPA will calculate, as described in section 4.2 of the TRM, the following values for the upcoming Rate Period:

(1) RHWM Tier 1 System Capability, including RHWM Augmentation;

(2) each customer’s RHWM;

(3) each customer’s Forecast Net Requirement; and

(4) each customer’s Above-RHWM Load.

2.135 “**RHWM Tier 1 System Capability**” means the Tier 1 System Firm Critical Output plus RHWM Augmentation.

2.136 “**RP Augmentation**” means the 7(i) Process forecast of the amount of power BPA needs on an annual basis to purchase for each Rate Period to meet all customers’ Forecast Tier 1 Load.

2.137 “SCA” or “Slice Computer Application” means BPA’s proprietary computer hardware, software and related processes, developed, updated, and maintained by BPA and consisting of: (1) the Simulator; (2) the BOS Module; (3) the Default User Interface; and (4) other related processes, including but not limited to communications, scheduling, electronic tagging and accounting for Slice Output Energy, all as described in Exhibit M.

2.138 “SCA Functionality Test” shall have the meaning as defined in section 5.10.1.

2.139 “SCA Implementation Date” shall have the meaning as defined in section 5.10.1.

2.140 “SCA Pass Date” shall have the meaning as defined in section 5.10.1.

2.141 “Scheduling Hour XX” means the 60-minute period ending at XX:00. For example, Scheduling Hour 04 means the 60-minute period ending at 4:00 a.m.

2.142 “Scheduling Points of Receipt” shall have the meaning as defined in section 14.1.

2.143 “Simulated Operating Scenario” means the simulated operation of the Simulator Projects, including the discharge amounts, generation amounts, and forebay elevations, as determined by the Simulator.

2.144 “Simulated Output Energy Schedule(s)” means the amount of energy that is calculated by the Simulator as EWEB’s simulated generation amount associated with each Simulator Project.

2.145 "Simulator" or "Slice Water Routing Simulator" means the Slice Computer Application (SCA) module used to determine EWEB's Slice Output and Delivery Limits available from the Simulator Projects.

2.146 "Simulator Initialization Time" shall have the meaning as defined in section 2 of Exhibit M.

2.147 "Simulator Modeling Period" shall have the meaning as defined in section 2 of Exhibit M.

2.148 "Simulator Parameters" means the operating parameters applicable to the Simulator Projects and which BPA develops as inputs to the Simulator to reflect Operating Constraints, pursuant to section 3.2 of Exhibit M.

2.149 "Simulator Pass Date" shall have the meaning as defined in section 5.10.1.

2.150 "Simulator Performance Test" shall have the meaning as defined in section 5.10.1.

2.151 "Simulator Project(s)" means any of the hydroelectric projects represented in the Simulator, including those projects that comprise the Coulee-Chief Complex and the Lower Columbia Complex.

2.152 "Slice/Block Power Sales Agreement" means this Agreement and all other agreements with Slice Customers that provide for the sale of the Slice/Block Product.

2.153 "Slice/Block Product" means EWEB's purchase obligation under the Slice Product and the Block Product to meet its regional consumer load obligation as described in section 3.1.

2.154 "Slice Customers" means all BPA customers that have executed a Slice/Block Power Sales Agreement.

2.155 "Slice Implementation Group" or "SIG" means the group that includes representatives from BPA, EWEB, and all other Slice Customers established pursuant to section 5.12.

2.156 "Slice Output" means the quantities of energy, peaking energy, storage, and ramping capabilities available from the Tier 1 System Resources, as adjusted for Tier 1 System Obligations and established pursuant to the SCA or an alternate procedure under section 5.10 or Exhibit O, that EWEB is entitled to purchase under the Slice Product, as determined by applying EWEB's Slice Percentage to such quantities.

2.157 "Slice Output Energy" means the energy made available to EWEB under the Slice Product.

2.158 "Slice Percentage" means the percentage set forth in section 2 of Exhibit K applicable during each Fiscal Year that is used to determine the Slice Output that is made available to EWEB.

2.159 "Slice Percentage Adjustment Ratio" or "SPAR" shall have the meaning as defined in section 1.1 of Exhibit K.

2.160 "Slice Percentage Determination Requirements Load" shall have the meaning as defined in section 1 of Exhibit Q.

2.161 "Slice Product" means BPA's power product under which Slice Output as defined herein is sold to EWEB pursuant to the terms and conditions set forth in section 5 of this Agreement.

2.162 "Slice Storage Account" or "SSA" shall have the meaning as defined in section 2 of Exhibit N.

2.163 **"Slice True-Up Adjustment Charge"** means the amount charged to each Slice Product customer determined in the Slice True-Up Adjustment in accordance with section 2.7 of the TRM.

2.164 "Soft Operating Constraint" means an Operating Constraint, other than a Hard or Absolute Operating Constraint, that is to be achieved on a day-ahead planning basis, but may be exceeded in real-time after coordinating with project operators, owners, or other federal agencies responsible for establishing such Operating Constraints.

2.165 "Specified Resource" means a Generating Resource or Contract Resource that has a nameplate capability or maximum hourly purchase amount greater than 200 kilowatts, that EWEB is required by statute or has agreed to use to serve its Total Retail Load. Each such resource is identified as a specific Generating Resource or as a specific Contract Resource with identified parties and is listed in sections 2 and 4 of Exhibit A.

2.166 "Spill" means water that passes a hydroelectric project without producing energy, including Bypass Spill, Elective Spill, Fish Spill, and Forced Spill.

2.167 "Statement of Intent" shall have the meaning as defined in section 2.3 of Exhibit C.

2.168 "Storage" means the ability of the Tier 1 System Resources to alter energy production among hours, days, and months by impounding water or releasing impounded water.

2.169 "Storage Content" means the amount of water stored in a project's reservoir, expressed in thousands of second-foot-days (ksfd). The Storage Content is typically calculated based on a conversion of such reservoir's measured forebay elevation, expressed in feet, to ksfd through the use of an established elevation-to-content conversion table.

2.170 "Storage Energy" means the amount of energy that would be produced if a project released a specified amount of Storage Content, and is determined by multiplying such Storage Content by a specified H/K, such as the project's at-site H/K or the combined H/K of the project and specified downstream projects.

2.171 "Storage Offset Account" or "SOA" means the account BPA maintains that records the cumulative amount by which EWEB's simulated Storage Content associated with each Simulator Project deviates from the actual Storage Content for each such Simulator Project.

2.172 "Super Majority" shall have the meaning as defined in section 5.12.1.

2.173 "Surplus Firm Power" means firm power that is in excess of BPA's obligations, including those incurred under sections 5(b), 5(c), and 5(d) of the Northwest Power Act, as available.

2.174 "Surplus Slice Output" means, for any month, the amount of Slice Output Energy (and associated capacity) that is available to EWEB under section 5 of this Agreement that exceeds EWEB's Requirements Slice Output for any such month.

2.175 "Third Party Transmission Provider" means a transmission provider other than BPA that delivers power to EWEB.

2.176 "Tier 1 Block Amount" means the amount of Firm Requirements Power made available to EWEB under the Block Product that is sold at Tier 1 Rates.

2.177 "Tier 1 Rate" means the Tier 1 Rate as defined in the TRM.

2.178 "Tier 1 RECs" shall have the meaning as defined in section 1 of Exhibit H.

2.179 **"Tier 1 System"** means the collection of resources and contract purchases that comprise the Tier 1 System Resources and the collection of contract loads and obligations that comprise the Designated BPA System Obligations.

2.180 **"Tier 1 System Capability"** means the Tier 1 System Firm Critical Output plus RP Augmentation.

2.181 **"Tier 1 System Firm Critical Output"** means the Firm Critical Output of Tier 1 System Resources less Tier 1 System Obligations.

2.182 **"Tier 1 System Obligations"** means the amount of energy and capacity that BPA forecasts for the Designated BPA System Obligations over a specific time period.

2.183 **"Tier 1 System Resources"** means the Federal System Hydro Generation Resources listed in Table 3.1 of the TRM; the Designated Non-Federally

Owned Resources listed in Table 3.2 of the TRM; and the Designated BPA Contract Purchases listed in Table 3.3 of the TRM.

2.184 "Tier 2 Block Amount" means the amount of Firm Requirements Power made available to EWEB under the Block Product that is sold at Tier 2 Rates.

2.185 **"Tier 2 Cost Pools"** means all of the Cost Pools to which Tier 2 Costs will be allocated by BPA.

2.186 "Tier 2 Load Growth Rate" means a Tier 2 Rate at which Load Following customers may elect to purchase Firm Requirements Power in accordance with section 2.2 of Exhibit C.

2.187 "Tier 2 Rate" means the Tier 2 Rate as defined in the TRM.

2.188 "Tier 2 RECs" shall have the meaning as defined in section 1 of Exhibit H.

2.189 "Tier 2 Short-Term Rate" means a Tier 2 Rate at which customers may elect to purchase Firm Requirements Power in accordance with section 2.4 of Exhibit C.

2.190 "Tier 2 Vintage Rate" means a Tier 2 Rate at which customers may elect to purchase Firm Requirements Power in accordance with section 2.3 of Exhibit C.

2.191 "Tiered Rate Methodology" or "TRM" means the long-term methodology established by BPA in a Northwest Power Act section 7(i) hearing as the Tiered Rate Methodology to implement the Policy (as defined in the TRM) construct of tiering BPA's Priority Firm Power rates for serving load under CHWM Contracts.

2.192 "Total Retail Load" means all retail electric power consumption, including electric system losses, within EWEB's electrical system excluding:

(1) those loads BPA and EWEB have agreed are nonfirm or interruptible loads

(2) transfer loads of other utilities served by EWEB

(3) any loads not on EWEB's electrical system or not within EWEB's service territory, unless specifically agreed to by BPA.

2.193 "Transfer Service" means the transmission, distribution and other services provided by a Third Party Transmission Provider to deliver electric energy and capacity over its transmission system.

2.194 "Transmission Services" means the organization, or its successor organization, within BPA that is responsible for the management and sale of transmission service on the Federal Columbia River Transmission System.

2.195 "Uncontrollable Force" shall have the meaning as defined in section 21.

2.196 "Unsold Slice Amount" shall have the meaning as defined in section 1 of Exhibit Q.

2.197 "Unsold Slice Percentage" shall have the meaning as defined in section 1 of Exhibit Q.

2.198 "Unspecified Resource Amount" means an amount of firm energy, listed in sections 3 and 4 of Exhibit A, that EWEB has agreed to supply and use to serve its Total Retail Load. Such amount is not attributed to a Specified Resource.

3. SLICE/BLOCK POWER PURCHASE OBLIGATION

3.1 Slice/Block Product Purchase Obligation

Commencing on October 1, 2011, and continuing for the duration of this Agreement, BPA shall sell to EWEB, and EWEB shall purchase from BPA, the Slice/Block Product, which includes: (1) a planned amount of Firm Requirements Power under the Block Product as set forth in sections 1 and 2 of Exhibit C; and (2) Slice Output under the Slice Product pursuant to section 5 and Exhibit K.

3.2 Take or Pay

EWEB shall pay rates established by BPA in a 7(i) Process, for: (1) the amounts of Firm Requirements Power that BPA makes available under the Block Product that EWEB is obligated to purchase pursuant to section 3.1(1), and (2) the Slice Output, including the amounts of Slice Output Energy that BPA makes available under the Slice Product that EWEB is obligated to purchase pursuant to section 3.1(2). EWEB shall pay such rates regardless of whether or not EWEB takes delivery of such amounts of Firm Requirements Power and Slice Output Energy.

3.3 Application of Dedicated Resources

EWEB agrees to serve a portion of its Total Retail Load with the Dedicated Resources listed in Exhibit A as follows:

(1) Specified Resources that are Generating Resources shall be listed in section 2.1 of Exhibit A,

(2) Specified Resources that are Contract Resources shall be listed in section 2.2 of Exhibit A, and

(3) Unspecified Resource Amounts shall be listed in section 3.1 of Exhibit A.

EWEB shall use its Dedicated Resources to serve its Total Retail Load, and specify amounts of its Dedicated Resources in the tables shown in Exhibit A, as stated below for each specific resource and type.

3.3.1 **Specified Resources**

3.3.1.1 **Application of Specified Resources**
EWEB shall use the output of all Specified Resources, listed in section 2 of Exhibit A, to serve EWEB's Total Retail Load. BPA shall determine EWEB's Net Requirement using the amounts listed in the then current Exhibit A for each Fiscal Year. The amounts listed are not intended to interfere with EWEB's operation of its Specified Resources.

3.3.1.2 **Determining Specified Resource Amounts**
EWEB shall state, for each Specified Resource listed in section 2 of Exhibit A, firm energy amounts for each Diurnal period and peak amounts for each month beginning with the later of the date the resource was dedicated to load or October 1, 2011, through the earlier of the date the resource will be permanently removed or September 30, 2028. BPA in consultation with EWEB shall determine the firm energy amounts for each Diurnal period and peak amounts for each month for each Specified Resource consistent with the 5(b)/9(c) Policy. BPA shall update the peak amounts listed in section 2 of Exhibit A pursuant to section 3.4.

3.3.2 **Unspecified Resource Amounts**

3.3.2.1 **Application of Unspecified Resource Amounts**
To serve Above-RHWM Load that EWEB commits to meet with Dedicated Resources in Exhibit C, EWEB shall provide and use Unspecified Resource Amounts to meet any amounts not met with its Specified Resources listed in section 2 of Exhibit A.

3.3.2.2 **Determining Unspecified Resource Amounts**
By September 15, 2011, and by each September 15 thereafter, the Parties shall calculate, and BPA shall fill in the tables in section 3.1 of Exhibit A with, EWEB's Unspecified Resource Amounts for the upcoming Fiscal Year. Upon termination or expiration of this Agreement any Unspecified Resource Amounts listed in Exhibit A shall expire, and EWEB shall have no further obligation to apply Unspecified Resource Amounts.

3.4 **Peak Amount Methodologies**

3.4.1 **Standard for Calculating Resource Peak Amounts**
The peak amounts for EWEB's Specified Resources will be stated at a future time in Exhibit A. Such resource peak amounts will be developed contemporaneously and consistent with the determination of peak energy amounts pursuant to Section 3.4.2. If BPA determines it is necessary to update such resource peak amounts in order to incorporate different resource peaking capability determination standards, then BPA may, consistent with BPA's 5(b)/9(c) Policy and in accordance with section 3.4.3, develop and apply such revised resource peaking capability determination standards.

3.4.2 **Method for Determining Peak Energy Amounts**
The amounts of peaking energy EWEB has purchased to meet its firm power load will be stated at a future time in Exhibit A. Until such time that peak energy amounts are stated in Exhibit A, the amounts of peaking energy available to EWEB are as provided under the Block Product and as calculated by the Slice Computer Application. BPA may adopt a methodology for calculating the amounts of peaking energy available to EWEB under this Agreement. Before peak energy amounts may be applied in Exhibit A, BPA shall: (1) complete a process to adopt a methodology, pursuant to section 3.4.3, which shall include a calculation of EWEB's total peak load, EWEB's peaking energy capability from its resources, and BPA's peaking energy capability for the Federal system, and (2) upon completion of such process, in consultation with EWEB, calculate the peak energy amounts in accordance with the methodology adopted and enter such amounts into Exhibit A. The application of any such methodology shall not by itself reduce BPA's obligation to provide peaking energy otherwise available under this Agreement to less than EWEB's net requirement peak stated in Exhibit A. BPA and EWEB shall take such actions and make such modifications, including to the Slice Computer Application, needed to timely implement any such methodology.

3.4.3 **Process for Modifying Peak Amounts**
Any methodology for determining the peak energy capability of Specified Resources as described in section 3.4.1, or EWEB's peak energy amounts available from BPA under this Agreement, as described in section 3.4.2, will be developed by BPA in a public process, including consultation with EWEB and other interested parties, a formal public comment process, and a record of decision. Except as otherwise agreed by EWEB and BPA, any such methodology shall not require modification of the peak amount of any Specified Resource, or the peak energy amounts listed in Exhibit A, until the first Fiscal Year of the Rate Period following BPA's written notice to

implement the revised peaking capability standard, which shall be given to EWEB at least 180 days before the start of such Fiscal Year.

3.5 **Changes to Dedicated Resources**

3.5.1 **Specified Resource Additions to Meet Above-RHWM Load**
By written notice to BPA, EWEB may elect to add Specified Resources to section 2 of Exhibit A to meet any obligations EWEB may have in Exhibit C to serve its Above-RHWM Load with Dedicated Resources. EWEB shall determine amounts for such Specified Resources in accordance with section 3.3.1.2 by June 30, 2011, and by June 30 of each Fiscal Year thereafter. BPA shall revise Exhibit A consistent with EWEB's elections.

3.5.2 **Resource Additions for a BPA Insufficiency Notice**
If BPA provides EWEB a notice of insufficiency and reduces its purchase obligation, in accordance with section 23.2, then EWEB may add Dedicated Resources to replace amounts of Firm Requirements Power BPA will not be providing due to insufficiency. The Parties shall revise Exhibit A to reflect such additions.

3.5.3 **Decrements for 9(c) Export**
If BPA determines, in accordance with section 23.6, that an export of a Specified Resource listed in section 2 of Exhibit A requires a reduction in the amount of Firm Requirements Power BPA sells EWEB then BPA shall notify EWEB of the amount and duration of the reduction in EWEB's Firm Requirements Power purchases from BPA. Within 20 days of such notification EWEB may add a Specified Resource to section 2 of Exhibit A in the amount of such decrement. If EWEB does not add a Specified Resource to meet such decrement, then within 30 days of such notification BPA shall add Unspecified Resource Amounts to section 3.2 of Exhibit A in the amount and for the duration of such decrement.

3.5.4 **Temporary Resource Removal**
By September 15, 2011, and by September 15 of each Fiscal Year thereafter, BPA shall revise EWEB's Dedicated Resource amounts listed in the tables of Exhibit A consistent with EWEB's resource removal elections made in accordance with section 10.

3.5.5 **Permanent Discontinuance of Resources**
EWEB may permanently remove a Specified Resource listed in section 2 of Exhibit A, consistent with the 5(b)/9(c) Policy on statutory discontinuance for permanent removal. If BPA makes a determination that EWEB's Specified Resource has met BPA's standards for a permanent removal, then BPA shall revise Exhibit A accordingly. If EWEB does not replace such resource with another Dedicated Resource, then EWEB's additional Firm Requirements Power purchases under this Agreement, as a result of such a resource

removal, may be subject to additional rates or charges as established in the Wholesale Power Rate Schedules and GRSPs.

3.5.6 **Resource Additions for Annexed Loads**
If EWEB acquires an Annexed Load after the Effective Date, EWEB shall add Dedicated Resources to Exhibit A to serve amounts of such load for which EWEB did not receive a CHWM addition pursuant to section 1.2.2 of Exhibit B. EWEB shall serve such load with Dedicated Resources for the remainder of the Purchase Period during which EWEB acquires such load. EWEB may only purchase Firm Requirements Power at Tier 2 Rates to serve such Annexed Load amounts, if EWEB has provided BPA with its election by a Notice Deadline for such power purchase at Tier 2 during the corresponding Purchase Period.

3.5.7 **Resource Additions/Removals for NLSLs**

3.5.7.1 To serve an NLSL listed in Exhibit D that is added after the Effective Date, EWEB may add Dedicated Resources to section 4 of Exhibit A. EWEB may discontinue serving its NLSL with the Dedicated Resources listed in section 4 of Exhibit A if BPA determines that EWEB's NLSL is no longer an NLSL in EWEB's service territory.

3.5.7.2 If EWEB elects to serve an NLSL with Dedicated Resources, then EWEB shall specify in section 4 of Exhibit A the maximum monthly and Diurnal Dedicated Resource amounts that EWEB plans to use to serve the NLSL. EWEB shall establish such firm energy amounts for each month beginning with the date the resource was dedicated to load through the earlier of the date the resource will be removed or September 30, 2028. EWEB shall serve the actual load of the NLSL up to such maximum amounts with such Dedicated Resource amounts. To the extent that the NLSL load is less than the maximum amount in any monthly or Diurnal period, EWEB shall have no right or obligation to use such amounts to serve the non-NLSL portion of its Total Retail Load. Specific arrangements to match such resources to the NLSL on an hourly basis shall be established in Exhibit D.

3.5.8 **PURPA Resources**
If EWEB is required by the Public Utility Regulatory Policies Act (PURPA) to acquire output from a Generating Resource, then such output shall be added as a Specified Resource pursuant to Exhibit A.

3.6 **Consumer-Owned Resources**
Except for any Consumer-Owned Resources serving an NLSL, which EWEB has applied to load consistent with section 23.3.7, EWEB shall apply the output of its Consumer-Owned Resources as follows:

3.6.1 **Existing Consumer-Owned Resources**
EWEB has designated, in sections 7.1, 7.2, or 7.3 of Exhibit A, the extent that each existing Consumer-Owned Resource as of the Effective Date will or will not serve Onsite Consumer Load. Such designation shall apply for the term of this Agreement.

3.6.2 **New Consumer-Owned Resources**
EWEB shall designate the extent that each Consumer-Owned Resource commencing commercial operation after the Effective Date will or will not serve Onsite Consumer Load. EWEB shall make such designation to BPA in writing within 120 days of the first production of energy by such resource. Such designation shall apply for the term of this Agreement.

Consistent with EWEB's designations, BPA shall list Consumer-Owned Resources serving Onsite Consumer Load in section 7.1 of Exhibit A, Consumer-Owned Resources not serving Onsite Consumer Load in section 7.2 of Exhibit A, and Consumer-Owned Resources serving both Onsite Consumer Load and load other than Onsite Consumer Load in section 7.3 of Exhibit A.

3.6.3 **Application of Consumer-Owned Resources Serving Onsite Consumer Load**
Power generated from Consumer-Owned Resources listed in section 7.1 of Exhibit A shall serve EWEB's Onsite Consumer Load. EWEB shall receive no compensation from BPA for excess power generated on any hour from such resources.

3.6.4 **Application of Consumer-Owned Resources Serving Load Other than Onsite Consumer Load**
EWEB shall ensure that power generated from Consumer-Owned Resources listed in section 7.2 of Exhibit A is scheduled for delivery and either: (1) sold to another utility in the Region to serve its Total Retail Load, (2) purchased by EWEB to serve its Total Retail Load (consistent with section 3.3), (3) marketed as an export, or (4) any combination of (1), (2), and (3) above.

3.6.5 **Application of Consumer-Owned Resources Serving Both Onsite Consumer Load and Load Other than Onsite Consumer Load**
If EWEB designates a Consumer-Owned Resource to serve both Onsite Consumer Load and load other than Onsite Consumer Load then EWEB shall select either Option A or Option B below.

3.6.5.1 **Option A: Maximum Amounts Serving Onsite Consumer Load**
If EWEB selects this Option A, then EWEB shall specify, in section 7.3 of Exhibit A, the maximum hourly amounts of an

identified Onsite Consumer Load that are to be served with power generated by an identified Consumer-Owned Resource. Such amounts shall be specified as Diurnal megawatt amounts, by month, and shall apply in all years for the term of this Agreement. Such amounts are not subject to change in accordance with section 3.6.6.

On any hour that the Onsite Consumer Load is less than the specified maximum hourly amounts, all such Onsite Consumer Load shall be served by EWEB with the identified Consumer-Owned Resource or with power other than Firm Requirements Power. Any hourly amounts of the identified Onsite Consumer Load in excess of the specified maximum hourly amounts shall be served with Firm Requirements Power. Any power generated from the identified Consumer-Owned Resource in excess of the specified maximum hourly amounts shall be applied to load other than Onsite Consumer Load in accordance with section 3.6.4.

3.6.5.2 **Option B: Maximum BPA-Served Onsite Consumer Load**

If EWEB selects this Option B, then EWEB shall specify, in section 7.3 of Exhibit A, the maximum hourly amounts of an identified Onsite Consumer Load that are to be served with Firm Requirements Power. Such amounts shall be specified as Diurnal megawatt amounts, by month, and shall apply in all years for the term of this Agreement. Such amounts are not subject to change in accordance with section 3.6.6.

On any hour that Onsite Consumer Load is less than the specified maximum hourly amounts, all such Onsite Consumer Load shall be served with Firm Requirements Power. EWEB shall serve any hourly amounts of the identified Onsite Consumer Load in excess of the specified maximum hourly amounts with power generated by the identified Consumer-Owned Resource or with power other than Firm Requirements Power. Any power generated from the identified Consumer-Owned Resource in excess of the amounts required to be used to serve the Onsite Consumer Load shall be applied to load other than Onsite Consumer Load in accordance with section 3.6.4.

3.6.6 **Changes to Consumer-Owned Resources**

Prior to each Fiscal Year EWEB shall notify BPA in writing of any changes in ownership, expected resource output, or other characteristic of Consumer-Owned Resources identified in section 7 of Exhibit A. If a Consumer-Owned Resource has permanently ceased operation and EWEB notifies BPA of such cessation, then BPA shall revise section 7 of Exhibit A to reflect such change as long as BPA agrees the determination is reasonable.

4. BLOCK PRODUCT

4.1 Block Product General Description

The Block Product is sold to provide a planned amount of Firm Requirements Power to serve a portion of EWEB's Annual Net Requirement.

4.2 Block Amount Shapes

4.2.1 Tier 1 Block Amount Shapes

Upon the execution of this Agreement, EWEB shall select one of the following shapes for Tier 1 Block Amounts: (1) a Flat Annual Shape, or (2) a Flat Within-Month Shape. The shape selected by EWEB shall be specified in section 1.2 of Exhibit C and shall remain fixed during the term of this Agreement.

4.2.2 Tier 2 Block Amount Shape

Tier 2 Block Amounts, sold to and purchased by EWEB for its load, shall only be made available by BPA to EWEB in a Flat Annual Shape.

4.2.3 Shaping Restrictions

No shaping options for Tier 1 Block Amounts and Tier 2 Block Amounts are permitted other than those described in sections 4.2.1 and 4.2.2.

4.3 Annual and Monthly Tier 1 Block Amounts

The annual and monthly Tier 1 Block Amounts shall be determined as follows:

4.3.1 Determination of Annual Tier 1 Block Amount

By September 15, 2011, and by each September 15 thereafter, BPA shall determine EWEB's annual Tier 1 Block Amount for the next Fiscal Year by subtracting the Critical Slice Amount for such Fiscal Year from the lesser of EWEB's Annual Net Requirement or its RHWM.

4.3.2 Determination of Monthly Tier 1 Block Amounts

EWEB's Tier 1 Block Amounts for each month of the Fiscal Year shall be determined by multiplying the annual Tier 1 Block Amount, as determined pursuant to section 4.3.1, by the Monthly Shaping Factors specified in section 1.2 of Exhibit C.

4.3.3 **Annual and Monthly Tier 1 Block Amounts Specified in Exhibit C**
EWEB's annual and monthly Tier 1 Block Amounts, as determined pursuant to this section 4.3 for each Fiscal Year, shall be specified in section 1 of Exhibit C.

4.4 **Annual Tier 2 Block Amounts**
The annual Tier 2 Block Amounts, if any, sold to and purchased by EWEB, shall be specified in section 2 of Exhibit C.

5. SLICE PRODUCT

5.1 **Slice Product General Description**
The Slice Product is a system sale of power that includes requirements power, surplus power, and hourly scheduling rights, all of which are indexed to the variable output capability of the FCRPS resources that comprise the Tier 1 System, and to the extent such capability is available to Power Services after Tier 1 System Obligations and Operating Constraints are met. These capabilities are accessed by EWEB through the Slice Computer Application, which shall reasonably represent and calculate the capabilities available to Power Services from such resources after Tier 1 System Obligations and Operating Constraints are met, including energy production, peaking, storage and ramping capability. The Slice Computer Application applies EWEB's Slice Percentage to such capabilities.

The Slice Product sold by BPA and purchased by EWEB is a power sale, and is not under any circumstances to be construed as a sale of the Tier 1 System Resources, Tier 1 System Resource capability, or a transfer of control of such Tier 1 System Resources.

BPA does not guarantee that the amount of Slice Output Energy made available under the Slice Product, combined with Firm Requirements Power made available under the Block Product, will be sufficient to meet EWEB's regional consumer load, on an hourly, daily, weekly, monthly, or annual basis. EWEB agrees that it has the obligation to supply nonfederal power to meet its Total Retail Load not met by its purchase of Slice Output and power from the Block Product.

Changes in the output of the Tier 1 System shall affect the amount of Slice Output made available to EWEB under this Agreement. Accordingly, EWEB understands and agrees it is exposed to Tier 1 System performance risk and water supply risk.

The Slice Product does not provide EWEB any rights to utilize Tier 1 System Resources for within-hour energy or capacity services, including but not limited to dynamic scheduling, self-supply of operating reserves, and self-supply of energy imbalance. Slice Output Energy is scheduled firm for the hour of delivery.

Notwithstanding any provision of this Agreement to the contrary, or EWEB's rights under this Agreement, BPA and Federal operating agencies at all times shall retain operational control of all resources comprising the FCRPS, including without limitation all such resources that comprise the Tier 1 System.

5.2 **Determination of Amounts of Slice Output Made Available to EWEB**
Slice Output made available to EWEB shall be adjusted by Operating Constraints in effect on the Tier 1 System. Such Operating Constraints shall be applied proportionately to the Tier 1 System output available to Power Services, EWEB, and all other Slice Customers.

The amount of Slice Output Energy made available to EWEB is based on a simulation of stream flows routed through the Simulator Projects, plus the BOS Base, using the Slice Computer Application, and as adjusted for Operating Constraints. Accordingly, EWEB understands and agrees that the amount of Slice Output Energy made available to EWEB may not precisely equal the result of its Slice Percentage multiplied by the Actual Tier 1 System Generation.

5.3 **Preliminary Slice Percentage, Initial Slice Percentage, Slice Percentage, and Adjustments to Slice Percentage**

5.3.1 **Preliminary Slice Percentage**
EWEB's Preliminary Slice Percentage shall be the percentage as specified in section 1 of Exhibit J as of the Effective Date.

5.3.2 **Initial Slice Percentage**
EWEB's Initial Slice Percentage shall be determined pursuant to section 4 of Exhibit Q. No later than May 1, 2011, BPA shall revise section 2 of Exhibit J to state EWEB's Initial Slice Percentage.

5.3.3 **Slice Percentage**
No later than 15 days prior to the beginning of each Fiscal Year, beginning with Fiscal Year 2012, BPA shall revise the table in section 2 of Exhibit K to include EWEB's Slice Percentage for each such Fiscal Year, as may be adjusted pursuant to section 1 of Exhibit K.

5.3.4. **Slice Percentage Not to Exceed Initial Slice Percentage**
EWEB understands and agrees that in no event shall its Slice Percentage exceed its Initial Slice Percentage during the term of this Agreement.

5.3.5 **Adjustments to Slice Percentage(10/17/08 Version)**
As set forth in section 1.3 of Exhibit K for each Fiscal Year, EWEB's Slice Percentage shall be adjusted: (1) when the amount of Additional CHWM for such Fiscal Year is greater than zero, or (2) such that

EWEB's purchase obligation under this Agreement does not exceed EWEB's Annual Net Requirement for such Fiscal Year.

5.4 **Critical Slice Amount**
BPA shall determine EWEB's Critical Slice Amount for Fiscal Year 2012 no later than 15 days prior to the first day of Fiscal Year 2012, and for each subsequent Fiscal Year no later than 15 days prior to the first day of each such Fiscal Year, using the procedure described in section 2 of Exhibit I.

5.5 **Disposition of Surplus Slice Output**

5.5.1 All sales, exchanges, or other dispositions of federal power are subject to and governed by federal law including, but not limited to, the Bonneville Project Act, P.L. 75-329 as amended, the Pacific Northwest Consumer Power Preference Act, P.L. 88-552, the Federal Columbia River Transmission System Act, P.L. 93-454, and the Northwest Power Act, P.L. No. 96-501, as amended.

5.5.2 All sales of Surplus Slice Output by EWEB for use outside the Region, or to parties not serving firm retail load in the Region, are subject to the provisions of the Pacific Northwest Consumer Power Preference Act and section 9(c) of the Northwest Power Act, and BPA and EWEB acknowledge their respective responsibilities thereunder.

5.5.3 The following uses of Surplus Slice Output shall not constitute a sale of Surplus Slice Output outside the Region:

5.5.3.1 Leaving the Surplus Slice Output in Storage or placing it in EWEB's Storage;

5.5.3.2 Exchanging Surplus Slice Output with another utility customer in the Region, or a statutorily enumerated type of exchange with a utility outside the Region;

5.5.3.3 Using Surplus Slice Output to displace EWEB's nonfederal resources identified in Exhibit A, or EWEB's market purchases that would have been made for serving its Total Retail Load; and

5.5.3.4 A sale of Surplus Slice Output to a BPA utility customer for service to that utility's Total Retail Load in the Region, consistent with sections 3(14) and 9(c) of the Northwest Power Act.

EWEB may demonstrate such uses of Surplus Slice Output by means of a storage account, executed contracts for binding sales or exchanges, or another form of offer and acceptance.

5.5.4 Pursuant to the Pacific Northwest Consumer Power Preference Act and section 9(c) of the Northwest Power Act, BPA shall have the right to curtail all or a portion of EWEB's: (1) Surplus Slice Output capacity upon 60 months written notice to EWEB, and (2) Surplus Slice Output energy upon 60 days written notice to EWEB. Any such notice shall specify the amounts and duration of the curtailment, and whether such capacity or energy is needed to meet BPA's capacity and energy requirements in the Region. Prior to issuing any such curtailment notice, BPA and EWEB shall consult in order to determine the quantity, if any, of Surplus Slice Output energy and capacity that may be subject to such curtailment. Such curtailments shall be limited to EWEB's proportional share of the amount needed, and for the duration necessary, to cover BPA's projection of its needs within the Region. Such curtailments are subject to sections 5.5.5 and 5.5.6.

5.5.5 If BPA issues a notice of curtailment pursuant to section 5.5.4, then it shall concurrently issue notices of curtailment, recall, or termination to all other extra regional and non-preference purchasers to whom BPA has sold Surplus Firm Power, or surplus capacity, for durations longer than specified in the notice, provided that such sales agreements contain provisions that allow for recall, curtailment or termination.

5.5.6 Following each month that Surplus Slice Output is curtailed pursuant to section 5.5.5 above, Power Services shall include a line item credit on EWEB's monthly customer bill issued equal to the amount of Surplus Slice Output energy curtailed during the preceding month, multiplied by the Monthly Reimbursement Value for the month during which the curtailment was in effect.

5.6 Disposition of Requirements Slice Output and Requirements Slice Output Test

5.6.1 **Disposition of Requirements Slice Output**
Requirements Slice Output (RSO) purchased by EWEB under this Agreement and made available by BPA shall be used solely for the purpose of serving EWEB's Total Retail Load. EWEB shall maintain monthly documentation establishing the delivery of RSO to serve its Total Retail Load, such as by schedule or by electronic tag, for each such month. EWEB shall make such documentation available to BPA upon request.

5.6.2 **Requirements Slice Output Test**

5.6.2.1 **Submission of Monthly Actual Total Retail Load Data**
On or before the 10th Business Day of each calendar month, EWEB shall submit to BPA its actual Total Retail Load for the preceding calendar month, expressed in MWh.

5.6.2.2 **RSO Test**
BPA shall compare: (1) EWEB's Slice Output Energy delivered to its actual Total Retail Load plus loss return schedules to Transmission Services (Slice-to-Load Delivery) during each month with (2) EWEB's RSO for each such month. Such comparison is the monthly RSO Test.

5.6.2.3 **Notification of Results of RSO Test**
On or before the 20th Business Day of each calendar month, BPA shall notify EWEB in writing of the results of the RSO Test conducted pursuant to section 5.6.2.2.

5.6.2.4 **Conditions that Result in Passage of RSO Test**

(1) If EWEB's Slice-to-Load Delivery in a month is greater than or equal to its RSO for such month, then EWEB shall have satisfied the requirements of the RSO Test for such month; or,

(2) If EWEB's Slice-to-Load Delivery in a month is less than its RSO for such month, but EWEB's Actual Slice Output Energy (ASOE) for the month is less than 107.5 percent of its RSO, and EWEB's monthly Slice-to-Load Delivery is greater than 92.5 percent of its ASOE for such month, then EWEB shall have satisfied the RSO Test for such month.

5.6.2.5 **Conditions Under Which BPA May Deem EWEB to Have Satisfied the RSO Test**

(1) If EWEB has not satisfied the requirements of the RSO Test pursuant to section 5.6.2.4, then EWEB may, within 14 calendar days after BPA provides EWEB with written notice of the RSO Test results pursuant to section 5.6.2.3, provide BPA with data that demonstrates EWEB took reasonable and prudent actions to otherwise satisfy the RSO Test for such month. Such data may include analysis indicating EWEB satisfied the RSO Test in each of two distinct periods of ten or more consecutive days within the month. If Power Services determines such data and/or analysis demonstrates such compliance, then BPA shall deem EWEB to have satisfied the RSO Test for such month. BPA shall have the sole discretion to determine whether EWEB shall be deemed to have satisfied the RSO Test pursuant to this section 5.6.2.5(1). BPA shall, no later than 14 calendar days following the day EWEB provides

such supporting data and/or analysis, notify EWEB, in writing, of its decision as to whether or not EWEB shall be deemed to have satisfied the RSO Test, and the basis for such decision.

(2) If recurring conditions exist that result in BPA repeatedly deeming EWEB to have satisfied the RSO Test, BPA and EWEB shall collaboratively develop documentation, through a separate letter agreement, that establishes for a specified prospective time period the conditions under which BPA shall deem EWEB to have satisfied the RSO Test.

5.6.2.6 **Conditions that Result in Failure of RSO Test and Associated Penalty**
If EWEB fails to satisfy the RSO Test per section 5.6.2.4, and is not deemed by BPA to have satisfied the RSO Test pursuant to section 5.6.2.5 for any month, then a penalty charge shall be assessed as follows for that month:

(1) The penalty charge shall be equal to EWEB's under-delivered amount for such month multiplied by the UAI Charge for energy for each such month.

(2) The under-delivered amount for such month is equal to the lesser of the amount EWEB's monthly Slice-to-Load Delivery is less than: (1) EWEB's RSO for the month, or (2) if section 5.6.2.4(2) is applicable, then 95 percent of EWEB's ASOE for the month.

5.7 **Northwest Power Act Section 6(m) Resource Acquisitions**
EWEB retains all rights to participate in any BPA major resource acquisitions pursuant to section 6(m) of the Northwest Power Act.

5.8 **Displacement of Columbia Generating Station (CGS)**

5.8.1 **Definitions**

5.8.1.1 "Additional Energy" means the amount of energy EWEB is entitled to receive if it elects not to participate in CGS Displacements during an Election Year, and is equal to EWEB's Slice Percentage multiplied by the difference between the Generation Benchmark and the expected level of CGS generation while displacement is in effect.

5.8.1.2 "Columbia Generating Station" or "CGS" means the nuclear powered generating facility located near Richland, Washington, and operated by Energy Northwest, or its successor.

5.8.1.3 "CGS Displacement" means a decision by Power Services to shut-down all or a portion of the power production at CGS due to market conditions.

5.8.1.4 "Election Year" means the 12-month period beginning each February 1 and ending the following January 31.

5.8.1.5 "Generation Benchmark" means the generation level at which Power Services reasonably expects CGS to operate, absent any CGS Displacement, which is typically about 1,130 MWh per hour.

5.8.1.6 "Incremental Cost" means the additional costs that Power Services would have incurred if CGS had been operated at full capability, and CGS Displacements had not been instituted, including the costs of nuclear fuel and variable operations and maintenance costs, expressed in dollars per MWh.

5.8.1.7 "Operating Plan" means the forecasted CGS monthly generation adopted in BPA's firm planning for a Fiscal Year.

5.8.2 **CGS Displacement Election**
No later than January 31, 2012, and no later than January 31 of each calendar year thereafter during the term of this Agreement, EWEB shall provide Power Services written notice stating whether or not it elects to participate in CGS Displacements for the Election Year that begins on the following day. Such election shall be irrevocable for each such Election Year, and shall apply to all CGS Displacements implemented by Power Services during such Election Year.

5.8.3 **Election to Participate in CGS Displacement**
If EWEB elects to participate in CGS Displacements, then EWEB shall not be entitled to Additional Energy.

5.8.4 **Election Not to Participate in CGS Displacements**
If EWEB elects to not participate in CGS Displacements, then EWEB shall be entitled to amounts of Additional Energy as described in this section 5.8.4.

5.8.4.1 EWEB shall take delivery of Additional Energy associated with each CGS Displacement as described in section 5.8.6. Power Services shall make such Additional Energy available to EWEB at the Scheduling Points of Receipt.

5.8.4.2 Power Services shall maintain for EWEB an account that will indicate the accumulated amount of Additional Energy that was made available to EWEB during each CGS Displacement and for each Fiscal Year.

5.8.4.3 Following the end of each Fiscal Year, EWEB shall pay an amount equal to EWEB's balance in the accumulated Additional Energy account multiplied by the Incremental Cost associated with each such Fiscal Year, and such account balance shall be set to zero. Such amount shall be included on EWEB's next power bill immediately after determination of the Incremental Cost pursuant to section 5.8.5.

5.8.5 **Operating Plan and Incremental Cost**
Within 30 days following the date that the Operating Plan for the upcoming Fiscal Year is adopted, Power Services shall provide EWEB such Operating Plan and the actual Incremental Cost associated with the immediately preceding Fiscal Year.

5.8.6 **Implementation of CGS Displacement**

5.8.6.1 BPA shall notify EWEB of any potential CGS Displacement as soon as BPA determines such CGS Displacement is likely to occur.

5.8.6.2 If a CGS Displacement occurs during a period when EWEB has elected not to participate in such CGS Displacement, BPA shall develop and submit to EWEB hourly schedules of Additional Energy as described in section 5.8.1.1.

5.8.6.3 Such Additional Energy amounts shall be computed by the BOS Module as a component of EWEB's BOS schedule, as described in section 4 of Exhibit M.

5.9 **Treatment of RHWM Augmentation**
EWEB shall purchase and receive a share of RHWM Augmentation in an amount equal to EWEB's Slice Percentage multiplied by the RHWM Augmentation for each Fiscal Year, as set forth in Exhibit L.

5.10 **SCA Functionality Test, Simulator Performance Test, and Implementation of the SCA**
This section sets out the SCA Functionality and Simulator Performance Tests. BPA shall promptly notify EWEB of the results of the SCA Functionality and Simulator Performance Tests.

5.10.1 **Definitions**

5.10.1.1 "Default User Interface," or "DUI," means the basic user interface that is developed by BPA and made available to EWEB for access to the SCA.

5.10.1.2 "Interim Slice Implementation Procedures" means the procedures set forth in Exhibit O that will be used on an interim basis to determine EWEB's available Slice Output and Delivery Limits in the event the SCA Implementation Date occurs after October 1, 2011, pursuant to section 5.10.3.

5.10.1.3 "SCA Functionality Test" means the test set forth in section 5.10.2 that is conducted to determine whether the SCA is complete, functional, and ready for daily implementation and use.

5.10.1.4 "SCA Implementation Date" means the latest of: (1) October 1, 2011, (2) 90 days after the SCA Pass Date, or (3) 90 days after the Simulator Pass Date.

5.10.1.5 "SCA Pass Date" means the date on which the SCA passes the SCA Functionality Test.

5.10.1.6 "Simulator Pass Date" means the date on which the Simulator passes the Simulator Performance Test.

5.10.1.7 "Simulator Performance Test" means the test conducted by BPA and consisting of four separate tests: a Storage Content test, an energy test, a peaking test, and a ramp down test, each as separately described in section 3.5.3 of Exhibit M.

5.10.2 **SCA Functionality Test**

5.10.2.1 **SCA Functionality Test Conducted No Later Than July 1, 2011**
The initial SCA Functionality Test shall be conducted by BPA no later than July 1, 2011.

5.10.2.2 **Determination of SCA Functionality Test Procedures**
BPA, in consultation with EWEB and other members of the SIG, shall, by April 15, 2011, establish a detailed written description of the validation procedures that will comprise the SCA Functionality Test. Such validation procedures shall include a comprehensive series of objective tests that establish if the SCA, including the Simulator, DUI and BOS module, are wholly functional and ready for daily implementation and use.

5.10.3 **SCA Implementation Date**

5.10.3.1 **SCA Implementation Date Established as October 1, 2011**
If the SCA Implementation Date is established as October 1, 2011, then BPA and EWEB shall commence implementation of the SCA beginning on October 1, 2011.

5.10.3.2 **SCA Implementation Date Occurs After October 1, 2011**
If the SCA Implementation Date is established later than October 1, 2011, then, beginning on October 1, 2011, and continuing until the SCA Implementation Date, BPA and EWEB shall implement the Interim Slice Implementation Procedures, pursuant to Exhibit O.

5.10.4 **Simulator Performance Test**

5.10.4.1 **Simulator Performance Test Date**
No later than August 1, 2010, BPA shall provide EWEB access to the Simulator that will be used by BPA to conduct the Simulator Performance Test. The Simulator Performance Test shall be conducted by BPA no later than October 31, 2010.

5.10.4.2 **Simulator Fails Simulator Performance Test**
If, as of October 31, 2010, the Simulator has failed one or more of the four tests that comprise the Simulator Performance Test, then EWEB may elect to change its purchase obligation pursuant to section 11.2.

5.10.5 **EWEB Unable to Utilize DUI**
If, as of the SCA Implementation Date, EWEB is not functionally ready to access and utilize the DUI, then beginning October 1, 2011 and continuing until 30 days after EWEB provides BPA with written notice that it is functionally ready to utilize the DUI, BPA shall use the SCA to determine EWEB's hourly Delivery Requests in accordance with the following procedures:

5.10.5.1 **Establishment of Preschedules**

(1) BPA shall set EWEB's Customer Inputs (generation requests) for Grand Coulee and Chief Joseph equal to Power Services planned Grand Coulee and Chief Joseph's respective generation;

(2) BPA shall set EWEB's Customer Inputs (elevation requests) for the LCOL Complex projects such that those projects pass inflow on an hourly basis; and

(3) BPA shall set EWEB's hourly BOS amount equal to EWEB's Slice Percentage multiplied by the BOS Base amount (no BOS Flex allowed).

(4) BPA shall communicate the above values to EWEB via facsimile.

5.10.5.2 **Updates to Preschedule Values**
Using the same criteria as set forth in section 5.10.5.1, BPA shall revise EWEB's Customer Inputs, and submit to EWEB its revised Delivery Requests, as needed to reflect BPA's latest estimated generation, inflow and BOS Base values: (1) by 1800 hours on the day prior to delivery, and (2) by 60 minutes prior to the beginning of each hour of delivery.

5.10.5.3 **Submission of Electronic Tags**
EWEB shall submit electronic tags to Power Services on preschedule and real time, pursuant to Exhibit F, which shall indicate energy amounts equal to EWEB's hourly Delivery Requests established under this section 5.10.5.

(1) If energy amounts indicated on EWEB's electronic tags are greater than its hourly Delivery Requests, then EWEB shall receive the electronic tag amounts and shall be charged at the UAI Charge for the energy that is in excess of the Slice Output Energy amount.

(2) If energy amounts indicated on EWEB's electronic tags are less than its hourly Delivery Requests, then EWEB shall receive the electronic tag amounts and shall forfeit the remaining Slice Output Energy amount.

5.10.5.4 **Delivery Limit Penalties**
Except as described in section 5.10.5.3, Delivery Limit penalties established in Exhibit N shall not be assessed for the first 90 days that the provisions described in this section 5.10.5 are in effect.

5.11 **Slice Computer Application Development Schedule**
The schedule attached hereto as Exhibit P represents timelines under which specific tasks associated with the development of the SCA shall be completed. EWEB and BPA understand and agree that: (1) the timelines specified in Exhibit P are not binding and are for information purposes only, and (2) the timelines set forth in this section 5 are binding. BPA, EWEB, and other

members of the SIG shall discuss the status of the various tasks identified in Exhibit P and their associated timelines.

5.12 Slice Implementation Group

5.12.1 Definitions

5.12.1.1 "Majority" means at least 51 percent of the Slice Implementation Group (SIG) members (or their alternates) present at a meeting of the SIG at which a Quorum has been established (counting only one representative for each Slice Customer and for BPA, even if both the SIG member and the alternate SIG member are present).

5.12.1.2 "Quorum" means the BPA SIG member and at least 60 percent of all Slice Customer SIG members (provided that if an alternate SIG member is present at a SIG meeting and the corresponding SIG member is not, the alternate SIG member shall be counted for purposes of determining a Quorum).

5.12.1.3 "Super Majority" means at least 66 percent of the Slice Customer SIG members (or their alternates) present at a meeting of the SIG at which a Quorum has been established (counting only one representative for each Slice Customer, even if both the SIG member and the alternate SIG member are present).

5.12.2 Slice Implementation Group

5.12.2.1 The Parties anticipate that implementation issues will arise regarding the Slice Product or the Slice Computer Application, and that a forum is needed for discussing alternatives and taking actions that may affect BPA and the Slice Customers. The SIG is hereby established for the purposes of: (1) considering, establishing and documenting modifications to the Slice Computer Application necessary to maintain its reasonable representation of Tier 1 System energy, peaking, storage, and ramping capability; (2) considering, establishing and documenting modifications to the Slice Computer Application necessary for EWEB and other Slice Customers to schedule Slice Output Energy under this Agreement; (3) establishing a clearinghouse for information regarding the Slice Product and the Slice Computer Application; and (4) establishing a forum for discussing any other issues regarding the Slice Product, the Slice Computer Application and associated procedures.

5.12.2.2 BPA and EWEB shall each appoint a SIG member and an alternate SIG member to attend SIG meetings. Appointment of a SIG member and an alternate SIG member shall initially be made in writing submitted to BPA and all other Slice Customers, and thereafter to the SIG chairperson. The Slice Customer SIG members shall elect a SIG chairperson each year who shall conduct SIG meetings. Any SIG meeting may be conducted by telephone conference call. Any action of the SIG, except as otherwise provided herein, shall be made by Majority vote of the SIG members (or any alternates acting in the absence of SIG members) attending the SIG meeting in person or by telephone. The SIG may adopt rules and procedures, including dates, times, and locations of meetings, as it deems necessary or desirable. A meeting may be called by any SIG member or alternate by providing all other SIG members and alternates with written notice at least seven calendar days in advance of such meeting, setting forth the date, location, and subject matter of such meeting. The SIG shall meet at least once during each Fiscal Year.

5.12.2.3 BPA shall have the right in its sole discretion to implement the upgrades, replacements and changes described in sections 5.12.2.3(1) through 5.12.2.3(3) only to the extent it determines such implementation is consistent with the Slice product as described in section 5.1, and only after: (1) such implementation and related testing is reviewed and discussed by the SIG; and (2) such upgrades, replacements and changes have been subjected to testing as determined by BPA to be relevant and sufficient to demonstrate that each upgrade, replacement, or change functions as intended and does not cause any other portion of the SCA to malfunction. Such implementation by BPA shall not be subject to approval by the SIG. Notwithstanding BPA's sole discretion to implement such upgrades, replacements and changes, EWEB may dispute BPA's determination of consistency with section 5.1 regarding any such upgrades, replacements, and changes, in accordance with section 22. If as a result of a dispute resolution process such upgrade, replacement, or change is determined to be inconsistent with section 5.1, then BPA, EWEB, and other members of the SIG shall consult to identify modifications that make such upgrade, replacement, or change consistent with section 5.1, and BPA shall promptly implement such modifications.

(1) BPA may change, upgrade or replace the Slice Computer Application as necessary to produce results that reasonably represent the energy production, peaking, storage, or ramping capability of the Tier 1 System.

(2) BPA may change, upgrade or replace the Slice Computer Application as necessary to maintain functionality with BPA's internal business processes and systems.

(3) BPA may determine how Operating Constraints are translated into Simulator Parameters for application within the Slice Computer Application, and in a manner that reflects in the Slice Computer Application the impacts of such Operating Constraints on the Tier 1 System.

5.12.2.4 Subject to the procedures set forth below and except as otherwise provided in section 5.12.2.3, BPA or any Slice Customer may propose changes to the Slice Computer Application. Any such proposal shall be made in writing and be provided to all members of SIG. The proposal shall state the change or changes proposed, the reasons for such proposed change or changes, the expected impacts or benefits, and the time frame of implementation.

5.12.2.5 Following receipt of written notice proposing a change to the SCA pursuant to section 5.12.2.4, the SIG chairperson shall convene the SIG to discuss such proposed change(s). The SIG shall decide, using its normal rules of procedure, the type of analysis (if any) that should be performed on the proposed change(s), and, as applicable, whether the proposed change(s) shall be further considered.

5.12.2.6 After an analysis (if any) is completed and distributed to the SIG members, the SIG chairperson shall convene a meeting of the SIG to discuss the proposed change(s), and any modifications thereto. If BPA elects to submit the proposed change(s) for public comment, the SIG chairperson will postpone any vote on the proposed change(s) for up to 45 calendar days to permit BPA to conduct a public comment process.

5.12.2.7 At a meeting of the SIG, the SIG chairperson shall put to a vote the question of whether the proposed change(s) should be recommended for implementation. If a Majority of the SIG members vote in favor of implementing the proposed change(s), then the proposed change(s) will be implemented by BPA unless:

(1) the BPA SIG member opposes the proposed change(s), in which case the proposed change(s) shall not be

adopted, and the Slice Computer Application shall not be revised; or

(2) the BPA SIG member approves the proposed change(s), and one or more Slice Customer SIG members who voted against the implementation of the proposed change(s) request in writing to all SIG members, within 10 calendar days of the Majority vote approving such implementation, a second vote by all Slice Customer SIG members on the question of whether the proposed change(s) should be implemented. In this event, implementation shall be deferred until such second vote is taken. Such second vote shall be taken within 20 calendar days of the date of such Majority vote. If a Super Majority of the Slice Customer SIG members affirm the proposal under such second vote to implement the proposed change(s), then the proposed change(s) will be implemented. If a Super Majority of the Slice Customer SIG members does not affirm under such second vote to implement the proposed change(s), then the proposed change(s) will not be implemented.

5.13 **Creditworthiness**
EWEB shall execute a Creditworthiness Agreement with BPA prior to or coincident with execution of this Agreement.

5.14 **True-Up Adjustment Charge**

5.14.1 **Interest Rate Applied to Slice True-Up Adjustment Charge and Time Periods During Which Interest is Applied**
BPA shall calculate a Slice True-Up Adjustment Charge annually pursuant to section 2.7.4 of the TRM.

5.14.1.1 **Determination of Interest Rate**
Interest shall be computed and added to the Slice True-Up Adjustment Charge using the daily simple interest rate. The daily simple interest rate shall be the Prime Rate for Large Banks as reported in the Wall Street Journal or successor publication in the first issue of the Fiscal Year in which the Slice True-Up Adjustment Charge is calculated, divided by 365. The daily simple interest rate will be fixed on the first day of the Fiscal Year in which the Slice True-Up Adjustment Charge is calculated for the time periods specified under section 5.14.1.2.

5.14.1.2 **Time Periods During Which Interest is Applied**
Interest determined pursuant to section 5.14.1.1 shall be computed and added to the Slice True-Up Adjustment Charge for EWEB for the time periods defined as follows:

(1) If the Slice True-Up Adjustment Charge is a credit to EWEB, then the period for interest computation will begin with the first day of the Fiscal Year in which the Slice True-Up Adjustment Charge is calculated, and will end on the due date of the bill that contains such credit.

(2) If the Slice True-Up Adjustment Charge is a charge payable to BPA, then the period for interest computation will begin with the first day of the Fiscal Year in which the Slice True-Up Adjustment Charge is calculated, and will end, with regard to the portion to be paid, on the due date for each of the three monthly bills in which the Slice True-Up Adjustment Charge appears. If EWEB elects to pay the charge in one month, then EWEB shall notify BPA in writing and the period for interest computation will begin with the first day of the Fiscal Year in which the Slice True-Up Adjustment Charge is calculated and will end on the due date for the next monthly bill issued following the day such Slice True-Up Adjustment Change is calculated.

(3) If a credit or charge contained in a Slice True-Up Adjustment Charge is subject to dispute resolution pursuant to Attachment A of the TRM or has been reserved for final disposition in the next 7(i) Process, all pursuant to the TRM, and if there is an adjustment to such credit or charge as a result thereof, then the period for the interest calculation shall begin on the first day of the Fiscal Year in which the disputed Slice True-Up Adjustment Charge was calculated and will end as specified in section 5.14.1.2(1) or (2) depending upon whether the adjustment is a credit or a charge.

6. TIERED RATE METHODOLOGY

6.1 BPA has proposed the TRM to FERC for either confirmation and approval for a period of 20 years (through September 30, 2028) or a declaratory order that the TRM meets cost recovery standards. The then-effective TRM shall apply in accordance with its terms and shall govern BPA's establishment, review and revision pursuant to section 7(i) of the Northwest Power Act, of all rates for power sold under this Agreement.

6.2 In the event that FERC approves the TRM for a period less than through September 30, 2028, or issues a declaratory order that the TRM meets cost recovery standards for a period less than through September 30, 2028, BPA shall, before the approved period of the TRM expires: (1) propose continuation of the TRM in a hearing conducted pursuant to section 7(i) of the Northwest Power Act or its successor; and then (2) resubmit the TRM to FERC for approval or declaratory affirmation of cost recovery standards through September 30, 2028.

6.3 The recitation of language from the TRM in this Agreement is not intended to incorporate such language into this Agreement. The TRM's language may be revised, but only in accordance with the requirements of TRM sections 12 and 13. If language of the TRM is revised, then any such language recited in this Agreement shall be modified accordingly, and the Amendment process of section 24.1 shall not apply to any such modifications.

6.4 Any disputes over the meaning of the TRM or rates or whether the Administrator is correctly implementing the TRM or rates, including but not limited to matters of whether the Administrator is correctly interpreting, applying, and otherwise adhering or conforming to the TRM or rate, shall (1) be resolved pursuant to any applicable procedures set forth in the TRM; (2) if resolved by the Administrator as part of a proceeding under section 7(i) of the Northwest Power Act, be reviewable as part of the United States Court of Appeals for the Ninth Circuit's review under section 9(e)(5) of the Northwest Power Act of the rates or rate matters determined in such section 7(i) proceeding (subject to any further review by the United States Supreme Court); and (3) if resolved by the Administrator outside such a section 7(i) proceeding, be reviewable as a final action by the United States Court of Appeals for the Ninth Circuit under section 9(e)(5) of the Northwest Power Act (subject to any further review by the United States Supreme Court). The remedies available to EWEB through such judicial review shall be EWEB's sole and exclusive remedy for such disputes, except as provided in the next paragraph.

Any knowing failure of BPA to abide by the TRM, or any BPA repudiation of its obligation here and under the TRM to revise the TRM only in accordance with the TRM sections 12 and 13 procedures for revision, would be a matter of contract to be resolved as would any other claim of breach of contract under this Agreement. For purposes of this paragraph, when there is a dispute between BPA and EWEB concerning what the TRM means or requires, a "knowing failure" shall occur only in the event the United States Court of Appeals for the Ninth Circuit or, upon further review, the United States Supreme Court rules against BPA on its position as to what the TRM means or requires and BPA thereafter persists in its prior position.

6.5 BPA shall not publish a Federal Register Notice regarding BPA rates or the TRM that prohibits, limits, or restricts EWEB's right to submit testimony or brief issues on rate matters regarding the meaning or implementation of the TRM or establishment of BPA rates pursuant to it, provided however for purposes of BPA's conformance to this paragraph a "rate matter" shall not include budgetary and program level issues.

6.6 The TRM established by BPA as of the Effective Date includes, among other things, the following:

6.6.1 Definitions (from Definitions section of the TRM):

"Contract High Water Mark" or **"CHWM"** means the amount (expressed in Average Megawatts), computed for each customer in accordance with section 4 of the TRM. For each customer with a CHWM Contract, the CHWM is used to calculate each customer's RHWM in the RHWM Process for each applicable Rate Period. The CHWM Contract specifies the CHWM for each customer.

"Rate Period High Water Mark" or **"RHWM"** means the amount, calculated by BPA in each RHWM Process (as defined in the TRM) pursuant to the formula in section 4.2.1 of the TRM and expressed in Average Megawatts, that BPA establishes for each customer based on the customer's CHWM and the RHWM Tier 1 System Capability (as defined in the TRM). The maximum planned amount of power a customer may purchase under Tier 1 Rates each Fiscal Year of the Rate Period is equal to the RHWM for Load Following customers and the lesser of RHWM or Annual Net Requirement for Block and Slice/Block customers.

"Contract Demand Quantity" or **"CDQ"** means the monthly quantity of demand (expressed in kilowatts) included in each customer's CHWM Contract that is subtracted from the Customer System Peak (as defined in the TRM) as part of the process of determining the customer's Demand Charge Billing Determinant (as defined in the TRM), as calculated in accordance with section 5.3.5 of the TRM.

6.6.2 Rate Period High Water Mark Calculation (from section 4.2.1 of the TRM):

Expressed as a formula, the RHWM will be calculated by BPA for each customer as follows:

$$RHWM = \frac{CHWM}{\Sigma CHWM} \times T1SC$$

where:

$RHWM$ = Rate Period High Water Mark, expressed in Average Megawatts

$CHWM$ = Contract High Water Mark

$\Sigma CHWM$ = sum of all customers' Contract High Water Marks, including those for customers without a CHWM Contract

$T1SC$ = forecast RHWM Tier 1 System Capability (as defined in the TRM), averaged for the Rate Period

7. HIGH WATER MARKS AND CONTRACT DEMAND QUANTITIES

7.1 Contract High Water Mark (CHWM)

BPA shall establish EWEB's CHWM in the manner defined in section 4.1 of the TRM that was current as of the Effective Date. EWEB's CHWM and the circumstances under which it can change are stated in Exhibit B.

7.2 Rate Period High Water Mark (RHWM)

EWEB's CHWM shall also be EWEB's RHWM for FY 2012 and FY 2013. BPA shall establish EWEB's RHWM for the next Rate Period by September 30, 2012, and for subsequent Rate Periods by September 30 of each Forecast Year thereafter. BPA shall establish EWEB's RHWM in the manner defined in section 4.2 of the TRM that was current as of the Effective Date.

7.3 Contract Demand Quantities (CDQs)

BPA shall establish EWEB's CDQs pursuant to the TRM. EWEB's CDQs are listed in Exhibit B.

8. APPLICABLE RATES

Purchases under this Agreement are subject to the following rate schedules, or their successors: Priority Firm Power (PF), New Resource Firm Power (NR), and Firm Power Products and Services (FPS), as applicable. Billing determinants for any purchases will be included in each rate schedule. Power purchases under this Agreement are subject to BPA's Wholesale Power Rate Schedules, established in accordance with the TRM, as applicable, and its GRSPs (or their successors).

8.1 Priority Firm Power (PF) Rates

BPA shall establish its PF power rates that apply to purchases under this Agreement pursuant to section 7 of the Northwest Power Act, and in accordance with the TRM. BPA shall establish PF power rates that include rate schedules for purchase amounts at Tier 1 Rates and purchase amounts at Tier 2 Rates. EWEB's purchases of: (1) Tier 1 Block Amounts, as specified in section 1 of Exhibit C, and (2) Critical Slice Amounts, as specified in section 2 of Exhibit I, shall be at Tier 1 Rates. EWEB's purchases of Tier 2 Block Amounts, if any, shall be at the applicable Tier 2 Rates and in accordance with the terms of section 2 of Exhibit C.

8.2 New Resource Firm Power (NR) Rate

Pursuant to sections 23.3.6 and 23.3.7, EWEB agrees to serve NLSLs with Dedicated Resources or Consumer-Owned Resources listed in section 4 or 7.4, respectively, of Exhibit A.

8.3 **Firm Power Products and Services (FPS) Rate**
Services sold under this Agreement to EWEB at the FPS rate, if any, are listed in Exhibit D.

8.4 **Additional Charges**
EWEB may incur additional charges or penalty charges as established in the Wholesale Power Rate Schedules and GRSPs, including the Unauthorized Increase Charge and the Resource Shaping Charge, or their successors.

9. ELECTIONS TO PURCHASE POWER PRICED AT TIER 2 RATES

9.1 **Determination and Notice to Serve Above-RHWM Load**
EWEB shall determine and provide notice, as described below, to BPA whether EWEB shall serve its Above-RHWM Load that is greater than or equal to 8,760 megawatt-hours with either: (1) Firm Requirements Power purchased from BPA at a Tier 2 Rate or rates, (2) Dedicated Resources, or (3) a specific combination of both (1) and (2). EWEB shall make such determination and provide such notice as follows:

9.1.1 **Notice Deadlines and Purchase Periods**
Notice Deadlines and corresponding Purchase Periods are as follows:

Notice Deadline		Purchase Period
November 1, 2009	For	FY 2012 – FY 2014
September 30, 2011	For	FY 2015 – FY 2019
September 30, 2016	For	FY 2020 – FY 2024
September 30, 2021	For	FY 2025 – FY 2028

9.1.2 **Elections to Purchase at Tier 2 Rates**
By each Notice Deadline, EWEB shall elect in writing to purchase, or not to purchase, Firm Requirements Power at Tier 2 Rates for at least the upcoming Purchase Period. If EWEB elects to purchase Firm Requirements Power at Tier 2 Rates, then EWEB shall make such election pursuant to sections 2.2 through 2.4 of Exhibit C. BPA shall update Exhibit C to state EWEB's Tier 2 Rate purchase elections.

9.1.3 **Elections Not to Purchase at Tier 2 Rates**
If EWEB elects under section 9.1.2 not to purchase Firm Requirements Power at Tier 2 Rates to serve Above-RHWM Load for a Purchase Period, BPA shall update section 2.1 of Exhibit C to indicate such election. Such election shall not eliminate any existing obligation that extends into the Purchase Period or beyond to purchase Firm Requirements Power at Tier 2 Rates.

9.1.4 **Failure to Make an Election**
If EWEB makes no election by a Notice Deadline in section 9.1.1 for the corresponding Purchase Period, EWEB shall be deemed to have

elected not to purchase Firm Requirements Power at Tier 2 Rates to serve Above-RHWM Load, except for any existing obligation to purchase such power that extends into the Purchase Period or beyond.

9.2 **Tier 2 Rate Alternatives**
Subject to the requirements of this section 9 and those stated in Exhibit C, EWEB shall have the right to purchase Firm Requirements Power at Tier 2 Vintage Rates and Tier 2 Short-Term Rates.

9.3 **Flat Block**
Amounts of Firm Requirements Power priced at Tier 2 Rates and purchased by EWEB shall be equal in all hours of the year.

10. TIER 2 REMARKETING AND RESOURCE REMOVAL
For the purpose of this section 10, any Dedicated Resources added to Exhibit A pursuant to section 3.5.3 or 3.5.7 do not have temporary resource removal or remarketing rights under this section. In addition, any Dedicated Resource amounts or amounts purchased at a Tier 2 Rate that would otherwise be made eligible for removal or remarketing due to the addition of resources under section 3.5.3 do not have temporary resource removal or remarketing rights under this section.

10.1 **Definition of Preliminary Net Requirement**
"Preliminary Net Requirement" means BPA's forecast of EWEB's Net Requirement for each Fiscal Year prior to the removal of any resources in accordance with this section 10.

10.2 **Resource Removal and Remarketing of Tier 2 Purchase Amounts – First Fiscal Year of Each Rate Period**
If EWEB's Preliminary Net Requirement for the first Fiscal Year of an upcoming Rate Period is less than the sum of: (1) EWEB's RHWM, and (2) EWEB's Tier 2 Rate purchase amounts, as stated in Exhibit C, then Tier 2 remarketing and removal of New Resources shall apply for such year to the extent necessary to comply with section 10.4. If such remarketing and removal of New Resources applies, then by August 31 of the applicable Rate Case Year, EWEB may notify BPA of the order and associated amounts of EWEB's Tier 2 Rate purchase amounts that BPA shall remarket and the New Resources EWEB shall remove for the upcoming Fiscal Year. If compliance with the requirements of section 10.4 would cause EWEB to remove part or all of any New Resource that EWEB uses to fulfill a state or federal renewable resource standard or other comparable legal obligation, then EWEB shall have the right to substitute its right to remove New Resources for the same amount of Existing Resources to the extent necessary to comply with section 10.4, provided that the hourly, monthly, and Diurnal amounts so removed shall be equal to the hourly, monthly, and Diurnal amounts provided by the New Resources that EWEB would have otherwise been obligated to remove.

If EWEB does not provide BPA with such timely notice in accordance with the preceding paragraph, then BPA shall determine the order and associated amounts of Tier 2 remarketing and removal of New Resources to the extent necessary to comply with section 10.4.

10.3 **Resource Removal and Remarketing of Tier 2 Purchase Amounts – Subsequent Fiscal Years of Each Rate Period**
For each subsequent Fiscal Year of each Rate Period, the process established in section 10.2 shall also apply, and after BPA remarkets all Tier 2 Rate purchase amounts and EWEB removes all amounts of its New Resources, then Existing Resources are eligible for resource removal to the extent necessary to comply with section 10.5. By August 31 prior to the applicable Fiscal Year, EWEB may notify BPA of the order and associated amounts of Existing Resource removal for the upcoming Fiscal Year.

If EWEB does not provide BPA with such timely notice, then BPA shall determine the order of and associated amounts of Existing Resource removal for the upcoming Fiscal Year.

10.4 **Extent of Removal for the First Fiscal Year of Each Rate Period**
Tier 2 remarketing and resource removal pursuant to section 10.2 shall apply until:

(1) the remarketed Tier 2 Rate purchase amounts plus the removed New Resource amounts equal the amount by which EWEB's Tier 2 Rate purchase amounts plus its RHWM exceed its Preliminary Net Requirement, or

(2) all of EWEB's Tier 2 Rate purchase amounts are remarketed and all of its New Resources are removed.

10.5 **Extent of Removal for Subsequent Fiscal Years of Each Rate Period**
For each subsequent Fiscal Year of a Rate Period, Tier 2 remarketing and resource removal pursuant to section 10.3 shall apply as stated in section 10.4. In addition, if EWEB's Preliminary Net Requirement for the applicable subsequent Fiscal Year of a Rate Period is lower than EWEB's Preliminary Net Requirement for the first Fiscal Year of the same Rate Period, then resource removal shall apply to EWEB's Existing Resources. As long as EWEB has Existing Resources to remove, the amount of such removal shall equal the lesser of: (1) the remaining amount that EWEB's RHWM exceeds its Preliminary Net Requirement, or (2) the difference between EWEB's Preliminary Net Requirement for the first Fiscal Year and EWEB's Preliminary Net Requirement for the applicable subsequent Fiscal Year of the Rate Period. If EWEB's Preliminary Net Requirement for the applicable subsequent Fiscal Year of a Rate Period is greater than or equal to EWEB's Preliminary Net Requirement for the first Fiscal Year of the same Rate Period, then resource removal shall not apply to EWEB's Existing Resources.

10.6 Partial Resource Removal

When only a portion of a Specified Resource or Unspecified Resource Amounts is being removed pursuant to section 10.2 or 10.3, such resources shall be removed proportionally to maintain the same annual shape for the resource that EWEB has established in Exhibit A.

10.7 Rounding of Tier 2 Rate Purchase Amounts

To the extent remarketing of Tier 2 Rate purchase amounts results in an amount less than a whole Average Megawatt, BPA shall round such amount to a whole Average Megawatt.

10.8 Remarketing of Power Priced at Tier 2 Rates

Consistent with rates established under the TRM, EWEB shall be subject to applicable charges or credits associated with BPA's remarketing of purchase amounts of Firm Requirements Power at Tier 2 Rates. Except as specified in section 10.9, EWEB shall be responsible for remarketing of any amounts of its Dedicated Resources, Specified or Unspecified, that are removed pursuant to sections 10.2 or 10.3.

10.9 Removal of Resources Taking DFS

The following shall apply for any Dedicated Resources: (1) for which EWEB is purchasing DFS under this Agreement, and (2) that are partially or entirely removed in accordance with sections 10.2 or 10.3.

10.9.1 EWEB shall continue to supply the entire amount of any such resources to BPA consistent with applicable provisions stated in Exhibit D.

10.9.2 BPA shall remarket the amounts of any such resources that are removed pursuant to sections 10.2 or 10.3 in the same manner BPA remarkets Tier 2 Rate purchase amounts in section 10.8. BPA shall continue to provide DFS in accordance with applicable provisions in Exhibit D to any amounts of such resources that remain after resource removal.

11. RIGHT TO CHANGE PURCHASE OBLIGATION

11.1 One-Time Right to Change Purchase Obligation

Subject to this section 11.1, EWEB shall have a one-time right to change its purchase obligation, identified in section 3, to another purchase obligation available from BPA, including Load Following or Block. If EWEB chooses to change its purchase obligation under this section 11.1, then EWEB shall first provide notice to BPA of its intent and then confirm its decision as established below. Any elections of Tier 2 Rate alternatives, Dedicated Resource additions, or other notices given to BPA under this Agreement shall continue to be applicable under the new purchase obligation, provided that BPA may update such terms and conditions consistent with the then current terms of the new purchase obligation, and additional costs may apply for service under the new purchase obligation as described in section 11.1.3.

11.1.1 **Notice to Change**

By May 31, 2016, EWEB may provide written notice to BPA that it is requesting to change its purchase obligation effective October 1, 2019, subject to confirmation described in section 11.1.4. EWEB's notice shall state the type of service requested.

11.1.2 **Limitations Due to Peak Load Increase**

By July 31, 2016, BPA shall assess the aggregate effect of all requests to change purchase obligations on BPA's forecast of its total monthly firm coincident peak loads in the first year the changes become effective. If the increase in this peak load in any one month exceeds 300 megawatts, then BPA may, after consulting with EWEB and other customers with a CHWM Contract, do one of the following to reduce the increase in such peak load to 300 megawatts: (1) deny EWEB's request to change its purchase obligation, or (2) approve EWEB's request but defer the date on which EWEB's new purchase obligation change becomes effective.

11.1.3 **Charge to Change Purchase Obligation**

In addition to the limitations established in section 11.1.2, EWEB may be subject to charges, in addition to the rates for the new service, as a result of changing its purchase obligation pursuant to this section 11.1. Such additional charges shall recover all additional costs that: (1) will be incurred by BPA to serve EWEB under its new purchase obligation compared to its existing purchase obligation, and (2) would otherwise result in a rate impact on all other customers receiving service under a CHWM Contract. If EWEB makes a request to change its purchase obligation pursuant to this section 11.1, then by August 31, 2016, BPA shall determine and present EWEB with any such additional charges. BPA shall not be required to make a payment to EWEB as a result of EWEB changing its purchase obligation.

11.1.4 **Change Confirmation**

Within 30 days of BPA's presentation to EWEB of the additional charges determined in section 11.1.3, EWEB shall provide BPA with written notice whether it wishes to proceed with its request to change its purchase obligation. If EWEB does not provide BPA with such confirmation, then EWEB's existing purchase obligation identified in section 3 shall continue to apply.

11.1.5 **Amendment to Reflect New Purchase Obligation**

Following EWEB's confirmation of its decision to change its purchase obligation, the Parties shall amend this Agreement to replace the terms of EWEB's current purchase obligation with the terms of the new purchase obligation. The amended Agreement shall be effective no later than October 1, 2019.

11.2 Additional Rights to Change Purchase Obligation

In addition to the opportunity to change its purchase obligation provided in section 11.1, EWEB may elect to change its purchase obligation to that stated in section 11.2.4 after the occurrence of any of the events listed in sections 11.2.1 through 11.2.3.

11.2.1 Simulator Fails Simulator Performance Test

If, as of October 31, 2010, BPA has failed to perform the Simulator Performance Test, or the Simulator has failed one or more of the four tests that comprise the Simulator Performance Test, then EWEB may change its purchase obligation to that stated in 11.2.4 by providing written notice to BPA in accordance with section 20. Such written notice must be received by BPA no later than January 15, 2011. Unless the Parties agree otherwise, the effective date of the change in purchase obligation to the contingent contract amendment shall be July 1, 2011.

11.2.2 No Slice Output Energy Available on a Forecasted Basis

EWEB may change its purchase obligation to that stated in 11.2.4 by providing written notice in accordance with section 20 not later than 60 days after BPA forecasts, prior to the first day of any Fiscal Year, that there will be no Slice Output Energy available for delivery to EWEB during such Fiscal Year and the immediately following Fiscal Year, or in the event there is no Slice Output Energy available to EWEB during any two consecutive Fiscal Years. Unless the Parties agree otherwise, the effective date of the contingent contract amendment shall be October 1 of the Fiscal Year in which BPA has forecasted that there will be no Slice Output Energy available for delivery to EWEB.

11.2.3 Changes to Transmission Scheduling Practices

EWEB may change its purchase obligation to that stated in section 11.2.4 by providing written notice to BPA in accordance with section 20 not later than 60 calendar days after BPA, or its successor, adopts standards, rules, practices or procedures, that require EWEB to schedule hourly energy based on Scheduling Points of Receipt for each of the Tier 1 System Resources from which EWEB may receive Slice Output Energy under this Agreement. Unless the Parties agree otherwise, the effective date of the contingent contract amendment shall be October 1 of the Fiscal Year following the date BPA adopts such policy.

11.2.4 Alternative Requirements Power Purchase Obligation

EWEB selects the Load Following Power Purchase Obligation as the purchase obligation that it will purchase in the event EWEB changes its purchase obligation under the events specified in sections 11.2.1 through 11.2.3. Not later than the deadlines shown in sections 11.2.1 through 11.2.3, the Parties shall execute a contract amendment for the selected purchase obligation. Such contract amendment shall contain the same terms and conditions as this Agreement, including any elections or choices made under this Agreement that are applicable to the new purchase obligation selected by EWEB.

11.2.5 **Waiver of Certain Claims for Damages**
In the event that EWEB changes its purchase obligation in accordance with this section 11, EWEB agrees not to seek and hereby waives the right, if any such right exists, to pursue any claim for damages from BPA due to any such change. This waiver is limited to any claims EWEB may have arising from changes to EWEB's purchase obligation under this section 11. This waiver has no application to, and EWEB hereby expressly preserves, any claims for damages arising under any other section of this Agreement.

12. BILLING CREDITS AND RESIDENTIAL EXCHANGE

12.1 Billing Credits
If EWEB develops a Generating Resource to serve its loads, then EWEB agrees that it shall forego any request for, and BPA is not obligated to include, billing credits, as defined in section 6(h) of the Northwest Power Act, on EWEB's bills under this Agreement. This section does not apply to any billing credit contracts in effect as of the Effective Date.

12.2 Agreement to Limit Exchange Costs of Existing Resources
EWEB agrees it will not seek and shall not receive residential exchange benefits pursuant to section 5(c) of the Northwest Power Act other than pursuant to Section IV(G) of BPA's 2008 Average System Cost Methodology or its successor. EWEB recognizes that the quantity of residential load will be determined in a subsequent policy or rate determination. EWEB's agreement in this section 12.2 is a material precondition to BPA offering and executing this Agreement.

13. SCHEDULING
EWEB shall schedule power in accordance with Exhibit F.

14. DELIVERY

14.1 Definitions

14.1.1 "Integrated Network Segment" means those facilities of the Federal Columbia River Transmission System that are required for the delivery of bulk power supplies, the costs for which are recovered through generally applicable transmission rates, and that are identified as facilities in the Integrated Network Segment, or its successor, in the BPA segmentation study for the applicable transmission rate period as determined in a hearing establishing or revising BPA's transmission rates pursuant to section 7(i) of the Northwest Power Act.

14.1.2 "Primary Points of Receipt" means the points on the Pacific Northwest transmission system where Firm Requirements Power is forecasted to be made available by Power Services to EWEB for purposes of obtaining a long-term firm transmission contract.

14.1.3 "Scheduling Points of Receipt" means the points on the Pacific Northwest transmission system where Slice Output Energy is made available by Power Services to EWEB for purposes of transmission scheduling.

14.2 **Transmission Service**

14.2.1 EWEB is responsible for delivery of power from the Scheduling Points of Receipt.

14.2.2 EWEB shall provide at least 60 days' notice to Power Services prior to changing Balancing Authority Areas.

14.2.3 At EWEB's request, Power Services shall provide EWEB with Primary Points of Receipt and other information needed to enable EWEB to obtain long-term firm transmission for delivery of power sold under this Agreement. If required by Transmission Services for purposes of transmission scheduling, then Power Services shall provide EWEB with Scheduling Points of Receipt. Power Services has the right to provide power to EWEB at Scheduling Points of Receipt that are different than the Primary Points of Receipt. If BPA does provide power to EWEB at Scheduling Points of Receipt that are different than the Primary Points of Receipt, then BPA shall reimburse EWEB for any incremental, direct, non-administrative costs incurred by EWEB to comply with delivering Firm Requirements Power from such a Scheduling Point of Receipt to EWEB's load if the following conditions, as outlined in (1) or (2) below, have been met:

(1) If EWEB has long-term Point to Point (PTP) transmission service (as defined in BPA's Open Access Transmission Tariff) for delivery of Firm Requirements Power to its load:

(A) EWEB has requested long-term firm transmission service to deliver its Firm Requirements Power using the Primary Points of Receipt and other information provided by Power Services; and

(B) EWEB has submitted a request to redirect its long-term firm PTP transmission service to deliver Firm Requirements Power from the Scheduling Point of Receipt on a firm basis, but that request was not granted; and

(C) EWEB's transmission schedule was curtailed due to non-firm status under PTP transmission service or EWEB can provide proof of the reimbursable costs incurred to replace the curtailed schedule.

(2) If EWEB has long-term Network Integration Transmission Service (as defined in BPA's Open Access Transmission Tariff) for delivery of Firm Requirements Power to its load:

(A) EWEB has requested long-term firm transmission service to deliver its Firm Requirements Power using the Primary Points of Receipt and other information provided by Power Services; and

(B) EWEB's transmission schedule was curtailed due to non-firm status under its secondary service status and EWEB can provide proof of the reimbursable costs incurred to replace the curtailed schedule.

14.3 **Liability for Delivery**
EWEB waives any claims against BPA arising under this Agreement for non-delivery of power to any points beyond the applicable Scheduling Points of Receipt, except for reimbursement of costs as described in section 14.2.3. BPA shall not be liable under this Agreement for any third-party claims related to the delivery of power after it leaves the Scheduling Points of Receipt. Neither Party shall be liable under this Agreement to the other Party for damage that results from any sudden, unexpected, changed, or abnormal electrical condition occurring in or on any electric system, regardless of ownership. These limitations on liability apply regardless of whether or not this Agreement provides for Transfer Service.

14.4 **Real Power Losses**
BPA is responsible for the real power losses necessary to deliver Tier 1 Block Amounts and Tier 2 Block Amounts to EWEB's PODs listed in Exhibit E.

EWEB shall be responsible for all real power losses associated with the delivery of its Slice Output Energy.

14.5 **Metering Losses**
BPA shall adjust measured amounts of power to account for losses, if any, that occur between EWEB's PODs and the respective POMs, as specified in Exhibit E.

15. METERING

15.1 **Requirements for Meters**
BPA shall access EWEB's load meter data for purposes of forecasting and planning. The following requirements shall apply to all meters listed in Exhibit E.

15.1.1 **BPA Owned Meters**

At BPA's expense, BPA shall operate, maintain, and replace, as necessary all metering equipment owned by BPA that is needed to forecast and plan for EWEB's power needs under this Agreement. EWEB authorizes BPA to maintain and replace any BPA owned meter on EWEB facilities. With reasonable notice from BPA and for the purpose of implementing this provision, EWEB shall grant BPA reasonable physical access to BPA owned meters at BPA's request.

If, at any time, BPA or EWEB determines that a BPA owned meter is defective or inaccurate, then BPA shall adjust, repair, or replace the meter to provide accurate metering as soon as practical.

BPA shall give EWEB access to meter data from the BPA owned meters listed in Exhibit E.

15.1.2 **Non-BPA Owned Meters**

15.1.2.1 **Customer Owned Meters**

For all EWEB owned metering equipment that is needed by BPA to forecast and plan for EWEB's power needs under this Agreement, EWEB shall give BPA direct, electronic access to meter data from all EWEB owned meters that are capable of being accessed electronically. For the purpose of inspection, EWEB shall grant BPA reasonable physical access to EWEB's meters at BPA's request.

EWEB shall operate, maintain, and replace, as necessary at EWEB expense, all EWEB owned metering equipment.

If, at any time, BPA or EWEB determines that a EWEB owned meter listed in Exhibit E is defective or inaccurate, then EWEB shall adjust, repair, or replace the meter, or shall make commercially reasonable efforts to arrange for the completion of such actions, to provide accurate metering as soon as practical. BPA shall have the right to witness any meter tests conducted by EWEB on EWEB owned meters listed in Exhibit E and, with reasonable advance notice, BPA may conduct tests on such meters. EWEB shall have the right to witness any meter tests conducted by BPA.

15.1.2.2 **Non-BPA Owned Meters Not Owned by EWEB**

For non-BPA owned meters not owned by EWEB needed by BPA to forecast and plan, EWEB shall make commercially reasonable efforts to arrange for such meters to be operated, maintained and replaced, as necessary.

If, at any time, it is determined that a non-BPA owned meter not owned by EWEB listed in Exhibit E is defective or inaccurate, then EWEB shall make commercially reasonable efforts to arrange to adjust, repair, or replace the meter, to provide accurate metering as soon as practical. To the extent possible, BPA may witness any meter tests on non-BPA owned meters not owned by EWEB listed in Exhibit E and, with reasonable advance notice, BPA may conduct tests on such meters. EWEB shall have the right to witness any meter tests conducted by BPA.

15.1.2.3 **Non-BPA Owned Meters Owned by a Third-Party Transmission Provider**

This section 15.1.2 shall not apply to non-BPA owned meters that are owned by a Third-Party Transmission Provider with which BPA holds a transmission contract for service to EWEB load. In these cases the metering arrangements shall be between BPA and the Third-Party Transmission Provider.

15.1.3 **New Meters**

A separate agreement addressing the location, cost responsibility, access, maintenance, testing, and liability of the Parties with respect to new meters shall be between EWEB and Transmission Services.

All new and replaced meters installed by BPA or EWEB shall meet the American National Standard Institute standards, including, but not limited to, C12.20, Electricity Meters--0.2 and 0.5 Accuracy Classes and the Institute of Electrical and Electronics Engineers, Inc. standard C57.13, Requirements for Instrument Transformers, or their successors. Any new and replaced meters shall be able to record meter data hourly, store data for a minimum of 45 days, and be accessed electronically.

15.2 **Metering an NLSL**

Any loads that are monitored by BPA for an NLSL determination and any NLSLs shall be metered pursuant to section 23.3.4.

15.3 **Metering Exhibit**

EWEB shall provide meter data specified in section 17.3 and shall notify BPA of any changes to PODs, POMs, Interchange Points and related information for which it is responsible. BPA shall list EWEB's PODs and meters in Exhibit E.

16. BILLING AND PAYMENT

16.1 **Billing**

BPA shall bill EWEB monthly for all products and services provided during the preceding month(s). BPA may send EWEB an estimated bill followed by a final bill. The Issue Date is the date BPA electronically sends the bill to

EWEB. If electronic transmittal of the entire bill is not practical, then BPA shall transmit a summary electronically, and send the entire bill by United States mail.

16.2 **Payment**
EWEB shall pay all bills electronically in accordance with instructions on the bill. Payment of all bills, whether estimated or final, must be received by the 20th day after the Issue Date of the bill (Due Date). If the 20th day is a Saturday, Sunday, or federal holiday, then the Due Date is the next Business Day.

If EWEB has made payment on an estimated bill then:

(1) if the amount of the final bill exceeds the amount of the estimated bill, then EWEB shall pay BPA the difference between the estimated bill and final bill by the final bill's Due Date; or

(2) if the amount of the final bill is less than the amount of the estimated bill, then BPA shall pay EWEB the difference between the estimated bill and final bill by the 20th day after the final bill's Issue Date. If the 20th day is a Saturday, Sunday, or federal holiday, BPA shall pay the difference by the next Business Day.

16.3 **Late Payments**
After the Due Date, a late payment charge equal to the higher of:

(1) the Prime Rate (as reported in the Wall Street Journal or successor publication in the first issue published during the month in which payment was due) plus 4 percent, divided by 365; or

(2) the Prime Rate times 1.5, divided by 365;

shall be applied each day to any unpaid balance.

16.4 **Termination**
If EWEB has not paid its bill in full by the Due Date, it shall have 45 days to cure its nonpayment by making payment in full. If EWEB does not provide payment within three Business Days after receipt of an additional written notice from BPA, and BPA determines in its sole discretion that EWEB is unable to make the payments owed, then BPA may terminate this Agreement. Written notices sent under this section 16.4 must comply with section 20.

16.5 **Disputed Bills**

16.5.1 If EWEB disputes any portion of a charge or credit on EWEB's estimated or final bills, EWEB shall provide written notice to BPA with a copy of the bill noting the disputed amounts. Notwithstanding whether any portion of the bill is in dispute, EWEB shall pay the entire bill by the Due Date. This section 16.5.1 does not allow EWEB to challenge the validity of any BPA rate.

16.5.2 Unpaid amounts on a bill (including both disputed and undisputed amounts) are subject to the late payment charges provided above. Notice of a disputed charge on a bill does not constitute BPA's agreement that a valid claim under contract law has been stated.

16.5.3 If the Parties agree, or if after a final determination of a dispute pursuant to section 22, EWEB is entitled to a refund of any portion of the disputed amount, then BPA shall make such refund with simple interest computed from the date of receipt of the disputed payment to the date the refund is made. The daily interest rate shall equal the Prime Rate (as reported in the Wall Street Journal or successor publication in the first issue published during the month in which payment was due) divided by 365.

17. INFORMATION EXCHANGE AND CONFIDENTIALITY

17.1 General Requirements

Upon request, each Party shall provide the other Party with any information that is necessary to administer this Agreement and to forecast EWEB's Total Retail Load, forecast BPA system load, comply with NERC reliability standards, prepare bills, resolve billing disputes, administer Transfer Service, and otherwise implement this Agreement. For example, this obligation includes transmission and power scheduling information and load and resource metering information (such as one-line diagrams, metering diagrams, loss factors, etc.). In addition, EWEB shall provide information BPA requests about Dedicated Resources for purposes of meeting BPA's statutory obligations under section 7(b) of the Northwest Power Act. Information requested under this section 17.1 shall be provided in a timely manner. If EWEB fails to provide BPA with information EWEB is required to provide pursuant to this Agreement and the absence of such information makes it impossible for BPA to perform a calculation, make a determination, or take an action required under this Agreement, then BPA may suspend its obligation to perform such calculation, make such determination, or take such action until EWEB has provided such information to BPA.

17.2 Reports

17.2.1 Within 30 days after final approval of EWEB's annual financial report and statements by EWEB's authorized officer, EWEB shall either e-mail them to BPA at kslf@bpa.gov or, if any of the information is publicly available, then EWEB shall notify BPA of its availability.

17.2.2 Within 30 days after its submittal to the Energy Information Administration (EIA), or its successor, EWEB shall e-mail a copy of its Annual Form EIA-861 Reports to BPA at kslf@bpa.gov. If EWEB is not required to submit such reports to the EIA, then this requirement does not apply.

17.3 Meter Data

17.3.1 In accordance with section 15 and Exhibit E, the Parties shall notify each other of any changes to PODs, POMs, Interchange Points and related information for which it is responsible. EWEB shall ensure BPA has access to all data from load and resource meters that BPA determines is necessary to forecast, plan, schedule, and bill under this Agreement. Access to this data shall be on a schedule determined by BPA. Meter data shall be in hourly increments for all meters that record hourly data. Meter data includes, but is not limited to: EWEB's actual amounts of energy used or expended for loads and resources, and the physical attributes of EWEB's meters.

17.3.2 EWEB consents to allow Power Services to receive the following information from Transmission Services or BPA's metering function: (1) EWEB's meter data, as specified in section 17.3.1, section 15, and Exhibit E, and (2) notification of outages or load shifts.

17.3.3 At least 15 calendar days in advance, EWEB shall e-mail BPA at: (1) mdm@bpa.gov and (2) the contact shown in section 20 when the following events are planned to occur on EWEB's system that will affect the load measured by the meters listed in Exhibit E: (1) installation of a new meter, (2) changes or updates to an existing meter not owned by BPA, (3) any planned line or planned meter outages, and (4) any planned load shifts from one POD to another. This section 17.3.3 is not intended to apply to retail meters not listed in Exhibit E.

17.3.4 If an unplanned load shift or outage occurs, materially affecting the load measured by the meters listed in Exhibit E, then EWEB shall e-mail BPA at: (1) mdm@bpa.gov, and (2) the contact shown in section 20 within 72 hours after the event.

17.4 Data for Determining CHWM and CDQs

Upon request, EWEB shall provide to BPA any load and resource information that BPA determines is reasonably necessary to calculate EWEB's CHWM and CDQs. This may include historical load data not otherwise available to BPA and other data necessary to allow BPA to adjust for weather normalization.

17.5 Hourly Total Retail Load Data

BPA shall notify EWEB by June 30, 2009, if BPA determines that it does not have adequate hourly meter data to calculate EWEB's Total Retail Load. If BPA sends such notification, EWEB shall e-mail the following hourly data to BPA at kslf@bpa.gov according to the schedule below. EWEB shall submit such data in a comma-separated-value (csv) format with the time/date stamp in one column and load amounts, with units of measurement specified, in another column.

17.5.1 By December 31, 2009, EWEB shall send to BPA EWEB's actual hourly Total Retail Load data for Fiscal Year 2002 through Fiscal Year 2009.

17.5.2 By December 31, 2010, EWEB shall send to BPA, EWEB's actual hourly Total Retail Load data for each Point of Delivery for Fiscal Year 2010.

17.5.3 By December 31, 2011, and by December 31 of each year thereafter, EWEB shall send BPA EWEB's actual hourly Total Retail Load data for the immediately preceding Fiscal Year.

17.6 **Total Retail Load Forecast**
By June 30, 2011, and by June 30 of each year thereafter, EWEB shall provide BPA a forecast of EWEB's monthly energy and EWEB's system coincidental peak of EWEB's Total Retail Load for the upcoming ten Fiscal Years. EWEB shall e-mail the forecast to BPA at kslf@bpa.gov, in a comma-separated-value (csv) format. EWEB shall send the csv file with the following data elements in separate columns:

(1) four-digit calendar year,

(2) three-character month identifier,

(3) monthly energy forecast,

(4) unit measurement of monthly energy forecast,

(5) monthly EWEB-system coincidental peak forecast, and

(6) unit measurement of monthly EWEB-system coincidental peak forecast.

17.7 **Transparency of Net Requirements Process**

17.7.1 **Data Made Publicly Available**
By July 31, 2011, and by July 31 every year thereafter, BPA shall make the following information publicly available to EWEB and all other BPA regional utility customers with a CHWM:

(1) EWEB's measured Total Retail Load data for the previous Fiscal Year in monthly energy amounts and monthly customer-system peak amounts,

(2) BPA's forecast of EWEB's Total Retail Load, for the upcoming Fiscal Year, in monthly energy amounts and monthly customer-system peak amounts, and

(3) EWEB's Dedicated Resource energy and peak amounts for the upcoming Fiscal Year and the previous Fiscal Year.

17.7.2 **Waiver of Confidentiality and Comment Process**
EWEB waives all claims of confidentiality regarding the data described above. EWEB may provide comments regarding the published data to BPA within ten Business Days after notification. After reviewing any comments and no later than 60 days from the date BPA originally releases such data, BPA shall make available a final set of data and an explanation of any changes to EWEB and all other customers with a CHWM.

17.8 **Confidentiality**
Before EWEB provides information to BPA that is confidential, or is otherwise subject to privilege, or nondisclosure, EWEB shall clearly designate such information as confidential. BPA shall notify EWEB as soon as practicable of any request received under the Freedom of Information Act (FOIA), or under any other federal law or court or administrative order, for any confidential information. BPA shall only release such confidential information to comply with FOIA or if required by any other federal law or court or administrative order. BPA shall limit the use and dissemination of confidential information within BPA to employees who need it for purposes of administering this Agreement.

17.9 **Resources Not Used to Serve Total Retail Load**
EWEB shall list in section 6 of Exhibit A all Generating Resources and Contract Resources EWEB owns that are: (1) not Specified Resources listed in section 2 of Exhibit A, and (2) greater than 200 kilowatts of nameplate capability. At BPA's request EWEB shall provide BPA with additional data if needed to verify the information listed in section 6 of Exhibit A.

18. CONSERVATION AND RENEWABLES

18.1 Conservation

18.1.1 **Evaluations**
At BPA's expense, BPA may conduct, and EWEB shall cooperate in, conservation impact and project implementation process evaluations to assess the amount, cost-effectiveness, and reliability of conservation in BPA's or EWEB's service area.

BPA shall select the timing, frequency, and type of such evaluations. BPA shall do so with reasonable consideration of EWEB's and EWEB's consumers' needs.

18.1.2 **Reporting Requirements**

18.1.2.1 This section 18.1.2.1 does not apply if EWEB's Total Retail Load from the most recent prior Fiscal Year is 25 annual Average Megawatts or less, or if EWEB purchases all of its power from BPA to serve its Total Retail Load. Beginning June 1, 2010, and no later than June 1 every 2 years thereafter, EWEB shall submit a 10-year conservation plan stating EWEB's projection of planned conservation, including biennial conservation targets. This requirement may be satisfied by submitting any plans EWEB prepares in the normal course of business if the plans include, or are supplemented by, the information required above. This includes plans required under state law (such as the Washington State Energy Independence Act (RCW 19.285)).

18.1.2.2 EWEB shall verify and report all cost-effective (as defined by section 3(4) of the Northwest Power Act) non-BPA-funded conservation measures and projects savings achieved by EWEB through the Regional Technical Forum's Planning, Tracking and Reporting System or its successor tool. Verification protocols of conservation measures and projects, reporting timelines and documentation requirements shall comply with BPA's Energy Efficiency Implementation Manual or its successor.

18.2 **Renewable Resources**

18.2.1 **Renewable Energy Certificates**
BPA shall transfer Renewable Energy Certificates (RECs), or their successors, to EWEB in accordance with Exhibit H.

18.2.2 **Reporting Requirements**
This section 18.2.2 does not apply if EWEB's Total Retail Load is 25 annual Average Megawatts or less or if EWEB purchases all of its power from BPA to serve its Total Retail Load. If EWEB's Total Retail Load is above 25 annual Average Megawatts, the following requirements may be satisfied by submitting plans and reports EWEB prepares in the normal course of business as long as such plans and reports include the information required below.

Beginning September 1, 2012, and by September 1 every year thereafter, EWEB shall provide BPA with the following:

(1) updated information on power forecasted to be generated over the forthcoming calendar year by renewable resources with nameplate capabilities greater than 200 kilowatts, including net metered renewable resources operating behind the BPA

meter, used by EWEB to serve its Total Retail Load, under Exhibit A. Such information shall include: project name, fuel type(s), location, date power purchase contract signed, project energization date, capacity, capacity factor, remaining term of purchase (or if direct ownership remaining life of the project), and the percentage of output that will be used to serve EWEB's Total Retail Load that calendar year. Where resources are jointly owned by EWEB and other customers that have a CHWM Contract, EWEB may either submit a report on behalf of all owners or identify the customer that will submit the report;

(2) the amount of all purchases of RECs used to meet requirements under state or federal law for the forthcoming calendar year; and

(3) if EWEB is required under state law or by Transmission Services to prepare long-term integrated resource plans or resource forecasts, then EWEB shall provide Power Services with updated copies of such or authorize Transmission Services to provide them directly to Power Services.

19. RESOURCE ADEQUACY

By November 30, 2010, and by November 30 each year thereafter, EWEB shall provide to the Pacific Northwest Utilities Conference Committee (PNUCC), or its successor, forecasted loads and resources data to facilitate a region-wide assessment of loads and resources in a format, length of time, and level of detail specified in PNUCC's Northwest Regional Forecast Data Request.

After consultation with the Regional Resource Adequacy Forum, or a successor, BPA may require EWEB to submit additional data to the Northwest Power and Conservation Council (Council) that BPA determines is necessary for the Council to perform a regional resource adequacy assessment.

The requirements of this section 19 are waived if EWEB purchases from BPA all of its power to serve its Total Retail Load.

20. NOTICES AND CONTACT INFORMATION

Any notice required under this Agreement that requires such notice to be provided under the terms of this section shall be provided in writing to the other Party in one of the following ways:

(1) delivered in person;

(2) by a nationally recognized delivery service with proof of receipt;

(3) by United States Certified Mail with return receipt requested;

(4) electronically, if both Parties have means to verify the electronic notice's origin, date, time of transmittal and receipt; or

(5) by another method agreed to by the Parties.

Notices are effective when received. Either Party may change the name or address for delivery of notice by providing notice of such change or other mutually agreed method. The Parties shall deliver notices to the following person and address:

If to EWEB:		If to BPA:	
Eugene Water & Electric Board		Bonneville Power Administration	
500 East Fourth Avenue		905 N.E. 11th Avenue	
P.O. Box 10148		P. O. Box 3621	
Eugene, OR 97401		Portland, OR 97208-3621	
Attn:	Randy L. Berggren General Manager	Attn:	Theresa E. Rockwood - PSW-6 Account Executive
Phone:	541.484.2411	Phone:	503.230.5738
FAX:	541.484.3762	FAX:	503.230.3242
E-Mail:	randy.berggren@eweb.or.us	E-Mail:	terockwood@bpa.gov

21. UNCONTROLLABLE FORCES

21.1 A Party shall not be in breach of an obligation under this Agreement to the extent its failure to fulfill the obligation is due to an Uncontrollable Force. "Uncontrollable Force" means an event beyond the reasonable control, and without the fault or negligence, of the Party claiming the Uncontrollable Force, that prevents that Party from performing its obligations under this Agreement and which that Party could not have avoided by the exercise of reasonable care, diligence and foresight. Uncontrollable Forces include each event listed below, to the extent it satisfies the foregoing criteria, but are not limited to these listed events:

(1) any curtailment or interruption of firm transmission service on BPA's or a Third Party Transmission Provider's System that prevents delivery of Firm Requirements Power sold under this Agreement to EWEB;

(2) any failure of EWEB's distribution or transmission facilities that prevents EWEB from delivering power to end-users;

(3) strikes or work stoppage;

(4) floods, earthquakes, other natural disasters, or terrorist acts; and

(5) final orders or injunctions issued by a court or regulatory body having subject matter jurisdiction which the Party claiming the Uncontrollable Force, after diligent efforts, was unable to have stayed,

suspended, or set aside pending review by a court having subject matter jurisdiction.

21.2 Neither the unavailability of funds or financing, nor conditions of national or local economies or markets shall be considered an Uncontrollable Force. The economic hardship of either Party shall not constitute an Uncontrollable Force. Nothing contained in this provision shall be construed to require either Party to settle any strike or labor dispute in which it may be involved.

21.3 If an Uncontrollable Force prevents a Party from performing any of its obligations under this Agreement, such Party shall:

(1) immediately notify the other Party of such Uncontrollable Force by any means practicable and confirm such notice in writing as soon as reasonably practicable;

(2) use commercially reasonable efforts to mitigate the effects of such Uncontrollable Force, remedy its inability to perform, and resume full performance of its obligation hereunder as soon as reasonably practicable;

(3) keep the other Party apprised of such efforts on an ongoing basis; and

(4) provide written notice of the resumption of performance.

Written notices sent under this section must comply with section 20.

22. GOVERNING LAW AND DISPUTE RESOLUTION

This Agreement shall be interpreted consistent with and governed by federal law. EWEB and BPA shall identify issue(s) in dispute arising out of this Agreement and make a good faith effort to negotiate a resolution of such disputes before either may initiate litigation or arbitration. Such good faith effort shall include discussions or negotiations between the Parties' executives or managers. Pending resolution of a contract dispute or contract issue between the Parties or through formal dispute resolution of a contract dispute arising out of this Agreement, the Parties shall continue performance under this Agreement unless to do so would be impossible or impracticable. Unless the Parties engage in binding arbitration as provided for in this section 22, the Parties reserve their rights to individually seek judicial resolution of any dispute arising under this Agreement.

22.1 Judicial Resolution

Final actions subject to section 9(e) of the Northwest Power Act are not subject to arbitration under this Agreement and shall remain within the exclusive jurisdiction of the United States Court of Appeals for the Ninth Circuit. Such final actions include, but are not limited to, the establishment and the implementation of rates and rate methodologies. Any dispute regarding any rights or obligations of EWEB or BPA under any rate or rate methodology, or BPA policy, including the implementation of such policy, shall not be subject to arbitration under this Agreement. For purposes of this section 22, BPA policy means any written document adopted by BPA as a final action in a decision record or record of decision that establishes a policy of general application or makes a determination under an applicable statute or regulation. If BPA determines that a dispute is excluded from arbitration under this section 22, then EWEB may apply to the federal court having jurisdiction for an order determining whether such dispute is subject to nonbinding arbitration under this section 22.

22.2 **Arbitration**
Any contract dispute or contract issue between the Parties arising out of this Agreement, which is not excluded by section 22.1 above, shall be subject to arbitration, as set forth below.

EWEB may request that BPA engage in binding arbitration to resolve any dispute. If EWEB requests such binding arbitration and BPA determines in its sole discretion that binding arbitration of the dispute is appropriate under BPA's Binding Arbitration Policy or its successor, then BPA shall engage in such binding arbitration, provided that the remaining requirements of this section 22.2 and sections 22.3 and 22.4 are met. BPA may request that EWEB engage in binding arbitration to resolve any dispute. In response to BPA's request, EWEB may agree to binding arbitration of such dispute, provided that the remaining requirements of this section 22.2 and sections 22.3 and 22.4 are met. Before initiating binding arbitration, the Parties shall draft and sign an agreement to engage in binding arbitration, which shall set forth the precise issue in dispute, the amount in controversy and the maximum monetary award allowed, pursuant to BPA's Binding Arbitration Policy or its successor.

Nonbinding arbitration shall be used to resolve any dispute arising out of this contract that is not excluded by section 22.1 above and is not resolved via binding arbitration, unless EWEB notifies BPA that it does not wish to proceed with nonbinding arbitration.

22.3 **Arbitration Procedure**
Any arbitration shall take place in Portland, Oregon, unless the Parties agree otherwise. The Parties agree that a fundamental purpose for arbitration is the expedient resolution of disputes; therefore, the Parties shall make best efforts to resolve an arbitrable dispute within 1 year of initiating arbitration. The rules for arbitration shall be agreed to by the Parties.

22.4 **Arbitration Remedies**
The payment of monies shall be the exclusive remedy available in any arbitration proceeding pursuant to this section 22. This shall not be interpreted to preclude the Parties from agreeing to limit the object of arbitration to the determination of facts. Under no circumstances shall specific performance be an available remedy against BPA.

22.5 Finality

22.5.1 In binding arbitration, the arbitration award shall be final and binding on the Parties, except that either Party may seek judicial review based upon any of the grounds referred to in the Federal Arbitration Act, 9 U.S.C. §1-16 (1988). Judgment upon the award rendered by the arbitrator(s) may be entered by any court having jurisdiction thereof.

22.5.2 In nonbinding arbitration, the arbitration award is not binding on the Parties. Each Party shall notify the other Party within 30 calendar days, or such other time as the Parties otherwise agreed to, whether it accepts or rejects the arbitration award. Subsequent to nonbinding arbitration, if either Party rejects the arbitration award, either Party may seek judicial resolution of the dispute, provided that such suit is brought no later than 395 calendar days after the date the arbitration award was issued.

22.6 Arbitration Costs

Each Party shall be responsible for its own costs of arbitration, including legal fees. Unless otherwise agreed to by the Parties, the arbitrator(s) may apportion all other costs of arbitration between the Parties in such manner as the arbitrator(s) deem reasonable taking into account the circumstances of the case, the conduct of the Parties during the proceeding, and the result of the arbitration.

23. STATUTORY PROVISIONS

23.1 Retail Rate Schedules

EWEB shall make its retail rate schedules available to BPA, as required by section 5(a) of the Bonneville Project Act, P.L. 75-329, within 30 days of each of EWEB's retail rate schedule effective dates. This requirement may be satisfied by EWEB informing BPA of its public website where such information is posted and kept current.

23.2 Insufficiency and Allocations

If BPA determines, consistent with section 5(b) of the Northwest Power Act and other applicable statutes, that it will not have sufficient resources on a planning basis to serve its loads after taking all actions required by applicable laws then BPA shall give EWEB a written notice that BPA may restrict service to EWEB. Such notice shall be consistent with BPA's insufficiency and allocations methodology, published in the Federal Register on March 20, 1996, and shall state the effective date of the restriction, the amount of EWEB's load to be restricted and the expected duration of the restriction. BPA shall not change that methodology without the written agreement of all public body, cooperative, federal agency and investor-owned utility customers in the Region purchasing federal power from BPA under section 5(b) of the Northwest Power Act. Such restriction shall take effect no sooner than 5 years after BPA provides notice to EWEB. If BPA imposes a restriction under this provision then the amount of Firm Requirements Power that BPA is obligated to provide and that EWEB is obligated to purchase pursuant to section 3 and Exhibit C shall be reduced to the amounts available under such allocation methodology for restricted service.

23.3 **New Large Single Loads and CF/CTs**

23.3.1 **Determination of an NLSL**
In accordance with BPA's NLSL Policy, BPA may determine that a load is an NLSL as follows:

23.3.1.1 BPA shall determine an increase in production load to be an NLSL if any load associated with a new facility, an existing facility, or an expansion of an existing facility, which is not contracted for, or committed to (CF/CT), as determined by the Administrator, by a public body, cooperative, investor-owned utility, or federal agency customer prior to September 1, 1979, and which will result in an increase in power requirements of such customer of ten Average Megawatts (87,600,000 kilowatt-hours) or more in any consecutive 12-month period.

23.3.1.2 For the sole purpose of computing the increase in energy consumption between any two consecutive 12-month periods of comparison under this section 23.3.1, reductions in the end-use consumer's load associated with a facility during the first 12-month period of comparison due to unusual events reasonably beyond the control of the end-use consumer shall be determined by BPA, and the energy consumption shall be computed as if such reductions had not occurred.

23.3.1.3 The Parties may agree that the installed production equipment at a facility will exceed 10 Average Megawatts consumption over any 12 consecutive months and such agreement shall constitute a binding NLSL determination.

23.3.2 **Determination of a Facility**
BPA shall make a written determination as to what constitutes a single facility, for the purpose of identifying an NLSL, based on the following criteria:

(1) whether the load is operated by a single end-use consumer;

(2) whether the load is in a single location;

(3) whether the load serves a manufacturing process which produces a single product or type of product;

(4) whether separable portions of the load are interdependent;

(5) whether the load is contracted for, served or billed as a single load under EWEB's customary billing and service policy;

(6) consideration of the facts from previous similar situations; and

(7) any other factors the Parties determine to be relevant.

23.3.3 **Administrative Obligations and Rights**

23.3.3.1 EWEB's CF/CT loads and NLSLs are listed in Exhibit D.

23.3.3.2 EWEB shall provide reasonable notice to BPA of any expected increase in a single load that may qualify as an NLSL. The Parties shall list any such potential NLSLs in Exhibit D. If BPA determines that any load associated with a single facility is capable of growing 10 Average Megawatts or more in a consecutive 12-month period, then such load shall be subject to monitoring as determined necessary by BPA.

23.3.3.3 When BPA makes a request, EWEB shall provide physical access to its substations and other service locations where BPA needs to perform inspections or gather information for purposes of implementing section 3(13) of the Northwest Power Act, including but not limited to making a final NLSL, facility, or CF/CT determination. EWEB shall make a request to the end-use consumer to provide BPA, at reasonable times, physical access to inspect a facility for these purposes.

23.3.3.4 Unless the Parties agree pursuant to section 23.3.1.3 above, BPA shall determine whether a new load or an increase in existing load at a facility is an NLSL. If BPA determines that the load is an NLSL, BPA shall notify EWEB and the Parties shall add the NLSL to Exhibit D to reflect BPA's determination.

23.3.4 **Metering an NLSL**
For any loads that are monitored by BPA for an NLSL determination, and for any loads at any facility that is determined by BPA to be an NLSL, BPA may, in its sole discretion, install BPA owned meters. If the Parties agree otherwise, EWEB may install meters meeting the exact specification BPA provides to EWEB. EWEB and BPA shall enter into a separate agreement for the location, ownership, cost responsibility, access, maintenance, testing, replacement and liability of the Parties with respect to such meters. EWEB shall arrange for metering locations that allow accurate measurement of the facility's load. EWEB shall arrange for BPA to have physical access to such meters and EWEB shall ensure BPA has access to all NLSL meter

data that BPA determines is necessary to forecast, plan, schedule, and bill for power.

23.3.5 **Undetermined NLSLs**
If BPA does not determine at the outset that an increase in load is an NLSL, then the Parties shall install metering equipment as required by section 23.3.4 above, and BPA shall bill EWEB for the increase in load at the applicable PF rate during any consecutive 12-month monitoring period. If BPA later determines that the increase in load is an NLSL, then BPA shall revise EWEB's bill to reflect the difference between the applicable PF rate and the applicable NR rate in effect for the monitoring period in which the increase takes place. EWEB shall pay that bill with simple interest computed from the start of the monitoring period to the date the payment is made. The daily interest rate shall equal the Prime Rate (as reported in the Wall Street Journal or successor publication in the first issue published during the month in which the monitoring period began) divided by 365.

If BPA concludes in its sole judgment that EWEB has not fulfilled its obligations, or has not been able to obtain access or information from the end-use consumer under sections 23.3.3 and 23.3.4, BPA may determine any load subject to NLSL monitoring to be an NLSL, in which case EWEB shall be billed and pay in accordance with the last two sentences of the preceding paragraph. Such NLSL determination shall be final unless EWEB proves to BPA's satisfaction that the applicable load did not exceed 10 Average Megawatts in any 12-month monitoring period.

23.3.6 **Service Elections for an NLSL**
EWEB shall serve all NLSLs with Dedicated Resource amounts in Exhibit A that are not already being used to serve EWEB's Total Retail Load in the region. EWEB agrees to provide such Dedicated Resources on a continuous basis as identified in Exhibit A. Under no circumstances shall BPA be required to acquire firm power for service to such NLSLs.

23.3.7 **Consumer-Owned Resources Serving an NLSL**

23.3.7.1 **Renewable Resource/Cogeneration Exception**
An end-use consumer served by EWEB, with a facility whose load is, in whole or in part, an NLSL, may reduce its NLSL to less than 10 Average Megawatts in a consecutive 12-month period by applying an onsite renewable resource or onsite cogeneration behind EWEB's meter to its facility load. EWEB shall ensure that such resource is continuously applied to serve the NLSL, consistent with BPA's "Renewables and On-Site Cogeneration Option under the NLSL Policy" portion of its Policy for Power Supply Role for

Fiscal Years 2007-2011, adopted February 4, 2005, and the NLSL policy included in BPA's Long Term Regional Dialogue Final Policy, July 2007, as amended or replaced. If the NLSL end-use consumer meets the qualification for the exception, then the Parties shall: (1) list the Consumer-Owned Resource serving the NLSL in section 7.4 of Exhibit A and (2) amend Exhibit D to add the onsite renewable resource or cogeneration facility and the requirements for such service.

23.3.7.2 **Consumer-Owned Resources that are not Renewable Resources/Cogeneration**
If EWEB serves an NLSL with a Consumer-Owned Resource that does not qualify for the renewable resource or cogeneration exception, the Parties shall list such Consumer-Owned Resource serving the NLSL in section 7.4 of Exhibit A.

23.4 **Priority of Pacific Northwest Customers**
The provisions of sections 9(c) and 9(d) of the Northwest Power Act and the provisions of P.L. 88-552 as amended by the Northwest Power Act are incorporated into this Agreement by reference. EWEB, together with other customers in the Region, shall have priority to BPA power consistent with such provisions.

23.5 **Prohibition on Resale**
EWEB shall not resell Firm Requirements Power except to serve EWEB's Total Retail Load or as otherwise permitted by federal law.

23.6 **Use of Regional Resources**

23.6.1 Within 60 days prior to the start of each Fiscal Year, EWEB shall provide notice to BPA of any Firm Power from a Generating Resource, or a Contract Resource during its term, that has been used to serve firm consumer load in the Region and that EWEB plans to export for sale outside the Region in the next Fiscal Year. For purposes of this section 23.6, "Firm Power" means electric power which is continuously made available from EWEB's operation of generation or from its purchased power, which is able to meet its Total Retail Load, except when such generation or power is curtailed or restricted due to an Uncontrollable Force. Firm Power includes firm energy and firm peaking energy or both.

BPA may request and EWEB shall provide within 30 days of such request, additional information on EWEB's sales and dispositions of non-federal resources if BPA has information that EWEB may have made such an export and not notified BPA. BPA may request and EWEB shall provide within 30 days of such request, information on the planned use of any or all of EWEB Generating and Contract Resources.

During any Purchase Period that EWEB has no purchase obligation for Firm Requirements Power under section 3, EWEB shall have no obligation to notify BPA of its exports under this section; *provided, however*, EWEB shall provide notification of all applicable exports in Purchase Periods when it has a purchase obligation.

23.6.2 EWEB shall be responsible for monitoring any Firm Power from Generating Resources and Contract Resources it sells in the Region to ensure such Firm Power is planned to be used to serve firm consumer load in the Region.

23.6.3 If EWEB fails to report to BPA in accordance with section 23.6.1, above, any of its planned exports for sale outside the Region of Firm Power from a Generating Resource or a Contract Resource that has been used to serve firm consumer load in the Region, and BPA makes a finding that an export which was not reported was made, BPA shall decrement the amount of its Firm Requirements Power sold under this Agreement by the amount of the export that was not reported and by any continuing export amount. Decrements under the preceding sentence shall be first to power that would otherwise be provided at Tier 1 Rates. When applicable, such decrements shall be identified in section 3.2 of Exhibit A.

23.6.4 For purposes of this section 23.6, an export for sale outside the Region means a contract for the sale or disposition of Firm Power from a Generating Resource or a Contract Resource during its term that has been used to serve firm consumer load in the Region, which contract will be performed in a manner that such output is no longer used or not planned to be used solely to serve firm consumer load in the Region. Delivery of Firm Power outside the Region under a seasonal exchange agreement that is made consistent with BPA's 5(b)/9(c) Policy will not be considered an export. Firm Power from a Generating Resource or a Contract Resource used to serve firm consumer load in the Region means the firm generating or load carrying capability of a Generating Resource or a Contract Resource as established under PNCA resource planning criteria, or other resource planning criteria generally used for such purposes within the Region.

23.7 **BPA Appropriations Refinancing**

The Parties agree that the provisions of section 3201(i) of the Bonneville Power Administration Refinancing section of the Omnibus Consolidated Rescissions and Appropriations Act of 1996 (BPA Refinancing Act), P.L. 104-134, 110 Stat. 1321, 350, as stated in the United States Code on the Effective Date, are incorporated by reference and are a material term of this Agreement.

24. STANDARD PROVISIONS

24.1 Amendments

Except where this Agreement explicitly allows for one Party to unilaterally amend a provision or exhibit, no amendment of this Agreement shall be of any force or effect unless set forth in writing and signed by authorized representatives of each Party.

24.2 Entire Agreement and Order of Precedence

This Agreement, including documents expressly incorporated by reference, constitutes the entire agreement between the Parties with respect to the subject matter of this Agreement. It supersedes all previous communications, representations, or contracts, either written or oral, which purport to describe or embody the subject matter of this Agreement. The body of this Agreement shall prevail over the exhibits to this Agreement in the event of a conflict.

24.3 Assignment

This Agreement is binding on any successors and assigns of the Parties. Neither Party may otherwise transfer or assign this Agreement, in whole or in part, without the other Party's written consent. Such consent shall not be unreasonably withheld. Without limiting the foregoing, BPA's refusal to consent to assignment shall not be considered unreasonable if, in BPA's sole discretion: (1) the sale of power by BPA to the assignee would violate any applicable statute, or (2) such sale might adversely affect the tax-exempt status of bonds issued as part of an issue that finances or refinances the Columbia Generating Station or that such sale might limit the ability to issue future tax-exempt bonds to finance or refinance the Columbia Generating Station. EWEB may not transfer or assign this Agreement to any of its retail consumers.

24.4 No Third-Party Beneficiaries

This Agreement is made and entered into for the sole benefit of the Parties, and the Parties intend that no other person or entity shall be a direct or indirect beneficiary of this Agreement.

24.5 Waivers

No waiver of any provision or breach of this Agreement shall be effective unless such waiver is in writing and signed by the waiving Party, and any such waiver shall not be deemed a waiver of any other provision of this Agreement or of any other breach of this Agreement.

24.6 BPA Policies

Any reference in this Agreement to BPA policies, including any revisions, does not constitute agreement of EWEB to such policy by execution of this Agreement, nor shall it be construed to be a waiver of the right of EWEB to seek judicial review of any such policy.

24.7 **Rate Covenant and Payment Assurance**
EWEB agrees that it shall establish, maintain and collect rates or charges sufficient to assure recovery of its costs for power and energy and other services, facilities and commodities sold, furnished or supplied by it through any of its electric utility properties. BPA may require additional forms of payment assurance if: (1) BPA determines that such rates and charges may not be adequate to provide revenues sufficient to enable EWEB to make the payments required under this Agreement, or (2) BPA identifies in a letter to EWEB that BPA has other reasonable grounds to conclude that EWEB may not be able to make the payments required under this Agreement. If EWEB does not provide payment assurance satisfactory to BPA, then BPA may terminate this Agreement. Written notices sent under this section must comply with section 20.

25. TERMINATION

25.1 **BPA's Right to Terminate**
BPA may terminate this Agreement if:

(1) EWEB fails to make payment as required by section 16.4, or

(2) EWEB fails to provide payment assurance satisfactory to BPA as required by section 24.7.

Such termination is without prejudice to any other remedies available to BPA under law.

25.2 **Customer's Right to Terminate**
EWEB may provide written notice to terminate this Agreement not later than 60 days after: (1) a Final FERC Order is issued declining to approve the Tiered Rate Methodology (if BPA seeks FERC's confirmation and approval of it), (2) FERC issues a final declaratory order finding that the TRM does not meet cost recovery standards, or (3) FERC issues a Final FERC Order that determines rates established consistent with the TRM cannot be approved because the TRM precludes the establishment of rates consistent with cost recovery. The notice shall include a date of termination not later than 90 days after the date of such notice. For purposes of this section 25.2, "Final FERC Order" means a dispositive order by FERC on the merits, and does not include any interim order. A dispositive order on the merits is, for purposes of this section, final when issued and there is no need to await a FERC order on rehearing before the decision is considered final.

26. SIGNATURES

The signatories represent that they are authorized to enter into this Agreement on behalf of the Party for which they sign.

THE CITY OF EUGENE, OREGON ACTING BY AND THROUGH THE EUGENE WATER & ELECTRIC BOARD	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By [redacted]	By [redacted]
Name Randy L. Berggren	Name Theresa E. Rockwood
Title General Manager	Title Account Executive
Date 12/1/08	Date 12-08-08

(PSW-W\Power\Contract\Customer\EWEB\13041\13041_Final.DOC) 11/24/08

Exhibit A
NET REQUIREMENTS AND RESOURCES

1. **NET REQUIREMENTS**
EWEB's Net Requirement equals its Total Retail Load minus EWEB's Dedicated Resources determined pursuant to section 3.3 of the body of this Agreement and listed in sections 2, 3, and 4 of this exhibit. The Parties shall not add or remove resource amounts to change EWEB's purchase obligations from BPA under section 3.1 of the body of this Agreement except in accordance with sections 3.5 and 10 of the body of this Agreement.

BPA shall annually calculate a forecast of EWEB's Net Requirement for the upcoming Fiscal Year as follows:

1.1 **Forecast of Total Retail Load**
By September 15, 2011, and by each September 15 thereafter, BPA shall fill in the table below with EWEB's Total Retail Load forecast (submitted pursuant to section 17.6 of the body of this Agreement) for the upcoming Fiscal Year. BPA shall notify EWEB by July 31 immediately preceding the start of the Fiscal Year if BPA determines EWEB's submitted forecast is reasonable or not reasonable. If BPA determines EWEB's submitted forecast is not reasonable, then BPA shall fill in the table below with a forecast BPA determines to be reasonable by September 15 immediately preceding the start of the Fiscal Year.

EWEB may submit to arbitration, which may be binding arbitration under a separate agreement or nonbinding arbitration as agreed to by the Parties, pursuant to section 22 of the body of the Agreement, the issue of the reasonableness of BPA's forecast of EWEB's Total Retail Load used by BPA to fill in the table below. Such arbitration shall not include issues of the interpretation or application of BPA's policies with respect to such forecast, including without limitation BPA's 5(b)/9(c) Policy.

Annual Forecast of Monthly Total Retail Load													
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	annual aMW
Fiscal Year 2012													
Energy (MWh)													
Peak (MW)													
Fiscal Year 2013													
Energy (MWh)													
Peak (MW)													
Fiscal Year 2014													
Energy (MWh)													
Peak (MW)													
Fiscal Year 2015													
Energy (MWh)													
Peak (MW)													

Annual Forecast of Monthly Total Retail Load													
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	annual aMW
Fiscal Year 2016													
Energy (MWh)													
Peak (MW)													
Fiscal Year 2017													
Energy (MWh)													
Peak (MW)													
Fiscal Year 2018													
Energy (MWh)													
Peak (MW)													
Fiscal Year 2019													
Energy (MWh)													
Peak (MW)													
Fiscal Year 2020													
Energy (MWh)													
Peak (MW)													
Fiscal Year 2021													
Energy (MWh)													
Peak (MW)													
Fiscal Year 2022													
Energy (MWh)													
Peak (MW)													
Fiscal Year 2023													
Energy (MWh)													
Peak (MW)													
Fiscal Year 2024													
Energy (MWh)													
Peak (MW)													
Fiscal Year 2025													
Energy (MWh)													
Peak (MW)													
Fiscal Year 2026													
Energy (MWh)													
Peak (MW)													
Fiscal Year 2027													
Energy (MWh)													
Peak (MW)													
Fiscal Year 2028													
Energy (MWh)													
Peak (MW)													
Notes: Fill in the table above with megawatt-hours rounded to whole megawatt-hours, with megawatts rounded to one decimal place, and annual Average Megawatts rounded to three decimal places.													

1.2 **Forecast of Net Requirements**

By September 15, 2011, and by each September 15 thereafter, BPA shall calculate, and fill in the table below with, EWEB's Net Requirement forecast for the upcoming Fiscal Year by month. EWEB's Net Requirement forecast equals EWEB's Total Retail Load forecast, shown in section 1.1 above, minus EWEB's Dedicated Resource amounts, shown in section 5 below.

On a planning basis EWEB shall serve that portion of its Total Retail Load that is not served with Firm Requirements Power with EWEB's Dedicated Resources.

Annual Forecast of Monthly Net Requirements													
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	annual aMW
Fiscal Year 2012													
Energy (MWh)													
Peak (MW)													
Fiscal Year 2013													
Energy (MWh)													
Peak (MW)													
Fiscal Year 2014													
Energy (MWh)													
Peak (MW)													
Fiscal Year 2015													
Energy (MWh)													
Peak (MW)													
Fiscal Year 2016													
Energy (MWh)													
Peak (MW)													
Fiscal Year 2017													
Energy (MWh)													
Peak (MW)													
Fiscal Year 2018													
Energy (MWh)													
Peak (MW)													
Fiscal Year 2019													
Energy (MWh)													
Peak (MW)													
Fiscal Year 2020													
Energy (MWh)													
Peak (MW)													
Fiscal Year 2021													
Energy (MWh)													
Peak (MW)													
Fiscal Year 2022													
Energy (MWh)													
Peak (MW)													
Fiscal Year 2023													
Energy (MWh)													
Peak (MW)													
Fiscal Year 2024													
Energy (MWh)													
Peak (MW)													
Fiscal Year 2025													
Energy (MWh)													
Peak (MW)													
Fiscal Year 2026													
Energy (MWh)													
Peak (MW)													

Annual Forecast of Monthly Net Requirements													
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	annual aMW
Fiscal Year 2027													
Energy (MWh)													
Peak (MW)													
Fiscal Year 2028													
Energy (MWh)													
Peak (MW)													
Note: Fill in the table above with megawatt-hours rounded to whole megawatt-hours, with megawatts rounded to one decimal place, and annual Average Megawatts rounded to three decimal places.													

2. LIST OF SPECIFIED RESOURCES

2.1 Generating Resources

All of EWEB's Generating Resources that are Specified Resources are listed below.

(1) **Carmen-Smith**

(A) **Special Provisions**
None.

(B) **Resource Profile**

Fuel Type	Date Resource Dedicated to Load	Date of Resource Removal	Percent of Resource Used to Serve Load	Nameplate Capability (MW)
Hydro	1979	N/A	100.0%	104.5

Statutory Status		Resource Status		DFS or SCS?		Dispatchable?		PNCA?		If PNCA, PNCA Updates?	
5b1A	5b1B	Existing	New	Yes	No	Yes	No	Yes	No	Yes	No
X		X				X		X			
Note: Fill in the table above with "X"s.											

(C) **Specified Resource Amounts**
Refer to Table #1, Carmen-Smith Resource Amounts, at the end of Exhibit A.

(2) **Leaburg**

(A) **Special Provisions**
None.

(B) **Resource Profile**

Fuel Type	Date Resource Dedicated to Load	Date of Resource Removal	Percent of Resource Used to Serve Load	Nameplate Capability (MW)
Hydro	1979	N/A	100.0%	15.0

Statutory Status		Resource Status		DFS or SCS?		Dispatchable?		PNCA?		If PNCA, PNCA Updates?	
5b1A	5b1B	Existing	New	Yes	No	Yes	No	Yes	No	Yes	No
X		X					X	X			
Note: Fill in the table above with "X"s.											

(C) **Specified Resource Amounts**
Refer to Table #2, Leaburg Resource Amounts, at the end of Exhibit A.

(3) **Trailbridge**

(A) **Special Provisions**
None.

(B) **Resource Profile**

Fuel Type	Date Resource Dedicated to Load	Date of Resource Removal	Percent of Resource Used to Serve Load	Nameplate Capability (MW)
Hydro	1979	N/A	100.0%	10.0

Statutory Status		Resource Status		DFS or SCS?		Dispatchable?		PNCA?		If PNCA, PNCA Updates?	
5b1A	5b1B	Existing	New	Yes	No	Yes	No	Yes	No	Yes	No
X		X					X	X			
Note: Fill in the table above with "X"s.											

(C) **Specified Resource Amounts**
Refer to Table #3, Trailbridge Resource Amounts, at the end of Exhibit A.

(4) **Walterville**

(A) **Special Provisions**
None.

(B) **Resource Profile**

Fuel Type	Date Resource Dedicated to Load	Date of Resource Removal	Percent of Resource Used to Serve Load	Nameplate Capability (MW)
Hydro	1979	N/A	100.0%	8.0

Statutory Status		Resource Status		DFS or SCS?		Dispatchable?		PNCA?		If PNCA, PNCA Updates?	
5b1A	5b1B	Existing	New	Yes	No	Yes	No	Yes	No	Yes	No
X		X					X	X			
Note: Fill in the table above with "X"s.											

(C) **Specified Resource Amounts**
Refer to Table #4, Walterville Resource Amounts, at the end of Exhibit A.

(5) **Smith Creek**

(A) **Special Provisions**
None.

(B) **Resource Profile**

Fuel Type	Date Resource Dedicated to Load	Date of Resource Removal	Percent of Resource Used to Serve Load	Nameplate Capability (MW)
Hydro	10/01/1991	N/A	100.0%	37.8

Statutory Status		Resource Status		DFS or SCS?		Dispatchable?		PNCA?		If PNCA, PNCA Updates?	
5b1A	5b1B	Existing	New	Yes	No	Yes	No	Yes	No	Yes	No
	X	X					X		X		
Note: Fill in the table above with "X"s.											

(C) **Specified Resource Amounts**
Refer to Table #5, Smith Creek Resource Amounts, at the end of Exhibit A.

(6) **Priest Rapids**

(A) **Special Provisions**
The Specified Resource amounts in the table in section 2.1(6)(C) below reflect a request that BPA determine statutory discontinuance that EWEB has not yet requested and the Administrator has not yet made as of the Effective Date. If, by October 1, 2010, BPA has not made a determination that a portion of EWEB's share of Priest Rapids has been permanently discontinued, then BPA shall revise the amounts in the table below accordingly.

(B) **Resource Profile**

Fuel Type	Date Resource Dedicated to Load	Date of Resource Removal	Percent of Resource Used to Serve Load	Nameplate Capability (MW)
Hydro	04/09/1986	N/A	0.14%	955.6

Statutory Status		Resource Status		DFS or SCS?		Dispatchable?		PNCA?		If PNCA, PNCA Updates?	
5b1A	5b1B	Existing	New	Yes	No	Yes	No	Yes	No	Yes	No
	X	X				X		X			
Note: Fill in the table above with "X"s.											

(C) **Specified Resource Amounts**
Refer to Table #6, Priest Rapids Resource Amounts, at the end of Exhibit A.

(7) **CEAEA for Priest Rapids**

(A) **Special Provisions**
Canadian Entitlement Allocation Extension Agreement (CEAEA) energy is a contractual obligation of U.S. Columbia River hydro projects to Canada, and nets against generation from non-Federal Wells, Rocky Reach, Rock Island, Wanapum, and Priest Rapids hydro projects. At the Effective Date, CEAEA values are fixed through March 2013. If the values or customer obligations under the CEAEA are adjusted or updated, BPA shall revise the CEAEA values shown in the table in section 2.1(7)(C) to reflect such adjustments or updates the next time Exhibit A is revised. CEAEA values shall be revised for future months only. CEAEA values shown for months prior to the date Exhibit A is revised shall not be changed.

(B) **Resource Profile**

Fuel Type	Date Resource Dedicated to Load	Date of Resource Removal	Percent of Resource Used to Serve Load	Nameplate Capability (MW)
N/A	04/09/1986	N/A	N/A	N/A

Statutory Status		Resource Status		DFS or SCS?		Dispatchable?		PNCA?		If PNCA, PNCA Updates?	
5b1A	5b1B	Existing	New	Yes	No	Yes	No	Yes	No	Yes	No
	X	X					X		X		
Note: Fill in the table above with "X"s.											

(C) **Specified Resource Amounts**
Refer to Table #7, CEAEA for Priest Rapids Resource Amounts, at the end of Exhibit A.

(8) **Wanapum**

(A) **Special Provisions**
The Specified Resource amounts in the table in section 2.1(8)(C) below reflect a request that BPA determine

statutory discontinuance that EWEB has not yet requested and the Administrator has not yet made as of the Effective Date. If, by October 1, 2010, BPA has not made a determination that a portion of EWEB's share of Wanapum has been permanently discontinued, then BPA shall revise the amounts in the table below accordingly.

(B) **Resource Profile**

Fuel Type	Date Resource Dedicated to Load	Date of Resource Removal	Percent of Resource Used to Serve Load	Nameplate Capability (MW)
Hydro	04/09/1986	N/A	0.14%	1038.0

Statutory Status		Resource Status		DFS or SCS?		Dispatchable?		PNCA?		If PNCA, PNCA Updates?	
5b1A	5b1B	Existing	New	Yes	No	Yes	No	Yes	No	Yes	No
	X	X				X		X			
Note: Fill in the table above with "X"s.											

(C) **Specified Resource Amounts**
Refer to Table #8, Wanapum Resource Amounts, at the end of Exhibit A.

(9) **CEAEA for Wanapum**

(A) **Special Provisions**
Canadian Entitlement Allocation Extension Agreement (CEAEA) energy is a contractual obligation of U.S. Columbia River hydro projects to Canada, and nets against generation from non-Federal Wells, Rocky Reach, Rock Island, Wanapum, and Priest Rapids hydro projects. At the Effective Date, CEAEA values are fixed through March 2013. If the values or customer obligations under the CEAEA are adjusted or updated, BPA shall revise the CEAEA values shown in the table in section 2.1(9)(C) to reflect such adjustments or updates the next time Exhibit A is revised. CEAEA values shall be revised for future months only. CEAEA values shown for months prior to the date Exhibit A is revised shall not be changed.

(B) **Resource Profile**

Fuel Type	Date Resource Dedicated to Load	Date of Resource Removal	Percent of Resource Used to Serve Load	Nameplate Capability (MW)
N/A	04/09/1986	N/A	N/A	N/A

Statutory Status		Resource Status		DFS or SCS?		Dispatchable?		PNCA?		If PNCA, PNCA Updates?	
5b1A	5b1B	Existing	New	Yes	No	Yes	No	Yes	No	Yes	No
	X	X					X		X		
Note: Fill in the table above with "X"s.											

(C) **Specified Resource Amounts**
Refer to Table #9, CEAEA for Wanapum Resource Amounts, at the end of Exhibit A.

(10) **Foote Creek 1**

(A) **Special Provisions**
None.

(B) **Resource Profile**

Fuel Type	Date Resource Dedicated to Load	Date of Resource Removal	Percent of Resource Used to Serve Load	Nameplate Capability (MW)
Wind	01/15/1999	N/A	15.0%	41.4

Statutory Status		Resource Status		DFS or SCS?		Dispatchable?		PNCA?		If PNCA, PNCA Updates?	
5b1A	5b1B	Existing	New	Yes	No	Yes	No	Yes	No	Yes	No
	X	X					X		X		
Note: Fill in the table above with "X"s.											

(C) **Specified Resource Amounts**
Refer to Table #10, Foote Creek 1 Resource Amounts, at the end of Exhibit A.

2.2 **Contract Resources**
EWEB does not have any Contract Resources that are Specified Resources at this time.

3. UNSPECIFIED RESOURCE AMOUNTS

3.1 **Unspecified Resource Amounts Used to Serve Total Retail Load**
EWEB does not have any Unspecified Resource Amounts at this time.

3.2 **Unspecified Resource Amounts for 9(c) Export Decrements**
BPA shall insert a table below pursuant to section 3.5.3 of the body of this Agreement.

4. DEDICATED RESOURCE AMOUNTS FOR AN NLSL

All of EWEB's Dedicated Resource amounts serving an NLSL, in accordance with section 3.5.7 of the body of this Agreement, are listed below.

(1) **Stone Creek Serving Hynix NLSL**

(A) **Special Provisions**
EWEB shall apply the resource output of Stone Creek pursuant to sections 1.3 and 3 of Exhibit D of this Agreement.

(B) **Resource Profile**

Fuel Type	Date Resource Dedicated to Load	Date of Resource Removal	Percent of Resource Used to Serve Load	Nameplate Capability (MW)
Hydro	10/2001	N/A	100.0%	12.0

Statutory Status		Resource Status		DFS or SCS?		Dispatchable?		PNCA?		If PNCA, PNCA Updates?	
5b1A	5b1B	Existing	New	Yes	No	Yes	No	Yes	No	Yes	No
	X	X					X		X		
Note: Fill in the table above with "X"s.											

(C) **Specified Resource Amounts**
Refer to Table #11, Stone Creek Serving Hynix Resource Amounts, at the end of Exhibit A.

(2) **International Paper (formerly Weyerhaeuser) Serving Hynix NLSL**

(A) **Special Provisions**
EWEB shall apply the resource output of International Paper pursuant to sections 1.3 and 3 of Exhibit D of this Agreement.

(B) **Resource Profile**

Fuel Type	Date Resource Dedicated to Load	Date of Resource Removal	Percent of Resource Used to Serve Load	Nameplate Capability (MW)
Waste Heat/Natural Gas	1979	05/30/2015	50.0%	51.2

Statutory Status		Resource Status		DFS or SCS?		Dispatchable?		PNCA?		If PNCA, PNCA Updates?	
5b1A	5b1B	Existing	New	Yes	No	Yes	No	Yes	No	Yes	No
X		X					X		X		
Note: Fill in the table above with "X"s.											

(C) **Specified Resource Amounts**
Refer to Table #12, International Paper Serving Hynix Resource Amounts, at the end of Exhibit A.

5. TOTAL DEDICATED RESOURCE AMOUNTS

The amounts in the table below equal the sum of all resource amounts used to serve EWEB's Total Retail Load listed above in sections 2, 3, and 4.

-

Total Dedicated Resource Amounts

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	annual aMW
Fiscal Year 2012													
Total (MWh)	34,477	43,422	47,365	49,776	37,901	37,178	39,522	60,724	49,131	32,126	25,068	32,629	55.706
HLH (MWh)	19,248	24,065	26,458	26,734	21,757	21,590	21,932	33,928	28,362	17,246	14,531	17,377	55.625
LLH (MWh)	15,229	19,357	20,907	23,042	16,144	15,588	17,590	26,796	20,769	14,880	10,537	15,252	55.809
Peak (MW)													N/A
Fiscal Year 2013													
Total (MWh)	34,477	43,424	47,369	49,775	36,596	37,182	39,522	60,724	49,131	32,126	25,068	32,629	55.710
HLH (MWh)	19,994	24,067	25,441	27,806	20,888	20,790	22,811	33,928	27,269	17,937	14,531	17,377	55.545
LLH (MWh)	14,483	19,357	21,928	21,969	15,708	16,392	16,711	26,796	21,862	14,189	10,537	15,252	55.921
Peak (MW)													N/A
Fiscal Year 2014													
Total (MWh)	34,477	43,424	47,369	49,775	36,596	37,182	39,522	60,724	49,131	32,126	25,068	32,629	55.710
HLH (MWh)	19,994	24,067	25,441	27,806	20,888	20,790	22,811	33,928	27,269	17,937	13,991	18,105	55.584
LLH (MWh)	14,483	19,357	21,928	21,969	15,708	16,392	16,711	26,796	21,862	14,189	11,077	14,524	55.872
Peak (MW)													N/A
Fiscal Year 2015													
Total (MWh)	34,477	43,424	47,369	49,775	36,596	37,182	39,522	60,724	44,763	25,969	18,530	27,655	53.195
HLH (MWh)	19,994	23,102	26,462	27,806	20,888	20,790	22,811	32,622	25,838	14,495	10,336	15,341	53.030
LLH (MWh)	14,483	20,322	20,907	21,969	15,708	16,392	16,711	28,102	18,925	11,474	8,194	12,314	53.405
Peak (MW)													N/A
Fiscal Year 2016													
Total (MWh)	27,659	36,113	39,612	41,676	30,567	29,699	33,753	55,636	44,763	25,969	18,530	27,655	46.862
HLH (MWh)	16,035	19,207	22,123	22,379	17,542	17,241	19,478	29,886	25,838	13,936	10,735	15,341	46.620
LLH (MWh)	11,624	16,906	17,489	19,297	13,025	12,458	14,275	25,750	18,925	12,033	7,795	12,314	47.171
Peak (MW)													N/A
Fiscal Year 2017													
Total (MWh)	27,659	36,115	39,616	41,675	29,515	29,703	33,753	55,636	44,763	25,969	18,530	27,655	46.871
HLH (MWh)	15,436	20,012	22,127	22,378	16,842	17,245	18,727	31,083	25,838	13,936	10,735	15,341	46.763
LLH (MWh)	12,223	16,103	17,489	19,297	12,673	12,458	15,026	24,553	18,925	12,033	7,795	12,314	47.009
Peak (MW)													N/A
Fiscal Year 2018													
Total (MWh)	27,659	36,115	39,616	41,675	29,515	29,703	33,753	55,636	44,763	25,969	18,530	27,655	46.871
HLH (MWh)	15,436	20,012	21,273	23,277	16,842	17,245	18,727	31,083	25,838	13,936	10,735	14,724	46.799
LLH (MWh)	12,223	16,103	18,343	18,398	12,673	12,458	15,026	24,553	18,925	12,033	7,795	12,931	46.962
Peak (MW)													N/A
Fiscal Year 2019													
Total (MWh)	27,659	36,115	39,616	41,675	29,515	29,703	33,753	55,636	44,763	25,969	18,530	27,655	46.871
HLH (MWh)	16,035	20,012	21,273	23,277	16,842	16,603	19,478	31,083	24,842	14,495	10,735	14,724	46.702
LLH (MWh)	11,624	16,103	18,343	18,398	12,673	13,100	14,275	24,553	19,921	11,474	7,795	12,931	47.087
Peak (MW)													N/A
Fiscal Year 2020													
Total (MWh)	27,659	36,113	39,612	41,676	30,567	29,699	33,753	55,636	44,763	25,969	18,530	27,655	46.862
HLH (MWh)	16,035	20,010	21,269	23,278	17,542	16,599	19,478	29,886	25,838	14,495	10,336	15,341	46.694
LLH (MWh)	11,624	16,103	18,343	18,398	13,025	13,100	14,275	25,750	18,925	11,474	8,194	12,314	47.076
Peak (MW)													N/A
Fiscal Year 2021													
Total (MWh)	27,659	36,115	39,616	41,675	29,515	29,703	33,753	55,636	44,763	25,969	18,530	27,655	46.871
HLH (MWh)	16,035	19,209	22,127	22,378	16,842	17,245	19,478	29,886	25,838	14,495	10,336	15,341	46.663
LLH (MWh)	11,624	16,906	17,489	19,297	12,673	12,458	14,275	25,750	18,925	11,474	8,194	12,314	47.136
Peak (MW)													N/A

Total Dedicated Resource Amounts													
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	annual aMW
Fiscal Year 2022													
Total (MWh)	27,659	36,115	39,616	41,675	29,515	29,703	33,753	55,636	44,763	25,969	18,530	27,655	46.871
HLH (MWh)	15,436	20,012	22,127	22,378	16,842	17,245	19,478	29,886	25,838	13,936	10,735	15,341	46.672
LLH (MWh)	12,223	16,103	17,489	19,297	12,673	12,458	14,275	25,750	18,925	12,033	7,795	12,314	47.124
Peak (MW)													N/A
Fiscal Year 2023													
Total (MWh)	27,659	36,115	39,616	41,675	29,515	29,703	33,753	55,636	44,763	25,969	18,530	27,655	46.871
HLH (MWh)	15,436	20,012	22,127	22,378	16,842	17,245	18,727	31,083	25,838	13,936	10,735	15,341	46.763
LLH (MWh)	12,223	16,103	17,489	19,297	12,673	12,458	15,026	24,553	18,925	12,033	7,795	12,314	47.009
Peak (MW)													N/A
Fiscal Year 2024													
Total (MWh)	27,659	36,113	39,612	41,676	30,567	29,699	33,753	55,636	44,763	25,969	18,530	27,655	46.862
HLH (MWh)	15,436	20,010	21,269	23,278	17,542	16,599	19,478	31,083	24,842	14,495	10,735	14,724	46.720
LLH (MWh)	12,223	16,103	18,343	18,398	13,025	13,100	14,275	24,553	19,921	11,474	7,795	12,931	47.041
Peak (MW)													N/A
Fiscal Year 2025													
Total (MWh)	27,659	36,115	39,616	41,675	29,515	29,703	33,753	55,636	44,763	25,969	18,530	27,655	46.871
HLH (MWh)	16,035	20,012	21,273	23,277	16,842	16,603	19,478	31,083	24,842	14,495	10,336	15,341	46.746
LLH (MWh)	11,624	16,103	18,343	18,398	12,673	13,100	14,275	24,553	19,921	11,474	8,194	12,314	47.030
Peak (MW)													N/A
Fiscal Year 2026													
Total (MWh)	27,659	36,115	39,616	41,675	29,515	29,703	33,753	55,636	44,763	25,969	18,530	27,655	46.871
HLH (MWh)	16,035	19,209	22,127	23,277	16,842	16,603	19,478	29,886	25,838	14,495	10,336	15,341	46.716
LLH (MWh)	11,624	16,906	17,489	18,398	12,673	13,100	14,275	25,750	18,925	11,474	8,194	12,314	47.069
Peak (MW)													N/A
Fiscal Year 2027													
Total (MWh)	27,659	36,115	39,616	41,675	29,515	29,703	33,753	55,636	44,763	25,969	18,530	27,655	46.871
HLH (MWh)	16,035	19,209	22,127	22,378	16,842	17,245	19,478	29,886	25,838	14,495	10,336	15,341	46.663
LLH (MWh)	11,624	16,906	17,489	19,297	12,673	12,458	14,275	25,750	18,925	11,474	8,194	12,314	47.136
Peak (MW)													N/A
Fiscal Year 2028													
Total (MWh)	27,659	36,113	39,612	41,676	30,567	29,699	33,753	55,636	44,763	25,969	18,530	27,655	46.862
HLH (MWh)	15,436	20,010	22,123	22,379	17,542	17,241	18,727	31,083	25,838	13,936	10,735	15,341	46.751
LLH (MWh)	12,223	16,103	17,489	19,297	13,025	12,458	15,026	24,553	18,925	12,033	7,795	12,314	47.002
Peak (MW)													N/A
Notes: Fill in the table above with megawatt-hours rounded to whole megawatt-hours, with megawatts rounded to one decimal place, and annual Average Megawatts rounded to three decimal places.													

6. **LIST OF RESOURCES NOT USED TO SERVE TOTAL RETAIL LOAD**
Pursuant to section 17 of the body of this Agreement, all Generating Resources and Contract Resources EWEB owns that are: (1) not Specified Resources listed in section 2 of Exhibit A, and (2) greater than 200 kilowatts of nameplate capability, are listed below.

(1) **Stateline**

(A) **Resource Profile**

Fuel Type	Type of Resource		Percent of Resource Not Used to Serve Load	Nameplate Capability (MW)
	Generating Resource	Contract Resource		
Wind	X		8.344%	299.6

(B) **Expected Resource Output**

Expected Output – Energy (aMW)									
Fiscal Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Annual aMW	5.613	5.613	5.613	5.613	5.613	5.613	5.613	5.613	5.613
Fiscal Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	
Annual aMW	5.613	5.613	5.613	5.613	5.613	5.613	1.403		
Note: Fill in the table above with annual Average Megawatts rounded to three decimal places.									

(2) **Klondike III**

(A) **Resource Profile**

Fuel Type	Type of Resource		Percent of Resource Not Used to Serve Load	Nameplate Capability (MW)
	Generating Resource	Contract Resource		
Wind	X		11.18%	223.6

(B) **Expected Resource Output**

Expected Output – Energy (aMW)									
Fiscal Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Annual aMW	6.706	6.706	6.706	6.706	6.706	6.706	6.706	6.706	6.706
Fiscal Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	
Annual aMW	6.706	6.706	6.706	6.706	6.706	6.706	6.706	1.118	
Note: Fill in the table above with annual Average Megawatts rounded to three decimal places.									

(3) **Industrial Finishes**

(A) **Resource Profile**

Fuel Type	Type of Resource		Percent of Resource Not Used to Serve Load	Nameplate Capability (MW)
	Generating Resource	Contract Resource		
Solar	X		100%	0.450

(B) **Expected Resource Output**

Expected Output – Energy (aMW)									
Fiscal Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Annual aMW	0.057	0.057	0.057	0.057	0.057	0.057			
Fiscal Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	
Annual aMW									
Note: Fill in the table above with annual Average Megawatts rounded to three decimal places.									

(4) **Willamette Beverage (Pepsi-Cola)**

(A) **Resource Profile**

Fuel Type	Type of Resource: Generating Resource	Type of Resource: Contract Resource	Percent of Resource Not Used to Serve Load	Nameplate Capability (MW)
Solar	X		100%	**0.250**

(B) **Expected Resource Output**

Expected Output – Energy (aMW)									
Fiscal Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Annual aMW	0.031	0.031	0.031	0.031	0.031	0.031			
Fiscal Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	
Annual aMW									
Note: Fill in the table above with annual Average Megawatts rounded to three decimal places.									

7. LIST OF CONSUMER-OWNED RESOURCES

7.1 **Consumer-Owned Resources Serving Onsite Consumer Load**
Pursuant to section 3.6 of the body of this Agreement, EWEB does not have any Consumer-Owned Resources serving Onsite Consumer Load at this time.

7.2 **Consumer-Owned Resources Serving Load Other than Onsite Consumer Load**
Pursuant to section 3.6 of the body of this Agreement, all of EWEB's Consumer-Owned Resources serving load other than Onsite Consumer Load are listed below.

(1) **Industrial Finishes**

(A) **Resource Profile**

Resource Owner	Fuel Type	Nameplate Capability (MW)
Industrial Finishes	Solar	**0.450**

(B) Expected Resource Output

Expected Output – Energy (aMW)									
Fiscal Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Annual aMW	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057
Fiscal Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	
Annual aMW	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	
Note: Fill in the table above with annual Average Megawatts rounded to three decimal places.									

(2) International Paper

(A) Resource Profile

Resource Owner	Fuel Type	Nameplate Capability (MW)
International Paper	Waste Heat/Natural Gas	**51.2**

(B) Expected Resource Output

Expected Output – Energy (aMW)									
Fiscal Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Annual aMW	8.844	8.839	8.839	11.354	17.688	17.678	17.678	17.678	17.688
Fiscal Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	
Annual aMW	17.678	17.678	17.678	17.688	17.678	17.678	17.678	17.688	
Note: Fill in the table above with annual Average Megawatts rounded to three decimal places.									

(3) University of Oregon #1

(A) Resource Profile

Resource Owner	Fuel Type	Nameplate Capability (MW)
University of Oregon	Waste Heat	**1.5**

(B) Expected Resource Output

Expected Output – Energy (aMW)									
Fiscal Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Annual aMW	0.484	0.484	0.484	0.484	0.484	0.484	0.484	0.484	0.484
Fiscal Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	
Annual aMW	0.484	0.484	0.484	0.484	0.484	0.484	0.484	0.484	
Note: Fill in the table above with annual Average Megawatts rounded to three decimal places.									

(4) **University of Oregon #3**

(A) **Resource Profile**

Resource Owner	Fuel Type	Nameplate Capability (MW)
University of Oregon	Waste Heat	2.5

(B) **Expected Resource Output**

Expected Output – Energy (aMW)									
Fiscal Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Annual aMW	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.103
Fiscal Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	
Annual aMW	0.103	0.103	0.103	0.103	0.103	0.103	0.103	0.103	
Note: Fill in the table above with annual Average Megawatts rounded to three decimal places.									

(5) **Willamette Beverage (Pepsi-Cola)**

(A) **Resource Profile**

Resource Owner	Fuel Type	Nameplate Capability (MW)
Willamette Beverage (Pepsi-Cola)	Solar	0.250

(B) **Expected Resource Output**

Expected Output – Energy (aMW)									
Fiscal Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Annual aMW	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031
Fiscal Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	
Annual aMW	0.031	0.031	0.031	0.031	0.031	0.031	0.031	0.031	
Note: Fill in the table above with annual Average Megawatts rounded to three decimal places.									

7.3 **Consumer-Owned Resources Serving Both Onsite Consumer Load and Load Other than Onsite Consumer Load**
Pursuant to section 3.6 of the body of this Agreement, EWEB does not have any Consumer-Owned Resources serving both Onsite Consumer Load and load other than Onsite Consumer Load at this time.

7.4 **Consumer-Owned Resources Serving an NLSL**
Pursuant to section 23.3.7 of the body of this Agreement, EWEB does not have any Consumer-Owned Resources serving an NLSL at this time.

8. **REVISIONS**
BPA shall revise this exhibit to reflect: (1) EWEB's elections regarding the application and use of all resources owned by EWEB and EWEB's retail

consumers and (2) BPA's determinations relevant to this exhibit and made in accordance with this Agreement.

(PSW-W\Power\Contract\Customer\EWEB\13041\13041_ExhA_Final.DOC) 11/24/08

EXHIBIT A TABLES

Table 1
Section 2.1(1)(C) – Carmen-Smith Specified Resource Amounts

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	annual aMW
Fiscal Year 2012													
Total (MWh)	9,598	12,257	12,648	12,648	11,554	11,665	9,288	10,788	12,096	11,160	10,230	11,592	15.429
HLH (MWh)	5,366	6,800	7,072	6,800	6,640	6,782	5,160	6,032	6,989	6,000	5,940	6,182	15.424
LLH (MWh)	4,232	5,457	5,576	5,848	4,914	4,883	4,128	4,756	5,107	5,160	4,290	5,410	15.434
Peak (MW)													N/A
Fiscal Year 2013													
Total (MWh)	9,598	12,257	12,648	12,648	11,155	11,665	9,288	10,788	12,096	11,160	10,230	11,592	15.425
HLH (MWh)	5,573	6,800	6,800	7,072	6,374	6,531	5,366	6,032	6,720	6,240	5,940	6,182	15.397
LLH (MWh)	4,025	5,457	5,848	5,576	4,781	5,134	3,922	4,756	5,376	4,920	4,290	5,410	15.461
Peak (MW)													N/A
Fiscal Year 2014													
Total (MWh)	9,598	12,257	12,648	12,648	11,155	11,665	9,288	10,788	12,096	11,160	10,230	11,592	15.425
HLH (MWh)	5,573	6,800	6,800	7,072	6,374	6,531	5,366	6,032	6,720	6,240	5,720	6,440	15.405
LLH (MWh)	4,025	5,457	5,848	5,576	4,781	5,134	3,922	4,756	5,376	4,920	4,510	5,152	15.451
Peak (MW)													N/A
Fiscal Year 2015													
Total (MWh)	9,598	12,257	12,648	12,648	11,155	11,665	9,288	10,788	12,096	11,160	10,230	11,592	15.425
HLH (MWh)	5,573	6,528	7,072	7,072	6,374	6,531	5,366	5,800	6,989	6,240	5,720	6,440	15.412
LLH (MWh)	4,025	5,729	5,576	5,576	4,781	5,134	3,922	4,988	5,107	4,920	4,510	5,152	15.442
Peak (MW)													N/A
Fiscal Year 2016													
Total (MWh)	9,598	12,257	12,648	12,648	11,554	11,665	9,288	10,788	12,096	11,160	10,230	11,592	15.429
HLH (MWh)	5,573	6,528	7,072	6,800	6,640	6,782	5,366	5,800	6,989	6,000	5,940	6,440	15.408
LLH (MWh)	4,025	5,729	5,576	5,848	4,914	4,883	3,922	4,988	5,107	5,160	4,290	5,152	15.455
Peak (MW)													N/A
Fiscal Year 2017													
Total (MWh)	9,598	12,257	12,648	12,648	11,155	11,665	9,288	10,788	12,096	11,160	10,230	11,592	15.425
HLH (MWh)	5,366	6,800	7,072	6,800	6,374	6,782	5,160	6,032	6,989	6,000	5,940	6,440	15.422
LLH (MWh)	4,232	5,457	5,576	5,848	4,781	4,883	4,128	4,756	5,107	5,160	4,290	5,152	15.429
Peak (MW)													N/A
Fiscal Year 2018													
Total (MWh)	9,598	12,257	12,648	12,648	11,155	11,665	9,288	10,788	12,096	11,160	10,230	11,592	15.425
HLH (MWh)	5,366	6,800	6,800	7,072	6,374	6,782	5,160	6,032	6,989	6,000	5,940	6,182	15.420
LLH (MWh)	4,232	5,457	5,848	5,576	4,781	4,883	4,128	4,756	5,107	5,160	4,290	5,410	15.432
Peak (MW)													N/A
Fiscal Year 2019													
Total (MWh)	9,598	12,257	12,648	12,648	11,155	11,665	9,288	10,788	12,096	11,160	10,230	11,592	15.425
HLH (MWh)	5,573	6,800	6,800	7,072	6,374	6,531	5,366	6,032	6,720	6,240	5,940	6,182	15.397
LLH (MWh)	4,025	5,457	5,848	5,576	4,781	5,134	3,922	4,756	5,376	4,920	4,290	5,410	15.461
Peak (MW)													N/A
Fiscal Year 2020													
Total (MWh)	9,598	12,257	12,648	12,648	11,554	11,665	9,288	10,788	12,096	11,160	10,230	11,592	15.429
HLH (MWh)	5,573	6,800	6,800	7,072	6,640	6,531	5,366	5,800	6,989	6,240	5,720	6,440	15.416
LLH (MWh)	4,025	5,457	5,848	5,576	4,914	5,134	3,922	4,988	5,107	4,920	4,510	5,152	15.444
Peak (MW)													N/A

Table 1 Section 2.1(1)(C) – Carmen-Smith Specified Resource Amounts													
	Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**annual aMW**
Fiscal Year 2021													
Total (MWh)	9,598	12,257	12,648	12,648	11,155	11,665	9,288	10,788	12,096	11,160	10,230	11,592	15.425
HLH (MWh)	5,573	6,528	7,072	6,800	6,374	6,782	5,366	5,800	6,989	6,240	5,720	6,440	15.408
LLH (MWh)	4,025	5,729	5,576	5,848	4,781	4,883	3,922	4,988	5,107	4,920	4,510	5,152	15.447
Peak (MW)													N/A
Fiscal Year 2022													
Total (MWh)	9,598	12,257	12,648	12,648	11,155	11,665	9,288	10,788	12,096	11,160	10,230	11,592	15.425
HLH (MWh)	5,366	6,800	7,072	6,800	6,374	6,782	5,366	5,800	6,989	6,000	5,940	6,440	15.417
LLH (MWh)	4,232	5,457	5,576	5,848	4,781	4,883	3,922	4,988	5,107	5,160	4,290	5,152	15.436
Peak (MW)													N/A
Fiscal Year 2023													
Total (MWh)	9,598	12,257	12,648	12,648	11,155	11,665	9,288	10,788	12,096	11,160	10,230	11,592	15.425
HLH (MWh)	5,366	6,800	7,072	6,800	6,374	6,782	5,160	6,032	6,989	6,000	5,940	6,440	15.422
LLH (MWh)	4,232	5,457	5,576	5,848	4,781	4,883	4,128	4,756	5,107	5,160	4,290	5,152	15.429
Peak (MW)													N/A
Fiscal Year 2024													
Total (MWh)	9,598	12,257	12,648	12,648	11,554	11,665	9,288	10,788	12,096	11,160	10,230	11,592	15.429
HLH (MWh)	5,366	6,800	6,800	7,072	6,640	6,531	5,366	6,032	6,720	6,240	5,940	6,182	15.409
LLH (MWh)	4,232	5,457	5,848	5,576	4,914	5,134	3,922	4,756	5,376	4,920	4,290	5,410	15.453
Peak (MW)													N/A
Fiscal Year 2025													
Total (MWh)	9,598	12,257	12,648	12,648	11,155	11,665	9,288	10,788	12,096	11,160	10,230	11,592	15.425
HLH (MWh)	5,573	6,800	6,800	7,072	6,374	6,531	5,366	6,032	6,720	6,240	5,720	6,440	15.405
LLH (MWh)	4,025	5,457	5,848	5,576	4,781	5,134	3,922	4,756	5,376	4,920	4,510	5,152	15.451
Peak (MW)													N/A
Fiscal Year 2026													
Total (MWh)	9,598	12,257	12,648	12,648	11,155	11,665	9,288	10,788	12,096	11,160	10,230	11,592	15.425
HLH (MWh)	5,573	6,528	7,072	7,072	6,374	6,531	5,366	5,800	6,989	6,240	5,720	6,440	15.412
LLH (MWh)	4,025	5,729	5,576	5,576	4,781	5,134	3,922	4,988	5,107	4,920	4,510	5,152	15.442
Peak (MW)													N/A
Fiscal Year 2027													
Total (MWh)	9,598	12,257	12,648	12,648	11,155	11,665	9,288	10,788	12,096	11,160	10,230	11,592	15.425
HLH (MWh)	5,573	6,528	7,072	6,800	6,374	6,782	5,366	5,800	6,989	6,240	5,720	6,440	15.408
LLH (MWh)	4,025	5,729	5,576	5,848	4,781	4,883	3,922	4,988	5,107	4,920	4,510	5,152	15.447
Peak (MW)													N/A
Fiscal Year 2028													
Total (MWh)	9,598	12,257	12,648	12,648	11,554	11,665	9,288	10,788	12,096	11,160	10,230	11,592	15.429
HLH (MWh)	5,366	6,800	7,072	6,800	6,640	6,782	5,160	6,032	6,989	6,000	5,940	6,440	15.426
LLH (MWh)	4,232	5,457	5,576	5,848	4,914	4,883	4,128	4,756	5,107	5,160	4,290	5,152	15.431
Peak (MW)													N/A
Notes: Fill in the table above with megawatt-hours rounded to whole megawatt-hours, with megawatts rounded to one decimal place, and annual Average Megawatts rounded to three decimal places.													

Table 2
Section 2.1(2)(C) – Leaburg Specified Resource Amounts

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	annual aMW
Fiscal Year 2012													
Total (MWh)	6,622	9,373	9,672	8,705	5,846	5,201	5,328	6,845	5,400	3,274	595	3,672	8.030
HLH (MWh)	3,702	5,200	5,408	4,680	3,360	3,024	2,960	3,827	3,120	1,760	346	1,958	8.010
LLH (MWh)	2,920	4,173	4,264	4,025	2,486	2,177	2,368	3,018	2,280	1,514	249	1,714	8.055
Peak (MW)													N/A
Fiscal Year 2013													
Total (MWh)	6,622	9,373	9,672	8,705	5,645	5,201	5,328	6,845	5,400	3,274	595	3,672	8.029
HLH (MWh)	3,845	5,200	5,200	4,867	3,226	2,912	3,078	3,827	3,000	1,830	346	1,958	7.999
LLH (MWh)	2,777	4,173	4,472	3,838	2,419	2,289	2,250	3,018	2,400	1,444	249	1,714	8.067
Peak (MW)													N/A
Fiscal Year 2014													
Total (MWh)	6,622	9,373	9,672	8,705	5,645	5,201	5,328	6,845	5,400	3,274	595	3,672	8.029
HLH (MWh)	3,845	5,200	5,200	4,867	3,226	2,912	3,078	3,827	3,000	1,830	333	2,040	8.013
LLH (MWh)	2,777	4,173	4,472	3,838	2,419	2,289	2,250	3,018	2,400	1,444	262	1,632	8.049
Peak (MW)													N/A
Fiscal Year 2015													
Total (MWh)	6,622	9,373	9,672	8,705	5,645	5,201	5,328	6,845	5,400	3,274	595	3,672	8.029
HLH (MWh)	3,845	4,992	5,408	4,867	3,226	2,912	3,078	3,680	3,120	1,830	333	2,040	8.007
LLH (MWh)	2,777	4,381	4,264	3,838	2,419	2,289	2,250	3,165	2,280	1,444	262	1,632	8.056
Peak (MW)													N/A
Fiscal Year 2016													
Total (MWh)	6,622	9,373	9,672	8,705	5,846	5,201	5,328	6,845	5,400	3,274	595	3,672	8.030
HLH (MWh)	3,845	4,992	5,408	4,680	3,360	3,024	3,078	3,680	3,120	1,760	346	2,040	7.982
LLH (MWh)	2,777	4,381	4,264	4,025	2,486	2,177	2,250	3,165	2,280	1,514	249	1,632	8.091
Peak (MW)													N/A
Fiscal Year 2017													
Total (MWh)	6,622	9,373	9,672	8,705	5,645	5,201	5,328	6,845	5,400	3,274	595	3,672	8.029
HLH (MWh)	3,702	5,200	5,408	4,680	3,226	3,024	2,960	3,827	3,120	1,760	346	2,040	7.999
LLH (MWh)	2,920	4,173	4,264	4,025	2,419	2,177	2,368	3,018	2,280	1,514	249	1,632	8.066
Peak (MW)													N/A
Fiscal Year 2018													
Total (MWh)	6,622	9,373	9,672	8,705	5,645	5,201	5,328	6,845	5,400	3,274	595	3,672	8.029
HLH (MWh)	3,702	5,200	5,200	4,867	3,226	3,024	2,960	3,827	3,120	1,760	346	1,958	8.004
LLH (MWh)	2,920	4,173	4,472	3,838	2,419	2,177	2,368	3,018	2,280	1,514	249	1,714	8.060
Peak (MW)													N/A
Fiscal Year 2019													
Total (MWh)	6,622	9,373	9,672	8,705	5,645	5,201	5,328	6,845	5,400	3,274	595	3,672	8.029
HLH (MWh)	3,845	5,200	5,200	4,867	3,226	2,912	3,078	3,827	3,000	1,830	346	1,958	7.999
LLH (MWh)	2,777	4,173	4,472	3,838	2,419	2,289	2,250	3,018	2,400	1,444	249	1,714	8.067
Peak (MW)													N/A
Fiscal Year 2020													
Total (MWh)	6,622	9,373	9,672	8,705	5,846	5,201	5,328	6,845	5,400	3,274	595	3,672	8.030
HLH (MWh)	3,845	5,200	5,200	4,867	3,360	2,912	3,078	3,680	3,120	1,830	333	2,040	8.008
LLH (MWh)	2,777	4,173	4,472	3,838	2,486	2,289	2,250	3,165	2,280	1,444	262	1,632	8.057
Peak (MW)													N/A

Table 2 Section 2.1(2)(C) – Leaburg Specified Resource Amounts													
	Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**annual aMW**
						Fiscal Year 2021							
Total (MWh)	6,622	9,373	9,672	8,705	5,645	5,201	5,328	6,845	5,400	3,274	595	3,672	8.029
HLH (MWh)	3,845	4,992	5,408	4,680	3,226	3,024	3,078	3,680	3,120	1,830	333	2,040	7.992
LLH (MWh)	2,777	4,381	4,264	4,025	2,419	2,177	2,250	3,165	2,280	1,444	262	1,632	8.076
Peak (MW)													N/A
						Fiscal Year 2022							
Total (MWh)	6,622	9,373	9,672	8,705	5,645	5,201	5,328	6,845	5,400	3,274	595	3,672	8.029
HLH (MWh)	3,702	5,200	5,408	4,680	3,226	3,024	3,078	3,680	3,120	1,760	346	2,040	7.993
LLH (MWh)	2,920	4,173	4,264	4,025	2,419	2,177	2,250	3,165	2,280	1,514	249	1,632	8.074
Peak (MW)													N/A
						Fiscal Year 2023							
Total (MWh)	6,622	9,373	9,672	8,705	5,645	5,201	5,328	6,845	5,400	3,274	595	3,672	8.029
HLH (MWh)	3,702	5,200	5,408	4,680	3,226	3,024	2,960	3,827	3,120	1,760	346	2,040	7.999
LLH (MWh)	2,920	4,173	4,264	4,025	2,419	2,177	2,368	3,018	2,280	1,514	249	1,632	8.066
Peak (MW)													N/A
						Fiscal Year 2024							
Total (MWh)	6,622	9,373	9,672	8,705	5,846	5,201	5,328	6,845	5,400	3,274	595	3,672	8.030
HLH (MWh)	3,702	5,200	5,200	4,867	3,360	2,912	3,078	3,827	3,000	1,830	346	1,958	7.997
LLH (MWh)	2,920	4,173	4,472	3,838	2,486	2,289	2,250	3,018	2,400	1,444	249	1,714	8.072
Peak (MW)													N/A
						Fiscal Year 2025							
Total (MWh)	6,622	9,373	9,672	8,705	5,645	5,201	5,328	6,845	5,400	3,274	595	3,672	8.029
HLH (MWh)	3,845	5,200	5,200	4,867	3,226	2,912	3,078	3,827	3,000	1,830	333	2,040	8.013
LLH (MWh)	2,777	4,173	4,472	3,838	2,419	2,289	2,250	3,018	2,400	1,444	262	1,632	8.049
Peak (MW)													N/A
						Fiscal Year 2026							
Total (MWh)	6,622	9,373	9,672	8,705	5,645	5,201	5,328	6,845	5,400	3,274	595	3,672	8.029
HLH (MWh)	3,845	4,992	5,408	4,867	3,226	2,912	3,078	3,680	3,120	1,830	333	2,040	8.007
LLH (MWh)	2,777	4,381	4,264	3,838	2,419	2,289	2,250	3,165	2,280	1,444	262	1,632	8.056
Peak (MW)													N/A
						Fiscal Year 2027							
Total (MWh)	6,622	9,373	9,672	8,705	5,645	5,201	5,328	6,845	5,400	3,274	595	3,672	8.029
HLH (MWh)	3,845	4,992	5,408	4,680	3,226	3,024	3,078	3,680	3,120	1,830	333	2,040	7.992
LLH (MWh)	2,777	4,381	4,264	4,025	2,419	2,177	2,250	3,165	2,280	1,444	262	1,632	8.076
Peak (MW)													N/A
						Fiscal Year 2028							
Total (MWh)	6,622	9,373	9,672	8,705	5,846	5,201	5,328	6,845	5,400	3,274	595	3,672	8.030
HLH (MWh)	3,702	5,200	5,408	4,680	3,360	3,024	2,960	3,827	3,120	1,760	346	2,040	8.001
LLH (MWh)	2,920	4,173	4,264	4,025	2,486	2,177	2,368	3,018	2,280	1,514	249	1,632	8.067
Peak (MW)													N/A
Notes: Fill in the table above with megawatt-hours rounded to whole megawatt-hours, with megawatts rounded to one decimal place, and annual Average Megawatts rounded to three decimal places.													

Table 3 Section 2.1(3)(C) – Trailbridge Specified Resource Amounts													
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	annual aMW
Fiscal Year 2012													
Total (MWh)	2,158	2,740	2,827	2,827	2,645	2,749	2,484	2,827	1,584	2,158	2,046	1,800	3.284
HLH (MWh)	1,206	1,520	1,581	1,520	1,520	1,598	1,380	1,581	915	1,160	1,188	960	3.284
LLH (MWh)	952	1,220	1,246	1,307	1,125	1,151	1,104	1,246	669	998	858	840	3.284
Peak (MW)													N/A
Fiscal Year 2013													
Total (MWh)	2,158	2,740	2,827	2,827	2,554	2,749	2,484	2,827	1,584	2,158	2,046	1,800	3.282
HLH (MWh)	1,253	1,520	1,520	1,581	1,459	1,539	1,435	1,581	880	1,206	1,188	960	3.282
LLH (MWh)	905	1,220	1,307	1,246	1,095	1,210	1,049	1,246	704	952	858	840	3.283
Peak (MW)													N/A
Fiscal Year 2014													
Total (MWh)	2,158	2,740	2,827	2,827	2,554	2,749	2,484	2,827	1,584	2,158	2,046	1,800	3.282
HLH (MWh)	1,253	1,520	1,520	1,581	1,459	1,539	1,435	1,581	880	1,206	1,144	1,000	3.281
LLH (MWh)	905	1,220	1,307	1,246	1,095	1,210	1,049	1,246	704	952	902	800	3.284
Peak (MW)													N/A
Fiscal Year 2015													
Total (MWh)	2,158	2,740	2,827	2,827	2,554	2,749	2,484	2,827	1,584	2,158	2,046	1,800	3.282
HLH (MWh)	1,253	1,459	1,581	1,581	1,459	1,539	1,435	1,520	915	1,206	1,144	1,000	3.276
LLH (MWh)	905	1,281	1,246	1,246	1,095	1,210	1,049	1,307	669	952	902	800	3.291
Peak (MW)													N/A
Fiscal Year 2016													
Total (MWh)	2,158	2,740	2,827	2,827	2,645	2,749	2,484	2,827	1,584	2,158	2,046	1,800	3.284
HLH (MWh)	1,253	1,459	1,581	1,520	1,520	1,598	1,435	1,520	915	1,160	1,188	1,000	3.277
LLH (MWh)	905	1,281	1,246	1,307	1,125	1,151	1,049	1,307	669	998	858	800	3.293
Peak (MW)													N/A
Fiscal Year 2017													
Total (MWh)	2,158	2,740	2,827	2,827	2,554	2,749	2,484	2,827	1,584	2,158	2,046	1,800	3.282
HLH (MWh)	1,206	1,520	1,581	1,520	1,459	1,598	1,380	1,581	915	1,160	1,188	1,000	3.279
LLH (MWh)	952	1,220	1,246	1,307	1,095	1,151	1,104	1,246	669	998	858	800	3.286
Peak (MW)													N/A
Fiscal Year 2018													
Total (MWh)	2,158	2,740	2,827	2,827	2,554	2,749	2,484	2,827	1,584	2,158	2,046	1,800	3.282
HLH (MWh)	1,206	1,520	1,520	1,581	1,459	1,598	1,380	1,581	915	1,160	1,188	960	3.282
LLH (MWh)	952	1,220	1,307	1,246	1,095	1,151	1,104	1,246	669	998	858	840	3.283
Peak (MW)													N/A
Fiscal Year 2019													
Total (MWh)	2,158	2,740	2,827	2,827	2,554	2,749	2,484	2,827	1,584	2,158	2,046	1,800	3.282
HLH (MWh)	1,253	1,520	1,520	1,581	1,459	1,539	1,435	1,581	880	1,206	1,188	960	3.282
LLH (MWh)	905	1,220	1,307	1,246	1,095	1,210	1,049	1,246	704	952	858	840	3.283
Peak (MW)													N/A
Fiscal Year 2020													
Total (MWh)	2,158	2,740	2,827	2,827	2,645	2,749	2,484	2,827	1,584	2,158	2,046	1,800	3.284
HLH (MWh)	1,253	1,520	1,520	1,581	1,520	1,539	1,435	1,520	915	1,206	1,144	1,000	3.278
LLH (MWh)	905	1,220	1,307	1,246	1,125	1,210	1,049	1,307	669	952	902	800	3.291
Peak (MW)													N/A

Table 3
Section 2.1(3)(C) – Trailbridge Specified Resource Amounts

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	annual aMW
Fiscal Year 2021													
Total (MWh)	2,158	2,740	2,827	2,827	2,554	2,749	2,484	2,827	1,584	2,158	2,046	1,800	3.282
HLH (MWh)	1,253	1,459	1,581	1,520	1,459	1,598	1,435	1,520	915	1,206	1,144	1,000	3.276
LLH (MWh)	905	1,281	1,246	1,307	1,095	1,151	1,049	1,307	669	952	902	800	3.291
Peak (MW)													N/A
Fiscal Year 2022													
Total (MWh)	2,158	2,740	2,827	2,827	2,554	2,749	2,484	2,827	1,584	2,158	2,046	1,800	3.282
HLH (MWh)	1,206	1,520	1,581	1,520	1,459	1,598	1,435	1,520	915	1,160	1,188	1,000	3.278
LLH (MWh)	952	1,220	1,246	1,307	1,095	1,151	1,049	1,307	669	998	858	800	3.288
Peak (MW)													N/A
Fiscal Year 2023													
Total (MWh)	2,158	2,740	2,827	2,827	2,554	2,749	2,484	2,827	1,584	2,158	2,046	1,800	3.282
HLH (MWh)	1,206	1,520	1,581	1,520	1,459	1,598	1,380	1,581	915	1,160	1,188	1,000	3.279
LLH (MWh)	952	1,220	1,246	1,307	1,095	1,151	1,104	1,246	669	998	858	800	3.286
Peak (MW)													N/A
Fiscal Year 2024													
Total (MWh)	2,158	2,740	2,827	2,827	2,645	2,749	2,484	2,827	1,584	2,158	2,046	1,800	3.284
HLH (MWh)	1,206	1,520	1,520	1,581	1,520	1,539	1,435	1,581	880	1,206	1,188	960	3.285
LLH (MWh)	952	1,220	1,307	1,246	1,125	1,210	1,049	1,246	704	952	858	840	3.282
Peak (MW)													N/A
Fiscal Year 2025													
Total (MWh)	2,158	2,740	2,827	2,827	2,554	2,749	2,484	2,827	1,584	2,158	2,046	1,800	3.282
HLH (MWh)	1,253	1,520	1,520	1,581	1,459	1,539	1,435	1,581	880	1,206	1,144	1,000	3.281
LLH (MWh)	905	1,220	1,307	1,246	1,095	1,210	1,049	1,246	704	952	902	800	3.284
Peak (MW)													N/A
Fiscal Year 2026													
Total (MWh)	2,158	2,740	2,827	2,827	2,554	2,749	2,484	2,827	1,584	2,158	2,046	1,800	3.282
HLH (MWh)	1,253	1,459	1,581	1,581	1,459	1,539	1,435	1,520	915	1,206	1,144	1,000	3.276
LLH (MWh)	905	1,281	1,246	1,246	1,095	1,210	1,049	1,307	669	952	902	800	3.291
Peak (MW)													N/A
Fiscal Year 2027													
Total (MWh)	2,158	2,740	2,827	2,827	2,554	2,749	2,484	2,827	1,584	2,158	2,046	1,800	3.282
HLH (MWh)	1,253	1,459	1,581	1,520	1,459	1,598	1,435	1,520	915	1,206	1,144	1,000	3.276
LLH (MWh)	905	1,281	1,246	1,307	1,095	1,151	1,049	1,307	669	952	902	800	3.291
Peak (MW)													N/A
Fiscal Year 2028													
Total (MWh)	2,158	2,740	2,827	2,827	2,645	2,749	2,484	2,827	1,584	2,158	2,046	1,800	3.284
HLH (MWh)	1,206	1,520	1,581	1,520	1,520	1,598	1,380	1,581	915	1,160	1,188	1,000	3.281
LLH (MWh)	952	1,220	1,246	1,307	1,125	1,151	1,104	1,246	669	998	858	800	3.287
Peak (MW)													N/A

Notes: Fill in the table above with megawatt-hours rounded to whole megawatt-hours, with megawatts rounded to one decimal place, and annual Average Megawatts rounded to three decimal places.

Table 4
Section 2.1(4)(C) – Walterville Specified Resource Amounts

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	annual aMW
Fiscal Year 2012													
Total (MWh)	4,687	6,850	7,068	7,068	4,385	2,823	2,952	4,613	2,448	2,455	1,190	2,592	5.593
HLH (MWh)	2,621	3,800	3,952	3,800	2,520	1,642	1,640	2,579	1,414	1,320	691	1,382	5.570
LLH (MWh)	2,066	3,050	3,116	3,268	1,865	1,181	1,312	2,034	1,034	1,135	499	1,210	5.622
Peak (MW)													N/A
Fiscal Year 2013													
Total (MWh)	4,687	6,850	7,068	7,068	4,234	2,823	2,952	4,613	2,448	2,455	1,190	2,592	5.591
HLH (MWh)	2,722	3,800	3,800	3,952	2,419	1,581	1,706	2,579	1,360	1,373	691	1,382	5.571
LLH (MWh)	1,965	3,050	3,268	3,116	1,815	1,242	1,246	2,034	1,088	1,082	499	1,210	5.617
Peak (MW)													N/A
Fiscal Year 2014													
Total (MWh)	4,687	6,850	7,068	7,068	4,234	2,823	2,952	4,613	2,448	2,455	1,190	2,592	5.591
HLH (MWh)	2,722	3,800	3,800	3,952	2,419	1,581	1,706	2,579	1,360	1,373	666	1,440	5.578
LLH (MWh)	1,965	3,050	3,268	3,116	1,815	1,242	1,246	2,034	1,088	1,082	524	1,152	5.609
Peak (MW)													N/A
Fiscal Year 2015													
Total (MWh)	4,687	6,850	7,068	7,068	4,234	2,823	2,952	4,613	2,448	2,455	1,190	2,592	5.591
HLH (MWh)	2,722	3,648	3,952	3,952	2,419	1,581	1,706	2,480	1,414	1,373	666	1,440	5.569
LLH (MWh)	1,965	3,202	3,116	3,116	1,815	1,242	1,246	2,133	1,034	1,082	524	1,152	5.620
Peak (MW)													N/A
Fiscal Year 2016													
Total (MWh)	4,687	6,850	7,068	7,068	4,385	2,823	2,952	4,613	2,448	2,455	1,190	2,592	5.593
HLH (MWh)	2,722	3,648	3,952	3,800	2,520	1,642	1,706	2,480	1,414	1,320	691	1,440	5.547
LLH (MWh)	1,965	3,202	3,116	3,268	1,865	1,181	1,246	2,133	1,034	1,135	499	1,152	5.652
Peak (MW)													N/A
Fiscal Year 2017													
Total (MWh)	4,687	6,850	7,068	7,068	4,234	2,823	2,952	4,613	2,448	2,455	1,190	2,592	5.591
HLH (MWh)	2,621	3,800	3,952	3,800	2,419	1,642	1,640	2,579	1,414	1,320	691	1,440	5.561
LLH (MWh)	2,066	3,050	3,116	3,268	1,815	1,181	1,312	2,034	1,034	1,135	499	1,152	5.629
Peak (MW)													N/A
Fiscal Year 2018													
Total (MWh)	4,687	6,850	7,068	7,068	4,234	2,823	2,952	4,613	2,448	2,455	1,190	2,592	5.591
HLH (MWh)	2,621	3,800	3,800	3,952	2,419	1,642	1,640	2,579	1,414	1,320	691	1,382	5.568
LLH (MWh)	2,066	3,050	3,268	3,116	1,815	1,181	1,312	2,034	1,034	1,135	499	1,210	5.621
Peak (MW)													N/A
Fiscal Year 2019													
Total (MWh)	4,687	6,850	7,068	7,068	4,234	2,823	2,952	4,613	2,448	2,455	1,190	2,592	5.591
HLH (MWh)	2,722	3,800	3,800	3,952	2,419	1,581	1,706	2,579	1,360	1,373	691	1,382	5.571
LLH (MWh)	1,965	3,050	3,268	3,116	1,815	1,242	1,246	2,034	1,088	1,082	499	1,210	5.617
Peak (MW)													N/A
Fiscal Year 2020													
Total (MWh)	4,687	6,850	7,068	7,068	4,385	2,823	2,952	4,613	2,448	2,455	1,190	2,592	5.593
HLH (MWh)	2,722	3,800	3,800	3,952	2,520	1,581	1,706	2,480	1,414	1,373	666	1,440	5.571
LLH (MWh)	1,965	3,050	3,268	3,116	1,865	1,242	1,246	2,133	1,034	1,082	524	1,152	5.622
Peak (MW)													N/A

Table 4
Section 2.1(4)(C) – Walterville Specified Resource Amounts

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	annual aMW
Fiscal Year 2021													
Total (MWh)	4,687	6,850	7,068	7,068	4,234	2,823	2,952	4,613	2,448	2,455	1,190	2,592	5.591
HLH (MWh)	2,722	3,648	3,952	3,800	2,419	1,642	1,706	2,480	1,414	1,373	666	1,440	5.550
LLH (MWh)	1,965	3,202	3,116	3,268	1,815	1,181	1,246	2,133	1,034	1,082	524	1,152	5.644
Peak (MW)													N/A
Fiscal Year 2022													
Total (MWh)	4,687	6,850	7,068	7,068	4,234	2,823	2,952	4,613	2,448	2,455	1,190	2,592	5.591
HLH (MWh)	2,621	3,800	3,952	3,800	2,419	1,642	1,706	2,480	1,414	1,320	691	1,440	5.555
LLH (MWh)	2,066	3,050	3,116	3,268	1,815	1,181	1,246	2,133	1,034	1,135	499	1,152	5.638
Peak (MW)													N/A
Fiscal Year 2023													
Total (MWh)	4,687	6,850	7,068	7,068	4,234	2,823	2,952	4,613	2,448	2,455	1,190	2,592	5.591
HLH (MWh)	2,621	3,800	3,952	3,800	2,419	1,642	1,640	2,579	1,414	1,320	691	1,440	5.561
LLH (MWh)	2,066	3,050	3,116	3,268	1,815	1,181	1,312	2,034	1,034	1,135	499	1,152	5.629
Peak (MW)													N/A
Fiscal Year 2024													
Total (MWh)	4,687	6,850	7,068	7,068	4,385	2,823	2,952	4,613	2,448	2,455	1,190	2,592	5.593
HLH (MWh)	2,621	3,800	3,800	3,952	2,520	1,581	1,706	2,579	1,360	1,373	691	1,382	5.571
LLH (MWh)	2,066	3,050	3,268	3,116	1,865	1,242	1,246	2,034	1,088	1,082	499	1,210	5.621
Peak (MW)													N/A
Fiscal Year 2025													
Total (MWh)	4,687	6,850	7,068	7,068	4,234	2,823	2,952	4,613	2,448	2,455	1,190	2,592	5.591
HLH (MWh)	2,722	3,800	3,800	3,952	2,419	1,581	1,706	2,579	1,360	1,373	666	1,440	5.578
LLH (MWh)	1,965	3,050	3,268	3,116	1,815	1,242	1,246	2,034	1,088	1,082	524	1,152	5.609
Peak (MW)													N/A
Fiscal Year 2026													
Total (MWh)	4,687	6,850	7,068	7,068	4,234	2,823	2,952	4,613	2,448	2,455	1,190	2,592	5.591
HLH (MWh)	2,722	3,648	3,952	3,952	2,419	1,581	1,706	2,480	1,414	1,373	666	1,440	5.569
LLH (MWh)	1,965	3,202	3,116	3,116	1,815	1,242	1,246	2,133	1,034	1,082	524	1,152	5.620
Peak (MW)													N/A
Fiscal Year 2027													
Total (MWh)	4,687	6,850	7,068	7,068	4,234	2,823	2,952	4,613	2,448	2,455	1,190	2,592	5.591
HLH (MWh)	2,722	3,648	3,952	3,800	2,419	1,642	1,706	2,480	1,414	1,373	666	1,440	5.550
LLH (MWh)	1,965	3,202	3,116	3,268	1,815	1,181	1,246	2,133	1,034	1,082	524	1,152	5.644
Peak (MW)													N/A
Fiscal Year 2028													
Total (MWh)	4,687	6,850	7,068	7,068	4,385	2,823	2,952	4,613	2,448	2,455	1,190	2,592	5.593
HLH (MWh)	2,621	3,800	3,952	3,800	2,520	1,642	1,640	2,579	1,414	1,320	691	1,440	5.564
LLH (MWh)	2,066	3,050	3,116	3,268	1,865	1,181	1,312	2,034	1,034	1,135	499	1,152	5.631
Peak (MW)													N/A

Notes: Fill in the table above with megawatt-hours rounded to whole megawatt-hours, with megawatts rounded to one decimal place, and annual Average Megawatts rounded to three decimal places.

Table 5 Section 2.1(5)(C) – Smith Creek Specified Resource Amounts													
	Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**annual aMW**
Fiscal Year 2012													
Total (MWh)	1,270	868	355	26	475	690	8,148	26,542	19,930	2,862	0	38	6.968
HLH (MWh)	710	482	198	14	273	401	4,527	14,841	11,515	1,539	0	20	7.028
LLH (MWh)	560	386	157	12	202	289	3,621	11,701	8,415	1,323	0	18	6.892
Peak (MW)													N/A
Fiscal Year 2013													
Total (MWh)	1,270	868	355	26	459	690	8,148	26,542	19,930	2,862	0	38	6.985
HLH (MWh)	737	482	191	15	262	386	4,708	14,841	11,072	1,600	0	20	6.986
LLH (MWh)	533	386	164	11	197	304	3,440	11,701	8,858	1,262	0	18	6.984
Peak (MW)													N/A
Fiscal Year 2014													
Total (MWh)	1,270	868	355	26	459	690	8,148	26,542	19,930	2,862	0	38	6.985
HLH (MWh)	737	482	191	15	262	386	4,708	14,841	11,072	1,600	0	21	6.986
LLH (MWh)	533	386	164	11	197	304	3,440	11,701	8,858	1,262	0	17	6.984
Peak (MW)													N/A
Fiscal Year 2015													
Total (MWh)	1,270	868	355	26	459	690	8,148	26,542	19,930	2,862	0	38	6.985
HLH (MWh)	737	462	198	15	262	386	4,708	14,270	11,515	1,600	0	21	6.957
LLH (MWh)	533	406	157	11	197	304	3,440	12,272	8,415	1,262	0	17	7.020
Peak (MW)													N/A
Fiscal Year 2016													
Total (MWh)	1,270	868	355	26	475	690	8,148	26,542	19,930	2,862	0	38	6.968
HLH (MWh)	737	462	198	14	273	401	4,708	14,270	11,515	1,539	0	21	6.927
LLH (MWh)	533	406	157	12	202	289	3,440	12,272	8,415	1,323	0	17	7.019
Peak (MW)													N/A
Fiscal Year 2017													
Total (MWh)	1,270	868	355	26	459	690	8,148	26,542	19,930	2,862	0	38	6.985
HLH (MWh)	710	482	198	14	262	401	4,527	14,841	11,515	1,539	0	21	7.026
LLH (MWh)	560	386	157	12	197	289	3,621	11,701	8,415	1,323	0	17	6.933
Peak (MW)													N/A
Fiscal Year 2018													
Total (MWh)	1,270	868	355	26	459	690	8,148	26,542	19,930	2,862	0	38	6.985
HLH (MWh)	710	482	191	15	262	401	4,527	14,841	11,515	1,539	0	20	7.047
LLH (MWh)	560	386	164	11	197	289	3,621	11,701	8,415	1,323	0	18	6.906
Peak (MW)													N/A
Fiscal Year 2019													
Total (MWh)	1,270	868	355	26	459	690	8,148	26,542	19,930	2,862	0	38	6.985
HLH (MWh)	737	482	191	15	262	386	4,708	14,841	11,072	1,600	0	20	6.986
LLH (MWh)	533	386	164	11	197	304	3,440	11,701	8,858	1,262	0	18	6.984
Peak (MW)													N/A
Fiscal Year 2020													
Total (MWh)	1,270	868	355	26	475	690	8,148	26,542	19,930	2,862	0	38	6.968
HLH (MWh)	737	482	191	15	273	386	4,708	14,270	11,515	1,600	0	21	6.940
LLH (MWh)	533	386	164	11	202	304	3,440	12,272	8,415	1,262	0	17	7.004
Peak (MW)													N/A

Table 5 Section 2.1(5)(C) – Smith Creek Specified Resource Amounts													
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	annual aMW
Fiscal Year 2021													
Total (MWh)	1,270	868	355	26	459	690	8,148	26,542	19,930	2,862	0	38	6.985
HLH (MWh)	737	462	198	14	262	401	4,708	14,270	11,515	1,600	0	21	6.960
LLH (MWh)	533	406	157	12	197	289	3,440	12,272	8,415	1,262	0	17	7.017
Peak (MW)													N/A
Fiscal Year 2022													
Total (MWh)	1,270	868	355	26	459	690	8,148	26,542	19,930	2,862	0	38	6.985
HLH (MWh)	710	482	198	14	262	401	4,708	14,270	11,515	1,539	0	21	6.946
LLH (MWh)	560	386	157	12	197	289	3,440	12,272	8,415	1,323	0	17	7.034
Peak (MW)													N/A
Fiscal Year 2023													
Total (MWh)	1,270	868	355	26	459	690	8,148	26,542	19,930	2,862	0	38	6.985
HLH (MWh)	710	482	198	14	262	401	4,527	14,841	11,515	1,539	0	21	7.026
LLH (MWh)	560	386	157	12	197	289	3,621	11,701	8,415	1,323	0	17	6.933
Peak (MW)													N/A
Fiscal Year 2024													
Total (MWh)	1,270	868	355	26	475	690	8,148	26,542	19,930	2,862	0	38	6.968
HLH (MWh)	710	482	191	15	273	386	4,708	14,841	11,072	1,600	0	20	6.982
LLH (MWh)	560	386	164	11	202	304	3,440	11,701	8,858	1,262	0	18	6.949
Peak (MW)													N/A
Fiscal Year 2025													
Total (MWh)	1,270	868	355	26	459	690	8,148	26,542	19,930	2,862	0	38	6.985
HLH (MWh)	737	482	191	15	262	386	4,708	14,841	11,072	1,600	0	21	6.986
LLH (MWh)	533	386	164	11	197	304	3,440	11,701	8,858	1,262	0	17	6.984
Peak (MW)													N/A
Fiscal Year 2026													
Total (MWh)	1,270	868	355	26	459	690	8,148	26,542	19,930	2,862	0	38	6.985
HLH (MWh)	737	462	198	15	262	386	4,708	14,270	11,515	1,600	0	21	6.957
LLH (MWh)	533	406	157	11	197	304	3,440	12,272	8,415	1,262	0	17	7.020
Peak (MW)													N/A
Fiscal Year 2027													
Total (MWh)	1,270	868	355	26	459	690	8,148	26,542	19,930	2,862	0	38	6.985
HLH (MWh)	737	462	198	14	262	401	4,708	14,270	11,515	1,600	0	21	6.960
LLH (MWh)	533	406	157	12	197	289	3,440	12,272	8,415	1,262	0	17	7.017
Peak (MW)													N/A
Fiscal Year 2028													
Total (MWh)	1,270	868	355	26	475	690	8,148	26,542	19,930	2,862	0	38	6.968
HLH (MWh)	710	482	198	14	273	401	4,527	14,841	11,515	1,539	0	21	7.005
LLH (MWh)	560	386	157	12	202	289	3,621	11,701	8,415	1,323	0	17	6.920
Peak (MW)													N/A
Notes: Fill in the table above with megawatt-hours rounded to whole megawatt-hours, with megawatts rounded to one decimal place, and annual Average Megawatts rounded to three decimal places.													

Table 6
Section 2.1(6)(C) – Priest Rapids Specified Resource Amounts

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	annual aMW
Fiscal Year 2012													
Total (MWh)	392	421	538	460	353	297	194	381	457	365	414	344	0.526
HLH (MWh)	219	234	301	247	203	173	108	213	264	196	240	184	0.526
LLH (MWh)	173	187	237	213	150	124	86	168	193	169	174	160	0.525
Peak (MW)													N/A
Fiscal Year 2013													
Total (MWh)	392	421	538	460	341	297	194	381	457	365	414	344	0.526
HLH (MWh)	228	234	289	257	195	166	112	213	254	204	240	184	0.524
LLH (MWh)	164	187	249	203	146	131	82	168	203	161	174	160	0.527
Peak (MW)													N/A
Fiscal Year 2014													
Total (MWh)	392	421	538	460	341	297	194	381	457	365	414	344	0.526
HLH (MWh)	228	234	289	257	195	166	112	213	254	204	232	191	0.524
LLH (MWh)	164	187	249	203	146	131	82	168	203	161	182	153	0.527
Peak (MW)													N/A
Fiscal Year 2015													
Total (MWh)	392	421	538	460	341	297	194	381	457	365	414	344	0.526
HLH (MWh)	228	224	301	257	195	166	112	205	264	204	232	191	0.525
LLH (MWh)	164	197	237	203	146	131	82	176	193	161	182	153	0.526
Peak (MW)													N/A
Fiscal Year 2016													
Total (MWh)	392	421	538	460	353	297	194	381	457	365	414	344	0.526
HLH (MWh)	228	224	301	247	203	173	112	205	264	196	240	191	0.524
LLH (MWh)	164	197	237	213	150	124	82	176	193	169	174	153	0.527
Peak (MW)													N/A
Fiscal Year 2017													
Total (MWh)	392	421	538	460	341	297	194	381	457	365	414	344	0.526
HLH (MWh)	219	234	301	247	195	173	108	213	264	196	240	191	0.525
LLH (MWh)	173	187	237	213	146	124	86	168	193	169	174	153	0.526
Peak (MW)													N/A
Fiscal Year 2018													
Total (MWh)	392	421	538	460	341	297	194	381	457	365	414	344	0.526
HLH (MWh)	219	234	289	257	195	173	108	213	264	196	240	184	0.525
LLH (MWh)	173	187	249	203	146	124	86	168	193	169	174	160	0.526
Peak (MW)													N/A
Fiscal Year 2019													
Total (MWh)	392	421	538	460	341	297	194	381	457	365	414	344	0.526
HLH (MWh)	228	234	289	257	195	166	112	213	254	204	240	184	0.524
LLH (MWh)	164	187	249	203	146	131	82	168	203	161	174	160	0.527
Peak (MW)													N/A
Fiscal Year 2020													
Total (MWh)	392	421	538	460	353	297	194	381	457	365	414	344	0.526
HLH (MWh)	228	234	289	257	203	166	112	205	264	204	232	191	0.525
LLH (MWh)	164	187	249	203	150	131	82	176	193	161	182	153	0.527
Peak (MW)													N/A

Table 6
Section 2.1(6)(C) – Priest Rapids Specified Resource Amounts

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	annual aMW
Fiscal Year 2021													
Total (MWh)	392	421	538	460	341	297	194	381	457	365	414	344	0.526
HLH (MWh)	228	224	301	247	195	173	112	205	264	204	232	191	0.524
LLH (MWh)	164	197	237	213	146	124	82	176	193	161	182	153	0.527
Peak (MW)													N/A
Fiscal Year 2022													
Total (MWh)	392	421	538	460	341	297	194	381	457	365	414	344	0.526
HLH (MWh)	219	234	301	247	195	173	112	205	264	196	240	191	0.525
LLH (MWh)	173	187	237	213	146	124	82	176	193	169	174	153	0.527
Peak (MW)													N/A
Fiscal Year 2023													
Total (MWh)	392	421	538	460	341	297	194	381	457	365	414	344	0.526
HLH (MWh)	219	234	301	247	195	173	108	213	264	196	240	191	0.525
LLH (MWh)	173	187	237	213	146	124	86	168	193	169	174	153	0.526
Peak (MW)													N/A
Fiscal Year 2024													
Total (MWh)	392	421	538	460	353	297	194	381	457	365	414	344	0.526
HLH (MWh)	219	234	289	257	203	166	112	213	254	204	240	184	0.524
LLH (MWh)	173	187	249	203	150	131	82	168	203	161	174	160	0.527
Peak (MW)													N/A
Fiscal Year 2025													
Total (MWh)	392	421	538	460	341	297	194	381	457	365	414	344	0.526
HLH (MWh)	228	234	289	257	195	166	112	213	254	204	232	191	0.524
LLH (MWh)	164	187	249	203	146	131	82	168	203	161	182	153	0.527
Peak (MW)													N/A
Fiscal Year 2026													
Total (MWh)	392	421	538	460	341	297	194	381	457	365	414	344	0.526
HLH (MWh)	228	224	301	257	195	166	112	205	264	204	232	191	0.525
LLH (MWh)	164	197	237	203	146	131	82	176	193	161	182	153	0.526
Peak (MW)													N/A
Fiscal Year 2027													
Total (MWh)	392	421	538	460	341	297	194	381	457	365	414	344	0.526
HLH (MWh)	228	224	301	247	195	173	112	205	264	204	232	191	0.524
LLH (MWh)	164	197	237	213	146	124	82	176	193	161	182	153	0.527
Peak (MW)													N/A
Fiscal Year 2028													
Total (MWh)	392	421	538	460	353	297	194	381	457	365	414	344	0.526
HLH (MWh)	219	234	301	247	203	173	108	213	264	196	240	191	0.525
LLH (MWh)	173	187	237	213	150	124	86	168	193	169	174	153	0.526
Peak (MW)													N/A

Notes: Fill in the table above with megawatt-hours rounded to whole megawatt-hours, with megawatts rounded to one decimal place, and annual Average Megawatts rounded to three decimal places.

Table 7 Section 2.1(7)(C) – CEAEA for Priest Rapids Specified Resource Amounts													
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	annual aMW
Fiscal Year 2012													
Total (MWh)	-31	-31	-32	-31	-30	-33	-29	-31	-30	-30	-31	-29	-0.042
HLH (MWh)	-31	-30	-31	-30	-30	-33	-29	-30	-30	-29	-31	-28	-0.074
LLH (MWh)	0	-1	-1	-1	0	0	0	-1	0	-1	0	-1	-0.002
Peak (MW)													N/A
Fiscal Year 2013													
Total (MWh)	-31	-30	-30	-31	-28	-30	-29	-31	-30	-30	-31	-29	-0.041
HLH (MWh)	-31	-29	-29	-30	-28	-30	-29	-30	-30	-29	-31	-28	-0.072
LLH (MWh)	0	-1	-1	-1	0	0	0	-1	0	-1	0	-1	-0.002
Peak (MW)													N/A
Fiscal Year 2014													
Total (MWh)	-31	-30	-30	-31	-28	-30	-29	-31	-30	-30	-31	-29	-0.041
HLH (MWh)	-31	-29	-29	-30	-28	-30	-29	-30	-30	-29	-31	-28	-0.072
LLH (MWh)	0	-1	-1	-1	0	0	0	-1	0	-1	0	-1	-0.002
Peak (MW)													N/A
Fiscal Year 2015													
Total (MWh)	-31	-30	-30	-31	-28	-30	-29	-31	-30	-30	-31	-29	-0.041
HLH (MWh)	-31	-29	-29	-30	-28	-30	-29	-30	-30	-29	-31	-28	-0.072
LLH (MWh)	0	-1	-1	-1	0	0	0	-1	0	-1	0	-1	-0.002
Peak (MW)													N/A
Fiscal Year 2016													
Total (MWh)	-31	-31	-32	-31	-30	-33	-29	-31	-30	-30	-31	-29	-0.042
HLH (MWh)	-31	-30	-31	-30	-30	-33	-29	-30	-30	-29	-31	-28	-0.073
LLH (MWh)	0	-1	-1	-1	0	0	0	-1	0	-1	0	-1	-0.002
Peak (MW)													N/A
Fiscal Year 2017													
Total (MWh)	-31	-30	-30	-31	-28	-30	-29	-31	-30	-30	-31	-29	-0.041
HLH (MWh)	-31	-29	-29	-30	-28	-30	-29	-30	-30	-29	-31	-28	-0.072
LLH (MWh)	0	-1	-1	-1	0	0	0	-1	0	-1	0	-1	-0.002
Peak (MW)													N/A
Fiscal Year 2018													
Total (MWh)	-31	-30	-30	-31	-28	-30	-29	-31	-30	-30	-31	-29	-0.041
HLH (MWh)	-31	-29	-29	-30	-28	-30	-29	-30	-30	-29	-31	-28	-0.072
LLH (MWh)	0	-1	-1	-1	0	0	0	-1	0	-1	0	-1	-0.002
Peak (MW)													N/A
Fiscal Year 2019													
Total (MWh)	-31	-30	-30	-31	-28	-30	-29	-31	-30	-30	-31	-29	-0.041
HLH (MWh)	-31	-29	-29	-30	-28	-30	-29	-30	-30	-29	-31	-28	-0.072
LLH (MWh)	0	-1	-1	-1	0	0	0	-1	0	-1	0	-1	-0.002
Peak (MW)													N/A
Fiscal Year 2020													
Total (MWh)	-31	-31	-32	-31	-30	-33	-29	-31	-30	-30	-31	-29	-0.042
HLH (MWh)	-31	-30	-31	-30	-30	-33	-29	-30	-30	-29	-31	-28	-0.073
LLH (MWh)	0	-1	-1	-1	0	0	0	-1	0	-1	0	-1	-0.002
Peak (MW)													N/A

Table 7 Section 2.1(7)(C) – CEAEA for Priest Rapids Specified Resource Amounts													
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	annual aMW
Fiscal Year 2021													
Total (MWh)	-31	-30	-30	-31	-28	-30	-29	-31	-30	-30	-31	-29	-0.041
HLH (MWh)	-31	-29	-29	-30	-28	-30	-29	-30	-30	-29	-31	-28	-0.072
LLH (MWh)	0	-1	-1	-1	0	0	0	-1	0	-1	0	-1	-0.002
Peak (MW)													N/A
Fiscal Year 2022													
Total (MWh)	-31	-30	-30	-31	-28	-30	-29	-31	-30	-30	-31	-29	-0.041
HLH (MWh)	-31	-29	-29	-30	-28	-30	-29	-30	-30	-29	-31	-28	-0.072
LLH (MWh)	0	-1	-1	-1	0	0	0	-1	0	-1	0	-1	-0.002
Peak (MW)													N/A
Fiscal Year 2023													
Total (MWh)	-31	-30	-30	-31	-28	-30	-29	-31	-30	-30	-31	-29	-0.041
HLH (MWh)	-31	-29	-29	-30	-28	-30	-29	-30	-30	-29	-31	-28	-0.072
LLH (MWh)	0	-1	-1	-1	0	0	0	-1	0	-1	0	-1	-0.002
Peak (MW)													N/A
Fiscal Year 2024													
Total (MWh)	-31	-31	-32	-31	-30	-33	-29	-31	-30	-30	-31	-29	-0.042
HLH (MWh)	-31	-30	-31	-30	-30	-33	-29	-30	-30	-29	-31	-28	-0.074
LLH (MWh)	0	-1	-1	-1	0	0	0	-1	0	-1	0	-1	-0.002
Peak (MW)													N/A
Fiscal Year 2025													
Total (MWh)	-31	-30	-30	-31	-28	-30	-29	-31	-30	-30	-31	-29	-0.041
HLH (MWh)	-31	-29	-29	-30	-28	-30	-29	-30	-30	-29	-31	-28	-0.072
LLH (MWh)	0	-1	-1	-1	0	0	0	-1	0	-1	0	-1	-0.002
Peak (MW)													N/A
Fiscal Year 2026													
Total (MWh)	-31	-30	-30	-31	-28	-30	-29	-31	-30	-30	-31	-29	-0.041
HLH (MWh)	-31	-29	-29	-30	-28	-30	-29	-30	-30	-29	-31	-28	-0.072
LLH (MWh)	0	-1	-1	-1	0	0	0	-1	0	-1	0	-1	-0.002
Peak (MW)													N/A
Fiscal Year 2027													
Total (MWh)	-31	-30	-30	-31	-28	-30	-29	-31	-30	-30	-31	-29	-0.041
HLH (MWh)	-31	-29	-29	-30	-28	-30	-29	-30	-30	-29	-31	-28	-0.072
LLH (MWh)	0	-1	-1	-1	0	0	0	-1	0	-1	0	-1	-0.002
Peak (MW)													N/A
Fiscal Year 2028													
Total (MWh)	-31	-31	-32	-31	-30	-33	-29	-31	-30	-30	-31	-29	-0.042
HLH (MWh)	-31	-30	-31	-30	-30	-33	-29	-30	-30	-29	-31	-28	-0.073
LLH (MWh)	0	-1	-1	-1	0	0	0	-1	0	-1	0	-1	-0.002
Peak (MW)													N/A
Notes: Fill in the table above with megawatt-hours rounded to whole megawatt-hours, with megawatts rounded to one decimal place, and annual Average Megawatts rounded to three decimal places.													

Table 8
Section 2.1(8)(C) – Wanapum Specified Resource Amounts

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	annual aMW
Fiscal Year 2012													
Total (MWh)	356	390	514	429	324	275	199	369	537	486	497	309	0.533
HLH (MWh)	199	216	287	230	186	160	111	206	310	261	289	165	0.533
LLH (MWh)	157	174	227	199	138	115	88	163	227	225	208	144	0.533
Peak (MW)													N/A
Fiscal Year 2013													
Total (MWh)	356	390	514	429	312	275	199	369	537	486	497	309	0.533
HLH (MWh)	207	216	276	240	179	154	115	206	298	272	289	165	0.533
LLH (MWh)	149	174	238	189	133	121	84	163	239	214	208	144	0.534
Peak (MW)													N/A
Fiscal Year 2014													
Total (MWh)	356	390	514	429	312	275	199	369	537	486	497	309	0.533
HLH (MWh)	207	216	276	240	179	154	115	206	298	272	278	172	0.532
LLH (MWh)	149	174	238	189	133	121	84	163	239	214	219	137	0.535
Peak (MW)													N/A
Fiscal Year 2015													
Total (MWh)	356	390	514	429	312	275	199	369	537	486	497	309	0.533
HLH (MWh)	207	208	287	240	179	154	115	198	310	272	278	172	0.533
LLH (MWh)	149	182	227	189	133	121	84	171	227	214	219	137	0.534
Peak (MW)													N/A
Fiscal Year 2016													
Total (MWh)	356	390	514	429	324	275	199	369	537	486	497	309	0.533
HLH (MWh)	207	208	287	230	186	160	115	198	310	261	289	172	0.532
LLH (MWh)	149	182	227	199	138	115	84	171	227	225	208	137	0.535
Peak (MW)													N/A
Fiscal Year 2017													
Total (MWh)	356	390	514	429	312	275	199	369	537	486	497	309	0.533
HLH (MWh)	199	216	287	230	179	160	111	206	310	261	289	172	0.533
LLH (MWh)	157	174	227	199	133	115	88	163	227	225	208	137	0.534
Peak (MW)													N/A
Fiscal Year 2018													
Total (MWh)	356	390	514	429	312	275	199	369	537	486	497	309	0.533
HLH (MWh)	199	216	276	240	179	160	111	206	310	261	289	165	0.533
LLH (MWh)	157	174	238	189	133	115	88	163	227	225	208	144	0.533
Peak (MW)													N/A
Fiscal Year 2019													
Total (MWh)	356	390	514	429	312	275	199	369	537	486	497	309	0.533
HLH (MWh)	207	216	276	240	179	154	115	206	298	272	289	165	0.533
LLH (MWh)	149	174	238	189	133	121	84	163	239	214	208	144	0.534
Peak (MW)													N/A
Fiscal Year 2020													
Total (MWh)	356	390	514	429	324	275	199	369	537	486	497	309	0.533
HLH (MWh)	207	216	276	240	186	154	115	198	310	272	278	172	0.532
LLH (MWh)	149	174	238	189	138	121	84	171	227	214	219	137	0.534
Peak (MW)													N/A

Table 8 Section 2.1(8)(C) – Wanapum Specified Resource Amounts													
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	annual aMW
Fiscal Year 2021													
Total (MWh)	356	390	514	429	312	275	199	369	537	486	497	309	0.533
HLH (MWh)	207	208	287	230	179	160	115	198	310	272	278	172	0.533
LLH (MWh)	149	182	227	199	133	115	84	171	227	214	219	137	0.535
Peak (MW)													N/A
Fiscal Year 2022													
Total (MWh)	356	390	514	429	312	275	199	369	537	486	497	309	0.533
HLH (MWh)	199	216	287	230	179	160	115	198	310	261	289	172	0.533
LLH (MWh)	157	174	227	199	133	115	84	171	227	225	208	137	0.535
Peak (MW)													N/A
Fiscal Year 2023													
Total (MWh)	356	390	514	429	312	275	199	369	537	486	497	309	0.533
HLH (MWh)	199	216	287	230	179	160	111	206	310	261	289	172	0.533
LLH (MWh)	157	174	227	199	133	115	88	163	227	225	208	137	0.534
Peak (MW)													N/A
Fiscal Year 2024													
Total (MWh)	356	390	514	429	324	275	199	369	537	486	497	309	0.533
HLH (MWh)	199	216	276	240	186	154	115	206	298	272	289	165	0.533
LLH (MWh)	157	174	238	189	138	121	84	163	239	214	208	144	0.534
Peak (MW)													N/A
Fiscal Year 2025													
Total (MWh)	356	390	514	429	312	275	199	369	537	486	497	309	0.533
HLH (MWh)	207	216	276	240	179	154	115	206	298	272	278	172	0.532
LLH (MWh)	149	174	238	189	133	121	84	163	239	214	219	137	0.535
Peak (MW)													N/A
Fiscal Year 2026													
Total (MWh)	356	390	514	429	312	275	199	369	537	486	497	309	0.533
HLH (MWh)	207	208	287	240	179	154	115	198	310	272	278	172	0.533
LLH (MWh)	149	182	227	189	133	121	84	171	227	214	219	137	0.534
Peak (MW)													N/A
Fiscal Year 2027													
Total (MWh)	356	390	514	429	312	275	199	369	537	486	497	309	0.533
HLH (MWh)	207	208	287	230	179	160	115	198	310	272	278	172	0.533
LLH (MWh)	149	182	227	199	133	115	84	171	227	214	219	137	0.535
Peak (MW)													N/A
Fiscal Year 2028													
Total (MWh)	356	390	514	429	324	275	199	369	537	486	497	309	0.533
HLH (MWh)	199	216	287	230	186	160	111	206	310	261	289	172	0.533
LLH (MWh)	157	174	227	199	138	115	88	163	227	225	208	137	0.534
Peak (MW)													N/A

Notes: Fill in the table above with megawatt-hours rounded to whole megawatt-hours, with megawatts rounded to one decimal place, and annual Average Megawatts rounded to three decimal places.

Table 9
Section 2.1(9)(C) – CEAEA for Wanapum Specified Resource Amounts

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	annual aMW
Fiscal Year 2012													
Total (MWh)	-30	-30	-31	-30	-29	-31	-28	-30	-29	-29	-30	-28	-0.040
HLH (MWh)	-30	-29	-30	-29	-29	-31	-28	-29	-29	-28	-30	-27	-0.071
LLH (MWh)	0	-1	-1	-1	0	0	0	-1	0	-1	0	-1	-0.002
Peak (MW)													N/A
Fiscal Year 2013													
Total (MWh)	-30	-29	-29	-31	-27	-30	-28	-30	-29	-29	-30	-28	-0.040
HLH (MWh)	-30	-28	-28	-30	-27	-30	-28	-29	-29	-28	-30	-27	-0.070
LLH (MWh)	0	-1	-1	-1	0	0	0	-1	0	-1	0	-1	-0.002
Peak (MW)													N/A
Fiscal Year 2014													
Total (MWh)	-30	-29	-29	-31	-27	-30	-28	-30	-29	-29	-30	-28	-0.040
HLH (MWh)	-30	-28	-28	-30	-27	-30	-28	-29	-29	-28	-30	-27	-0.070
LLH (MWh)	0	-1	-1	-1	0	0	0	-1	0	-1	0	-1	-0.002
Peak (MW)													N/A
Fiscal Year 2015													
Total (MWh)	-30	-29	-29	-31	-27	-30	-28	-30	-29	-29	-30	-28	-0.040
HLH (MWh)	-30	-28	-28	-30	-27	-30	-28	-29	-29	-28	-30	-27	-0.070
LLH (MWh)	0	-1	-1	-1	0	0	0	-1	0	-1	0	-1	-0.002
Peak (MW)													N/A
Fiscal Year 2016													
Total (MWh)	-30	-30	-31	-30	-29	-31	-28	-30	-29	-29	-30	-28	-0.040
HLH (MWh)	-30	-29	-30	-29	-29	-31	-28	-29	-29	-28	-30	-27	-0.071
LLH (MWh)	0	-1	-1	-1	0	0	0	-1	0	-1	0	-1	-0.002
Peak (MW)													N/A
Fiscal Year 2017													
Total (MWh)	-30	-29	-29	-31	-27	-30	-28	-30	-29	-29	-30	-28	-0.040
HLH (MWh)	-30	-28	-28	-30	-27	-30	-28	-29	-29	-28	-30	-27	-0.070
LLH (MWh)	0	-1	-1	-1	0	0	0	-1	0	-1	0	-1	-0.002
Peak (MW)													N/A
Fiscal Year 2018													
Total (MWh)	-30	-29	-29	-31	-27	-30	-28	-30	-29	-29	-30	-28	-0.040
HLH (MWh)	-30	-28	-28	-30	-27	-30	-28	-29	-29	-28	-30	-27	-0.070
LLH (MWh)	0	-1	-1	-1	0	0	0	-1	0	-1	0	-1	-0.002
Peak (MW)													N/A
Fiscal Year 2019													
Total (MWh)	-30	-29	-29	-31	-27	-30	-28	-30	-29	-29	-30	-28	-0.040
HLH (MWh)	-30	-28	-28	-30	-27	-30	-28	-29	-29	-28	-30	-27	-0.070
LLH (MWh)	0	-1	-1	-1	0	0	0	-1	0	-1	0	-1	-0.002
Peak (MW)													N/A
Fiscal Year 2020													
Total (MWh)	-30	-30	-31	-30	-29	-31	-28	-30	-29	-29	-30	-28	-0.040
HLH (MWh)	-30	-29	-30	-29	-29	-31	-28	-29	-29	-28	-30	-27	-0.071
LLH (MWh)	0	-1	-1	-1	0	0	0	-1	0	-1	0	-1	-0.002
Peak (MW)													N/A

Table 9 Section 2.1(9)(C) – CEAEA for Wanapum Specified Resource Amounts													
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	annual aMW
Fiscal Year 2021													
Total (MWh)	-30	-29	-29	-31	-27	-30	-28	-30	-29	-29	-30	-28	-0.040
HLH (MWh)	-30	-28	-28	-30	-27	-30	-28	-29	-29	-28	-30	-27	-0.070
LLH (MWh)	0	-1	-1	-1	0	0	0	-1	0	-1	0	-1	-0.002
Peak (MW)													N/A
Fiscal Year 2022													
Total (MWh)	-30	-29	-29	-31	-27	-30	-28	-30	-29	-29	-30	-28	-0.040
HLH (MWh)	-30	-28	-28	-30	-27	-30	-28	-29	-29	-28	-30	-27	-0.070
LLH (MWh)	0	-1	-1	-1	0	0	0	-1	0	-1	0	-1	-0.002
Peak (MW)													N/A
Fiscal Year 2023													
Total (MWh)	-30	-29	-29	-31	-27	-30	-28	-30	-29	-29	-30	-28	-0.040
HLH (MWh)	-30	-28	-28	-30	-27	-30	-28	-29	-29	-28	-30	-27	-0.070
LLH (MWh)	0	-1	-1	-1	0	0	0	-1	0	-1	0	-1	-0.002
Peak (MW)													N/A
Fiscal Year 2024													
Total (MWh)	-30	-30	-31	-30	-29	-31	-28	-30	-29	-29	-30	-28	-0.040
HLH (MWh)	-30	-29	-30	-29	-29	-31	-28	-29	-29	-28	-30	-27	-0.071
LLH (MWh)	0	-1	-1	-1	0	0	0	-1	0	-1	0	-1	-0.002
Peak (MW)													N/A
Fiscal Year 2025													
Total (MWh)	-30	-29	-29	-31	-27	-30	-28	-30	-29	-29	-30	-28	-0.040
HLH (MWh)	-30	-28	-28	-30	-27	-30	-28	-29	-29	-28	-30	-27	-0.070
LLH (MWh)	0	-1	-1	-1	0	0	0	-1	0	-1	0	-1	-0.002
Peak (MW)													N/A
Fiscal Year 2026													
Total (MWh)	-30	-29	-29	-31	-27	-30	-28	-30	-29	-29	-30	-28	-0.040
HLH (MWh)	-30	-28	-28	-30	-27	-30	-28	-29	-29	-28	-30	-27	-0.070
LLH (MWh)	0	-1	-1	-1	0	0	0	-1	0	-1	0	-1	-0.002
Peak (MW)													N/A
Fiscal Year 2027													
Total (MWh)	-30	-29	-29	-31	-27	-30	-28	-30	-29	-29	-30	-28	-0.040
HLH (MWh)	-30	-28	-28	-30	-27	-30	-28	-29	-29	-28	-30	-27	-0.070
LLH (MWh)	0	-1	-1	-1	0	0	0	-1	0	-1	0	-1	-0.002
Peak (MW)													N/A
Fiscal Year 2028													
Total (MWh)	-30	-30	-31	-30	-29	-31	-28	-30	-29	-29	-30	-28	-0.040
HLH (MWh)	-30	-29	-30	-29	-29	-31	-28	-29	-29	-28	-30	-27	-0.071
LLH (MWh)	0	-1	-1	-1	0	0	0	-1	0	-1	0	-1	-0.002
Peak (MW)													N/A
Notes: Fill in the table above with megawatt-hours rounded to whole megawatt-hours, with megawatts rounded to one decimal place, and annual Average Megawatts rounded to three decimal places.													

Table 10 Section 2.1(10)(C) – Foote Creek 1 Specified Resource Amounts													
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	annual aMW
Fiscal Year 2012													
Total (MWh)	1,372	1,545	2,631	2,580	1,634	1,828	1,581	1,249	1,074	1,036	792	1,101	2.097
HLH (MWh)	767	857	1,471	1,387	939	1,063	878	698	621	557	460	587	2.094
LLH (MWh)	605	688	1,160	1,193	695	765	703	551	453	479	332	514	2.102
Peak (MW)													N/A
Fiscal Year 2013													
Total (MWh)	1,372	1,545	2,631	2,580	1,577	1,828	1,581	1,249	1,074	1,036	792	1,101	2.097
HLH (MWh)	797	857	1,414	1,443	901	1,023	914	698	597	579	460	587	2.091
LLH (MWh)	575	688	1,217	1,137	676	805	667	551	477	457	332	514	2.104
Peak (MW)													N/A
Fiscal Year 2014													
Total (MWh)	1,372	1,545	2,631	2,580	1,577	1,828	1,581	1,249	1,074	1,036	792	1,101	2.097
HLH (MWh)	797	857	1,414	1,443	901	1,023	914	698	597	579	443	612	2.092
LLH (MWh)	575	688	1,217	1,137	676	805	667	551	477	457	349	489	2.102
Peak (MW)													N/A
Fiscal Year 2015													
Total (MWh)	1,372	1,545	2,631	2,580	1,577	1,828	1,581	1,249	1,074	1,036	792	1,101	2.097
HLH (MWh)	797	823	1,471	1,443	901	1,023	914	672	621	579	443	612	2.097
LLH (MWh)	575	722	1,160	1,137	676	805	667	577	453	457	349	489	2.096
Peak (MW)													N/A
Fiscal Year 2016													
Total (MWh)	1,372	1,545	2,631	2,580	1,634	1,828	1,581	1,249	1,074	1,036	792	1,101	2.097
HLH (MWh)	797	823	1,471	1,387	939	1,063	914	672	621	557	460	612	2.093
LLH (MWh)	575	722	1,160	1,193	695	765	667	577	453	479	332	489	2.102
Peak (MW)													N/A
Fiscal Year 2017													
Total (MWh)	1,372	1,545	2,631	2,580	1,577	1,828	1,581	1,249	1,074	1,036	792	1,101	2.097
HLH (MWh)	767	857	1,471	1,387	901	1,063	878	698	621	557	460	612	2.091
LLH (MWh)	605	688	1,160	1,193	676	765	703	551	453	479	332	489	2.103
Peak (MW)													N/A
Fiscal Year 2018													
Total (MWh)	1,372	1,545	2,631	2,580	1,577	1,828	1,581	1,249	1,074	1,036	792	1,101	2.097
HLH (MWh)	767	857	1,414	1,443	901	1,063	878	698	621	557	460	587	2.093
LLH (MWh)	605	688	1,217	1,137	676	765	703	551	453	479	332	514	2.101
Peak (MW)													N/A
Fiscal Year 2019													
Total (MWh)	1,372	1,545	2,631	2,580	1,577	1,828	1,581	1,249	1,074	1,036	792	1,101	2.097
HLH (MWh)	797	857	1,414	1,443	901	1,023	914	698	597	579	460	587	2.091
LLH (MWh)	575	688	1,217	1,137	676	805	667	551	477	457	332	514	2.104
Peak (MW)													N/A
Fiscal Year 2020													
Total (MWh)	1,372	1,545	2,631	2,580	1,634	1,828	1,581	1,249	1,074	1,036	792	1,101	2.097
HLH (MWh)	797	857	1,414	1,443	939	1,023	914	672	621	579	443	612	2.093
LLH (MWh)	575	688	1,217	1,137	695	805	667	577	453	457	349	489	2.103
Peak (MW)													N/A

Table 10 Section 2.1(10)(C) – Foote Creek 1 Specified Resource Amounts													
	Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**annual aMW**
Fiscal Year 2021													
Total (MWh)	1,372	1,545	2,631	2,580	1,577	1,828	1,581	1,249	1,074	1,036	792	1,101	2.097
HLH (MWh)	797	823	1,471	1,387	901	1,063	914	672	621	579	443	612	2.093
LLH (MWh)	575	722	1,160	1,193	676	765	667	577	453	457	349	489	2.101
Peak (MW)													N/A
Fiscal Year 2022													
Total (MWh)	1,372	1,545	2,631	2,580	1,577	1,828	1,581	1,249	1,074	1,036	792	1,101	2.097
HLH (MWh)	767	857	1,471	1,387	901	1,063	914	672	621	557	460	612	2.093
LLH (MWh)	605	688	1,160	1,193	676	765	667	577	453	479	332	489	2.101
Peak (MW)													N/A
Fiscal Year 2023													
Total (MWh)	1,372	1,545	2,631	2,580	1,577	1,828	1,581	1,249	1,074	1,036	792	1,101	2.097
HLH (MWh)	767	857	1,471	1,387	901	1,063	878	698	621	557	460	612	2.091
LLH (MWh)	605	688	1,160	1,193	676	765	703	551	453	479	332	489	2.103
Peak (MW)													N/A
Fiscal Year 2024													
Total (MWh)	1,372	1,545	2,631	2,580	1,634	1,828	1,581	1,249	1,074	1,036	792	1,101	2.097
HLH (MWh)	767	857	1,414	1,443	939	1,023	914	698	597	579	460	587	2.092
LLH (MWh)	605	688	1,217	1,137	695	805	667	551	477	457	332	514	2.104
Peak (MW)													N/A
Fiscal Year 2025													
Total (MWh)	1,372	1,545	2,631	2,580	1,577	1,828	1,581	1,249	1,074	1,036	792	1,101	2.097
HLH (MWh)	797	857	1,414	1,443	901	1,023	914	698	597	579	443	612	2.092
LLH (MWh)	575	688	1,217	1,137	676	805	667	551	477	457	349	489	2.102
Peak (MW)													N/A
Fiscal Year 2026													
Total (MWh)	1,372	1,545	2,631	2,580	1,577	1,828	1,581	1,249	1,074	1,036	792	1,101	2.097
HLH (MWh)	797	823	1,471	1,443	901	1,023	914	672	621	579	443	612	2.097
LLH (MWh)	575	722	1,160	1,137	676	805	667	577	453	457	349	489	2.096
Peak (MW)													N/A
Fiscal Year 2027													
Total (MWh)	1,372	1,545	2,631	2,580	1,577	1,828	1,581	1,249	1,074	1,036	792	1,101	2.097
HLH (MWh)	797	823	1,471	1,387	901	1,063	914	672	621	579	443	612	2.093
LLH (MWh)	575	722	1,160	1,193	676	765	667	577	453	457	349	489	2.101
Peak (MW)													N/A
Fiscal Year 2028													
Total (MWh)	1,372	1,545	2,631	2,580	1,634	1,828	1,581	1,249	1,074	1,036	792	1,101	2.097
HLH (MWh)	767	857	1,471	1,387	939	1,063	878	698	621	557	460	612	2.092
LLH (MWh)	605	688	1,160	1,193	695	765	703	551	453	479	332	489	2.104
Peak (MW)													N/A
Notes: Fill in the table above with megawatt-hours rounded to whole megawatt-hours, with megawatts rounded to one decimal place, and annual Average Megawatts rounded to three decimal places.													

Table 11
Section 4(1)(C) – Stone Creek Serving Hynix NLSL Specified Resource Amounts

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	annual aMW
Fiscal Year 2012													
Total (MWh)	1,265	1,730	3,422	6,994	3,410	4,235	3,636	2,083	1,296	2,232	2,827	6,264	4.485
HLH (MWh)	707	960	1,914	3,760	1,960	2,462	2,020	1,165	749	1,200	1,642	3,341	4.454
LLH (MWh)	558	770	1,508	3,234	1,450	1,773	1,616	918	547	1,032	1,185	2,923	4.523
Peak (MW)													N/A
Fiscal Year 2013													
Total (MWh)	1,265	1,730	3,422	6,994	3,293	4,235	3,636	2,083	1,296	2,232	2,827	6,264	4.484
HLH (MWh)	734	960	1,840	3,910	1,882	2,371	2,101	1,165	720	1,248	1,642	3,341	4.461
LLH (MWh)	531	770	1,582	3,084	1,411	1,864	1,535	918	576	984	1,185	2,923	4.512
Peak (MW)													N/A
Fiscal Year 2014													
Total (MWh)	1,265	1,730	3,422	6,994	3,293	4,235	3,636	2,083	1,296	2,232	2,827	6,264	4.484
HLH (MWh)	734	960	1,840	3,910	1,882	2,371	2,101	1,165	720	1,248	1,581	3,480	4.477
LLH (MWh)	531	770	1,582	3,084	1,411	1,864	1,535	918	576	984	1,246	2,784	4.492
Peak (MW)													N/A
Fiscal Year 2015													
Total (MWh)	1,265	1,730	3,422	6,994	3,293	4,235	3,636	2,083	1,296	2,232	2,827	6,264	4.484
HLH (MWh)	734	922	1,914	3,910	1,882	2,371	2,101	1,120	749	1,248	1,581	3,480	4.481
LLH (MWh)	531	808	1,508	3,084	1,411	1,864	1,535	963	547	984	1,246	2,784	4.487
Peak (MW)													N/A
Fiscal Year 2016													
Total (MWh)	1,265	1,730	3,422	6,994	3,410	4,235	3,636	2,083	1,296	2,232	2,827	6,264	4.485
HLH (MWh)	734	922	1,914	3,760	1,960	2,462	2,101	1,120	749	1,200	1,642	3,480	4.473
LLH (MWh)	531	808	1,508	3,234	1,450	1,773	1,535	963	547	1,032	1,185	2,784	4.499
Peak (MW)													N/A
Fiscal Year 2017													
Total (MWh)	1,265	1,730	3,422	6,994	3,293	4,235	3,636	2,083	1,296	2,232	2,827	6,264	4.484
HLH (MWh)	707	960	1,914	3,760	1,882	2,462	2,020	1,165	749	1,200	1,642	3,480	4.467
LLH (MWh)	558	770	1,508	3,234	1,411	1,773	1,616	918	547	1,032	1,185	2,784	4.505
Peak (MW)													N/A
Fiscal Year 2018													
Total (MWh)	1,265	1,730	3,422	6,994	3,293	4,235	3,636	2,083	1,296	2,232	2,827	6,264	4.484
HLH (MWh)	707	960	1,840	3,910	1,882	2,462	2,020	1,165	749	1,200	1,642	3,341	4.469
LLH (MWh)	558	770	1,582	3,084	1,411	1,773	1,616	918	547	1,032	1,185	2,923	4.503
Peak (MW)													N/A
Fiscal Year 2019													
Total (MWh)	1,265	1,730	3,422	6,994	3,293	4,235	3,636	2,083	1,296	2,232	2,827	6,264	4.484
HLH (MWh)	734	960	1,840	3,910	1,882	2,371	2,101	1,165	720	1,248	1,642	3,341	4.461
LLH (MWh)	531	770	1,582	3,084	1,411	1,864	1,535	918	576	984	1,185	2,923	4.512
Peak (MW)													N/A
Fiscal Year 2020													
Total (MWh)	1,265	1,730	3,422	6,994	3,410	4,235	3,636	2,083	1,296	2,232	2,827	6,264	4.485
HLH (MWh)	734	960	1,840	3,910	1,960	2,371	2,101	1,120	749	1,248	1,581	3,480	4.475
LLH (MWh)	531	770	1,582	3,084	1,450	1,864	1,535	963	547	984	1,246	2,784	4.497
Peak (MW)													N/A

Table 11 Section 4(1)(C) – Stone Creek Serving Hynix NLSL Specified Resource Amounts													
	Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**annual aMW**
Fiscal Year 2021													
Total (MWh)	1,265	1,730	3,422	6,994	3,293	4,235	3,636	2,083	1,296	2,232	2,827	6,264	4.484
HLH (MWh)	734	922	1,914	3,760	1,882	2,462	2,101	1,120	749	1,248	1,581	3,480	4.469
LLH (MWh)	531	808	1,508	3,234	1,411	1,773	1,535	963	547	984	1,246	2,784	4.502
Peak (MW)													N/A
Fiscal Year 2022													
Total (MWh)	1,265	1,730	3,422	6,994	3,293	4,235	3,636	2,083	1,296	2,232	2,827	6,264	4.484
HLH (MWh)	707	960	1,914	3,760	1,882	2,462	2,101	1,120	749	1,200	1,642	3,480	4.474
LLH (MWh)	558	770	1,508	3,234	1,411	1,773	1,535	963	547	1,032	1,185	2,784	4.496
Peak (MW)													N/A
Fiscal Year 2023													
Total (MWh)	1,265	1,730	3,422	6,994	3,293	4,235	3,636	2,083	1,296	2,232	2,827	6,264	4.484
HLH (MWh)	707	960	1,914	3,760	1,882	2,462	2,020	1,165	749	1,200	1,642	3,480	4.467
LLH (MWh)	558	770	1,508	3,234	1,411	1,773	1,616	918	547	1,032	1,185	2,784	4.505
Peak (MW)													N/A
Fiscal Year 2024													
Total (MWh)	1,265	1,730	3,422	6,994	3,410	4,235	3,636	2,083	1,296	2,232	2,827	6,264	4.485
HLH (MWh)	707	960	1,840	3,910	1,960	2,371	2,101	1,165	720	1,248	1,642	3,341	4.472
LLH (MWh)	558	770	1,582	3,084	1,450	1,864	1,535	918	576	984	1,185	2,923	4.501
Peak (MW)													N/A
Fiscal Year 2025													
Total (MWh)	1,265	1,730	3,422	6,994	3,293	4,235	3,636	2,083	1,296	2,232	2,827	6,264	4.484
HLH (MWh)	734	960	1,840	3,910	1,882	2,371	2,101	1,165	720	1,248	1,581	3,480	4.477
LLH (MWh)	531	770	1,582	3,084	1,411	1,864	1,535	918	576	984	1,246	2,784	4.492
Peak (MW)													N/A
Fiscal Year 2026													
Total (MWh)	1,265	1,730	3,422	6,994	3,293	4,235	3,636	2,083	1,296	2,232	2,827	6,264	4.484
HLH (MWh)	734	922	1,914	3,910	1,882	2,371	2,101	1,120	749	1,248	1,581	3,480	4.481
LLH (MWh)	531	808	1,508	3,084	1,411	1,864	1,535	963	547	984	1,246	2,784	4.487
Peak (MW)													N/A
Fiscal Year 2027													
Total (MWh)	1,265	1,730	3,422	6,994	3,293	4,235	3,636	2,083	1,296	2,232	2,827	6,264	4.484
HLH (MWh)	734	922	1,914	3,760	1,882	2,462	2,101	1,120	749	1,248	1,581	3,480	4.469
LLH (MWh)	531	808	1,508	3,234	1,411	1,773	1,535	963	547	984	1,246	2,784	4.502
Peak (MW)													N/A
Fiscal Year 2028													
Total (MWh)	1,265	1,730	3,422	6,994	3,410	4,235	3,636	2,083	1,296	2,232	2,827	6,264	4.485
HLH (MWh)	707	960	1,914	3,760	1,960	2,462	2,020	1,165	749	1,200	1,642	3,480	4.468
LLH (MWh)	558	770	1,508	3,234	1,450	1,773	1,616	918	547	1,032	1,185	2,784	4.506
Peak (MW)													N/A
Notes: Fill in the table above with megawatt-hours rounded to whole megawatt-hours, with megawatts rounded to one decimal place, and annual Average Megawatts rounded to three decimal places.													

Table 12 Section 4(2)(C) – International Paper Serving Hynix NLSL Specified Resource Amounts													
	Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**annual aMW**
Fiscal Year 2012													
Total (MWh)	6,818	7,309	7,753	8,100	7,334	7,479	5,769	5,088	4,368	6,157	6,538	4,974	8.844
HLH (MWh)	3,812	4,055	4,335	4,355	4,215	4,349	3,205	2,845	2,524	3,310	3,796	2,653	8.846
LLH (MWh)	3,006	3,254	3,418	3,745	3,119	3,130	2,564	2,243	1,844	2,847	2,742	2,321	8.841
Peak (MW)													N/A
Fiscal Year 2013													
Total (MWh)	6,818	7,309	7,753	8,100	7,081	7,479	5,769	5,088	4,368	6,157	6,538	4,974	8.839
HLH (MWh)	3,959	4,055	4,168	4,529	4,046	4,187	3,333	2,845	2,427	3,442	3,796	2,653	8.844
LLH (MWh)	2,859	3,254	3,585	3,571	3,035	3,292	2,436	2,243	1,941	2,715	2,742	2,321	8.834
Peak (MW)													N/A
Fiscal Year 2014													
Total (MWh)	6,818	7,309	7,753	8,100	7,081	7,479	5,769	5,088	4,368	6,157	6,538	4,974	8.839
HLH (MWh)	3,959	4,055	4,168	4,529	4,046	4,187	3,333	2,845	2,427	3,442	3,655	2,764	8.838
LLH (MWh)	2,859	3,254	3,585	3,571	3,035	3,292	2,436	2,243	1,941	2,715	2,883	2,210	8.842
Peak (MW)													N/A
Fiscal Year 2015													
Total (MWh)	6,818	7,309	7,753	8,100	7,081	7,479	5,769	5,088	N/A	N/A	N/A	N/A	6.324
HLH (MWh)	3,959	3,893	4,335	4,529	4,046	4,187	3,333	2,736	N/A	N/A	N/A	N/A	6.315
LLH (MWh)	2,859	3,416	3,418	3,571	3,035	3,292	2,436	2,352	N/A	N/A	N/A	N/A	6.335
Peak (MW)													N/A
Notes: Fill in the table above with megawatt-hours rounded to whole megawatt-hours, with megawatts rounded to one decimal place, and annual Average Megawatts rounded to three decimal places.													

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Exhibit B
HIGH WATER MARKS AND CONTRACT DEMAND QUANTITIES

1. CONTRACT HIGH WATER MARK (CHWM)

1.1 CHWM Amount

By September 15, 2011, BPA shall fill in the table below with EWEB's CHWM. Once established, EWEB's CHWM shall not change for the term of this Agreement except as allowed in section 1.2 of this exhibit.

CHWM (annual aMW):	
Note: BPA shall round the number in the table above to three decimal places.	

1.2 Changes to CHWM

If a change is made to EWEB's CHWM pursuant to this section 1.2, then BPA shall determine and notify EWEB of the date such change will be effective as follows:

1.2.1 If a load included in EWEB's Measured 2010 Load, as defined in the TRM, is later found to have been an NLSL in FY 2010, then BPA shall reduce EWEB's CHWM by the amount of the NLSL. BPA shall notify EWEB 30 days prior to when the updated CHWM will become effective. EWEB shall be liable for payment of any charges to adjust for the ineligible Tier 1 PF rate purchases dating back to October 1, 2011.

1.2.2 If EWEB acquires an Annexed Load from a utility that has a CHWM, then BPA shall increase EWEB's CHWM by adding part of the other utility's CHWM to EWEB's CHWM. The CHWM increase shall be effective on the date that EWEB begins service to the Annexed Load. BPA shall establish the amount of the CHWM addition as follows:

(1) If EWEB and the other utility involved in the annexation agree on the amount of the CHWM addition, then BPA shall adopt that amount if BPA determines such amount is reasonable.

(2) If EWEB and the other utility cannot agree on the amount of the CHWM addition, or if BPA determines the amount agreed to in section 1.2.2(1) of this exhibit is unreasonable, then the amount of the CHWM addition shall equal the calculated amount below; provided however, BPA may adjust the calculated amount below to reflect the division of Dedicated Resources between the utilities and other pertinent information advanced by EWEB and the other utility:

$$\left[\frac{\text{Annexed Load minus annexed NLSLs, if any}}{\text{Other utility's pre-annexation Total Retail Load minus total NLSLs, if any}} \right] \times \left[\text{Other utility's pre-annexation CHWM} \right]$$

1.2.3 If another utility with a CHWM annexes load of EWEB, then BPA shall reduce EWEB's CHWM by adding part of EWEB's CHWM to the other utility's CHWM. The CHWM reduction shall be effective on the date that the other utility begins service to the Annexed Load. BPA shall establish the amount of the CHWM reduction as follows:

(1) If EWEB and the other utility involved in the annexation agree on the amount of the CHWM reduction, then BPA shall adopt that amount if BPA determines such amount is reasonable.

(2) If EWEB and the other utility cannot agree on the amount of the CHWM reduction, or if BPA determines the amount agreed to in section 1.2.3(1) of this exhibit is unreasonable, then the amount of the CHWM reduction shall equal the calculated amount below; ***provided however***, BPA may adjust the calculated amount below to reflect the division of Dedicated Resources between the utilities and other pertinent information advanced by EWEB and the other utility:

$$\left[\frac{\text{Annexed Load minus annexed NLSLs, if any}}{\text{EWEB's pre-annexation Total Retail Load minus total NLSLs, if any}} \right] \times \left[\text{EWEB's pre-annexation CHWM} \right]$$

1.2.4 BPA may change EWEB's CHWM if BPA's Administrator determines that BPA is required by court order about an Annexed Load to make such changes. BPA shall determine the effective date of such a change and shall update this exhibit with the changed CHWM.

2. CONTRACT DEMAND QUANTITIES (CDQs)

2.1 CDQ Amounts

By September 15, 2011, BPA shall fill in the table below with EWEB's monthly CDQs. Calculation of such CDQs is established in the TRM. EWEB's monthly CDQs shall not change for the term of this Agreement except as allowed below.

Monthly Contract Demand Quantities												
	Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**
kW												
Note: BPA shall round the amounts in the table above to the nearest whole kilowatt.												

2.2 Changes Due to Annexation

The Parties shall determine when changes to EWEB's CDQs, as allowed below, will become effective.

2.2.1 If EWEB acquires an Annexed Load from a utility that has monthly CDQs, then BPA shall increase EWEB's CDQ for each month by adding the portion of the other utility's monthly CDQ that is attributable to such Annexed Load. For each month, the sum of EWEB's and the other utility's post-annexation CDQs shall not exceed the sum of the pre-annexation CDQs for such utilities. BPA shall establish the amount of the CDQ additions as follows:

(1) If EWEB and the other utility involved in the annexation agree on the amounts of the CDQ additions, then BPA shall adopt those amounts.

(2) If EWEB and the other utility cannot agree on the amounts of the CDQ additions, then BPA shall determine the amounts based on the monthly load factors of the Annexed Load.

2.2.2 If another utility with monthly CDQs annexes load of EWEB, then BPA shall reduce EWEB's CDQ for each month by removing the portion of EWEB's monthly CDQ that is attributable to the load that was annexed. For each month, the sum of EWEB's and the other utility's post-annexation CDQs shall not exceed the sum of the pre-annexation CDQs for such utilities. BPA shall establish the amount of the CDQ reductions as follows:

(1) If EWEB and the other utility involved in the annexation agree on the amounts of the CDQ reductions, then BPA shall adopt those amounts.

(2) If EWEB and the other utility cannot agree on the amounts of the CDQ reductions, then BPA shall determine the amounts based on the monthly load factors of the Annexed Load.

3. REVISIONS

BPA may revise this exhibit to the extent allowed in sections 1 and 2 of this exhibit. All other changes shall be made by mutual agreement.

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Exhibit C
PURCHASE OBLIGATIONS

1. DETERMINATION OF TIER 1 BLOCK AMOUNTS

1.1 Determination of Annual Tier 1 Block Amounts
By September 15, 2011, and by each September 15 thereafter, BPA shall enter in the table below EWEB's annual Tier 1 Block Amount as determined pursuant to section 4.3.1 of the body of this Agreement.

Annual Tier 1 Block Amounts		
Fiscal Year	**Annual Tier 1 Block Amount (aMW)**	**Annual Tier 1 Block Amount (MWh)**
2012		
2013		
2014		
2015		
2016		
2017		
2018		
2019		
2020		
2021		
2022		
2023		
2024		
2025		
2026		
2027		
2028		

1.2 Flat Within-Month Shape
EWEB's monthly Tier 1 Block Amounts, expressed in MWh, shall be determined based on the Monthly Shaping Factors. EWEB's Monthly Shaping Factors that are used to determine monthly Tier 1 Block Amounts shall be determined as follows:

1.2.1 Monthly Shaping Factors for a Flat Within-Month Shape
EWEB's Monthly Shaping Factors for a Flat Within-Month Shape shall be determined in accordance with section 1.2.1.2 of this exhibit, using EWEB's "monthly 2010 load values" and "annual 2010 load value" as determined in accordance with section 1.2.1.1 of this exhibit.

1.2.1.1 Calculation of Monthly and Annual 2010 Load Values
Each "monthly 2010 load value" for EWEB shall be equal to EWEB's monthly Total Retail Load for FY 2010, as adjusted in accordance with sections 4.1.1.1 and 4.1.1.2 of the TRM.

EWEB's "annual 2010 load value" shall be equal to the sum of EWEB's "monthly 2010 load values" for all months of FY 2010.

1.2.1.2 **Calculation of Monthly Shaping Factors for a Flat Within-Month Shape**
EWEB's Monthly Shaping Factors for a Flat Within-Month Shape shall be determined as follows:

(1) The "monthly shape numerator" shall be equal to (a) the "monthly 2010 load value" for the corresponding month in FY 2010 minus (b) EWEB's Existing Resource amounts for the each month of FY 2012, as listed in section 2 of Exhibit A, expressed in MWh;

(2) The "monthly shape denominator" shall be equal to (a) the "annual 2010 load value," minus (b) the sum of EWEB's Existing Resource amounts for the all months of FY 2012, as listed in section 2 of Exhibit A, expressed in MWh; and

(3) The Monthly Shaping Factors for a Flat Within-Month Shape shall be equal to (a) the "monthly shape numerator" for each month, divided by (b) the "monthly shape denominator" for each such month, rounded to three decimal places and set forth in the table below.

Monthly Shaping Factors													
Month	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Total**
Monthly Shaping Factor													1.000

1.3 **Monthly Tier 1 Block Amounts**
The monthly Tier 1 Block Amounts for each month of each Fiscal Year, beginning with FY 2012, shall be equal to: (1) the annual Tier 1 Block Amount as specified in section 1.1 of this exhibit multiplied by (2) the Monthly Shaping Factor for the corresponding month as specified in section 1.2 of this exhibit, rounded to a whole number. BPA shall enter such amounts into the table below. Due to rounding, total megawatt-hour deliveries during any Fiscal Year may be slightly different than the megawatt-hours stated in section 1.1 of this exhibit. EWEB shall schedule the monthly Tier 1 Block Amounts as flat as possible on all hours of each month.

Monthly Tier 1 Block Amounts (MWh)												
FY	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
2012												
2013												
2014												
2015												
2016												
2017												
2018												
2019												
2020												
2021												
2022												
2023												
2024												
2025												
2026												
2027												
2028												

2. FIRM REQUIREMENTS POWER AT TIER 2 RATES

2.1 Notice to Purchase Zero Amounts at Tier 2 Rates

If EWEB elects not to purchase Firm Requirements Power at Tier 2 Rates for a Purchase Period, then by March 31 immediately following the corresponding Notice Deadline, BPA shall update this exhibit to indicate such election by adding an "X" to the applicable cell in the following table. Such election means that for the Purchase Period specified below, EWEB shall: (1) purchase zero amounts of Firm Requirements Power at Tier 2 Rates, and (2) serve all of its Above-RHWM Load with power other than Firm Requirements Power.

Zero Tier 2	Purchase Period
	FY 2012 - FY 2014
	FY 2015 - FY 2019
	FY 2020 - FY 2024
	FY 2025 - FY 2028

2.2 Tier 2 Load Growth Rate

EWEB shall not have the right to purchase Firm Requirements Power at Tier 2 Load Growth Rates for the term of this Agreement.

2.3 Tier 2 Vintage Rates

2.3.1 Election Process

2.3.1.1 Right to Convert

Subject to the amounts of power BPA makes available at one or more Tier 2 Vintage Rates, EWEB shall have the right to convert some or all of the amounts of Firm Requirements Power it has elected to purchase at Tier 2 Short-Term Rates, as stated in section 2.4 of this exhibit, to an equal purchase amount at Tier 2 Vintage Rates.

2.3.1.2 **Statement of Intent**
If EWEB elects to purchase Firm Requirements Power from BPA at Tier 2 Vintage Rates, then EWEB shall sign a Statement of Intent offered by BPA. "Statement of Intent" means a statement prepared by BPA and signed by EWEB that describes the approach and cost structure that will be used for a specific Tier 2 Cost Pool. If BPA establishes a Tier 2 Cost Pool for a Tier 2 Vintage Rate consistent with the Statement of Intent, then EWEB agrees to have the portion of its Tier 2 Rate power purchase specified in the Statement of Intent priced at that rate. If BPA is unable to establish the Tier 2 Cost Pool for the specific Tier 2 Vintage Rate, then EWEB agrees to purchase such amount of Firm Requirements Power at Tier 2 Short-Term Rates, except as stated in section 2.3.1.5 of this exhibit.

2.3.1.3 **Insufficient Availability**
The Statement of Intent shall include procedures to allocate between competing applications for a specific Tier 2 Cost Pool if requests exceed amounts available.

2.3.1.4 **Conversion Costs**
Upon establishment of a Tier 2 Vintage Rate for which EWEB signed a Statement of Intent, EWEB shall be liable for payment of any outstanding costs under Tier 2 Short-Term Rates that apply to EWEB. Such costs shall be those that BPA: (1) is obligated to pay and will not recover from EWEB under Tier 2 Short-Term Rates as a result of the conversion, and (2) is unable to recover through other transactions. BPA shall determine such costs, if any, in the first 7(i) Process that establishes the applicable Tier 2 Vintage Rate. In no event shall BPA make payment to EWEB as a result of EWEB's conversion of purchase amounts at Tier 2 Short-Term Rates to purchase amounts at Tier 2 Vintage Rates.

2.3.1.5 **Additional Offerings**
In addition to the right to convert to Tier 2 Vintage Rates established in section 2.3.1.1 of this exhibit, EWEB may have the opportunity to purchase Firm Requirements Power at Tier 2 Vintage Rates regardless of whether EWEB is purchasing at Tier 2 Short-Term Rates if:

(1) BPA determines, in its sole discretion, that all requests for service at Tier 2 Vintage Rates by

purchasers of Firm Requirements Power at Tier 2 Short-Term Rates are able to be satisfied, and

(2) BPA determines, in its sole discretion, to offer EWEB a Statement of Intent that would provide EWEB the opportunity to purchase Firm Requirements at Tier 2 Vintage Rates.

If EWEB signs a Statement of Intent offered by BPA pursuant to this section 2.3.1.5, and if BPA is unable to establish the Tier 2 Cost Pool for the applicable Tier 2 Vintage Rate, then EWEB's current elections for service to its Above-RHWM Load shall continue to apply.

Except as provided in this section 2.3.1, any election by EWEB to purchase Firm Requirements Power at Tier 2 Vintage Rates shall not relieve EWEB of any obligation to purchase Firm Requirements Power at another Tier 2 Rate.

2.3.1.6 **Exhibit Updates**
By September 15 immediately following the establishment of a Tier 2 Vintage Rate for which EWEB signed a Statement of Intent, BPA shall amend this exhibit to show EWEB's Tier 2 Vintage Rate purchases and remove EWEB's Tier 2 Short-Term Rate purchases by the amounts purchased at the Tier 2 Vintage Rate, if EWEB is converting to the Tier 2 Vintage Rate from the Tier 2 Short-Term Rate. BPA shall insert applicable tables, terms, and conditions for each Tier 2 Vintage Rate in section 2.3.2 of this exhibit.

2.3.2 **Vintage Rate Elections**
EWEB has no Tier 2 Vintage Rate elections at this time.

2.4 **Tier 2 Short-Term Rate**
If EWEB elects by the applicable Notice Deadline to purchase Firm Requirements Power at Tier 2 Short-Term Rates for a Purchase Period, then in its election EWEB shall state its purchase amounts of such power for each year of the corresponding Purchase Period. By March 31 immediately following each Notice Deadline, BPA shall update the table below with: (1) EWEB's purchase amounts, if any, at Tier 2 Short-Term Rates for the corresponding Purchase Period, or (2) a zero purchase amount if EWEB does not elect to purchase Firm Requirements Power at Tier 2 Short-Term Rates for the corresponding Purchase Period.

Tier 2 Short-Term Rate Table					
Fiscal Year	**2012**	**2013**	**2014**	**2015**	**2016**
aMW					
Fiscal Year	**2017**	**2018**	**2019**	**2020**	**2021**
aMW					

Tier 2 Short-Term Rate Table					
Fiscal Year	**2022**	**2023**	**2024**	**2025**	**2026**
aMW					
Fiscal Year	**2027**	**2028**			
aMW					
Note: Insert whole megawatt amounts for each year of the applicable Purchase Period.					

2.5 **Amounts of Power to be Billed at Tier 2 Rates**

Prior to each Fiscal Year and consistent with EWEB's elections, BPA shall determine the amounts, if any, of Firm Requirements Power at Tier 2 Rates that need to be remarketed subject to section 10 of the body of this Agreement. By September 15 of each Fiscal year beginning September 15, 2011, BPA shall update the table below for the upcoming Fiscal Year with: (1) the annual average amounts of Firm Requirements Power which EWEB shall purchase at each applicable Tier 2 Rate, (2) any remarketed Tier 2 Rate purchase amounts, and (3) the total amount of Firm Requirements Power priced at Tier 2 Rates, net of any remarketed amounts.

Annual Amounts Priced at Tier 2 Rates (aMW)									
Fiscal Year	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
No Tier 2 at this time									
Minus Remarketed Amounts									
Total Amount at Tier 2									
Fiscal Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	
No Tier 2 at this time									
Minus Remarketed Amounts									
Total Amount at Tier 2									
Notes: 1. List each applicable Tier 2 rate in the table above. For the first applicable Tier 2 rate replace **No Tier 2 at this time** with the name of the applicable Tier 2 rate. For each additional Tier 2 rate, add a new row above the **Remarketed Amounts** row. If EWEB elects not to purchase at Tier 2 rates, then leave **No Tier 2 at this time** in the table and leave the remainder of the table blank. 2. Fill in the table above with whole annual Average Megawatts.									

3. MONTHLY PF RATES

Applicable monthly Tier 1 and Tier 2 Rates are specified in BPA Wholesale Power Rate Schedules and GRSPs.

4. REVISIONS

BPA shall revise this exhibit to reflect EWEB's elections regarding service to its Above-RHWM Load and BPA's determinations relevant to this exhibit and made in accordance with this Agreement.

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Exhibit D
ADDITIONAL PRODUCTS AND SPECIAL PROVISIONS

1. CF/CT AND NEW LARGE SINGLE LOADS

1.1 CF/CT Loads

The Administrator has determined that the following loads were contracted for, or committed to be served (CF/CT), as of September 1, 1979, as defined in section 3(13)(A) of the Northwest Power Act, and are subject to PF rates:

End-use consumer's name: International Paper
Facility name: Springfield Containerboard Mill
Facility location: Springfield, OR
Date of CF/CT determination: July 16, 1990
Facility description: Wood products plant
Amount of firm energy (megawatts at 100 percent load factor) contracted for, or committed to: 65.2 annual Average Megawatts

1.2 Potential NLSLs

EWEB has no identified potential NLSLs.

1.3 Existing NLSLs

1.3.1 Hynix NLSL

EWEB has an NLSL and agrees to serve the NLSL with a firm resource that is not already dedicated to serve its other firm end-use consumer loads. The Parties shall list such Dedicated Resources in Exhibit A, Net Requirements and Resources. The Parties shall administer service to the following NLSL consistent with section 23.3 of this Agreement.

End–use consumer name: Hynix's successor in interest (formerly Hyundai Electronics America)
Facility location: Eugene, OR
Date load determined as an NLSL: October 29, 1996
Approximate load: 26 annual Average Megawatts
Description of NLSL: Electric component plant
Manner of service:

(1) At the time of contract execution, Hynix has ceased operation of its facility in Eugene, Oregon. Since the future of the facility is unknown, and for purposes of this section 1.3.1 only, reference to the end-use consumer name shall be "Hynix's successor in interest."

(2) EWEB shall serve the "Hynix's successor in interest" NLSL with the following Dedicated Resources, as listed in Exhibit A: Stone Creek and International Paper (IP), and consistent with Section 3 of this Exhibit.

(3) In the event the "Hynix's successor in interest" NLSL exceeds the total output of the combined Stone Creek and IP resources, EWEB shall meet the remaining "Hynix's successor in interest" load from its own resources or purchases.

(4) In the event the Hynix NLSL goes away, EWEB shall dispose of the output of the Stone Creek and IP resources pursuant to Section 3 below of this Exhibit.

(5) If BPA changes its NLSL policy with regard to EWEB's "Hynix's successor in interest"NLSL, EWEB may request that BPA evaluate the Administrator's October 29, 1996, determination of the "Hynix's successor in interest"NLSL for conformance to the new NLSL policy.

1.3.2 **Renewable Resource/Cogeneration Exception**
EWEB's end-use consumer is not currently applying an onsite renewable resource or cogeneration facility to an NLSL.

2. RESOURCE SUPPORT SERVICES

RSS is only available to EWEB to support resources that are Specified Resources used to serve Total Retail Load that are added after September 30, 2006. EWEB's purchase of RSS shall include all support services necessary to convert the actual scheduled output from the resource being supported into a flat annual block.

2.1 BPA shall develop the RSS products to support applicable Specified Resources listed in section 2 of Exhibit A for the FY 2012-2014 Purchase Period and offer such as a revision to this exhibit by August 1, 2009. Prior to that date, BPA shall provide EWEB a reasonable opportunity to provide input into the development of the products and the related contract provisions. If EWEB requests that BPA provide such service, then the Parties shall execute a revision to this exhibit by the November 1, 2009, Notice Deadline. By each Notice Deadline thereafter, EWEB may purchase RSS from BPA to support applicable Specified Resources listed in section 2 of Exhibit A for the corresponding Purchase Period.

2.2 If EWEB adds a new Specified Resource within a Purchase Period to meet its obligations to serve Above-RHWM Load with Dedicated Resources, consistent with section 3.5.1 of the body of this Agreement, EWEB may purchase RSS from BPA to support such resource. Such purchase shall be for the remainder of the Purchase Period and for the following Purchase Period. EWEB shall notify BPA of its decision to purchase RSS for a new Specified Resource by October 31 of a Rate Case Year and the elected RSS will be effective at the start of the upcoming Rate Period.

3. SALE OF STONE CREEK AND INTERNATIONAL PAPER RESOURCES TO HYNIX OR ITS SUCCESSOR

EWEB shall apply the output of its Stone Creek Hydro resource (Stone Creek) and its share of International Paper (IP) resource (formerly Weyerhaeuser's co-generation facility) in Eugene, on an annual basis, to the load of Hynix Semiconductor America, formerly Hyundai Electronics America (Hynix) or its successor, in Eugene, Oregon, a New Large Single Load (NLSL) on EWEB. For each fiscal year and in the event the Hynix load exceeds the total output of the combined IP and Stone Creek resources, EWEB shall meet the remaining Hynix or successor load from its own resources or purchases. In the event the planned annual Hynix load is less than the output of the IP & Stone Creek resources, EWEB agrees to dispose of any such excess output from those resources as follows:

3.1 **Stone Creek**

EWEB will either (a) offer to sell all or part of the output to BPA; (b) use all or part of the output to serve EWEB's Load or load growth; (c) use all or part of the output to serve EWEB's NLSL loads; or, (d) other application that is consistent with BPA policy under section 3d of the 1964 Pacific Northwest Preference Act, P.L. 88-552.

3.2 **International Paper**

Before EWEB makes an offer to sell or dispose of the output to an extra-regional utility or to a marketer, EWEB will (a) offer to sell all or part of the output to BPA; (b) offer to sell all or part of the output to other BPA customer with a net requirement load for service to those customers' Total Retail Load; (c) use all or part of the output to serve EWEB's Total Retail Load that may constitute a New Large Single Load; or (d) use all or part of the output to serve EWEB's load or load growth.

4. REVISIONS

This exhibit shall be revised by mutual agreement of the Parties to reflect additional products EWEB purchases during the term of this Agreement.

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Exhibit E
METERING

1. METERING

1.1 Directly Connected Points of Delivery and Load Metering

(1) **BPA POD Name:** Alvey 115-EWEB;
BPA POD Number: 25;
WECC Balancing Authority: BPAT;

Location: the point in BPA's J.P. Alvey Substation where the 115 kV facilities of BPA and EWEB are connected;

Voltage: 115 kV;

Metering: in BPA's J.P. Alvey Substation in the Alvey-Currin 115 kV circuit over which such electric power flows;

(A) **BPA Meter Point Name:** Alvey Out;
BPA Meter Point Number: 1245;
Direction for PF Billing Purposes: Positive;
Manner of Service: Direct, BPA to EWEB;

(B) **BPA Meter Point Name:** Alvey In;
BPA Meter Point Number: 1246;
Direction for PF Billing Purposes: Negative;
Manner of Service: Direct, BPA to EWEB;

Metering Loss Adjustment: None;

Exceptions: None.

(2) **BPA POD Name:** Alvey 230-PACW;
BPA POD Number: 3226;
WECC Balancing Authority: BPAT;

Location: the point in EWEB's McKenzie Substation where the 230 kV facilities of BPA and EWEB are connected;

Voltage: 230 kV;

Metering:

(A) in EWEB's McKenzie Substation, in EWEB's 230/115 kV transformer over which such electric power flows; **TBD** *

(i) **BPA Meter Point Name:** Sub McKenzie - In;
BPA Meter Point Number: 2152;
Direction for PF Billing Purposes: Positive;
Manner of Service: Direct, BPA to EWEB;

(ii) **BPA Meter Point Name:** Sub McKenzie - Out;
BPA Meter Point Number: 2153;
Direction for PF Billing Purposes: Negative;
Manner of Service: Direct, EWEB to BPA;

(iii) **BPA Meter Point Name:** 69 kV EWEB to PPL;
BPA Meter Point Number: 2646;
Direction for PF Billing Purposes: Negative;
Manner of Service: Direct EWEB to BPA;

(iv) **BPA Meter Point Name:** 69 kV PPL to EWEB;
BPA Meter Point Number: 2647;
Direction for PF Billing Purposes: Positive;
Manner of Service: Direct, BPA to EWEB;

(B) in BPA's Alvey Substation in the 230 kV circuit over which such electric power flows;

(i) **BPA Meter Point Name:** 230 kV EWEB to PPL;
BPA Meter Point Number: 2644;
Direction for PF Billing Purposes: Negative;
Manner of Service: Direct, EWEB to BPA;

(ii) **BPA Meter Point Name:** 230 kV PPL to EWEB;
BPA Meter Point Number: 2645;
Direction for PF Billing Purposes: Positive;
Manner of Service: Direct, BPA to EWEB;

Metering Loss Adjustment: TBD *

Exceptions: None.

(3) **BPA POD Name:** Bertelsen 115 kV;
BPA POD Number: TBD *
WECC Balancing Authority: BPAT;

Location: the point between structures 3/3 and 3/4 in the Eugene-Bertelsen section of BPA's Eugene-Alvey 115 kV line No. 1 where the facilities of BPA and EWEB are connected;

Voltage: 115 kV;

Metering: in EWEB's Bertelsen Substation in the 12.5 kV circuit over which such electric power flows;

BPA Meter Point Name: Bertelsen Out;
BPA Meter Point Number: 390;
Direction for PF Billing Purposes: Positive;
Manner of Service: Direct, BPA to EWEB;

Metering Loss Adjustment: BPA shall adjust for losses between the POD and the Bertelsen POM. Such adjustments shall be specified in writing between BPA and EWEB;

Exception: None.

(4) **BPA POD Name:** Dillard Tap 115 kV;
BPA POD Number: 180;
WECC Balancing Authority: BPAT;

Location: the point at structure No. 10/3 in BPA's Eugene-Alvey 115 kV line No. 2 where the facilities of BPA and EWEB are connected;

Voltage: 115 kV;

Metering: in EWEB's Dillard Substation in the 115 kV circuit over which such electric power flows;

(A) **BPA Meter Point Name:** Dillard Out;
BPA Meter Point Number: 555;
Direction for PF Billing Purposes: Positive;
Manner of Service: Direct, BPA to EWEB;

(B) **BPA Meter Point Name:** Dillard In;
BPA Meter Point Number: 556;
Direction for PF Billing Purposes: Negative;
Manner of Service: Direct, EWEB to BPA;

Metering Loss Adjustment: None;

Exception: None.

(5) **BPA POD Name:** Eugene 115 kV;
BPA POD Number: 221;
WECC Balancing Authority: BPAT;

Location: the point in BPA's Eugene Substation where the 115 kV facilities of BPA and EWEB are connected;

Voltage: 115 kV;

Metering: in BPA's Eugene Substation in the 115 kV circuits over which such electric power flows;

(A) **BPA Meter Point Name:** Eugene 115 Out;
BPA Meter Point Number: 1249;
Direction for PF Billing Purposes: Positive;
Manner of Service: Direct, BPA to EWEB;

(B) **BPA Meter Point Name:** Eugene 115 In;
BPA Meter Point Number: 1250;
Direction for PF Billing Purposes: Negative;
Manner of Service: Direct, EWEB to BPA;

(C) **BPA Meter Point Name:** Eugene 115 kV Bethel In;
BPA Meter Point Number: 2142;
Direction for PF Billing Purposes: Negative;
Manner of Service: Direct, EWEB to BPA;

(D) **BPA Meter Point Name:** Eugene 115 kV Bethel Out;
BPA Meter Point Number: 2143;
Direction for PF Billing Purposes: Positive;
Manner of Service: Direct, BPA to EWEB;

Metering Loss Adjustment: None;

Exceptions: None.

(6) **BPA POD Name:** Hawkins 115 kV;
BPA POD Number: 313;
WECC Balancing Authority: BPAT;

Location: the point at structure 6/6 in the Bertelsen-Hawkins section of BPA's Eugene-Alvey 115 kV line No. 1 where the facilities of BPA and EWEB are connected;

Voltage: 115 kV;

Metering: in EWEB's Hawkins Substation in the 12.5 kV circuit over which such electric power flows;

BPA Meter Point Name: Hawkins Out;
BPA Meter Point Number: 357;
Direction for PF Billing Purposes: Positive;
Manner of Service: Direct, BPA to EWEB;

Metering Loss Adjustment: BPA shall adjust for losses between the POD and the Hawkins Out POM. Such adjustments shall be specified in writing between BPA and EWEB;

Exceptions: None.

(7) **BPA POD Name:** Lane 115 kV;
BPA POD Number: 385;
WECC Balancing Authority: BPAT;

Location: the points in BPA's Lane Substation where the 115 kV facilities of BPA and EWEB are connected;

Voltage: 115 kV;

Metering: in BPA's Lane Substation in the 115 kV circuits over which such electric power flows;

(A) **BPA Meter Point Name:** Lane #1 Out;
BPA Meter Point Number: 1247;
Direction for PF Billing Purposes: Positive;
Manner of Service: Direct, BPA to EWEB;

(B) **BPA Meter Point Name:** Lane #1 In;
BPA Meter Point Number: 1248;
Direction for PF Billing Purposes: Negative;
Manner of Service: Direct, EWEB to BPA;

(C) **BPA Meter Point Name:** Lane #2 Out;
BPA Meter Point Number: 974;
Direction for PF Billing Purposes: Positive;
Manner of Service: Direct, BPA to EWEB;

(D) **BPA Meter Point Name:** Lane #2 In;
BPA Meter Point Number: 975;
Direction for PF Billing Purposes: Negative;
Manner of Service: Direct, EWEB to BPA;

Metering Loss Adjustment: None;

Exceptions: None.

(8) **BPA POD Name:** McKenzie 115 kV;
BPA POD Number: 4114;
WECC Balancing Authority: BPAT;

Location: the point in EWEB's McKenzie Substation where the 115 kV facilities of BPA and EWEB are connected;

Voltage: 115 kV;

Metering:

(A) in EWEB's Thurston Substation in the 115 kV circuits over which such electric power flows;

(i) **BPA Meter Point Name:** Thurston/Willakenzie In;
BPA Meter Point Number: 1812;
Direction for PF Billing Purposes: Negative;
Manner of Service: Direct, EWEB to BPA;

(ii) **BPA Meter Point Name:** Thurston/Willakenzie Out;
BPA Meter Point Number: 1813;
Direction for PF Billing Purposes: Positive;
Manner of Service: Direct, BPA to EWEB;

(B) in EWEB's McKenzie Substation in the 115 kV circuit over which such electric power flows;

(i) **BPA Meter Point Name:** EWEB McKenzie Thurston In;
BPA Meter Point Number: 3071;
Direction for PF Billing Purposes: Negative;
Manner of Service: Direct, EWEB to BPA;

(ii) **BPA Meter Point Name:** EWEB McKenzie Thurston Out;
BPA Meter Point Number: 3072;
Direction for PF Billing Purposes: Positive;
Manner of Service: Direct, BPA to EWEB;

Metering Loss Adjustment: None;

Exceptions: None.

(9) **BPA POD Name:** Thurston 115 kV;
BPA POD Number: 3930;
WECC Balancing Authority: BPAT;

Location: the point at structure No. 39/4 in BPA's Cougar-Mckenzie No. 1 transmission line where the facilities of BPA and EWEB are connected;

Voltage: 115 kV;

Metering:

(A) in EWEB's Thurston Substation in the 115 kV circuits over which such electric power flows;

(i) **BPA Meter Point Name:** Thurston Out;
BPA Meter Point Number: 504;
Direction for PF Billing Purposes: Positive;
Manner of Service: Direct, BPA to EWEB;

(ii) **BPA Meter Point Name:** Thurston In;
BPA Meter Point Number: 505;
Direction for PF Billing Purposes: Negative;
Manner of Service: Direct, EWEB to BPA;

(B) in EWEB's Thurston Substation in the 12.5 kV circuits over which such electric power flows;

BPA Meter Point Name: Thurston/Springfield Out;
BPA Meter Point Number: 609;
Direction for PF Billing Purposes: Positive;
Manner of Service: Direct, BPA to EWEB;

Metering Loss Adjustment: BPA shall adjust for losses between the POD and the Thurston/Springfield Out POM. Such adjustments shall be specified in writing between BPA and EWEB;

Exceptions: None.

(10) **BPA POD Name:** Willow Creek 115-EWEB;
BPA POD Number: 2040;
WECC Balancing Authority: BPAT;

Location: the point at structure 2/3 in the Bertelsen - Willow Creek section of BPA's Eugene - Alvey 115 kV line No. 1 where the facilities of BPA and EWEB are connected;

Voltage: 115 kV;

Metering: in EWEB's Willow Creek Substation in the 115 kV circuit over which such electric power flows;

(A) **BPA Meter Point Name:** Willow Creek N. Bus In;
BPA Meter Point Number: 2040;
Direction for PF Billing Purposes: Negative;
Manner of Service: Direct, EWEB to BPA;

(B) **BPA Meter Point Name:** Willow Creek N. Bus Out;
BPA Meter Point Number: 2041;
Direction for PF Billing Purposes: Positive;
Manner of Service: Direct, BPA to EWEB;

(C) **BPA Meter Point Name:** Willow Creek S. Bus In;
BPA Meter Point Number: 2042;
Direction for PF Billing Purposes: Negative;
Manner of Service: Direct, EWEB to BPA;

(D) **BPA Meter Point Name:** Willow Creek S. Bus Out;
BPA Meter Point Number: 2043;
Direction for PF Billing Purposes: Positive;
Manner of Service: Direct, BPA to EWEB;

Metering Loss Adjustment: None;

Exceptions: None.

1.2 **Transfer Points of Delivery and Load Metering**
None.

1.3 **Resource Locations and Metering TBD***

(1) **Resource Name:** Carmen Smith Tap; **TBD***

Metering: in «Owner's Name»'s Carmen Smith Substation in the 115 kV circuit«s» over which such electric power flows; **TBD ***

(A) **BPA Meter Point Name:** Carmen Smith In;
BPA Meter Point Number: 26;
Direction for PF Billing Purposes: Positive;
Manner of Service: «Directly Connected/Wheeled, Resource to BPA to EWEB or Resource to EWEB to BPA»; **TBD***

(B) **BPA Meter Point Name:** Carmen Smith Out;
BPA Meter Point Number: 1305;
Direction for PF Billing Purposes: «Positive/Negative»; **TBD***
Manner of Service: «Direct/Transfer, Resource to BPA to EWEB or Resource to EWEB to BPA»; **TBD***

Metering Loss Adjustment: BPA shall adjust for losses between the «BPA POD Name» POD and the «BPA POM Names» POM(s). Such adjustments shall be specified in written correspondence between BPA and EWEB; **TBD***

Exceptions: TBD*

(2) **Resource Name:** «Resource Name» **TBD***

Metering: in «Owner's Name»'s Leaburg Substation in the «##» kV circuit«s» over which such electric power flows; **TBD***

(A) **BPA Meter Point Name:** Leaburg Generation #2 In;
BPA Meter Point Number: 2779;
Direction for PF Billing Purposes: TBD*;
Manner of Service: «Directly Connected/Wheeled, Resource to BPA to EWEB or Resource to EWEB to BPA»; **TBD***

(B) **BPA Meter Point Name:** Leaburg Genr #1 KWH In;
BPA Meter Point Number: 2782;
Direction for PF Billing Purposes: «Positive/Negative»; **TBD***
Manner of Service: «Direct/Transfer, Resource to BPA to EWEB or Resource to EWEB to BPA»; **TBD***

Metering Loss Adjustment: BPA shall adjust for losses between the «BPA POD Name» POD and the «BPA POM Names» POM(s). Such adjustments shall be specified in written correspondence between BPA and EWEB; **TBD***

Exceptions: TBD*

(3) **Resource Name: «Resource Name» TBD***

Metering: in «Owner's Name»'s Walterville Substation in the «##» kV circuit«s» over which such electric power flows; **TBD***

BPA Meter Point Name: Walterville Genr In;
BPA Meter Point Number: 2783;
Direction for PF Billing Purposes: TBD*;
Manner of Service: «Directly Connected/Wheeled, Resource to BPA to EWEB or Resource to EWEB to BPA»; **TBD***

Metering Loss Adjustment: BPA shall adjust for losses between the «BPA POD Name» POD and the «BPA POM Names» POM(s). Such adjustments shall be specified in written correspondence between BPA and EWEB; **TBD***

Exceptions: TBD*

(4) **Resource Name: «Resource Name» TBD***

Metering: in «Owner's Name»'s «Substation Name» Substation in the «##» kV circuit«s» over which such electric power flows; **TBD***

(A) **BPA Meter Point Name:** Weyco Genr #4 EWEB In;
BPA Meter Point Number: 2784;
Direction for PF Billing Purposes: TBD*
Manner of Service: «Directly Connected/Wheeled, Resource to BPA to EWEB or Resource to EWEB to BPA»; **TBD***

(B) **BPA Meter Point Name:** Weyco Genr #3 EWEB In;
BPA Meter Point Number: 2785;
Direction for PF Billing Purposes: «Positive/Negative»; **TBD***
Manner of Service: «Direct/Transfer, Resource to BPA to EWEB or Resource to EWEB to BPA»; **TBD***

(C) **BPA Meter Point Name:** Weyco Genr #1 EWEB In;
BPA Meter Point Number: 2786;
Direction for PF Billing Purposes: «Positive/Negative»; **TBD***
Manner of Service: «Direct/Transfer, Resource to BPA to EWEB or Resource to EWEB to BPA»; **TBD***

(D) **BPA Meter Point Name:** Weyco Genr #2 EWEB In;
BPA Meter Point Number: 2787;
Direction for PF Billing Purposes: «Positive/Negative»; **TBD***
Manner of Service: «Direct/Transfer, Resource to BPA to EWEB or Resource to EWEB to BPA»; **TBD***

Metering Loss Adjustment: BPA shall adjust for losses between the «BPA POD Name» POD and the «BPA POM Names» POM(s). Such adjustments shall be specified in written correspondence between BPA and EWEB; **TBD***

Exceptions: TBD*

* **TBD** - This data element is unresolved and shall be determined by BPA prior to June 1, 2011.

2. REVISIONS

Each Party shall notify the other in writing if updates to this exhibit are necessary to accurately reflect the actual characteristics of POD and meter information described in this exhibit. The Parties shall revise this exhibit to reflect such changes. The Parties shall mutually agree on any such exhibit revisions and agreement shall not be unreasonably withheld or delayed. The effective date of any exhibit revision shall be the date the actual circumstances described by the revision occur.

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Exhibit F
SCHEDULING

1. SCHEDULING FEDERAL POWER

EWEB is responsible for scheduling all amounts of Slice Output Energy, Tier 1 Block Amounts and Tier 2 Block Amounts purchased under this Agreement from the Scheduling Points of Receipt to their ultimate destination, and for creating associated electronic tags. EWEB agrees to provide copies of such electronic tags to Power Services consistent with the requirements of this Exhibit F.

2. COORDINATION REQUIREMENTS

2.1 Prescheduling

EWEB shall submit delivery schedules of Slice Output Energy, Tier 1 Block Amounts and Tier 2 Block Amounts to Power Services by 1100 Pacific Prevailing Time the day(s) on which prescheduling occurs, as specified by WECC. Preschedule electronic tags are due to Power Services in accordance with the parameters specified in section 4 of this exhibit.

2.2 Real-Time Scheduling

EWEB shall have the right to submit new or modified schedules and electronic tags associated with deliveries of Slice Output Energy in real-time in accordance with the parameters specified in section 4 of this exhibit.

2.3 After the Fact

Power Services and EWEB agree to reconcile all transactions, schedules and accounts at the end of each month (as early as possible within the first 10 calendar days of the next month). Power Services and EWEB shall verify all transactions per this Agreement, as to product or type of service, hourly amounts, daily and monthly totals, and related charges.

3. SLICE OUTPUT ENERGY SCHEDULING REQUIREMENTS

3.1 Schedule submissions to Power Services will primarily be via Power Services approved electronic methods, which may include specific interfaces. However, other Power Services' agreed-upon submission methods (verbal, fax, etc.) are acceptable if electronic systems are temporarily not available. Transmission scheduling arrangements are handled under separate agreements/provisions with the designated transmission provider, and may not necessarily be the same requirements as Power Services' scheduling arrangements.

3.2 Schedules of Slice Output Energy submitted to Power Services by EWEB shall comply with Delivery Limits established in the Slice Computer Application.

3.3 The timeline within which Power Services shall approve or deny EWEB's Delivery Requests, as represented by EWEB's electronic tags, shall conform to Power Services' then current preschedule and real-time scheduling guidelines as specified in section 4 of this exhibit.

3.3.1 For the purpose of approving requests for deliveries of Slice Output Energy, Power Services shall approve electronic tags, as described in section 3.3.2 below, that EWEB submits to Power Services consistent with section 3.2 above prior to the applicable Power Services scheduling deadline, as specified in section 4 of this exhibit.

3.3.2 Electronic tags submitted to Power Service shall: (1) identify BPA as the generation providing entity, (2) identify EWEB as first downstream purchasing-selling entity, (3) identify hourly energy amounts in MWh, and (4) maintain all data consistent with applicable industry standards.

3.3.3 Power Services shall have the sole discretion to accept or deny electronic tags that EWEB submits to Power Services after the applicable Power Services' scheduling deadline set forth in section 4 of this exhibit, regardless of the reason for the late submission, and regardless of submission method (electronic, verbal, fax, etc.).

3.3.4 Changes to tagged energy amounts required by the Balancing Authority for maintaining system reliability, as determined by the responsible Balancing Authority, shall be implemented by Power Services and EWEB at the time of such notification by the Balancing Authority.

3.4 EWEB shall be responsible for verifying the sum of its hourly tagged and non-tagged (e.g., transmission loss schedules, etc., that are not tagged) energy amounts is equal to its Delivery Request, as described in section 7 of Exhibit M, for each Scheduling Hour.

3.4.1 EWEB shall have the right to submit adjusted Customer Inputs to Power Services, pursuant to section 4.1 of this exhibit, in order to alter the associated Simulated Output Energy Schedules within established Delivery Limits, such that EWEB's Delivery Request is made equal to the sum of its tagged and non-tagged energy amounts for each Scheduling Hour.

3.4.2 For each Scheduling Hour, the amount EWEB's hourly tagged and non-tagged energy amount is in excess of its Delivery Request shall be subject to the UAI Charge for energy, and the amount EWEB's hourly tagged and non-tagged energy amount is less than its Delivery Request shall be forfeited.

3.4.3 Electronic tag and Delivery Request mismatches that result from Balancing Authority reliability required actions shall not be subject to penalty if such required reliability action is implemented by the

Balancing Authority less than 30 minutes prior to the start of the Scheduling Hour in which the mismatch occurs.

4. SCHEDULING DEADLINES

4.1 Customer Input Submission Deadline

EWEB shall have until 15 minutes prior to the start of each Scheduling Hour to submit revised Customer Inputs to Power Services in order to affect the associated Simulated Output Energy Schedules for each such Scheduling Hour. Power Services shall have the sole discretion to reject for any reason EWEB's Customer Inputs associated with the upcoming Scheduling Hour that are submitted to Power Services after 15 minutes prior to the start of each such Scheduling Hour.

4.2 Real-Time Electronic Tag Submission Deadline

Power Services shall approve electronic tags, as described in section 3.3.2 of this exhibit, that are consistent with section 3.2 of this exhibit and submitted to Power Services by EWEB prior to the Power Services' scheduling deadline, which is 30 minutes prior to the start of each Scheduling Hour.

4.3 Preschedule Electronic Tag Submissions

Unless otherwise mutually agreed, all EWEB preschedule electronic tags will be submitted to Power Services according to NERC instructions and deadlines for electronic tagging, as specified or modified by the Balancing Authority and WECC.

5. SCHEDULING OF DEDICATED RESOURCES

No later than 10 days following the end of each month, EWEB agrees that it will electronically copy Power Services on all electronic tags that were created or modified during the previous month in association with the delivery of EWEB's Dedicated Resources, if any, listed in sections 2, 3, and 4 of Exhibit A.

6. REVISIONS

BPA may unilaterally revise this exhibit:

(1) to implement changes that BPA determines are necessary to allow it to meet its power scheduling obligations under this Agreement, or

(2) to comply with the prevailing industry practice and requirements, currently set by WECC, NAESB, or NERC, or their successors or assigns.

BPA shall provide a draft of any material revisions of this exhibit to EWEB, with a reasonable time for comment, prior to BPA providing written notice of the revision. Revisions are effective 45 days after BPA provides written notice of the revisions to EWEB unless, in BPA's sole judgment, less notice is necessary to comply with an emergency change to the requirements of the WECC, NAESB, NERC, or their successors or assigns. In this case, BPA shall specify the effective date of such revisions.

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Exhibit G
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Exhibit H
RENEWABLE ENERGY CERTIFICATES AND CARBON ATTRIBUTES

1. **DEFINITIONS**

1.1 "Carbon Credit" means an Environmental Attribute consisting of greenhouse gas emission credits, certificates, or similar instruments.

1.2 "Environmental Attributes" means the current or future credits, benefits, emission reductions, offsets and allowances attributable to the generation of energy from a resource. Environmental Attributes do not include the tax credits associated with such resource. One megawatt-hour of energy generation from a resource is associated with one megawatt-hour of Environmental Attributes.

1.3 "Environmentally Preferred Power RECS" or "EPP RECs" means the portion of BPA's Tier 1 RECs that is equal to an amount of up to 130 percent of the annual average of equivalent environmentally preferred power (EPP) contracted for as of October 1, 2009, for FYs 2010 and 2011 under Subscription power sales contracts containing rights to Environmental Attributes through FY 2016, as determined by BPA to be necessary to administer such rights.

1.4 "Renewable Energy Certificates" or "RECs" means the certificates, documentation, or other evidence that demonstrates, in the tracking system selected under section 5 of this exhibit, the ownership of Environmental Attributes.

1.5 "Tier 1 RECs" means the RECs composed of a blend, by fuel source, based on annual generation of the resources listed in or pursuant to section 2 of this exhibit.

1.6 "Tier 2 RECs" means the RECs associated with generation of the resources whose costs are allocated to a given Tier 2 Cost Pool in accordance with the TRM.

2. **BPA'S TIER 1 REC INVENTORY**

BPA's Tier 1 REC inventory shall include all RECs that BPA has determined are associated with resources whose output is used to establish Tier 1 System Capability, as Tier 1 System Capability is defined in the TRM. The disposition of any Carbon Credits that BPA determines are associated with resources listed in, or in accordance with, this section 2 shall be as described in section 3 of this exhibit. The disposition of any Carbon Credits that BPA determines are associated with resources not listed in, or in accordance with, this section 2 shall be consistent with section 7 of this exhibit. As of the Effective Date, BPA has determined that the following resources have RECs associated with them that will be included in the Tier 1 REC inventory: Foote Creek I, Foote Creek II, Stateline, Condon, Klondike I, Klondike III, and Ashland Solar. BPA shall maintain this list on a publicly accessible BPA website and shall periodically update this list to include any then-current resources that BPA has determined have Tier 1 RECs associated with them. BPA shall calculate its inventory of Tier 1 RECs annually and after the fact based on energy generated by listed resources during the previous calendar year.

3. **EWEB'S SHARE OF TIER 1 RECS**
Beginning April 15, 2012, and by April 15 every year thereafter over the term of this Agreement, BPA shall:

(1) transfer to EWEB, or manage in accordance with section 5 of this exhibit, at no additional charge or premium beyond EWEB's payment of the otherwise applicable Tier 1 Rate, a pro rata share of Tier 1 RECs based on EWEB's RHWM divided by the total RHWMs of all holders of CHWM Contracts; and

(2) for transferred RECs, provide EWEB with a letter assigning title of such Tier 1 RECs to EWEB.

The amount of Tier 1 RECs available to BPA to transfer or manage shall be subject to available Tier 1 REC inventory, excluding amounts of Tier 1 REC inventory used to provide EPP RECs.

4. **TIER 2 RECS**
If EWEB chooses to purchase Firm Requirements Power at a Tier 2 Rate, and there are RECs which BPA has determined are associated with the resources whose costs are allocated to the Tier 2 Cost Pool for such rate, then beginning April 15 of the year immediately following the first Fiscal Year in which EWEB's Tier 2 purchase obligation commences, and by April 15 every year thereafter for the duration of EWEB's Tier 2 purchase obligation, BPA shall, based on EWEB's election pursuant to section 5 of this exhibit, transfer to or manage for EWEB a pro rata share of applicable Tier 2 RECs generated during the previous calendar year. The pro rata share of Tier 2 RECs BPA transfers to EWEB shall be the ratio of EWEB's amount of power purchased at the applicable Tier 2 Rate to the total amount of purchases under that Tier 2 Rate.

5. **TRANSFER, TRACKING, AND MANAGEMENT OF RECS**
Subject to BPA's determination that the commercial renewable energy tracking system WREGIS is adequate as a tracking system, BPA shall transfer EWEB's share of Tier 1 RECs, and Tier 2 RECs if applicable, to EWEB via WREGIS or its successor. If, during the term of this Agreement, BPA determines in consultation with customers that WREGIS is not adequate as a tracking system, then BPA may change commercial tracking systems with one year advance notice to EWEB. In such case, the Parties shall establish a comparable process for BPA to provide EWEB its RECs.

Starting on July 15, 2011, and by July 15 prior to each Rate Period through the term of this Agreement, EWEB shall notify BPA which one of the following three options it chooses for the transfer and management of EWEB's share of Tier 1 RECs, and Tier 2 RECs if applicable, for each upcoming Rate Period:

(1) BPA shall transfer EWEB's RECs into EWEB's own WREGIS account, which shall be established by EWEB; or

(2) BPA shall transfer EWEB's RECs into a BPA-managed WREGIS subaccount. Such subaccount shall be established by BPA on EWEB's behalf and the terms and conditions of which shall be determined by the Parties in a separate agreement; or

(3) EWEB shall give BPA the authority to market EWEB's RECs on EWEB's behalf. BPA shall annually credit EWEB for EWEB's pro rata share of all revenues generated by sales of RECs from the same rate pool on its April bill, issued in May.

If EWEB fails to notify BPA of its election by July 15 before the start of each Rate Period, then EWEB shall be deemed to have elected the option in section 5(3) of this exhibit.

Any RECs BPA transfers to EWEB on April 15 of each year shall be limited to those generated January 1 through December 31 of the prior year, except that any RECs BPA transfers to EWEB by April 15, 2012, shall be limited to those generated October 1, 2011, through December 31, 2011.

6. FEES

BPA shall pay any reasonable fees associated with: (1) the provision of EWEB's RECs and (2) the establishment of any subaccounts in EWEB's name pursuant to sections 5(1) and 5(2) of this exhibit. EWEB shall pay all other fees associated with any WREGIS or successor commercial tracking system, including WREGIS retirement, reserve, and export fees.

7. CARBON CREDITS

In the absence of carbon regulations or legislation directly affecting BPA, BPA intends to convey the value of any future Carbon Credits associated with resources whose costs are recovered in Tier 1 or Tier 2 Rates to EWEB on a pro rata basis in the same manner as described for Tier 1 RECs and Tier 2 RECs in sections 3 and 4 of this exhibit. This value may be conveyed as: (1) the Carbon Credits themselves; (2) a revenue credit after BPA markets such Carbon Credits; or (3) the ability to claim that power purchases at the applicable PF rate are derived from certain federal resources.

8. BPA'S RIGHT TO TERMINATE EWEB'S RECS AND/OR CARBON CREDITS

To the extent necessary to comply with any federal regulation or legislation which addresses Carbon Credits or any other form of Environmental Attribute(s) and includes compliance costs applicable to BPA, BPA may, upon reasonable notice to EWEB, terminate EWEB's contract rights to Tier 1 RECs under section 3 of this exhibit and/or EWEB's pro rata share of Carbon Credits under section 7 of this exhibit.

9. RATEMAKING TREATMENT

Notwithstanding the transfer, sharing, management, conveyance, marketing or crediting of RECs and Carbon Credits, or the value of any or all of them, pursuant to this Exhibit H, BPA reserves any ratemaking authority it otherwise possesses to determine and factor in a share of the value and/or cost of any or all of the RECs and Carbon Credits for the purpose of: (1) determining applicable wholesale rates pursuant to section 7(c)(2) of the Northwest Power Act; and (2) establishing the rate(s) applicable to BPA sales pursuant to section 5(c) of the Northwest Power Act in a manner that BPA determines provides an appropriate sharing of the benefits and/or costs of the federal system and comparably reflects treatment of RECs and Carbon Credits in the calculation of a utility's average system cost of resources. BPA further reserves its ratemaking authority to recover any costs resulting from such ratemaking actions through rates, including rates applicable to EWEB. This paragraph does not constitute EWEB's agreement to statutory ratemaking authority BPA does not otherwise have.

10. REVISIONS

BPA shall revise this Exhibit H to reflect BPA's determinations relevant to this exhibit and made in accordance with this Agreement. Any other revisions to this Exhibit H shall be by mutual agreement.

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Exhibit I
CRITICAL SLICE AMOUNTS

1. ESTABLISHING ADJUSTED ANNUAL RHWM TIER 1 SYSTEM CAPABILITY

No later than 90 days prior to the start of each Fiscal Year, beginning with FY 2012, BPA shall determine the annual and monthly Average Megawatt and MWh amounts of Adjusted Annual RHWM Tier 1 System Capability for the upcoming Fiscal Year.

Such Adjusted Annual RHWM Tier 1 System Capability amounts shall be determined by adjusting the Fiscal Year amounts used to calculate the RHWM Tier 1 System Capability for known and determinable events that have occurred since the most recently concluded RHWM Process, such as changes in the availability or performance of Tier 1 System Resources, changes in Tier 1 System Obligations or the requirements of an applicable biological opinion, and which events: (1) would have caused BPA to use different assumptions in determining the RHWM Tier 1 System Capability had such events been known before the RHWM Process; (2) will result in the Adjusted Annual RHWM Tier 1 System Capability differing materially from the applicable annual RHWM Tier 1 System Capability; and (3) will be reflected in BPA's operation of the FCRPS during the applicable Fiscal Year. The monthly Average Megawatt amounts of Adjusted Annual RHWM Tier 1 System Capability so determined shall be specified in the applicable rows of the table below for each Fiscal Year. The monthly Adjusted Annual RHWM Tier 1 System Capability expressed in megawatt-hours will be the product of the monthly Adjusted Annual RHWM Tier 1 System Capability in Average Megawatts multiplied by the number of hours in the month, and will be specified in the applicable rows of the table below for each Fiscal Year.

Adjusted Annual RHWM Tier 1 System Capability													
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	annual aMW
Fiscal Year 2012													
Energy (aMW)													
Energy (MWh)													
Fiscal Year 2013													
Energy (aMW)													
Energy (MWh)													
Fiscal Year 2014													
Energy (aMW)													
Energy (MWh)													
Fiscal Year 2015													
Energy (aMW)													
Energy (MWh)													
Fiscal Year 2016													
Energy (MWh)													
Peak (MW)													
Fiscal Year 2017													
Energy (MWh)													
Peak (MW)													

Adjusted Annual RHWM Tier 1 System Capability													
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	annual aMW
Fiscal Year 2018													
Energy (aMW)													
Energy (MWh)													
Fiscal Year 2019													
Energy (aMW)													
Energy (MWh)													
Fiscal Year 2020													
Energy (aMW)													
Energy (MWh)													
Fiscal Year 2021													
Energy (aMW)													
Energy (MWh)													
Fiscal Year 2022													
Energy (aMW)													
Energy (MWh)													
Fiscal Year 2023													
Energy (aMW)													
Energy (MWh)													
Fiscal Year 2024													
Energy (aMW)													
Energy (MWh)													
Fiscal Year 2025													
Energy (aMW)													
Energy (MWh)													
Fiscal Year 2026													
Energy (aMW)													
Energy (MWh)													
Fiscal Year 2027													
Energy (aMW)													
Energy (MWh)													
Fiscal Year 2028													
Energy (aMW)													
Energy (MWh)													
Note: Fill in the table above with megawatt-hour values rounded to a whole number, and average megawatt values rounded to three decimal places.													

2. ESTABLISHING CRITICAL SLICE AMOUNTS

By September 15, 2011, and by each September 15 thereafter, BPA shall determine EWEB's Critical Slice Amounts by multiplying the monthly average megawatt amounts of Adjusted Annual RHWM Tier 1 System Capability set forth in the table in section 1 for each Fiscal Year by EWEB's Slice Percentage applicable to each such Fiscal Year stated in section 2 of Exhibit K. The Critical Slice Amounts so determined will be specified in the applicable row of the table below for each Fiscal Year. The monthly Critical Slice Amounts, expressed as megawatt-hours, shall be the product of the monthly Critical Slice Amounts in Average Megawatts multiplied by the number of hours in the applicable month, and will be specified in the applicable row of the table below for each Fiscal Year.

Annual Critical Slice Amount													
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	annual aMW
Fiscal Year 2012													
Energy (aMW)													
Energy (MWh)													
Fiscal Year 2013													
Energy (aMW)													
Energy (MWh)													
Fiscal Year 2014													
Energy (aMW)													
Energy (MWh)													
Fiscal Year 2015													
Energy (aMW)													
Energy (MWh)													
Fiscal Year 2016													
Energy (MWh)													
Peak (MW)													
Fiscal Year 2017													
Energy (MWh)													
Peak (MW)													
Fiscal Year 2018													
Energy (aMW)													
Energy (MWh)													
Fiscal Year 2019													
Energy (aMW)													
Energy (MWh)													
Fiscal Year 2020													
Energy (aMW)													
Energy (MWh)													
Fiscal Year 2021													
Energy (aMW)													
Energy (MWh)													
Fiscal Year 2022													
Energy (aMW)													
Energy (MWh)													
Fiscal Year 2023													
Energy (aMW)													
Energy (MWh)													
Fiscal Year 2024													
Energy (aMW)													
Energy (MWh)													
Fiscal Year 2025													
Energy (aMW)													
Energy (MWh)													
Fiscal Year 2026													
Energy (aMW)													
Energy (MWh)													
Fiscal Year 2027													
Energy (aMW)													
Energy (MWh)													

Annual Critical Slice Amount													
	Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**annual aMW**
Fiscal Year 2028													
Energy (aMW)													
Energy (MWh)													
Note: Fill in the table above with megawatt-hour values rounded to a whole number, and average megawatt values rounded to three decimal places.													

3. REVISIONS

By September 15, 2011, and by each September 15 thereafter, BPA shall provide EWEB a revised Exhibit I reflecting the annual and monthly Adjusted Annual RHWM Tier 1 System Capability and Critical Slice Amounts for the upcoming Fiscal Year determined in accordance with this Exhibit I, and a written summary stating any changes to the assumptions used by BPA to determine the RHWM Tier 1 System Capability for such Fiscal Year, the reasons for such change and the resulting impacts to the RHWM Tier 1 System Capability. Other changes shall be by mutual agreement of the Parties.

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Exhibit J
PRELIMINARY SLICE PERCENTAGE AND INITIAL SLICE PERCENTAGE

1. **PRELIMINARY SLICE PERCENTAGE**
   EWEB's Preliminary Slice Percentage is as specified below:
   Preliminary Slice Percentage = 1.69944%, or 0.0169944 as a decimal value.

2. **INITIAL SLICE PERCENTAGE**
   EWEB's Initial Slice Percentage shall be determined in accordance with section 4 of Exhibit Q. Promptly following such determination, BPA shall enter EWEB's Initial Slice Percentage below:

   Initial Slice Percentage = xx.xxxxx%, or 0.xxxxxxx as a decimal value.

3. **REVISIONS**
   No later than May 1, 2011, BPA shall revise section 2 of this Exhibit J to enter EWEB's Initial Slice Percentage.

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Exhibit K
ANNUAL DETERMINATION OF SLICE PERCENTAGE

1. ANNUAL SLICE PERCENTAGE DETERMINATION PROCESS

1.1 Definitions

The following definitions apply only to this exhibit.

1.1.1 "Slice Percentage Adjustment Ratio" or "SPAR" means, for a given Fiscal Year, the ratio that is determined by dividing: (1) the Initial CHWM by (2) the sum of the Initial CHWM and the Additional CHWM for such Fiscal Year. The SPAR shall be expressed as a five-digit decimal number and entered into the table in section 1.2 below.

1.1.2 "Tier 1 Purchase Amount" means the lesser of EWEB's Annual Net Requirement or EWEB's RHWM.

1.2 Establishing SPAR Amounts

No later than 15 days prior to the first day of each Fiscal Year, beginning with FY 2012, BPA shall compute the SPAR for such Fiscal Year and enter it into the table below.

Fiscal Year	Slice Percentage Adjustment Ratio
FY 2012	x.xxxxx
FY 2013	x.xxxxx
FY 2014	x.xxxxx
FY 2015	x.xxxxx
FY 2016	x.xxxxx
FY 2017	x.xxxxx
FY 2018	x.xxxxx
FY 2019	x.xxxxx
FY 2020	x.xxxxx
FY 2021	x.xxxxx
FY 2022	x.xxxxx
FY 2023	x.xxxxx
FY 2024	x.xxxxx
FY 2025	x.xxxxx
FY 2026	x.xxxxx
FY 2027	x.xxxxx
FY 2028	x.xxxxx

1.3 Determination of Slice Percentage

By September 15, 2011, and by each September 15 thereafter, BPA shall determine EWEB's Slice Percentage by adjusting EWEB's Initial Slice Percentage, as set forth in section 2 of Exhibit J, using the procedure set forth below.

1.3.1 **Annual Net Requirement Greater Than or Equal to the Product of AART1SC*ISP*SPAR**
If EWEB's Annual Net Requirement is greater than or equal to the product of: (1) the Adjusted Annual RHWM Tier 1 System Capability, (2) EWEB's Initial Slice Percentage, and (3) the SPAR, then EWEB's Slice Percentage shall be set equal to its Initial Slice Percentage multiplied by the SPAR.

1.3.2 **Annual Net Requirement Less Than the Product of AART1SC*ISP*SPAR**
If EWEB's Annual Net Requirement is less than the product of: (1) the Adjusted Annual RHWM Tier 1 System Capability, (2) EWEB's Initial Slice Percentage, and (3) the SPAR, then EWEB's Slice Percentage shall be set equal to the ratio determined by dividing (A) the product of EWEB's Tier 1 Purchase Amount and the SPAR, by (B) the Adjusted Annual RHWM Tier 1 System Capability.

2. SLICE PERCENTAGE

BPA shall enter EWEB's Slice Percentage calculated pursuant to section 1.3 of this exhibit into the table below as a percentage rounded to the fifth digit, and as a decimal value rounded to the seventh digit.

Fiscal Year	Slice Percentage (decimal value)
FY 2012	xx.xxxxx % (0.xxxxxxx)
FY 2013	xx.xxxxx % (0.xxxxxxx)
FY 2014	xx.xxxxx % (0.xxxxxxx)
FY 2015	xx.xxxxx % (0.xxxxxxx)
FY 2016	xx.xxxxx % (0.xxxxxxx)
FY 2017	xx.xxxxx % (0.xxxxxxx)
FY 2018	xx.xxxxx % (0.xxxxxxx)
FY 2019	xx.xxxxx % (0.xxxxxxx)
FY 2020	xx.xxxxx % (0.xxxxxxx)
FY 2021	xx.xxxxx % (0.xxxxxxx)
FY 2022	xx.xxxxx % (0.xxxxxxx)
FY 2023	xx.xxxxx % (0.xxxxxxx)
FY 2024	xx.xxxxx % (0.xxxxxxx)
FY 2025	xx.xxxxx % (0.xxxxxxx)
FY 2026	xx.xxxxx % (0.xxxxxxx)
FY 2027	xx.xxxxx % (0.xxxxxxx)
FY 2028	xx.xxxxx % (0.xxxxxxx)

3. REVISIONS

BPA shall revise the table in section 1.2 and the table in section 2 of this Exhibit K for each Fiscal Year in accordance with the terms of this Exhibit K. Other changes to this Exhibit K shall be by mutual agreement of the Parties.

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Exhibit L
RHWM AUGMENTATION

1. RHWM AUGMENTATION AMOUNTS

The amounts of RHWM Augmentation applicable to each Fiscal Year of each Rate Period shall be entered into the table below no later than 60 days after the conclusion of the RHWM Process for each such Rate Period.

Fiscal Year	RHWM Augmentation
FY 2012	xxx aMW
FY 2013	xxx aMW
FY 2014	xxx aMW
FY 2015	xxx aMW
FY 2016	xxx aMW
FY 2017	xxx aMW
FY 2018	xxx aMW
FY 2019	xxx aMW
FY 2020	xxx aMW
FY 2021	xxx aMW
FY 2022	xxx aMW
FY 2023	xxx aMW
FY 2024	xxx aMW
FY 2025	xxx aMW
FY 2026	xxx aMW
FY 2027	xxx aMW
FY 2028	xxx aMW

2. MODELING OF RHWM AUGMENTATION IN THE SLICE COMPUTER APPLICATION

The amounts of RHWM Augmentation listed in section 1 of this exhibit will be a component of the BOS Base amount as determined by the BOS Module pursuant to section 4.4.1 of Exhibit M, and shall be made available to EWEB in a Flat Annual Shape for the applicable Fiscal Year.

3. REVISIONS

This Exhibit L shall be revised by BPA in accordance with its terms and such revision provided to EWEB not later than 60 days after the conclusion of each RHWM Process.

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Exhibit M
SLICE COMPUTER APPLICATION

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1. SLICE COMPUTER APPLICATION – GENERAL DESCRIPTION

The Slice Computer Application is a proprietary BPA computer application developed and maintained by BPA in consultation with EWEB and other SIG members. The Slice Computer Application consists of the Slice Water Routing Simulator, the Balance of System Module, the Default User Interface, and other related processes used for scheduling, tagging, and accounting of Slice Output and communication of information, all as described below.

The Slice Computer Application is used to determine EWEB's hourly Slice Output Energy amounts that will be made available by Power Services for delivery to EWEB. The total amount of Slice Output Energy to be scheduled each hour is comprised of the results of the Simulator and the BOS Module, as set forth in section 7 of this exhibit.

In the event Exhibit O is implemented pursuant to section 5.10.3.2 of the body of this Agreement, only sections 3.5, 5, 8, and 9 of this Exhibit M shall be in effect as long as Exhibit O remains in effect.

2. DEFINITIONS

The following definitions apply only to this Exhibit M.

2.1 "Algorithm Tuning Parameters" means factors, coefficients, or variables that are embedded within Simulator algorithms or formulas and are adjusted by Power Services as needed to appropriately implement provisions of this Agreement.

2.2 "Bypass Spill" means Spill that occurs at a hydroelectric project associated with lock operations, leakage and fish bypass systems.

2.3 "Forced Spill" means Spill other than Bypass Spill, Elective Spill, or Fish Spill that occurs at a hydroelectric project and is unavoidable in order to operate the project within applicable Operating Constraints.

2.4 "Incremental Side Flows" means the portion of a hydroelectric project's natural inflow that enters the river on which the project is located between that project and the next-upstream project.

2.5 "Logic Control Parameters" means flags or toggles that are embedded within the Slice Computer Application logic and are set by Power Services as needed to appropriately implement provisions of this Agreement.

2.6 "Simulator Initialization Time" means the date and time that represents the beginning of the first one-hour period of the Simulator Modeling Period.

2.7 "Simulator Modeling Period" means the variable time period represented by the Simulator output, including between 41 and 48 one-hour time periods and an additional 22 to 24 eight-hour time periods, as described in section 3.1.2 of this exhibit.

3. SLICE WATER ROUTING SIMULATOR

3.1 General Description

The Simulator is designed to determine EWEB's potential range of available Simulated Output Energy Schedules and Delivery Limits associated with the Simulator Projects. EWEB shall utilize the Simulator to simulate the routing of available stream flow through the Simulator Projects in compliance with established Simulator Parameters. Power Services is responsible for establishing and managing Simulator Parameters within the Simulator, pursuant to section 3.2 of this exhibit, and EWEB is responsible for establishing and managing Customer Inputs within the Simulator, pursuant to section 3.3 of this exhibit. EWEB shall use the Slice Computer Application to determine and make its requests for Slice Output Energy scheduled from Power Services.

3.1.1 The Simulator will be managed, updated and maintained by BPA. EWEB shall have access to the Simulator for the purpose of running various Simulated Operating Scenarios.

3.1.2 The Simulator shall be designed to produce Simulated Operating Scenarios in one-hour time periods for no less than 41 hours and no more than 48 hours, and additional eight-hour time periods for no less than 22 periods and no more than 24 periods, depending upon the Simulator Initialization Time.

3.1.2.1 The one-hour time periods shall begin with the hour that directly follows the Simulator Initialization Time and will continue for between 41 and 48 hours, ending with either Scheduling Hour 06, 14, or 22.

3.1.2.2 The eight-hour time periods shall include the three periods each day ending with Scheduling Hours 06, 14, and 22. The eight-hour time periods shall begin with the first eight-hour period following the one-hour time periods and shall continue for between 22 and 24 periods, ending with the eight-hour period that ends with Scheduling Hour 22.

3.1.3 The Simulator shall incorporate approximate hydraulic time lags between Simulator Projects.

3.1.4 The Simulator shall reflect the application of all Operating Constraints in effect for each Simulator Project, including compliance with Operating Constraints in effect at downstream projects.

3.1.5 The Simulator shall calculate simulated inflows to Grand Coulee based upon forecast (or measured when available) discharges from upstream projects plus forecast Incremental Side Flows between those projects and Grand Coulee, as adjusted for forecast Banks Lake irrigation pumping flows.

3.1.6 The Simulator shall compute the simulated Grand Coulee discharge, generation, and forebay elevation based on EWEB's Customer Inputs and shall use such computed discharge to establish EWEB's simulated Chief Joseph inflow, given appropriate time lags, and as adjusted for forecast Chief Joseph Incremental Side Flows.

3.1.7 The Simulator shall calculate simulated inflows to McNary based upon forecast (or measured when available) discharges from Priest Rapids and Ice Harbor after considering approximate hydraulic time lags between those projects and McNary, as adjusted for forecast McNary Incremental Side Flows. The Simulator shall also incorporate EWEB's Hydraulic Link Adjustment, pursuant to section 3.7 of this exhibit, into EWEB's simulated McNary inflow.

3.1.8 The Simulator shall compute the simulated McNary discharge, generation, and forebay elevation based on EWEB's Customer Inputs and shall use such computed discharge to establish EWEB's simulated

John Day inflow, given appropriate time lags, and as adjusted for forecast John Day Incremental Side Flows.

3.1.9 The Simulator will compute the simulated discharge, generation and forebay elevations for John Day, The Dalles and Bonneville, as well as simulated inflows into The Dalles and Bonneville for EWEB, in a like manner.

3.1.10 The Simulator will not be designed to accept aggregated Customer Inputs for the LCOL Complex or the Coulee-Chief Complex. EWEB may develop aggregated Customer Inputs for use in its in-house processes but must translate such aggregated Customer Inputs into individual Customer Inputs for each Simulator Project to enable the Slice Computer Application to validate EWEB's simulated operation of individual Simulator Projects against Operating Constraints.

3.2 **Simulator Parameters**

Power Services shall establish, monitor and update the Simulator Parameters, as specified in this section 3.2, applicable to each Simulator Project to reflect: (1) Operating Constraints in effect or to take effect at the actual Tier 1 System Resource, and (2) forecast system conditions used by BPA in the operation of the Tier 1 System Resources, for the entire Simulator Modeling Period. Power Services shall designate each Operating Constraint established as a Simulator Parameter as either an Absolute Operating Constraint, a Hard Operating Constraint, or a Soft Operating Constraint. The simulated operating capability available from the Simulator Projects as affected by the Simulator Parameters shall reasonably represent the actual operating capability available from the Tier 1 System Resources that comprise the Simulator Projects as affected by the associated Operating Constraints. To the maximum extent practicable, Power Services shall monitor the operating conditions that affect the Simulator Projects and shall revise the Simulator Parameters as necessary to reflect changes.

3.2.1 Power Services shall have the right to revise Simulator Parameters affecting each Scheduling Hour up to one hour prior to the beginning of each such Scheduling hour. For example, Power Services shall have the right to revise Simulator Parameters affecting Scheduling Hour 13 up until 11:00 a.m.

3.2.2 The Simulator Parameters shall include:

(1) Hourly regulated inflows (Grand Coulee and McNary only);

(2) Hourly Incremental Side Flows;

(3) Initial forebay elevations;

(4) Water to energy conversion factors (H/Ks);

(5) Content to elevation conversion tables;

(6) Project turbine capacities;

(7) Spill limitations and requirements, including Bypass Spill quantities;

(8) Generation limitations and requirements;

(9) Discharge limitations and requirements as needed to meet both discharge and tailwater elevation requirements;

(10) Forebay limitations and requirements;

(11) System wide requirements that affect the Simulator Projects (e.g. Vernita Bar, chum spawning, or Operating Reserves);

(12) Algorithm Tuning Parameters;

(13) Logic Control Parameters that affect the Simulator Projects (e.g. CGS Displacement election, PSB enforcement flag, etc.); and,

(14) Simulator Parameters as implemented pursuant to section 5.12 of the body of this Agreement and included in the specification manual described in section 3.5.1 of this exhibit.

3.3 **EWEB's Customer Inputs and Use of the Simulator**
EWEB shall be responsible for accessing the Simulator and submitting at least one Customer Input for each of the Simulator Projects for each one-hour and eight-hour time period for the entire Simulator Modeling Period. EWEB is required to submit Customer Inputs to the Simulator separately from all other Slice Customers' Customer Inputs.

3.3.1 Customer Inputs shall include:

(1) Generation requests;

(2) Elevation requests;

(3) Discharge requests; and,

(4) Customer Inputs as implemented pursuant to section 5.12 of the body of this Agreement and included in the specification manual described in section 3.5.1 of this exhibit.

3.3.2 Customer Inputs shall be stated in terms of whole project capability rather than EWEB's Slice Percentage of project capability.

3.3.3 The Simulator shall include criteria for prioritizing Customer Inputs among generation, elevation, and discharge requests. Using these criteria, EWEB may specify, in its Customer Inputs, the relative priority of its generation, elevation, or discharge requests, which shall be used by the Simulator to produce a Simulated Operating Scenario in accordance with applicable Simulator Parameters.

3.3.4 Upon submission to Power Services, the Simulator shall process EWEB's Customer Inputs to determine a Simulated Operating Scenario. The simulated generation values resulting from each Simulated Operating Scenario shall represent EWEB's potential Simulated Output Energy Schedules. Simulated Output Energy Schedules are not considered schedules for power delivery.

3.3.5 For each Simulated Operating Scenario the Slice Computer Application will provide EWEB with a report stating for each Simulator Project: (1) the resulting simulated generation, discharge and elevation values, (2) which, if any, Absolute or Hard Operating Constraints limited the Simulated Operating Scenario, and (3) which, if any, Absolute or Hard Operating Constraints were violated.

3.3.6 If EWEB submits Customer Inputs for a Simulated Operating Scenario that would otherwise result in violations of one or more Absolute or Hard Operating Constraints, the Simulator shall, to the extent possible, establish a Simulated Operating Scenario that conforms to the Absolute or Hard Operating Constraints. In such event, EWEB shall make the election to either cancel the submission of its Customer Inputs or accept the results of the Simulated Operating Scenario.

3.3.7 EWEB shall have the right to modify and submit to Power Services its Customer Inputs for each Scheduling Hour within the scheduling deadline established in section 4.1 of Exhibit F. As of the scheduling deadline prior to each Scheduling Hour, the Simulator shall process the Customer Inputs last submitted by EWEB to determine EWEB's final Simulated Operating Scenario and associated final Slice Output Energy Schedules, which shall be the basis of EWEB's Delivery Request, as described in section 7 of this exhibit, for each such Scheduling Hour.

3.3.8 At least once per day, EWEB shall be required to produce a Simulated Operating Scenario that demonstrates all Simulator Projects are in compliance with all applicable Operating Constraints for the duration of the Simulator Modeling Period.

3.3.9 Power Services shall provide EWEB with access, via the Slice Computer Application, to a test version of the Simulator that can be used for scenario testing. In this test version EWEB shall have the ability to modify Simulator Parameters.

3.4 **Simulator Output**
Based on the Simulator Parameters and Customer Inputs in effect, the Simulator shall produce the following results for each one-hour and eight-hour time period for the entire Simulator Modeling Period:

3.4.1 EWEB's potential Simulated Output Energy Schedules (simulated generation), simulated discharge, and simulated forebay elevation associated with each Simulator Project.

3.4.2 A list of Customer Inputs that resulted in violation of Operating Constraints within the Simulated Operating Scenario, pursuant to section 3.3.6 of this exhibit, or that were not achieved by the Simulator, for each Simulator Project.

3.4.3 A list of Operating Constraints that were violated within EWEB's simulated operation for each Simulator Project.

3.4.4 An explanation for each occurrence listed pursuant to sections 3.4.2 and 3.4.3 of this exhibit.

3.4.5 EWEB's Hydraulic Link Adjustment amounts as established pursuant to section 3.7 of this exhibit.

3.5 **Simulator Documentation, Performance Test, and Accuracy**

3.5.1 **Simulator Documentation**
Power Services, with EWEB's input, shall develop a manual with specifications describing the Simulator computations, processes and algorithms in sufficient detail to permit EWEB to understand and verify the Simulator computations and accuracy of the Simulator outputs. The Simulator specification manual shall include, but shall not be limited to, the following:

(1) A documented list of data points, including the source systems of record, such as BPA's internal modeling tools or stream flow forecasting databases, that are accessed and used to determine Simulator Parameters;

(2) Full documentation, excluding computer code, of the processes by which the Simulator computes and produces output values;

(3) Full documentation, excluding computer code, of the Simulator functions available to EWEB, including access and controls of the Simulator; and

(4) Full documentation of the data output/display processes and communication protocols associated with EWEB's computer systems.

3.5.2 If requested, Power Services may provide EWEB assistance in developing an operational manual to explain how the Simulator is to be operated by EWEB. After a reasonable period of time (as determined by Power Services) following the SCA Implementation Date, Power Services may charge EWEB for any such assistance Power Services provides.

3.5.3 **Simulator Performance Test**
Power Services shall conduct the Simulator Performance Test specified in this section 3.5.3 of this exhibit, and as required pursuant to section 5.10.4 of the body of this Agreement and section 3.5.4.2 of this exhibit.

3.5.3.1 **Storage Content Test**
Using actual stream flows (including calculated Incremental Side Flows), operating constraints, initial monthly Simulator Project forebay elevations, and Simulator Project discharges for the months of January through September 2010, as input parameters, Power Services shall produce Simulated Operating Scenarios for each month of that period. Power Services shall compute the hourly Storage Content difference for each Simulator Project as the difference between the simulated Storage Content and the actual Storage Content for each such Simulator Project for each hour of the test period. For each month of the test period, a Simulator Project will have passed the Storage Content test if: (1) the hourly Storage Content difference is greater than the Storage Content value contained in column A of the table below on no more than 4 percent of the hours in the month; and, (2) no hourly Storage Content difference during the month is greater than the lesser of (i) the Storage Content value contained in column B of the table below or (ii) one-half of the applicable monthly available Storage Content. If a Simulator Project fails either of these tests for a month, then such Simulator Project will have failed the Storage Content test for such month.

Simulator Project	Column A	Column B
Grand Coulee	5 ksfd	15 ksfd
Chief Joseph	5 ksfd	11.5 ksfd
McNary	5 ksfd	15 ksfd
John Day	5 ksfd	15 ksfd
The Dalles	5 ksfd	12.5 ksfd
Bonneville	5 ksfd	15 ksfd

The overall Storage Content test will be deemed to have failed if one or more of the following occurs:

(1) Grand Coulee fails the test in one or more of the nine months;

(2) More than 25 percent of the 54 monthly tests fail;

(3) Four or more Simulator Projects fail the test in any single month; or

(4) Any of the Simulator Projects fail the test in all 9 months.

3.5.3.2 **Energy Test**

Using actual stream flows (including calculated Incremental Side Flows), operating constraints, initial monthly Simulator Project forebay elevations, Simulator Project discharge values, and Simulator Project H/Ks for the months of January through September 2010, as input parameters, Power Services shall produce Simulated Operating Scenarios for each month of that period. Power Services shall compute the daily and monthly differences between the simulated generation and actual generation for each Simulator Project. For each month of the test period, a Simulator Project will have passed the energy test if: (1) for each day of the month the daily generation difference is no greater than 5 percent of the associated Simulator Project's actual daily generation; and, (2) the monthly generation difference is no greater than 3 percent of the associated Simulator Project's actual monthly generation. The overall energy test will be deemed to have failed if one or more of the following occurs:

(1) Grand Coulee fails the test in one or more of the 9 months;

(2) More than 25 percent of the 54 monthly tests fail;

(3) Four or more Simulator Projects fail the monthly test in any single month; or

(4) Any of the Simulator Projects fail the test in all 9 months.

3.5.3.3 **Peaking Test**

Power Services shall produce a separate Simulated Operating Scenario as specified below, for the hottest consecutive 3-day period and the coldest consecutive 3-day period that occurred during the period January through September 2010.

The 3-day test periods shall be determined by Power Services based on the weighted-average temperatures for three major load centers: Portland, Seattle, and Spokane. The weighted-average temperatures for these load centers will be determined as follows:

(1) Each city's daily maximum and daily minimum temperature will be averaged;

(2) The resulting day-average temperature from each city will be weighted by applying load center percentage weightings, which will be determined by Power Services and will sum to 100 percent for the three cities; and

(3) The resulting weighted day-average temperatures for each city will then be combined to determine each day's weighted-average load center temperature.

The daily weighted-average load center temperatures will be averaged for each consecutive 3-day period for the January through September 2010 period. The lowest such average will establish the coldest 3-day period and the highest such average will establish the hottest 3-day period.

The Simulated Operating Scenarios will be developed using actual stream flows (including calculated Incremental Side Flows), operating constraints, and initial Simulator Project forebay elevations from the 3-day test periods as input parameters. Each Simulator Project's hourly generation request will be set equal to such Simulator Project's actual generation value from the representative test periods. Power Services will compare each of the Simulator Project's simulated hourly generation values to such Simulator Project's actual hourly generation values for each of the 6 peak hours on any of the test days. The 6 peak hours shall be established as the 6 hours with the largest combined actual Simulator Project generation each day. The peaking test will be deemed to have failed if either of the following occurs:

(1) The Simulator Projects' combined simulated generation value deviates from the Simulator Projects' combined actual generation value by more than 200 aMW over the 6 peak hours on any of the test days; or

(2) The Simulator Projects' combined simulated generation value deviates from the Simulator Projects' combined actual generation value by more than 400 MW on any of the 6 peak hours on any of the test days.

3.5.3.4 **Ramp Down Test**

Using actual stream flows (including calculated Incremental Side Flows), operating constraints, initial Simulator Project forebay elevations, and Simulator Project generation values from the dates specified below as input parameters, Power Services shall develop a separate Simulated Operating Scenario for each specified date. Power Services shall compute the difference between the simulated Grand Coulee generation change and the actual Grand Coulee generation change for each two consecutive hours between Scheduling Hour 20 and Scheduling Hour 02 for each study day. The ramp down test will be deemed to have failed if one or more of the following occurs:

(1) The difference between the simulated and actual Grand Coulee generation change is greater than 300 MW on any two consecutive hours between Scheduling Hour 20 and Scheduling Hour 02, on any ramp down test date;

(2) The average difference between the simulated and actual Grand Coulee generation change is greater than 100 MW for each two consecutive hours between Scheduling Hour 20 and Scheduling Hour 02 on any ramp down test date.

(3) The ramp down test dates will be:
January 7-8 (Th-F) and 16-17 (Sa-Su), 2010,
February 4-5 (Th-F) and 24-25 (W-Th), 2010,
March 10-11 (W-Th) and 22-23 (M-Tu), 2010,
April 2-3 (F-Sa) and 19-20 (M-Tu), 2010,
May 6-7 (Th-F) and 27-28 (Th-F), 2010,
June 9-10 (W-Th) and 21-22 (M-Tu), 2010,
July 1-2 (Th-F) and 30-31 (F-Sa), 2010,
August 12-13 (Th-F) and 20-21 (F-Sa), 2010,
September 6-7 (M-Tu) and 16-17 (Th-F), 2010.

3.5.3.5 **Changes to Simulator Performance Test Criteria**

If the Simulator Performance Test fails, and after Power Services discusses the results of the test with EWEB, the Parties agree the test criteria is unreasonable, inappropriate, or unattainable, then the Parties may mutually agree to either deem the Simulator Performance Test as having passed, or alter the test criteria prior to conducting subsequent Simulator Performance Tests.

3.5.4 **Simulator Accuracy**

EWEB and Power Services acknowledge that model errors are inevitable. No cumulative accounting of model error impacts shall be required or established.

3.5.4.1 To minimize such errors Power Services shall ensure Simulator Parameters established for the Simulator reasonably reflect the expected values for forecasted inflows and Operating Constraints and that the Simulator reasonably represents the operational attributes of the Simulator Projects. Power Services shall develop a process to account and correct for differences between forecasted and measured inflows and H/K values reflected in the Simulator in an effort to minimize cumulative deviations. EWEB shall accept such inputs and corrections, and shall ensure that Customer Inputs established for the Simulator reasonably reflect EWEB's intended use of hourly scheduling flexibility within the established Delivery Limits.

3.5.4.2 As an ongoing check of the Simulator's accuracy, Power Services shall run a retrospective Simulator Performance Test as described in section 3.5.3 of this exhibit by October 31 of each calendar year during the term of this Agreement, beginning with calendar year 2012. The Simulator accuracy criteria for each Simulator Performance Test shall be set equal to actual Simulator accuracy associated with the preceding Simulator Performance Test results, unless the Parties agree otherwise through the SIG process. The specific study dates for each Simulator Performance Test shall be as agreed by the Parties. The test criteria for each Simulator Performance Test may be modified as agreed by the Parties. The results of each such test shall be made available to EWEB by November 15 of each calendar year. The frequency of such tests may be modified by agreement of the Parties through the SIG process.

3.5.4.3 If any annual Simulator Performance Test results are not within the accuracy criteria established pursuant to section 3.5.4.2 of this exhibit, Power Services, in consultation with EWEB and other members of the SIG, shall promptly implement modifications needed to bring the Simulator output in compliance with such accuracy criteria.

3.5.5 **Documentation of Simulator Updates, Upgrades, or Replacements and EWEB's Required Actions**

At least 30 days prior to Power Services implementing any updates, upgrades, or replacements to the Simulator, the Simulator specifications manual described in section 3.5.1 of this exhibit shall be revised by Power Services and distributed to EWEB's SIG representative. Within such 30 day period EWEB shall test its systems and provide sufficient training to its staff to allow it to prudently manage the changes resulting from the updates, upgrades, or replacements.

3.6 Calculation and Application of the Calibrated Simulator Discharge

3.6.1 Power Services shall calculate EWEB's Calibrated Simulator Discharge for each Simulator Project by summing the following components for each hour.

(1) The value produced by dividing EWEB's Simulated Output Energy Schedule by the actual H/K associated with each such Simulator Project. For Grand Coulee and Chief Joseph the actual H/K shall reflect the previous day average, whereas for all other Simulator Projects, the actual H/K shall reflect the previous hour. For Grand Coulee only, the actual H/K shall reflect an adjustment based on EWEB's SOA for Grand Coulee;

(2) The actual Bypass Spill associated with each such Simulator Project;

(3) The actual required Fish Spill associated with each such Simulator Project;

(4) EWEB's simulated Elective Spill associated with each such Simulator Project; and,

(5) EWEB's simulated Forced Spill associated with each such Simulator Project.

3.6.2 EWEB's Calibrated Simulator Discharge for each Simulator Project shall be used to establish EWEB's Storage Offset Account balances, as described in section 4 of Exhibit N.

3.7 Calculation and Application of the Hydraulic Link Adjustment

3.7.1 EWEB's Hydraulic Link Adjustment values shall be determined for the following periods of each day of this Agreement, beginning October 1, 2011.

(1) The period including hours ending 2300 through 0600;

(2) The period including hours ending 0700 through 1400; and

(3) The period including hours ending 1500 through 2200.

3.7.2 EWEB's Hydraulic Link Adjustment values shall be equal to EWEB's average Chief Joseph Calibrated Simulator Discharge for each period above, minus the average Chief Joseph measured discharge for the same period.

3.7.3 EWEB's Hydraulic Link Adjustment values shall be applied as an adjustment to EWEB's simulated inflow to McNary in an equivalent amount for each hour of the same period for the following day.

4. BALANCE OF SYSTEM MODULE

The BOS Module will include processes that compute: (1) the BOS Base amounts, (2) the BOS Flex amounts, (3) EWEB's BOS Deviation Return amounts, and (4) EWEB's Additional Energy amounts, all as specified below.

4.1 BOS Base Amount

Consistent with the following provisions, the BOS Base amount shall be determined by Power Services and provided to EWEB.

4.1.1 The BOS Base amount, for each hour, shall be equal to the sum of: (1) Power Services' latest planned or scheduled generation amounts associated with the BOS Complex projects, (2) the amount of Elective Spill Power Services implements on the BOS Complex projects, (3) the amount of RHWM Augmentation, as described in Exhibit L, and (4) the forecast amount of energy associated with Tier 1 System Obligations. Tier 1 System Obligations will be netted against or added to the BOS Complex generation as appropriate. Energy associated with RHWM Augmentation included in the BOS Base amount shall be applied in equal amounts each hour of each FY.

4.1.2 EWEB's hourly BOS Base schedules shall be equal to the hourly BOS Base amounts multiplied by EWEB's Slice Percentage.

4.2 BOS Flex Amount

Consistent with the following provisions, the BOS Flex amount shall be determined by Power Services and made available to EWEB on an as available basis.

4.2.1 The BOS Module will: (1) determine if there is sufficient flexibility to reshape the hourly generation associated with the Lower Snake Complex that is included in the BOS Base amount, and if so, (2) provide as output the resulting amount by which the BOS Base amount can be increased or decreased on any given hour. The BOS Module will specify the BOS Flex amounts that are available for preschedule as well as adjusted BOS Flex amounts that are available for real-time.

4.2.2 Such BOS Flex amounts shall reflect, in the judgment of Power Services, the amount by which the BOS Base amount can reasonably be reshaped using the within-day flexibility available in the Lower Snake Complex, taking into account the Operating Constraints and stream flow conditions.

4.2.3 EWEB shall determine its planned hourly use of the BOS Flex and submit to Power Services as part of the preschedule process, positive and negative hourly BOS Flex schedules that sum to zero for each day. A positive hourly BOS Flex schedule shall reflect an increase relative to the BOS Base amount and a negative hourly schedule shall reflect a decrease relative to the BOS Base amount.

4.2.4 In real-time, EWEB shall update its hourly BOS Flex schedules to comply with revised BOS Flex amounts. If a mid-day change to the BOS Flex amounts prohibits EWEB from scheduling its net day-total BOS Flex energy to equal zero, then EWEB shall adjust its BOS Flex schedules to bring its net day total BOS Flex schedule as close to zero as possible within the revised BOS Flex amounts. EWEB's BOS Deviation Account balance shall be adjusted to compensate for any non-zero day-total BOS Flex amount scheduled for any calendar day.

4.2.5 The BOS Flex available to EWEB shall be equal to the BOS Flex determined pursuant to this section 4.2 multiplied by EWEB's Slice Percentage.

4.2.6 If EWEB determines it has a significant risk of not meeting its firm load service at any time, EWEB may request that Power Services, as time permits and based on its professional judgment, assess the ability to modify the established BOS Flex amounts within applicable Operating Constraints. If Power Services alters such BOS Flex amounts, such updated values shall apply to all Slice Customers. EWEB acknowledges such assessment by Power Services may result in an increase, decrease or no change to any of the remaining hourly BOS Flex amounts.

4.3 **BOS Deviation Return Amounts**
The BOS Module will compute and establish EWEB's BOS Deviation Return amounts as established in section 4.4.1 of Exhibit N.

4.4 **Additional Energy Amounts**
The BOS Module will compute and establish EWEB's Additional Energy schedules pursuant to section 5.8 of the body of this Agreement.

4.5 **Total BOS Amounts**
EWEB's total BOS amount shall be equal to the sum of the following components, rounded to a whole number:

(1) the BOS Base schedule as established pursuant to section 4.1 of this exhibit;

(2) the BOS Flex schedule as established pursuant to section 4.2 of this exhibit;

(3) the BOS Deviation Return amount described in section 4.3 of this exhibit; and,

(4) the Additional Energy amount described in section 4.4 of this exhibit.

5. DEFAULT USER INTERFACE

Power Services shall develop and maintain a Default User Interface (DUI) for EWEB's use in interacting with the Slice Computer Application. EWEB may utilize the DUI as its primary interface or may use an interface it develops in-house. If EWEB's primary interface is not the DUI, then EWEB shall maintain back-up functionality through, and staff capability to operate, the DUI in the event EWEB's in-house interface is unavailable. The DUI shall include the functional capabilities listed below.

(1) Provide EWEB access to the Simulator for submittal of Customer Inputs and to run Simulated Operating Scenarios.

(2) Provide EWEB feedback and reports from the Simulator and BOS Module as set forth in sections 3.4 and 4.2.1 of this exhibit.

(3) Provide EWEB input/output displays related to the Simulator and BOS Module.

6. SCA REPORTS

6.1 No later than 5 minutes following the end of each Scheduling Hour, the SCA shall provide EWEB a detailed report that specifies: (1) EWEB's Calibrated Simulator Discharges as specified in section 3.6 of this exhibit, (2) EWEB's SOA balances as specified in section 4 of Exhibit N, (3) EWEB's adjusted forebay elevations for the Simulator Projects as specified in section 4.3 of Exhibit N, and (4) the after-the-fact project data EWEB shall use to verify its hourly SOA balances.

6.2 Power Services shall make available to EWEB, via the Slice Computer Application, a report which shall present all changes to Simulator Parameters that have been made by Power Services between a user specified start date/time and end date/time. Power Services shall include brief, concise explanatory statements coincidental with significant Simulator Parameter changes.

6.3 Power Services shall make available to EWEB, via the Slice Computer Application, a report which shall present all Prudent Operating Decisions implemented by Power Services in the Simulator, between a user specified start date/time and end date/time. The report shall include the reason for imposing the Prudent Operating Decision and the manner in which Power Services incorporated the Prudent Operating Decision into the Simulator Parameters.

7. HOURLY DELIVERY REQUEST

EWEB's hourly Delivery Request for Slice Output Energy associated with any given Scheduling Hour shall be equal to the sum of the following components:

(1) the sum of EWEB's final Simulated Output Energy Schedules established per section 3.3.7 of this exhibit for each of the Simulator Projects multiplied by EWEB's Slice Percentage, rounded to a whole number; and,

(2) EWEB's total BOS amount, established pursuant to section 4.5 of this exhibit.

EWEB shall revise its hourly Delivery Requests for Slice Output Energy consistent with the requirements of section 3.4 of Exhibit F.

8. SCA TRIAL PERIODS

BPA shall facilitate four separate week-long SCA trial periods. During these trial periods, BPA shall maintain a test version of the SCA in a form as near to production status as possible, including the functionality for EWEB to submit Customer Inputs and run the Simulator to produce Simulated Operating Scenarios and final Simulated Operating Scenarios through the DUI and through the secure network protocols, and to receive results from the submittal processes. The selection of specific weeks for such trial periods will be coordinated through the SIG, but shall begin no later than April 1, 2011 and shall end no later than August 1, 2011. Results and feedback of the trial periods will be reported to the SIG at which time any suggestions for improving the SCA, the Simulator, or the processes necessary to support and maintain the SCA will be discussed and considered by the Parties.

9. REVISIONS

Revisions to this Exhibit M shall be by mutual agreement of the Parties.

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Exhibit N
SLICE IMPLEMENTATION PROCEDURES

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1. SLICE IMPLEMENTATION PROCEDURES – GENERAL DESCRIPTION

The procedures established in this Exhibit N shall be used by BPA and EWEB in conjunction with Exhibit M to implement deliveries of energy sold to EWEB under the Slice Product.

In the event Exhibit O is implemented pursuant to section 5.10.3.2 of the body of this Agreement and provisions of this Exhibit N are in conflict with provisions of Exhibit O, provisions of Exhibit O shall prevail.

2. DEFINITIONS

The following definitions apply only to this Exhibit N.

2.1 "Multiyear Hydroregulation Study" means a hydroregulation study that simulates the prospective monthly operation of the Tier 1 System, typically for a 12-month period, given a range of stream flow sequences.

2.2 "Slice Storage Account" or "SSA" means the account maintained by Power Services that records the sum of: (1) EWEB's Grand Coulee Storage Offset Account balance, and (2) the product of EWEB's Slice Percentage and the Grand Coulee actual Storage Content.

3. DATA PROVIDED BY POWER SERVICES

In addition to information exchanged and provided through provisions of Exhibit M and in order to assist EWEB in managing and planning the use of its Slice Output, Power Services shall provide EWEB the following information.

3.1 Tier 1 System operational information as described in sections 7, 8 and 9 of this exhibit.

3.2 EWEB's SOA and BOS deviation account balances as described in section 4 of this exhibit.

4. STORAGE AND DEVIATION ACCOUNTING

As described below, Power Services shall determine and make available to EWEB separate storage deviation account balances (Storage Offset Accounts or SOA) for each Simulator Project. The Storage Offset Accounts shall use measured project discharges, H/K values, and forebay elevations as benchmarks. Power Services shall also determine and make available to EWEB an energy deviation account balance for the BOS Complex. The BOS Deviation Accounting benchmark shall be the Actual BOS Generation.

4.1 EWEB's Storage Offset Account balances shall be established for each Simulator Project each hour in terms of the cumulative difference, expressed in thousands of second-foot-days (ksfd), between EWEB's simulated project Storage Contents and actual project Storage Contents, based on the sum of the following components:

4.1.1 For each Simulator Project except Grand Coulee and McNary, EWEB's Calibrated Simulator Discharge, as described in section 3.6 of Exhibit M, from the next-upstream Simulator Project minus such next-upstream Simulator Project's measured discharge, after considering approximate time lags;

4.1.2 The measured discharge from each Simulator Project minus EWEB's Calibrated Simulator Discharge from such Simulator Project;

4.1.3 For McNary only, EWEB's Hydraulic Link Adjustment, as described in section 3.7 of Exhibit M, and;

4.1.4 EWEB's prior-hour SOA balance for each Simulator Project.

4.2 Power Services shall initialize EWEB's September 30, 2011, SOA balance for each Simulator Project at zero.

4.3 For purposes of initializing EWEB's official hourly simulated forebay elevations in the Simulator, EWEB's SOA balance for each Simulator Project shall be added to the associated project's actual Storage Content and the result shall be converted to an equivalent forebay elevation using content-to-elevation tables established for such project.

4.4 EWEB's BOS Deviation Account shall be equal to the cumulative difference, expressed in MWd, between EWEB's BOS Base amount for each Scheduling Hour and the product of the Actual BOS Generation and EWEB's Slice Percentage for each such hour. EWEB's BOS Deviation Account balance shall be adjusted based on the following procedures:

4.4.1 Any time the absolute value of EWEB's BOS Deviation Account balance, as of midnight the day prior to a day on which prescheduling occurs, is greater than 2 MWd per EWEB's Slice Percentage (Slice Percentage * 2 * 100), EWEB shall schedule BOS Deviation Return energy each hour the following preschedule day in an amount equal to 1 MW per EWEB's Slice Percentage, rounded to a whole number. Such BOS Deviation Return energy shall be scheduled as positive or negative values, as appropriate to reduce EWEB's BOS Deviation Account balance toward zero.

4.4.2 On or before the 15th day of each month Power Services shall determine and provide to EWEB the results of an Actual BOS Generation calculation for the previous month that incorporates updated actual project generation and Tier 1 System Obligation values for each hour of such month. Based on the monthly Actual BOS Generation calculation, Power Services shall determine a monthly BOS deviation, expressed in MWd, relative to the hourly BOS Base amounts. On the 20th day of each month Power Services shall adjust EWEB's BOS Deviation Account balance by an amount equal to EWEB's Slice Percentage multiplied by the monthly BOS deviation associated with such previous month.

4.5 EWEB shall make all reasonable efforts to adjust its requests for deliveries of Slice Output Energy to reduce its SOA balances to zero by 2400 hours PPT on September 30, 2028, or the date of termination of this Agreement, whichever occurs earlier. Any balances in EWEB's SOAs as of the earlier of 2400 hours on September 30, 2028, or the date of termination of this Agreement shall be converted to energy amounts by multiplying such SOA balances by the associated federal downstream H/Ks. The resulting energy amounts shall be summed with EWEB's BOS Deviation Account balance as of the earlier of 2400 hours on September 30, 2028, or the date of termination of this Agreement. The resulting amount of energy, expressed in MWh, if positive, shall be delivered by Power Services to EWEB, or if negative, delivered by EWEB to Power Services, within the next 30 days after the termination of this Agreement.

5. OPERATING CONSTRAINT AND BOS FLEX VIOLATIONS

5.1 Operating Constraint Violations

The Simulator is designed such that EWEB's Simulated Operating Scenario maintains compliance with all Hard and Absolute Operating Constraints. However, Power Services and EWEB recognize there may be occasions where one or more Hard or Absolute Operating Constraints are violated within a Simulated Operating Scenario. In the event the Customer Inputs submitted by EWEB result in the violation of one or more Hard or Absolute Operating Constraints in a final Simulated Operating Scenario, as established per section 3.3.7 of Exhibit M, Power Services shall establish operating guidelines based upon its determination of how Power Services would operate the system under similar conditions, such as operating to a minimum flow constraint, that EWEB shall follow until such time as EWEB's final Simulated Operating Scenario is in compliance with all Operating

Constraints. Power Services may also, upon its determination that EWEB could have reasonably avoided such Operating Constraint violation, apply a penalty pursuant to section 5.1.4 of this exhibit for as long as such Hard or Absolute Operating Constraint is violated based upon EWEB's final Simulated Operating Scenarios.

5.1.1 EWEB shall be responsible for monitoring and anticipating potential Operating Constraint violations on a prospective basis and adjusting Customer Inputs as needed to maintain compliance.

5.1.2 Hourly Operating Constraint validations and violations associated with the Simulator Projects shall be based on Customer Inputs established by EWEB and submitted to Power Services within the Power Services real-time scheduling deadline pursuant to section 4.1 of Exhibit F.

5.1.3 Grand Coulee's Project Storage Bound validations, violations and resulting penalties shall be determined pursuant to section 6 of this exhibit.

5.1.4 Pursuant to the terms set forth in section 5 above, Power Services shall have the right to reduce EWEB's Delivery Request by up to 100% of EWEB's total Simulated Output Energy Schedule for the Lower Columbia Complex for lower Columbia Simulator Project violations, or the Coulee-Chief Complex for Grand Coulee or Chief Joesph Simulator Project violations, on any given hour, taking into account the extent to which BPA determines it would face consequences under similar conditions, subject to the following provisions:

5.1.4.1 Only for hours in which EWEB's final Simulated Operating Scenarios are in violation of a Hard or Absolute Operating Constraint at one or more Simulator Projects;

5.1.4.2 Only to the extent Power Services notifies EWEB of the reduction at least 60 minutes prior to the Scheduling Hour on which the reduction shall be applied;

5.1.4.3 Only to the extent EWEB fails to remedy the Operating Constraint violation prior to the deadline established in section 4.1 of Exhibit F, and;

5.1.4.4 Only for violations of Hard or Absolute Operating Constraints other than Grand Coulee's PSB.

5.2 **BOS Flex Violations**

Hourly Delivery Limit validations and violations associated with BOS Flex amounts shall be based on EWEB's BOS Flex schedules submitted to Power Services as of the deadline set forth in section 4.2 of Exhibit F. EWEB's BOS Flex schedules that exceed EWEB's Slice Percentage multiplied by positive

BOS Flex amounts shall be subject to the UAI Charge for energy and EWEB's BOS Flex schedules that are less than EWEB's Slice Percentage multiplied by negative BOS Flex amounts shall be forfeited.

6. GRAND COULEE PROJECT STORAGE BOUND (PSB) EXCEEDENCES

When Grand Coulee's upper or lower PSB is established as either a Soft or Hard Operating Constraint, EWEB's simulated Grand Coulee forebay elevation shall be validated against such Grand Coulee's PSB once each day. Such validations shall occur as of Scheduling Hour 05 for the upper PSB and Scheduling Hour 22 for the lower PSB. When Grand Coulee's upper or lower PSB is established as an Absolute Operating Constraint, no PSB validation will be necessary and the Simulator will not allow violations of Absolute Operating Constraints.

6.1 Determination of Grand Coulee PSB

Power Services shall estimate the upper and lower Grand Coulee PSB associated with each day of the following 3 months as part of each 3-month forecast submitted pursuant to section 8 of this exhibit, and shall update such Grand Coulee PSB as conditions change and as needed to reflect updated Operating Constraints. To determine Grand Coulee's PSBs, Power Services shall calculate the Storage Content associated with the Grand Coulee upper and lower ORCs as established by Operating Constraints in effect. Power Services shall apply a Storage Content difference between the upper and lower Grand Coulee PSB equivalent to at least ½-foot at all times except when Grand Coulee is required to fill to 1290.0 feet for verification of refill. Power Services may specify other conditions under which this ½-foot difference does not apply.

6.2 Application of the Grand Coulee PSB

Power Services shall designate each Grand Coulee PSB that does not represent an Absolute Operating Constraint as either a Hard Operating Constraint or a Soft Operating Constraint. Unless designated otherwise by Power Services, Grand Coulee PSB associated with date-specific required forebay elevations shall be designated as Hard Operating Constraints and Grand Coulee PSB associated with interpolated points in effect on days between such date-specific required forebay elevations shall be designated as Soft Operating Constraints. EWEB shall maintain its Slice Storage Account balance within the upper and lower Grand Coulee PSB that are designated as Hard Operating Constraints, or be subject to penalties as established in section 6.4 of this exhibit. EWEB's Slice Storage Account balance may exceed the upper or lower Grand Coulee PSB designated as Soft Operating Constraints without penalty. However, EWEB recognizes that maintaining an SSA that is not within the upper and lower Grand Coulee PSB increases EWEB's risk of violating the Grand Coulee PSB designated as Hard Operating Constraints and incurring the associated penalties.

6.3 Determination of EWEB's Grand Coulee PSB Exceedence

EWEB's Grand Coulee PSB exceedence shall be equal to the Storage Content by which EWEB's Slice Storage Account balance is: (1) in excess of the value determined by multiplying EWEB's Slice Percentage by the upper Grand

Coulee Project Storage Bound, or (2) less than the value determined by multiplying EWEB's Slice Percentage by the lower Grand Coulee Project Storage Bound. An upper Grand Coulee PSB exceedence is denoted as a positive value, while a lower Grand Coulee PSB exceedence is denoted as negative value.

6.4 **Grand Coulee PSB Exceedences, EWEB's Actions, and Penalties**

6.4.1 EWEB shall be responsible for monitoring its SSA balance and any Grand Coulee PSB exceedence. If EWEB's Grand Coulee PSB exceedence is positive, denoting an exceedence of the upper Grand Coulee PSB, on a day in which the upper Grand Coulee PSB is designated as a Hard Operating Constraint, the following shall apply.

6.4.1.1 EWEB shall immediately modify and submit to Power Services its Customer Inputs associated with Grand Coulee such that the most restrictive maximum discharge constraint in effect at the Simulator Projects is achieved in its Simulated Operating Scenario. EWEB shall maintain such simulated operation until such time as EWEB's SSA balance is within Grand Coulee's upper and lower PSB.

6.4.1.2 If EWEB fails to take the action specified in section 6.4.1.1 of this exhibit, then EWEB's Grand Coulee SOA balance shall be reduced by an amount equal to the PSB exceedence determined pursuant to section 6.3 of this exhibit.

6.4.2 If EWEB's Grand Coulee PSB exceedence is negative, denoting an exceedence of the lower Grand Coulee PSB, on a day in which the lower Grand Coulee PSB is designated as a Hard Operating Constraint, the following shall apply.

6.4.2.1 EWEB shall immediately modify and submit to Power Services its Customer Inputs associated with Grand Coulee such that the most restrictive minimum discharge constraint in effect at the Simulator Projects is achieved in its Simulated Operating Scenario. EWEB shall maintain such simulated operation until such time as EWEB's SSA balance is within Grand Coulee's upper and lower PSB.

6.4.2.2 If EWEB fails to take the action specified in section 6.4.2.1 of this exhibit, then a penalty shall be applied to EWEB equal to Grand Coulee's at-site Storage Energy amount, expressed in MWh, associated with the absolute value of the Grand Coulee PSB exceedence determined pursuant to section 6.3 of this exhibit multiplied by the UAI Charge for energy.

7. COMMUNICATIONS

7.1 EWEB shall be solely responsible for its internal dissemination of information provided by Power Services pursuant to Exhibit M and this Exhibit N.

7.2 EWEB shall be able to utilize the Default User Interface, as described in section 5 of Exhibit M, to review the Simulator Parameters established by Power Services.

7.3 Power Services shall make reasonable efforts to promptly notify EWEB of potential and significant system condition or operational changes via e-mail, XML messaging, and/or the daily conference call described in section 7.5 of this exhibit.

7.4 Power Services shall communicate Federal Operating Decisions and Prudent Operating Decisions to EWEB in the following manner:

7.4.1 An initial listing and description of Federal Operating Decisions and Prudent Operating Decisions that affect the Simulator Projects and are in effect as of September 30, 2011;

7.4.2 A publication via the Slice Computer Application as soon as practicable after BPA is informed of a Federal Operating Decision, or BPA makes either a Federal Operating Decision or Prudent Operating Decision affecting the Simulator Projects; and

7.4.3 A verbal report to the attendees during the next scheduled daily conference call as described in section 7.5 of this exhibit regarding Federal Operating Decisions or Prudent Operating decisions that have a material impact on the operation of the Simulator Projects, BOS Complex, or Tier 1 System Obligations.

7.5 Beginning September 28, 2011, and on each Business Day thereafter, Power Services shall initiate an informational conference call with EWEB and the other Slice Customers promptly at 12:40 PPT to discuss current and upcoming operating parameters and other related matters. The time and frequency of the call may be changed upon the mutual agreement of Power Services, EWEB, and the other SIG members. EWEB shall receive notice from Power Services via e-mail at least three Business Days prior to any such change.

7.6 Subject to the provisions set forth in section 5.12 of the body of this Agreement, Power Services, EWEB, and other Slice Customers shall establish a forum to review and discuss Operating Constraints and their application.

8. 3-MONTH FORECAST OF SLICE OUTPUT

8.1 Prior to September 24, 2011 and prior to the 24th day of each month thereafter, Power Services shall provide EWEB with the results of a 3-month forecast, pursuant to section 8.2 of this exhibit. Power Services shall revise such forecast during the month in the event conditions change significantly and shall make such revised forecast available to EWEB in a timely manner.

8.2 Power Services, consistent with its internal study processes, shall perform two single-trace hydroregulation studies that incorporate the expected stream flow condition for the upcoming 3-month period in weekly time periods. One study shall operate Grand Coulee as needed to satisfy the minimum Simulator Project flow constraint in order to attain the highest reservoir elevations possible at Grand Coulee, limited by its upper ORC, and one study shall operate Grand Coulee as needed to satisfy the Simulator Project maximum flow constraint in order to attain the lowest reservoir elevations possible at Grand Coulee, limited to its lower ORC. Both studies shall reflect a pass-inflow operation at all other Simulator Projects and the expected operation at all other Tier 1 System Resources and non-federal projects that are represented in the study, such as Brownlee, Kerr, and the mid-Columbia projects. Power Services shall initialize the starting reservoir Storage Contents for each study equal to the Storage Contents projected to occur at midnight on the study initialization date. Based on the results of these studies, Power Services shall provide to EWEB the weekly natural inflow, turbine discharge, generation, Spill discharge, and ending elevation for each of the Simulator Projects, the Snake Complex projects, Libby, Hungry Horse, Dworshak, and Keenleyside (Arrow); the weekly generation forecasts for the sum of the remaining BOS projects, excluding CGS; the weekly CGS generation forecast; and the weekly forecast of the individual Tier 1 System Obligations. Power Services shall also provide a summary of weekly aggregated planned generator maintenance outages for all Tier 1 System Resources, expressed in total MW, as well as the estimated daily Grand Coulee upper and lower PSB for the study period.

9. 12-MONTH FORECAST OF SLICE OUTPUT

9.1 Prior to July 15, 2011, and prior to each July 15 thereafter during the term of this Agreement, Power Services, EWEB, and other Slice purchasers shall meet to discuss and review inputs, assumptions, and content of the Multiyear Hydroregulation Study used to develop the 12-month forecast described in section 9.4 of this exhibit.

9.2 Prior to August 1, 2011, and prior to each August 1 thereafter during the term of this Agreement, Power Services shall provide EWEB with results from the 12-month forecast, pursuant to section 9.4 of this exhibit.

9.3 Prior to August 15, 2011, and prior to each August 15 thereafter during the term of this Agreement, Power Services, EWEB, and other Slice purchasers shall meet to discuss the results of the 12-month forecast described in section 9.4 of this exhibit.

9.4 Power Services, consistent with its internal study processes, shall perform a single Multiyear Hydroregulation Study for the upcoming October through September period representing a range of potential stream flow traces (typically 43 traces). The study shall reflect Grand Coulee operating to its ORC at times when its upper and lower ORC are equal. At times when Grand Coulee's upper and lower ORC are not equal, the study shall reflect Coulee operating in a manner that achieves all Simulator Project flow constraints when possible. The study shall represent a pass-inflow operation at all other Simulator Projects and the expected operation at all other Tier 1 System Resources and non-federal projects that are represented in the study, such as Brownlee, Kerr, and the mid-Columbia projects. Power Services shall initialize the starting reservoir Storage Contents for this study at the Storage Contents projected to occur at midnight on the study initialization date. Based on the results of this study, Power Services shall provide to EWEB the monthly natural inflow, turbine discharge, generation, Spill discharge, and ending elevation for each of the Simulator Projects, the Snake Complex projects, Libby, Hungry Horse, Dworshak, and Keenleyside (Arrow); the monthly generation forecasts for the sum of the remaining BOS projects, excluding CGS; the monthly CGS generation forecast; and the monthly forecast of the individual Tier 1 System Obligations. Power Services shall also provide a summary of monthly aggregated planned generator maintenance outages, expressed in total MW, for all Tier 1 System Resources.

10. CONGESTION MANAGEMENT

If there are congestion management requirements placed on Power Services by the Balancing Authority, Power Services shall adhere to the operational requirements of such congestion management requirements and shall apply such operational requirements to EWEB consistent with the terms of this Agreement.

11. CONFIDENTIALITY

BPA considers all prospective operational information associated with the Tier 1 System or any Tier 1 System Resource to be proprietary and business sensitive. Such information that is provided by BPA to EWEB or its scheduling agent pursuant to Exhibit M or this Exhibit N shall be treated as confidential by EWEB and its scheduling agent. EWEB shall limit its use of such information to its employees or agent solely for the implementation of the terms of this Agreement, and to no others. BPA reserves the right to withhold such operational information from scheduling agents that BPA determines are significant, active participants in WECC wholesale power or transmission markets and that are not purchasers of the Slice Product. If EWEB enlists the services of a scheduling agent that is not a purchaser of the Slice Product EWEB shall require its scheduling agent to develop systems or procedures that create functional separation between Slice related operational information and such scheduling agent's marketing functions.

12. REVISIONS

Revisions to this Exhibit N shall be by mutual agreement of the Parties.

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Exhibit O
INTERIM SLICE IMPLEMENTATION PROCEDURES

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This Exhibit O shall be implemented only if the SCA Implementation Date, as established pursuant to section 5.10.3.2 of the body of this Agreement, is later than October 1, 2011. If implemented, this Exhibit O shall be in effect beginning October 1, 2011 and shall remain in effect until the SCA Implementation Date.

If this Exhibit O is implemented, any provisions of this Exhibit O that are in conflict with provisions of Exhibit N shall prevail over such provisions of Exhibit N.

To implement the provisions of this Exhibit O, BPA and EWEB shall not utilize the Slice Computer Application as described in Exhibit M, but shall instead utilize the computer application developed and utilized to implement the Block and Slice Power Sales Agreements (Subscription Slice Agreements) that were in effect between October 1, 2001 and September 30, 2011. If EWEB was not a party to such Subscription Slice Agreements EWEB shall enlist the services of a BPA customer that was a party to such Subscription Slice Agreements, or its scheduling agent, in order to implement the provisions of this exhibit. The cost for such services that may be required for EWEB to implement this Exhibit O shall be borne solely by EWEB.

1. DEFINITIONS

Terms with initial capitalization that are not defined in this exhibit shall be as defined in the body of this Agreement. Generally, calculations associated with defined terms within this exhibit are for the whole of the Slice System. Wherever a similar value is needed for EWEB's share of the Slice System values, the term "individual" is inserted before the defined term. Defined terms that contain the word "Generation" are for the Slice System as a whole. Defined terms that contain the word "Output" or are preceded by "individual" are customer-specific.

For purposes of implementing this Exhibit O, all references to "Slice System", "Slice System Resources", "System Obligations", "Slice System Obligations" and any internal reference to "Slice System" will be deemed to mean Tier 1 System, such as Tier 1 System Resources, Tier 1 System Obligations and Tier 1 System Capability.

1(a) "Absolute Minimum Estimated Slice System Generation" means the least amount of energy the Slice System, as adjusted by System Obligations, can produce in a given time period.

1(b) "Actual Net Slice System Generation (ANSSG)" means the sum of the ATSG in megawatt-hours (MWh) and the gross Elective Spill in MWh used in the calculation of net Elective Spill in section 7(g)(2).

1(c) "Dispatchable Projects" means those Slice System generation resources that are available for redispatching with less advance notice than a calendar day, and include, but are not limited to, Grand Coulee, Chief Joseph, Lower Granite, Little Goose, Lower Monumental, Ice Harbor, McNary, John Day, The Dalles, and Bonneville.

1(d) "Estimated Slice System Generation (ESSG)" means the sum of the estimated generation produced at all the projects in the Slice System after adjustment for Operating Constraints and System Obligations over a given period of time.

1(e) "Fixed Flow" shall refer to an operational state when the maximum and minimum daily Estimated Slice System Generation, as provided by BPA pursuant to section 9(a)(5), are the same, and which is the result of Operating Constraints that restrict the ability to utilize the capability of the Slice System to store or draft water on different days.

1(f) "Grace Margin" means the amount by which EWEB may exceed its SSSB without incurring penalties.

1(g) "Grace Margin Spill Account (GMSA)" means the account which Power Services maintains that reflects the total amount of energy subtracted from the Slice purchasers' Slice Storage Deviation Accounts each day as a result of the Slice purchasers accruing Slice Storage Account balances that exceed their individual upper Slice System Storage Bound limit and their individual Grace Margin.

1(h) "Immediate Spill Deliveries" means energy BPA delivers to other parties for purposes of shifting spill from the FCRPS to the other parties' systems.

1(i) "Lower Snake Projects (LSN)" means the four hydroelectric Projects located on the lower reach of the Snake River, consisting of Lower Granite, Little Goose, Lower Monumental, and Ice Harbor.

1(j) "Non-Dispatchable Projects" means the Slice System generating resources that are not Dispatchable Projects.

1(k) "Pondage" means the ability of the hydro facilities of the Slice System to use lower river ponds (e.g., the LCOL and LSN) in combination with Grand Coulee and Chief Joseph to shift energy within the day and between days. Pondage includes Pondage Up and Pondage Down as described and calculated in section 3(c). Pondage Up may be used to exceed the daily maximum ESSG and/or the TOP HLH maximum ESSG. Pondage Down may be used to generate below the daily minimum ESSG.

1(l) "Ramp Rate" means the maximum rate of change in the level of generation for a specified period within all applicable Operating Constraints.

1(m) "Slice Output Limits" means all storage, energy, capacity, and rate of change limits defined in this exhibit that limit the availability and use of Slice Output by EWEB.

1(n) "Slice Storage Account" means the quantity equal to the sum of EWEB's SSDA and the product of EWEB's Slice Percentage and the Slice System Storage Energy, expressed in megawatt-days (MW-days).

1(o) "Slice System Deviation Account (SSDA)" means the amount of energy, in MW-days, that EWEB's ASOE deviates from the product of the ANSSG and EWEB's Slice Percentage, as described in section 7(d).

1(p) "Slice System Storage Bounds (SSSB)" means the maximum and minimum limits of the storage that is available to the Slice System, as calculated in section 3(b) below.

1(q) "Slice System Storage Energy (SSSE)" means the Storage Energy of the Slice System calculated by summing the Storage Energy in MW-days of certain Slice System projects, which shall include, but not be limited to Grand Coulee.

1(r) "Storage Energy" means the energy that would be produced if a reservoir released its entire Storage Content. Storage Energy amounts are determined by multiplying a reservoir's Storage Content, expressed in thousands of second-foot-days (KSFD), by such reservoir's at-site and downstream federal water-to-energy conversion factor (H/K).

1(s) "Technical Management Team" means that group comprised of representatives from federal and state (Oregon, Washington, Idaho, and Montana) agencies that is responsible for determining river operations in accordance with the FCRPS biological opinion and other applicable operational requirements.

1(t) “TOP Heavy Load Hours” or “TOP HLH” means the hours ending 0700 through 2200 Pacific prevailing time (PPT) for each day of the week (including Sundays and holidays).

1(u) “TOP Light Load Hours” or “TOP LLH” means the hours ending 0100 through 0600 PPT and hours ending 2300 through 2400 PPT for each day of the week (including Sundays and holidays).

1(v) “Weekly Constraint” means an operation of the FCRPS that requires a specific flow requirement for the week, typically specified as a discharge from McNary Dam. During this operation, the weekend average flow requirement must be at least 80% of the previous 5-weekday average discharge.

2. CALCULATION OF INDIVIDUAL LIMITS, ROUNDING, AND PENALTY CHARGES

2(a) This section intentionally left blank

2(b) This section intentionally left blank

2(c) This section intentionally left blank

2(d) **Calculation of EWEB’s Individual Limits**
Unless otherwise specified, the calculation of such individual values, in MW, MWh, or MW-days, shall be the product of such value for the Slice System and EWEB’s Slice Percentage.

2(e) **Rounding of Calculations**
All values in this exhibit that are expressed in terms of megawatts shall be expressed in whole megawatts. To the extent that a calculation results in a value that is not an integer, the number shall be converted to an integer using the following method:

2(e)(1) If the decimal is less than 0.50, round down to the nearest whole number.

2(e)(2) If the decimal is equal to or greater than 0.50, round up to the nearest whole number.

2(f) This section intentionally left blank

2(g) This section intentionally left blank

2(h) **Penalty Charges**
If, after the day, it is determined that EWEB has scheduled ASOE in excess of EWEB’s Slice Percentage of: (1) the one-hour maximum ESSG, (2) the one-hour maximum ESSG for Lower Snake Projects (LSN), (3) the one-hour maximum ESSG for the rest of the system, (4) the TOP HLH maximum ESSG for LSN, (5) the TOP HLH maximum ESSG for the rest of the system

(except as permitted in section 7(f) of this exhibit), (6) the daily maximum ESSG (except as permitted in section 7(f) of this exhibit) as adjusted by EWEB's right to Pondage, and/or (7) the Ramp Rate Up, all as calculated under the provisions of this Exhibit O, then EWEB may be charged at the Unauthorized Increase Charge for energy for the amount of such exceedence.

If, after the day, it is determined that EWEB has scheduled ASOE in an amount less than EWEB's Slice Percentage of: (1) the Absolute Minimum ESSG, (2) daily minimum ESSG as adjusted by EWEB's right to Pondage, and/or (3) the one-hour or two-hour Ramp Rate Down, all as calculated under the provisions of this Exhibit O (such amount to be designated as "generation shortfall"), EWEB's SSDA may be reduced by the generation shortfall. Such generation shortfall will be added to EWEB's ASOE when computing EWEB's Pondage and SSDA balances for that day.

Penalties assessed by Power Services pursuant to this Exhibit O may be waived by Power Services in accordance with section 25.5 of the body of this Agreement. Any waiver granted with respect to a specific circumstance shall not constitute a waiver of future exceedence, nor create a waiver for a recurrence of such circumstance or for any other circumstance.

3. CALCULATING THE SLICE SYSTEM STORAGE AND PONDAGE

The following procedures shall be used in determining all quantities related to SSSE, SSSB and Pondage values. The calculation of SSSE and SSSB set out below is a generic methodology, which is to be used in specific applications in this Exhibit.

3(a) Calculating the SSSE

Power Services shall calculate the SSSE, as defined in section 1(q), by summing the Storage Energy of the project(s) listed in section 1(q).

3(b) Calculating the SSSB

Prior to midnight on the 23rd day of each month, Power Services shall provide EWEB with a forecast of the upper and lower SSSB for the subsequent three months. To determine the SSSB, Power Services shall calculate the SSSE associated with the upper and the lower ORC, except that whenever Grand Coulee's upper ORC is 1,290.0 feet (full pool), the upper SSSB shall reflect the Storage Energy associated with 1,289.7 feet. The upper and the lower SSSB shall be increased or decreased as appropriate to reflect available Pondage.

3(c) Calculating Pondage

To calculate the Pondage limits Power Services will reflect the estimated effective H/K values, as adjusted for required Fish Spill, and shall assume the forebay elevations for the Simulator Projects are initialized for the day at two-thirds full within their current operational storage ranges. Using these input values for the current day or next day(s), as appropriate, Power Services shall calculate the maximum amount that the LCOL Complex and LSN Complex projects can be utilized, relative to their expected operation, to increase the maximum daily ESSG and decrease the minimum daily ESSG by utilizing storage capabilities to store or draft water as appropriate. The resulting ability of the Federal System to increase maximum daily ESSG represents Pondage Up and the resulting ability of the Federal System to decrease minimum daily ESSG represents Pondage Down. Storing water at a particular project may increase or decrease overall Slice System generation, depending on the Operating Constraints in effect, and Power Services shall include such adjustment in the calculation of Pondage on an ongoing basis. Pondage Up limits shall be reported in positive values and Pondage Down limits shall be reported in negative values.

3(c)(1) During times when the Hanford Reach protection level flow is in effect, as established pursuant to the Hanford Reach Fall Chinook Protection Program Agreement as it then exists, the Pondage Down limit will be increased (made more negative) on Saturdays, Sundays, and holidays as appropriate to reflect the right to reduce discharge from Grand Coulee and Chief Joseph to levels below such protection level flow.

3(c)(2) During Fixed Flow operations associated with Weekly Constraints at McNary Dam, as defined in section 1(u), Pondage Up will be modified to reflect the shaping and flexibility allowed between the weekdays and the weekends as follows:

For Monday-Friday: Increase Pondage Up by the product of .303 * 24 * H/K_{GCL} * weekly flow target
For Saturday: Increase Pondage Up by the product of .75 * .303 * 24 * H/K_{GCL} * weekly flow target
For Sunday: Increase Pondage Up by 0

Where:
H/K_{GCL} is the sum of the actual expected water-to-energy conversion factor for all Slice System projects from Grand Coulee to Bonneville Dam, taking into account the spill requirements at each of the projects, and the weekly McNary flow target, which is the flow requirement as determined by the Technical Management Team or through a Federal Operating Decision, in thousand second foot days (ksfd).

3(c)(3) During Fixed Flow operations, EWEB's Pondage Up balance shall be increased and Pondage Down balance shall be decreased (made more negative) from time to time based on the change in EWEB's SSDA balance since the start of the Fixed Flow operation. Such adjustment shall be calculated each day as described below and shall be applicable on the 2nd day following such calculation, as follows:

<u>Formula 1</u>
$UpAdj_I$ = Greater of 0 or [$(SSDA_{I-2} - SSDA_0)$*24 - (SSP * K)]

<u>Formula 2</u>
$DownAdj_I$ = Lesser of 0 or [$(SSDA_{I-2} - SSDA_0)$*24 + (SSP * K)]

Where:

UpAdj$_i$ is the amount of additional Pondage Up which EWEB shall have a right to utilize on day I.

DownAdj$_I$ is the amount of additional Pondage Down which EWEB shall have a right to utilize on day I.

SSDA$_{I-2}$ is EWEB's SSDA on the day 2 calendar days prior to day I.

SSDA$_0$ is EWEB's SSDA on the last day prior to the start of Fixed Flow operation.

SSP is EWEB's Slice Percentage.

K is a constant equal to 50,000 MWh. 50,000 MWh was selected as a reasonable deadband for accumulated changes in SSDA and is subject to change upon the mutual agreement of BPA and EWEB.

4. FORECASTED SLICE OUTPUT CALCULATION, POWER SERVICES REAL-TIME ADJUSTMENTS, ELECTIVE SPILL DECLARATION, AND RAMP RATE CALCULATIONS

The following procedures shall be used in determining EWEB's minimum and maximum available Slice Output on a daily and hourly basis.

4(a) Calculating the ESSG

To determine the ESSG, Power Services shall calculate for each project in the Slice System such project's generation in terms of MW. When calculating the generation of such a project, Power Services shall estimate the energy that could be produced with those generating units that are planned to be available for such period while observing all applicable Operating Constraints. Power Services shall calculate the ESSG by adding the generation of all projects included in the Slice System and adjusting for any forecasted System Obligations.

4(b) Projects With a Fixed Operation

There are several Slice System projects whose operation is typically governed by non-power requirements and, as such, their operation will not typically be altered for power purposes. These projects are listed in Table 3.1 of the TRM under the headings "Independent Hydro Projects" and in Table 3.2 of the TRM under the heading "Designated Non-Federally Owned Resources".

4(c) 12-Month Forecast of Slice Output Energy

BPA shall provide EWEB the results of a 12-month forecast as set forth in section 8.4 of Exhibit N, except BPA shall provide data associated with the appropriate corresponding terms defined in this Exhibit O rather than data associated with the terms Simulator Project, Snake Complex, BOS, and PSB as defined in Exhibit M.

4(d) **90-Day Forecast of Slice Output Energy**
BPA shall provide EWEB the results of a 90-day forecast as set forth in section 7.2 of Exhibit N, except BPA shall provide data associated with the appropriate corresponding terms defined in this Exhibit O rather than data associated with the terms Simulator Project, Snake Complex, BOS, and PSB as defined in Exhibit M.

4(e) **Calculating the Maximum and Minimum Daily ESSG**
Beginning on September 30, 2011, and on each Business Day thereafter for as long as this exhibit is in effect, Power Services shall provide EWEB with a forecast of the maximum and minimum ESSG for the total of all hours, the maximum ESSG for the total of the TOP HLHs, and the minimum ESSG for the total of the TOP LLHs of each day, for the upcoming preschedule day and the following six consecutive days.

In determining such maximum and minimum daily ESSG, Power Services shall perform two hydroregulation studies, one operating Grand Coulee as needed to achieve the maximum flow constraint in effect, and one operating Grand Coulee as needed to achieve the minimum flow constraint in effect. For such studies, Power Services shall initialize the starting reservoir Storage Contents to the previous day's actual elevations. Power Services shall incorporate forecasted probable regulated inflows for each project, forecasted unit outages, and all applicable Operating Constraints. For such studies, Power Services shall reflect the expected project operation of the LSN Complex, Hungry Horse, Libby, Dworshak and all non-federal projects. Power Services shall reflect a pass inflow operation of LCOL Complex to the extent allowed by such projects' Operating Constraints.

During periods of Fixed Flow operations, Power Services will compute the accumulated energy difference, in MWh, between each day's last official maximum and minimum daily ESSG, and that day's ANSSG with no adjustment for actual use of Pondage. On the first Business Day of each week, if the absolute value of the previous day's accumulated difference exceeds 15,000 MWh, Power Services will make an adjustment to the maximum and minimum daily ESSG values for the following day and each subsequent day through the following Sunday. Such daily adjustment shall be no greater than the accumulated deviation divided by the number of days over which the adjustment will be effective.

4(f) **Calculating the Daily ESSG Assuming a Pass-Inflow Operation**
Beginning on September 30, 2011, and on each Business Day thereafter as long as this exhibit is in effect, Power Services shall provide EWEB with a forecast of the daily ESSG assuming a pass inflow operation for the upcoming preschedule day and the following six consecutive days. To calculate this value, Power Services shall determine the daily ESSG based on the expected operation of the Slice System as adjusted by the Storage Energy associated

with the daily change in Storage Content expected to occur at the Dispatchable Projects. Parties agree that the foregoing study does not reflect then-current Federal Operating Decisions and Operating Constraints, and will not accurately reflect Slice Output Energy actually available.

4(g) **Calculating the Hourly Maximum ESSG**
Power Services shall calculate the hourly maximum ESSG separately for the LSN Complex and for the rest of the Slice System. For such maximums, Power Services shall sum the maximum hourly generation of the Slice System projects in each of the two groups above. The maximum hourly generation for each project shall be the lesser of the capability of the generating units that are available for service on that hour or the maximum generation allowed consistent with Operating Constraints.

Power Services shall also separately calculate for the LSN and for the rest of the Slice System, the maximum ESSG that can be produced over the TOP HLH in MWh, consistent with Operating Constraints. The LSN maximum generation for TOP HLH is that generation in excess of the minimum generation for the LSN on TOP HLH.

4(h) **Calculating the Hourly Absolute Minimum ESSG**
The hourly Absolute Minimum ESSG reflects the least amount of generation that the Slice System can produce in any hour, without causing Elective Spill. To determine the hourly Absolute Minimum ESSG, Power Services shall calculate the ESSG that would result from a minimum flow operation, while observing all Operating Constraints.

4(i) **Adjustments By Power Services**
On an hourly basis, Power Services shall monitor the Slice System and communicate to EWEB changes in the hourly and daily Slice Output Limits for the current day. Changes to the Slice Output Limits for the next day(s) may be communicated to EWEB at a later time, but shall be communicated as soon as practicable. EWEB shall make adjustments to its schedules to stay within such limits. No modifications to schedules that begin within 60 minutes from the notification by Power Services of such adjustment will be necessary. Power Services shall have the authority to make any such changes based on the conditions listed below.

4(i)(1) **Corrections of Errors, Omissions, or Assumptions**
Estimates of daily maximum ESSG, the hourly maximum ESSG, and Absolute Minimum ESSG may be adjusted in real-time by Power Services to reflect corrections of errors, omissions, or changes in the assumptions used to calculate the Slice System capability.

4(i)(2) **Changes in Federal Operating Decisions**
Power Services may adjust information and Slice Output Limits previously provided by Power Services to reflect new Federal Operating Decisions, the termination or suspension of a Federal Operating Decision already reflected in the estimates, or if Power

Services determines that the Slice Output Limits do not accurately reflect the actual Slice System operation on the current day.

4(i)(3) **Notification of Elective Spill**
Power Services shall notify EWEB of Elective Spill for TOP HLH and/or TOP LLH as soon as practicable after Power Services determines that it is at risk of having Elective Spill. Such notice shall include a revised TOP LLH Minimum ESSG, which will be updated to reflect operating conditions of the Slice System. If the System is declared to be in an Elective Spill condition for TOP HLH during periods of Fixed Flow operations, Power Services may not declare the system to be out of Elective Spill condition unless such declaration is made prior to the start of the actual day for which the declaration was made; *provided, however*, during a period of Elective Spill in TOP HLH the hourly maximum generation pursuant to section 4(g) may be reduced if necessary to cause a reduction in system generation as directed by another federal agency. Failure by BPA to notify EWEB of Elective Spill conditions shall not protect EWEB from Elective Spill allocation per section 7(g) below.

4(i)(4) **Changes in the Hourly or Daily Slice System Capability**
Power Services shall revise the estimates of daily maximum ESSG, the hourly maximum ESSG, or Absolute Minimum ESSG when there is a change on the Slice System that exceeds either 500 MW on any remaining hour or 200 aMW for the remaining hours of the day.

4(j) **Calculation of Maximum Ramp Rates**

4(j)(1) **Ramp Rate Up**
The Ramp Rate Up equals:

$MRR + NDG_N - NDG_{N-1}$

Where:

MRR = the maximum rate of increase in generation for the Dispatchable Projects between 2 hours.

NDG_N/NDG_{N-1} = The generation from the Non-Dispatchable Projects and the sum of the System Obligations for the schedule hour **N** and schedule hour **N-1**.

EWEB's increase in schedules between two hours shall be computed as:

$[RG_N - RG_{N-1}]$

Where:

RG_N/RG_{N-1} = The lesser of the hourly maximum generation times the SSP, or EWEB's requested generation for schedule hour **N** and schedule hour **N-1**.

If EWEB submits schedules such that the increase calculated in accordance with the immediately preceding formula exceeds the product of EWEB's Slice Percentage and the Ramp Rate Up, such exceedence will be subject to the UAI Charge for energy, and such exceedence amount will be subtracted from EWEB's daily ASOE for purposes of computing the daily Pondage and SSDA balances.

4(j)(2) **Ramp Rate Down**
Ramp Rate Down is the maximum rate of decrease in generation for the Dispatchable Projects over any three consecutive schedule hours. The Ramp Rate Down limit is calculated as both a limit to the amount of decrease in generation over any two consecutive hours and the decrease in generation over any three consecutive schedule hours.

One-Hour Test
The Ramp Rate Down limit between two consecutive hours, N-1 and N is the greater of:

4(j)(2)(i) C * SSP, or

4(j)(2)(ii) $B * (RG_{N-1} - HM_N)$

Two-Hour Test
The Ramp Rate Down limit between two hours, N-2 and N is the sum of:

4(j)(2)(i) The greater of $[(SSP * C) \text{ or } (A * (RG_{N-2} - HM_{N-1}))]$, and

4(j)(2)(ii) The greater of $\{(SSP * C) \text{ or } A * (RG_{N-2} - \text{the greater of } [(SSP * C) \text{ or } (A * (RG_{N-2} - HM_{N-1}) - HM_N)])\}$

In no event shall the results of the two-hour test cause a limit that would be less than C * SSP for any two consecutive hours.

Where:

A = 0.4

B = 0.5

C = The minimum hourly down ramp limit for the Slice System, set for 1,000 megawatts on all hours

SSP = EWEB's Slice Percentage

RG_N/RG_{N-2}= The greater of the Absolute Minimum ESSG times the SSP for hour N, or EWEB's requested generation for schedule hour N and schedule hour N-2

HM_N/HM_{N-2}= Absolute Minimum ESSG for schedule hour N and schedule hour N-2, multiplied by EWEB's Slice Percentage.

The following formula shall be used to determine EWEB's actual ramp down across any two hours:

$[(RG_N - SSP * (NDG_N + SO_N)) - (RG_{N-x} - SSP * (NDG_{N-x} + SO_{N-x}))]$

Where:

RG_{N-X} =The greater of the Absolute Minimum ESSG times the SSP, or the scheduled generation for the schedule hour **X** hours prior to hour **N**

SSP = EWEB's Slice Percentage

NDG_{N-X} = The Slice System generation from the Non-Dispatchable Projects for the schedule hour **X** hours prior to hour **N**

SO_{N-X} = The System Obligations for the schedule hour **X** hours prior to hour **N**

X shall be set to the value one for calculating EWEB's schedule decrease for the 1-hour Ramp Rate Down test and shall be set to the value two for the 2-hour Ramp Rate Down test.

If EWEB submits a schedule which results in the delivery of energy such that the decrease calculated in accordance with the preceding paragraph exceeds the Ramp Rate Down limit as determined for either the 1-hour test or 2-hour test as specified above, such exceedence will be subject to transfer from EWEB's SSDA, consistent with the provisions of section 2(h) of this Exhibit O. In the event that an exceedence of both the 1-hour test and 2-hour test occurs across the same delivery hour, the greater of the two amounts shall be so transferred, and such exceedence amount will be added to EWEB's daily ASOE for purposes of computing the daily Pondage and SSDA balances.

4(k) This section intentionally left blank.

5. CALCULATING ACTUAL SLICE OUTPUT

The following procedures shall be used in determining the actual quantities of Slice Output.

5(a) Calculation of Actual SSSE and Slice Storage Account Balance

Beginning October 2, 2011, and on each day thereafter as long as this Exhibit O is in effect, Power Services shall calculate and provide EWEB with the SSSE and EWEB's Slice Storage Account balance for the previous day, as measured in MW-days. Power Services shall calculate such SSSE based on the actual reservoir Storage Contents, as measured at midnight for the previous day. To determine EWEB's Slice Storage Account balance, Power Services shall sum the product of the SSSE and EWEB's Slice Percentage with EWEB's Slice Storage Deviation Account (SSDA) balance as of midnight the same day, as determined in section 7(d).

5(b) Calculation of ANSSG and ASOE

Beginning October 2, 2011, and on each day thereafter as long as this Exhibit O is in effect, Power Services shall calculate and provide EWEB with a daily accounting of the ANSSG produced on the previous day, as measured in MWh. Power Services shall calculate such ANSSG in the same manner as the ESSG but using: (1) actual project generation instead of forecasted generation, and (2) actual System Obligations instead of forecasted System Obligations, as adjusted by (3) the gross Elective Spill pursuant to section 7(g).

To determine EWEB's daily individual ASOE, Power Services shall sum for each hour of the day, the greater of EWEB's scheduled Slice Output Energy and EWEB's individual Absolute Minimum ESSG. In the event that EWEB's daily individual ASOE is less than the minimum individual Slice Output Limit for such day, as adjusted by EWEB's available Pond Down, EWEB's daily individual ASOE shall be deemed to be equal to the minimum individual Slice Output Limit for such day, as adjusted by EWEB's available Pond Down. The difference between EWEB's daily individual ASOE and the sum of EWEB's scheduled Slice Output Energy for all hours of such day shall be forfeited and transferred from EWEB's SSDA.

6. GRACE MARGIN

6(a) General

It is anticipated that EWEB's Slice Storage Account balance may not always be within its individual SSSB. Such deviation could be due to potential forecast or accounting errors on Power Services's part or errors on EWEB's part. A Grace Margin will be provided to mitigate any penalty. The Grace Margin is both added to the maximum storage bounds and subtracted from the minimum storage bounds. The Grace Margin is applied on an after-the-fact basis only. If the Slice System is in Fixed Flow, the UAI Charge will not be applied for being below the minimum storage bounds, nor will the forfeiture of energy for being above the maximum storage bounds be applied, as set forth in section 6(e). It is recognized that unusual events may require

EWEB and Power Services to institute by mutual oral or written agreement special actions with regard to the Grace Margin.

If, as of the last day of Fixed Flow, when the Slice System is transitioning to a period of operating within maximum and minimum storage bounds, EWEB's SSA balance exceeds its individual SSSB, EWEB shall have up to 7 days (or longer if allowed in section 6(e)) beginning on the day that such transition was commenced to bring its SSA balance within its individual SSSB by utilizing the procedure described in section 6(e) without penalty or charge. If, within such 7-day period, EWEB brings its SSA balance within its individual SSSB, the provisions described in section 6(e) shall become effective beginning on the day such compliance was achieved. If, within or by the end of such 7-day period, EWEB fails to bring its SSA balance within its individual SSSB, EWEB shall be subject to the penalties described in this section 6 for any amount its SSA balance remains outside the SSSB at the end of such 7-day period (or longer period if allowed in section 6(e)).

6(b) **Calculation of Grace Margin**
To determine EWEB's Grace Margin, Power Services shall calculate the greater of:

6(b)(1) The product of 17,300 MWh and EWEB's Slice Percentage, or

6(b)(2) The value equal to the difference between the forecast and actual daily ESSG assuming a pass-inflow operation on that day, multiplied by EWEB's Slice Percentage.

6(c) **Calculation of SSSB Exceedence**
Power Services shall determine the exceedence of EWEB's Slice Storage Account relative to EWEB's individual SSSB, by using Formula 3. Power Services shall also determine the quantity of EWEB's SSDA that is subject to forfeiture and transfer out of its SSA, if any, using Formula 4, and the quantity of energy subject to the Unauthorized Increase Charge for energy, if any, by using Formula 5.

Formula 3

$$\mathbf{E = (Greater\ of\ 0\ or\ (SSSE_I - uSSSB)) + (Lesser\ of\ 0\ or\ (SSSE_I - lSSSB))}$$

Where:

E is the amount by which EWEB's SSSE exceeds the Slice System Storage Bounds in MW-days.

$SSSE_I$ is EWEB's Slice Storage Account balance as measured in MW-days.

uSSSB is EWEB's individual upper Slice System Storage Bound as measured in MW-days.

lSSSB is EWEB's individual lower Slice System Storage Bound as measured in MW-days.

Formula 4
gmSPILL = Greater of {0, or the Lesser of [(0.99*DmaxGen – ASOE/24), or (E – GM_I)]}

Where:

E is EWEB's exceedence calculated in Formula 3 above in MW-days.

gmSPILL is the amount of EWEB's exceedence that is considered to be spilled as measured in MW-days.

GM_I is EWEB's individual Grace Margin as measured in MW-days.

DmaxGen is the maximum daily ESSG multiplied by EWEB's Slice Percentage as measured in MW-days.

Formula 5
gmUAI = Absolute value of {Lesser of {0, or the Greater of [(ASOE/24 – 1.01*DminGen), or (E + GM_I)]}}

Where:

E is EWEB's exceedence calculated in Formula 3 above in MW-days.

gmUAI is the amount of EWEB's exceedence, measured in MW-days, that is considered to be subject to the UAI Charge for energy.

GM_I is EWEB's individual Grace Margin as measured in MW-days.

DminGen is the minimum daily ESSG multiplied by EWEB's Slice Percentage as measured in MW-days.

Formula 6
[This formula has been intentionally left blank]

6(d) **Grace Margin Spill Account (GMSA)**
Power Services shall establish a GMSA that shall be initialized each day to zero and maintained in MW-days. Power Services shall calculate the GMSA pursuant to section 6(e)(3) and shall utilize the GMSA to calculate net Elective Spill pursuant to section 7(g)(2).

6(e) **Application of the Grace Margin**
Any time that gmSpill and gmUAI as calculated in Formulae 4 and 5 are greater than zero, the gmSpill or gmUAI must be eliminated by EWEB. EWEB shall take the action(s) described below to return its Slice Storage

Account balance to a condition that is within its Grace Margin to avoid the penalties below. If EWEB's exceedence as calculated in Formula 3 is greater than zero at a time when Grand Coulee's ORC is 1,290.0 feet, then EWEB shall take the actions specified in section 6(e)(2) by the day following the day on which EWEB is notified of such exceedence. In all other instances where EWEB's exceedence as calculated in Formula 3 above is not zero, EWEB shall take such actions by the third day following the day of notification. The day of notification shall be the day EWEB receives the ANSSG that applies to the day on which the exceedence occurs.

6(e)(1) This section intentionally left blank.

6(e)(2) EWEB shall adjust its ASOE in compliance with one of the following two requirements:

6(e)(2)(A) EWEB's exceedence as calculated in Formula 4 and 5 shall be reduced to zero; or

6(e)(2)(B) If Slice Output Limits prevent EWEB from making such adjustment, then EWEB shall continue to schedule its Slice Output Energy within 1 percent below the daily maximum or 1 percent above the daily minimum Slice Output Limit, without being required to utilize Pondage, for as many days as necessary to eliminate such exceedence.

If EWEB fails to schedule its ASOE or make a SSDA transfer as specified in section 6(e)(2), such exceedence, if positive, will be treated as gmSPILL pursuant to section 6(e)(3); if negative, such amount shall be treated as gmUAI pursuant to section 6(e)(4).

EWEB may elect to schedule its ASOE in a manner to reduce the exceedence amount to zero prior to the day following the day of notification, or the third day following the day of notification, as described in section 6(e). If EWEB does so, EWEB shall not be required to adjust its ASOE as specified in this section 6(e)(2).

6(e)(3) **Applied gmSpill and the Grace Margin Spill Account**
Power Services shall decrease EWEB's SSDA by the amount of gmSPILL calculated in Formula 4 above that is applied pursuant to sections 6(e) and 6(e)(2). In addition, Power Services shall add such amounts to the GMSA, which shall represent the sum of all Slice purchasers' applied gmSPILL for each day.

6(e)(4) **Unauthorized Increase Charge for Applied gmUAI**
Power Services shall charge EWEB for the amount of gmUAI calculated in Formula 5 above that is applied pursuant to sections 6(e), and 6(e)(2) at the UAI Charge for energy. In addition, Power Services shall increase EWEB's SSDA by the amount of gmUAI for which such a charge is assessed.

7. SLICE PARTICIPANT'S DAILY SLICE STORAGE DEVIATION ACCOUNT (SSDA) BALANCE, ALLOCATION OF ELECTIVE SPILL, AND PONDAGE ACCOUNT BALANCE

Power Services shall establish and maintain an accounting of the daily SSSE based upon the Slice System reservoirs' actual Storage Contents (actual SSSE). Power Services shall establish and maintain an accounting of the daily deviation of Slice Storage (SSDA) for EWEB as specified below. Power Services shall measure or calculate such account balances in MW-days as of midnight each day. For purposes of section 6 and this section 7, the SSDA shall only be computed as a daily storage balance and shall not be computed as an hourly estimate of EWEB's SSDA balances. EWEB shall utilize its SSDA as an indicator of its proximity to its individual SSSB and shall adjust its request of Slice Output Energy as needed to stay within such storage bounds. If EWEB's Slice Storage Account balance is outside of its individual SSSB, the Grace Margin rules in section 6 shall apply.

7(a) This section intentionally left blank.

7(b) **Initial Balances**

Power Services shall initialize the September 30, 2011, actual SSSE to the SSSE associated with the actual elevations of the projects in the Slice System as of 2400 hours PPT on September 30, 2011. Power Services shall initialize EWEB's September 30, 2011, SSDA balance to zero.

7(c) This section intentionally left blank.

7(d) **Daily Calculation of the SSDA Balance**

Beginning October 2, 2011, and on each day thereafter as long as this Exhibit O is in effect, Power Services shall calculate and provide EWEB with daily account balances of EWEB's dSSDA and SSDA for the previous day using Formulae 7 and 8.

Formula 7

$$\mathbf{SSDA_{-1} = SSDA_{-2} + dSSDA_{-1} - eSPILL_{I}}$$

Where:

$SSDA_{-1}$ is the SSDA for day −1 as measured in MW-days.

$SSDA_{-2}$ is the SSDA for day −2 as measured in MW-days.

$dSSDA_{-1}$ is the change in the SSDA for day −1 calculated in Formula 8 below, in MW-days.

$eSPILL_{I}$ is EWEB's allocated share of the net Elective Spill for the Slice System calculated in Formula 13 below, expressed in MW-days.

Formula 8
$$dSSDA_{-1} = [(SSP * ANSSG_{-1}) - ASOE_{-1}] / 24$$

Where:

$dSSDA_{-1}$ is the change in the SSDA for day –1 as measured in MW-days.

SSP is the Slice Percentage.

$ANSSG_{-1}$ is the ASSG for day –1 as measured in MWh.

$ASOE_{-1}$ is EWEB's individual ASOE for day –1 as measured in MWh.

7(e) **Termination of the Interim Slice Implementation Procedures and Slice Participant's SSDA Balance**
BPA shall provide EWEB notice that these Interim Slice Implementation Procedures shall terminate no less than five (5) days prior to the date of such termination. Any balance remaining in EWEB's SSDA as of 2400 hours on the date these Interim Slice Implementation Procedures are terminated shall be transferred to EWEB's BOS Deviation Account as the initial balance in that account.

7(f) **Procedures During Fixed Flow and Declared Elective Spill Condition for TOP HLH**
The procedures outlined in this subsection 7(f) shall be used when the Slice System is in a Fixed Flow state and Elective Spill is declared for TOP HLH.

7(f)(1) **Pondage Balance Calculation**
The daily change in EWEB's Pondage Account balance, calculated pursuant to section 7(h), shall be zero regardless of the difference between EWEB's generation schedule compared to its Slice Percentage of the daily maximum ESSG and daily minimum ESSG.

7(f)(2) **dSSDA Calculation**
The dSSDA as defined in section 7(d) of this exhibit shall be set to zero for each such calendar day.

7(f)(3) **Allocation of Expenses Associated with Elective Spill**
Expenses incurred by Power Services due to the delivery of Elective Spill energy will be allocated to EWEB by multiplying the amount of such expenses incurred by Power Services on such day by EWEB's Slice Percentage.

7(f)(4) **Daily Maximum ESSG**
EWEB will have the right to exceed its share of daily maximum ESSG, as adjusted by EWEB's available Pond Up.

7(f)(5) **TOP HLH Maximum ESSG for the Rest of the System**
EWEB will have the right to exceed its share of the TOP HLH maximum ESSG for the rest of the system, as adjusted by EWEB's available Pondage Up.

7(f)(6) **One-Hour Maximum ESSG**
EWEB will not have the right to exceed its share of the one-hour maximum ESSG.

7(g) **Procedures Due to Elective Spill in Other Conditions**
The procedures outlined in this section 7(g) shall be used to calculate and allocate actual amounts of Elective Spill that occur when the Slice System is not in a Fixed Flow state or when the Slice System is in a Fixed Flow state and Elective Spill is declared only for TOP LLH.

7(g)(1) **General**
Power Services may need to reduce the actual Elective Spill by delivering energy as Immediate Spill Deliveries or by paying other parties to take energy that would otherwise be implemented as Elective Spill. Power Services shall increase the Elective Spill quantity by the amount of energy delivered under either of such arrangements, which total shall be known as the gross Elective Spill.

7(g)(2) **Calculation of Net Elective Spill**
The quantity of Elective Spill that occurs on the Slice System on any given day shall be reduced by the quantity in the GMSA to determine net Elective Spill for that day. Power Services shall use Formula 9 to calculate the net Elective Spill for the Slice System.

<u>Formula 9</u>
$$\mathbf{eSPILL_{NET} = Greater\ of\ 0\ or\ (eSPILL_{GROSS} - GMSA - HourlySpill)}$$

Where:

$eSPILL_{NET}$ is the net Elective Spill for the Slice System to be allocated to the Slice Purchasers in MW-days.

$eSPILL_{GROSS}$ is the gross Elective Spill for the Slice System in MW-days.

GMSA is the sum of all Slice purchaser's applied gmSpill as calculated in section 6(e)(3) in MW-days.

HourlySpill is the total amount of energy transferred from all Slice customers SSDAs pursuant to the second paragraph of section 2(h).

7(g)(3) **Allocation of Net Elective Spill**

As needed, Power Services shall calculate for EWEB, all other Slice Customers, and Power Services, the net Elective Spill to be allocated to each Party, using Formulae 10, 11, and 12. When requested, Power Services shall make available to EWEB the calculations and all data necessary to verify the calculation of the allocated net Elective Spill.

Formula 10

$llhMINGEN = (llhASSG_{ADO} + eSPILL_{NET}*24)/TOP\ LLH$

Where:

llhMINGEN is the minimum TOP LLH Slice System generation needed to avoid Elective Spill for the day, expressed in average MW.

$llhASSG_{ADO}$ is the portion of the daily ASSG that was generated on TOP LLH, less the quantity of energy delivered as Immediate Spill Deliveries, and the energy for which Power Services paid other parties to take during such TOP LLH, expressed in MWh.

$eSPILL_{NET}$ is the net Elective Spill for the Slice System, to be allocated to the Slice Customers, as calculated in Formula 9 and expressed in MW-days.

TOP LLH is the number of TOP LLH in the day.

Formula 11

$llhADDGEN_I$ = the greater of

$((llhMINGEN * SSP) - llhASOE_I/TOP\ LLH)$ or 0

Where:

$llhADDGEN_I$ is EWEB's additional individual ASOE that was needed on TOP LLH to avoid Elective Spill for the day, as expressed in average MW.

llhMINGEN is the minimum TOP LLH Slice System generation needed to avoid Elective Spill for the day, calculated in Formula 10, expressed in average MW.

SSP is EWEB's Slice Percentage.

$llhASOE_I$ is the portion of EWEB's daily individual ASOE that was scheduled on TOP LLH, plus the energy associated with hourly spill penalties that occur on TOP LLH, as expressed in MWh.

TOP LLH is the number of TOP LLH in the day.

Formula 12

$$eSPILL_I = eSPILL_{NET} * llhADDGEN_I / llhADDGEN_{TOT}$$

Where:

$eSPILL_I$ is EWEB's allocated share of the net Elective Spill for the Slice System, expressed in MW-days.

$eSPILL_{NET}$ is the net Elective Spill for the Slice System to be allocated to the Slice Customers, as determined in Formula 9, expressed in MW-days.

$llhADDGEN_I$ is EWEB's minimum TOP LLH Slice System Generation needed to avoid Elective Spill for the day, as determined in Formula 11, expressed in average MW.

$llhADDGEN_{TOT}$ is the minimum TOP LLH Slice System generation needed to avoid Elective Spill for the day, as determined in Formula 11, summed for all Slice Customers, and expressed in average MW.

7(h) **Pondage Account and Daily/Weekly Use of Pondage**

Power Services shall establish and maintain daily accounting of the Pondage limits on the Slice System, calculated pursuant to section 3(c) of this Exhibit.

Power Services shall also establish and maintain an accounting of the daily use of Pondage for EWEB as specified below. Power Services shall measure or calculate such account balances in whole megawatt-hours (MWh) as of midnight PPT each day.

7(h)(1) EWEB's Pondage account will be calculated in daily energy quantities and shall be cumulative, with a negative balance indicating use of Pondage Up and a positive balance indicating use of Pondage Down. The account balance will be changed each day by the sum of the following items:

7(h)(1)(A) The energy amount by which EWEB's ASOE exceeds the daily maximum ESSG shall be subtracted from EWEB's Pondage account balance and the amount by which the ASOE is lower than the daily minimum ESSG shall be added to EWEB's Pondage account balance.

7(h)(1)(B) If EWEB's Pondage account balance for the prior day is positive, the account balance shall be decreased by the lesser of: (1) the amount of the Pondage account balance for the prior day, or (2) the amount that EWEB's ASOE is greater than the daily minimum ESSG, limited by the daily maximum ESSG.

7(h)(1)(C) If EWEB's Pondage account balance for the prior day is negative, the account balance shall be increased by the lesser of: (1) the amount of the Pondage account balance for the prior day, or (2) the amount that EWEB's ASOE is lower than the daily maximum ESSG, limited by the daily minimum ESSG.

7(h)(1)(D) If EWEB has specified amounts in addition to those calculated automatically by Power Services for the Pondage account balance to be used for Pondage operations, including taking and returning of energy from the Pondage account, then Power Services shall include such amounts in the calculation.

7(h)(2) If EWEB schedules ASOE such that its Pondage account balance does not exceed, in a positive amount, its Slice Percentage times the Pondage Down limit (note: a negative number), and does not exceed in a negative amount, its Slice Percentage times the Pondage Up limit (note: a positive number), no penalty for Pondage shall be applied. If EWEB's Pondage account balance exceeds either limit, the energy amount in excess of the limit will be assessed as gmSpill or gmUAI as appropriate, *provided however*, that if the Pondage limits become smaller, EWEB shall not be obligated to reduce the balance in order to comply with the limit and shall not be assessed gmSpill or gmUAI for that amount. However, any subsequent increases in EWEB's Pondage account balance while its balance exceeds the reduced limit will be subject to gmSpill or gmUAI as appropriate.

7(h)(3) During periods when protection level flows are in effect at Priest Rapids Dam pursuant to the Hanford Reach Fall Chinook Protection Program Agreement as it then exists, EWEB shall schedule ASOE such that EWEB's Pondage account balance is within its share of the Pondage Down limit by midnight of each Wednesday.

7(i) This section intentionally left blank

8. THIS SECTION INTENTIONALLY LEFT BLANK

9. DATA AND INFORMATION PROVIDED BY POWER SERVICES

9(a) Slice System Estimates Provided Each Business Day By Power Services

Power Services shall provide to EWEB no later than 1630 hours PPT on each Business Day the estimates specified in sections 9(a)(1) through 9(a)(13) for the day or days for which preschedules shall be established on the next Business Day in accordance with the WECC Preschedule Calendar, pursuant to section 2 of Exhibit F. All estimates will be provided net of expected Operating Constraints and in MWh except where noted. Power Services does not guarantee or assume any particular or specific result from use by EWEB of these estimates and any of the information provided.

9(a)(1) **One-Hour Maximum ESSG**

This estimate represents the maximum Slice System generation that can be produced for 1 hour. The ESSG shall be separated into the following two categories:

9(a)(1)(A) the LSN maximum generation for an hour that is in excess of the hourly minimum generation for the LSN for such hour; and

9(a)(1)(B) the rest of the Slice System.

9(a)(2) **TOP HLH Maximum ESSG**

This estimate represents the portion of the maximum ESSG that can be produced over the TOP HLH for:

9(a)(1)(A) the LSN, and

9(a)(1)(B) the rest of the Slice System.

9(a)(3) **Absolute Minimum ESSG**

This estimate reflects the Absolute Minimum ESSG that can be produced during any hour without causing Elective Spill.

9(a)(4) **TOP LLH Minimum ESSG**

This estimate is the amount of Slice System generation that needs to be produced over the TOP LLH to minimize the potential of Elective Spill given expected system conditions. This estimate is not a limit, and there is also no guarantee or assurance by Power Services that in providing this estimate, a Slice Output Energy request at that level will not incur some amount of Elective Spill.

9(a)(5) **Daily Maximum and Minimum ESSG**

This estimate represents the maximum and minimum amount of Slice System generation that can be produced for the day, without utilizing available Pondage.

9(a)(6) **Fixed Project Generation Schedules**

This estimate represents the hourly expected generation from the projects described in section 4(b).

9(a)(7) **Maximum Hourly Ramp Rates**

The estimate for the maximum hourly Ramp Rates, in MW, for increasing and decreasing Slice System generation will be calculated using the methodology in section 4(j).

9(a)(8) **Maximum and Minimum Storage Bounds**
This estimate will provide the SSSB in MW-days for the preschedule day and the following 6 days.

9(a)(9) **ESSG Pass-Inflow Forecast**
This is the theoretical ESSG, assuming a modified inflow operation, as discussed in section 4(f). This will provide EWEB with an estimated amount of Slice Output Energy to schedule in order to maintain its SSA balance from day to day.

9(a)(10) **Planned Unit Outages**
Under normal operating conditions, this will include planned unit outages of at least 500 MW for all Slice System projects for the next preschedule day and the following 6 days and will be provided during the daily conference call described in section 7.5 of Exhibit N. Power Services will provide more detailed planned unit outage information during times of severe weather events or anticipated regional power shortages. The outage information provided will be in terms of megawatts of capacity out of service for the Slice System.

9(a)(11) **Six-Day TOP HLH and TOP LLH Maximum and Minimum Generation**
This estimate will include a forecast of the maximum and minimum Estimated Slice System Generation expected to occur on TOP LLH and on TOP HLH, given unit availability and Operating Constraints for the 6 days after the day to be prescheduled.

9(a)(12) **Pondage Up and Pondage Down Available on the Slice System**
This estimate shall represent the cumulative amount of Pondage Up and Pondage Down available on the Slice System for the next preschedule day.

9(a)(13) **State of the Slice System**
Power Services shall provide to EWEB an indication of the expected state of the Slice System for the preschedule day(s). Such indication shall be that the Slice System is in a storage energy state unless there is a specific weekly or daily flow requirement on one of the LCOL projects, or the difference between the uSSSB and the lSSSB would be approximately the same as the potential size of the inflow forecast error. Power Services and EWEB shall review and evaluate the selection of the system state with the operations subcommittee throughout the Operating Year on a case-by-case basis in order to coordinate and plan the timing and transition between Slice System states.

If Power Services declares that the Slice System is operating in a Fixed Flow state, and emergency provisions are enacted through the

Northwest Power Pool Emergency Response Team ("NWPP ERT"), the Slice System will transition from a Fixed Flow state to an interim storage energy state. During the period that the NWPP ERT declares an emergency, there will be no assessment by Power Services for gmSpill or gmUAI. The maximum daily ESSG will be determined using the increased right to generation on the system, while the minimum daily ESSG will continue to reflect the system minimum discharge requirements.

Upon suspension of emergency provisions enacted by the NWPP ERT and as appropriate, the Slice System will return to the Fixed Flow state, with the maximum daily ESSG and the minimum daily ESSG set at the same value each day. For purposes of section 3(c)(3) of Exhibit O, the SSDA balance as the last day of the interim storage energy state will be the $SSDA_0$ that EWEB may use to adjust its Pondage rights for the duration of the subsequent Fixed Flow period.

Power Services shall also declare whether there is an expectation of Elective Spill during TOP LLH and/or Elective Spill during TOP HLH.

9(b) **Operating Constraints**
Power Services shall provide to EWEB changes to current Operating Constraints and the imposition of new Operating Constraints, as they become known to Power Services, which could impact the current and future generating capability of the Slice System. The Operating Constraints may be listed in terms of discharge, energy, or any other unit that is appropriate to convey the constraint.

9(c) **Slice System Actual Information Provided By Power Services**
Power Services shall provide EWEB with the following information at the times specified. In the event that actual information is not available, Power Services shall substitute its best available estimate of such information for such missing data and indicate to EWEB that the data is based on best available information. EWEB shall accept such estimates and the risk of reliance upon such estimates:

9(c)(1) SSSE, SSDA, and the Grand Coulee elevation as of midnight the previous day, as well as the ANSSG for the previous day, assuming no Elective Spill for such calculations, by 0800 hours PPT each day, and

9(c)(2) EWEB's allocation of Elective Spill, by 1200 hours PPT each Business Day.

9(d) This section intentionally left blank

9(e) This section intentionally left blank

10. WEEKLY CONSTRAINTS

10(a) **General**
Some Operating Constraints are expressed in terms of Weekly Constraints. If a Weekly Constraint is in effect, Power Services shall provide EWEB with information pursuant to this subsection. To the extent that Power Services is provided with an error margin for the Weekly Constraint with regard to any Operating Constraints, either before or after the fact, EWEB will be entitled to its Slice Percentage share of such error margin in any computation or accounting in this Exhibit O.

10(b) **Real-Time Changes**
If the nature and/or duration of the flow requirements associated with the Weekly Constraints described above change, Power Services shall provide EWEB with the necessary data for operating, consistent with such revised Weekly Constraints. Power Services shall provide to EWEB such data necessary to calculate the operational limits applicable to EWEB. EWEB shall adjust its operation for the remainder of the week to conform to the revised Weekly Constraint.

11. THIS SECTION INTENTIONALLY LEFT BLANK

12. THIS SECTION INTENTIONALLY LEFT BLANK

13. SCHEDULING REQUIREMENTS

EWEB shall schedule its Slice Output Energy in accordance with this section 13 and all sections of Exhibit F, except sections 3.2, 3.4.1, and 4.1.

13(a) **Prescheduling**
Schedules submitted after the Power Services prescheduling timeframe set forth in section 2.1 of Exhibit F will be accepted on a best efforts basis up to the time that the preschedule checkout process has been completed for that preschedule day by Power Services.

13(b) This section intentionally left blank.

13(c) **Scheduling Energy by Resource Groups**
EWEB shall separately distribute its request for energy between the LSN and the rest of the Slice System. EWEB's request for hourly energy from each resource group shall observe the limits for hourly maximum generation, maximum generation over the TOP HLH, and the hourly rate of change for such resource groups. Such hourly values will then be combined to be EWEB's request for hourly energy.

13(d) **Preschedule Limits**
Preschedules submitted by EWEB shall comply with all applicable requirements as set forth in this Exhibit O.

14. REVISIONS

Not less than 30 days prior to implementing this Exhibit O, BPA and EWEB shall review and revise, if necessary, the provisions herein using the procedures set forth in section 5.12 of the body of this Agreement.

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Exhibit P
SLICE COMPUTER APPLICATION DEVELOPMENT SCHEDULE

1. SLICE COMPUTER APPLICATION DEVELOPMENT SCHEDULE

The Following table represents milestones and the associated dates by which BPA intends to meet those milestones during development of the Slice Computer Application.

Milestone Description	Date
Publish SCA Requirements Document	1/30/2009
Project kick-off with Slice Customers	2/3/2009
Review of SCA Requirements Document Complete	3/2/2009
Publish Simulator Requirements Document	6/1/2009
Publish BOS and Reporting module Requirements Document	8/1/20009
Publish Customer Facing Web Service Design Specification	10/1/2009
Begin Prototype Simulator Testing	4/1/2010
Publish Draft Simulator Specification	6/1/2010
"Performance Test Ready" version of Simulator Complete	8/1/2010
Performance Test Complete	10/31/2010
Publish Simulator Specification	1/15/2011
Begin Customer application integration testing with Customer facing Web Service	1/15/2011
Publish Functionality Test Procedures	4/15/2011
Functionality Test Complete	7/1/2011
Begin Customer Training and Testing of SCA	7/1/2011
SCA "Go-Live"	10/1/2011

2. REVISIONS

The timelines represented in the table above are non-binding, pursuant to section 5.11 of the body of this Agreement, and are subject to change. BPA shall revise this Exhibit P as needed to reflect significant changes.

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Exhibit Q
DETERMINATION OF INITIAL SLICE PERCENTAGE

1. DEFINITIONS

The following definitions apply only to this Exhibit Q.

1.1 "Additional Slice Amount" means the additional portion of the Base Critical Slice Amount that EWEB elects to purchase from BPA as determined in section 3 of this exhibit, rounded to a 5 digit decimal annual aMW value.

1.2 "Base Tier 1 System Capability" means Tier 1 System Capability that is deemed equal to 7,400 aMW.

1.3 "Base Critical Slice Amount" means 2,000 annual aMW, which represents the Base Slice Percentage multiplied by the Base Tier 1 System Capability.

1.4 "Base Slice Percentage" means 27.027 percent.

1.5 "Combined Maximum Additional Slice Amount" means the sum of all of the Maximum Additional Slice Amounts of those Eligible Slice Customers that have notified BPA, in accordance with section 3.2 of this exhibit, of their elections to participate in the allocation of Unsold Slice Amount under section 3.3 of this exhibit.

1.6 "Eligible Slice Customers" means those Initial Slice Customers whose Maximum Additional Slice Amount is equal to or greater than one aMW.

1.7 "Initial Slice Customers" means those Slice Customers that hold an executed Slice/Block Power Sales Agreement as of January 1, 2011.

1.8 "Maximum Additional Slice Amount" means the maximum additional portion of the Base Critical Slice Amount that EWEB may elect to purchase from BPA, as determined in section 3.1 of this exhibit, rounded to an integer annual aMW value.

1.9 "Maximum Slice Amount" means the maximum portion of the Base Critical Slice Amount that EWEB may request from BPA as part of the Initial Slice Percentage computation, and is equal to EWEB's Slice Percentage Determination Requirements Load multiplied by 0.7, expressed as an integer annual aMW value. EWEB's Maximum Slice Amount is: 185.0 aMW

1.10 "Preliminary Slice Amount" means the integer annual aMW value that is equal to EWEB's Preliminary Slice Percentage, as set forth in Exhibit J section 1, multiplied by the Base Tier 1 System Capability.

1.11 "Slice Percentage Determination Requirements Load" means a forecast amount of EWEB's requirements load that is used only in the determination of EWEB's Preliminary Slice Percentage and Initial Slice Percentage. EWEB's Slice Percentage Determination Requirements Load is: 264.3 aMW

1.12 "Unsold Slice Amount" means that portion of the Base Critical Slice Amount that remains unsold, as computed in section 2.2 of this exhibit, rounded to an integer annual aMW value.

1.13 "Unsold Slice Percentage" means the percentage, if any, determined pursuant section 2.1 of this exhibit, expressed as a three decimal digit percentage.

2. DETERMINATION OF UNSOLD SLICE AMOUNT

No later than January 30, 2011, BPA shall determine the Unsold Slice Amount, using the procedure below.

2.1 Compute Unsold Slice Percentage

The Unsold Slice Percentage shall be equal to: (1) the Base Slice Percentage minus (2) the sum of the Preliminary Slice Percentages for all Initial Slice Customers.

2.2 Compute Unsold Slice Amount

The Unsold Slice Amount shall be equal to the Base Tier 1 System Capability multiplied by the Unsold Slice Percentage, expressed as an integer aMW value.

2.3 Unsold Slice Amount Less Than One aMW

If the Unsold Slice Amount is less than one aMW, then BPA shall notify EWEB no later than January 30, 2011, that there shall be no allocation of the Unsold Slice Amount and that EWEB's Initial Slice Percentage shall be as determined pursuant to section 4.1 of this exhibit.

2.4 Unsold Slice Amount Equal To or Greater Than One aMW

If the Unsold Slice Amount is equal to or greater than one aMW, then BPA shall provide written notice to EWEB no later than January 30, 2011 of the Unsold Slice Amount available for allocation. The Unsold Slice Amount shall be allocated pursuant to section 3 of this exhibit.

3. ALLOCATION PROCEDURES FOR UNSOLD AMOUNTS OF SLICE

No later than February 15, 2011, BPA shall make available to Initial Slice Customers the Unsold Slice Amount using the procedure below.

3.1 Compute Maximum Additional Slice Amount

EWEB's Maximum Additional Slice Amount shall be equal to its Maximum Slice Amount minus its Preliminary Slice Amount, rounded to an integer annual aMW value.

3.1.1 Maximum Additional Slice Amount Less Than One aMW

If EWEB's Maximum Additional Slice Amount is less than one aMW, then EWEB shall receive no allocation of the Unsold Slice Amount, and EWEB's Initial Slice Percentage shall be determined pursuant to section 4.2 of this exhibit.

3.1.2 **Maximum Additional Slice Amount Equal To or Greater Than One aMW**
If EWEB's Maximum Additional Slice Amount is equal to or greater than one aMW, EWEB shall be eligible to participate in the allocation of any Unsold Slice Amount as set forth in sections 3.2 and 3.3 of this exhibit.

3.2 **Slice Customers Determine Allocation of Unsold Slice Amounts Among Themselves**
EWEB, if it is an Eligible Slice Customer, shall make a good faith effort, working with the other Eligible Slice Customers, to determine, no later than March 1, 2011, an allocation of the Unsold Slice Amount, such that the sum of all Eligible Slice Customers' Additional Slice Amounts is less than or equal to the Unsold Slice Amount.

If the Eligible Slice Customers agree upon an allocation of the Unsold Slice Amount that conforms with the above limitation, then they shall submit the Additional Slice Amounts in a letter to BPA no later than March 1, 2011, signed by all Eligible Slice Customers, that sets out the name and Additional Slice Amount for each Eligible Slice Customer. EWEB's Initial Slice Percentage shall then be determined pursuant to section 4.5 of this exhibit.

If the Eligible Slice Customers are unable to agree by March 1, 2011 on an allocation of the Unsold Slice Amount, then EWEB shall provide written notification to BPA no later than March 8, 2011 that it elects to, or elects not to, participate in BPA's determination of Additional Slice Amounts, pursuant to section 3.3 of this exhibit. If EWEB elects not to participate in BPA's allocation of the Unsold Slice Amount, or fails to provide written notification to BPA of its election no later than March 8, 2011, then EWEB's Initial Slice Percentage shall be determined pursuant to section 4.4 of this exhibit.

3.3 **BPA's Allocation of Unsold Slice Amount**
BPA shall allocate the Unsold Slice Amount, as set forth in the procedure below, for each Eligible Slice Customer that has provided written notice on or before March 8, 2011 of its election to participate in such allocation.

3.3.1 **Compute Additional Slice Amount**
EWEB's Additional Slice Amount shall be equal to its Maximum Additional Slice Amount multiplied by the ratio determined by dividing: (1) the Unsold Slice Amount by (2) the Combined Maximum Additional Slice Amount.

3.3.2 **Additional Slice Amount is Less Than or Equal to Zero**
If EWEB's Additional Slice Amount is less than or equal to zero, then EWEB shall receive no allocation of Unsold Slice Amount under this section 3.3, and EWEB's Initial Slice Percentage shall be determined pursuant to section 4.3 of this exhibit.

3.3.3 **Additional Slice Amount is Greater Than Zero**
If EWEB's Additional Slice Amount is greater than zero then EWEB's Initial Slice Percentage shall be determined pursuant to section 4.5 of this exhibit.

4. DETERMINATION OF INITIAL SLICE PERCENTAGE

No later than April 15, 2011, BPA shall determine EWEB's Initial Slice Percentage pursuant to the applicable procedure below. EWEB's Initial Slice Percentage so determined, shall be entered into section 2 of Exhibit J.

4.1 **Determination of Initial Slice Percentage when Unsold Slice Amount Less Than One**
If the Unsold Slice Amount is less than one aMW, then BPA shall set EWEB's Initial Slice Percentage equal to EWEB's Preliminary Slice Percentage.

4.2 **Determination of Initial Slice Percentage when Maximum Additional Slice Amount Less Than One**
If EWEB's Maximum Additional Slice Amount is less than one aMW, then BPA shall set EWEB's Initial Slice Percentage equal to EWEB's Preliminary Slice Percentage.

4.3 **Determination of Initial Slice Percentage when Additional Slice Amount Less Than or Equal To Zero**
If EWEB's Additional Slice Amount is less than or equal to zero, then BPA shall set EWEB's Initial Slice Percentage equal to EWEB's Preliminary Slice Percentage.

4.4 **Determination of Initial Slice Percentage when EWEB Elects Not to Participate in Allocation of Unsold Slice Amount**
If EWEB elects, or is deemed under section 3.2 of this exhibit to have elected, not to participate in an allocation of Unsold Slice Amounts, then BPA shall set EWEB's Initial Slice Percentage equal to EWEB's Preliminary Slice Percentage.

4.5 **Determination of Initial Slice Percentage when Eligible Slice Customers Agree on Allocation of Unsold Slice Amount**
If the Eligible Slice Customers deliver a letter to BPA on or before March 1, 2011, in accordance with section 3.2 of this exhibit, then EWEB's Initial Slice Percentage shall be equal to: (1) the sum of EWEB's Preliminary Slice Amount plus EWEB's Additional Slice Amount as specified in the letter, divided by (2) the Base Tier 1 System Capability, expressed as a five decimal percentage.

4.6 **Determination of Initial Slice Percentage when BPA Allocates Additional Slice Amounts Greater Than Zero**
If EWEB's Additional Slice Amount, as determined by BPA pursuant to section 3.3 of this exhibit, is greater than zero, then EWEB's Initial Slice Percentage shall be equal to: (1) the sum of EWEB's Preliminary Slice

Amount plus EWEB's Additional Slice Amount, divided by (2) the Base Tier 1 System Capability, expressed as a five decimal percentage.

5. REVISIONS

Revisions to this Exhibit Q shall be by mutual agreement of the Parties.

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Rcv'd. 4/25/16 at 10:27am via Fed Ex. bm

Contract No. 16TX-16224

STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

EUGENE WATER & ELECTRIC BOARD

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STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT

This STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT (LGIA) is made and entered into this ____ day of ____________________ 20___, by and between EUGENE WATER & ELECTRIC BOARD, a public utility organized and existing under the laws of the State of Oregon, an Interconnection Customer with a Large Generating Facility (Interconnection Customer), and the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION, (Transmission Provider and/or Transmission Owner). Interconnection Customer and Transmission Provider each may be referred to as a "Party" or collectively as the "Parties."

RECITALS

WHEREAS, Transmission Provider operates the Transmission System; and

WHEREAS, Interconnection Customer intends to own, lease and/or control and operate the Generating Facility identified as a Large Generating Facility in Appendix C to this LGIA; and

WHEREAS, Interconnection Customer and Transmission Provider have agreed to enter into this LGIA for the purpose of interconnecting the Large Generating Facility with the Transmission System;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein, it is agreed:

When used in this LGIA, terms with initial capitalization that are not defined in Article 1 shall have the meanings specified in the Article in which they are used or the Open Access Transmission Tariff (Tariff).

Article 1. Definitions

Adverse System Impact shall mean the negative effects due to technical or operational limits on conductors or equipment being exceeded that may compromise the safety and reliability of the electric system.

Affected System shall mean an electric system other than the Transmission Provider's Transmission System that may be affected by the proposed interconnection.

Affected System Operator shall mean the entity that operates an Affected System.

Affiliate shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

Ancillary Services shall mean those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

Applicable Laws and Regulations shall mean all duly promulgated applicable Federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Applicable Reliability Council shall mean the reliability council applicable to the Transmission System to which the Generating Facility is directly interconnected.

Applicable Reliability Standards shall mean the requirements and guidelines of NERC, the Applicable Reliability Council and the Control Area of the Transmission System to which the Generating Facility is directly interconnected.

Base Case shall mean the base case power flow, short circuit and stability data bases used for the Interconnection Studies by the Transmission Provider or Interconnection Customer.

Breach shall mean the failure of a Party to perform or observe any material term or condition of the LGIA.

Breaching Party shall mean a Party that is in Breach of the LGIA.

Business Day shall mean Monday through Friday, excluding Federal Holidays.

Calendar Day shall mean any day including Saturday, Sunday or a Federal Holiday.

Clustering shall mean the process whereby a group of Interconnection Requests is studied together, instead of serially, for the purpose of conducting the Interconnection System Impact Study.

Commercial Operation shall mean the status of a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

Commercial Operation Date of a unit shall mean the date on which the Generating Facility commences Commercial Operation as agreed to by the Parties pursuant to Appendix E to the LGIA.

Confidential Information shall mean any confidential, proprietary or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy or compilation relating to the present or planned business of a Party, which is designated as confidential by the Party supplying the information, whether conveyed orally, electronically, in writing, through inspection or otherwise.

Control Area shall mean an electrical system or systems bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the interconnection. A Control Area must be certified by the Applicable Reliability Council.

Default shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 17 of the LGIA.

Dispute Resolution shall mean the procedure for resolution of a dispute between the Parties in which they will first attempt to resolve the dispute on an informal basis.

Distribution System shall mean the Transmission Provider's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which distribution systems operate differ among areas.

Distribution Upgrades shall mean the additions, modifications and upgrades to the Transmission Provider's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Generating Facility and render the transmission service necessary to affect Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

Effective Date shall mean the date on which the LGIA becomes effective upon execution by the Parties, or if filed unexecuted, upon the date specified by FERC.

Emergency Condition shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of a Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to Transmission Provider's Transmission System, Transmission Provider's Interconnection Facilities or the electric systems of others to which the Transmission Provider's Transmission System is directly connected; or (3) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Generating Facility or Interconnection Customer's Interconnection Facilities. System restoration and black start shall be considered Emergency Conditions; provided that Interconnection Customer is not obligated by the LGIA to possess black start capability.

Energy Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission Provider's Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or nonfirm capacity of the Transmission Provider's Transmission System on an as available basis. Energy Resource Interconnection Service in and of itself does not convey transmission service.

Engineering & Procurement (E&P) Agreement shall mean an agreement that authorizes the Transmission Provider to begin engineering and procurement of long lead-time items necessary for the establishment of the interconnection in order to advance the implementation of the Interconnection Request.

Environmental Law shall mean Applicable Laws or Regulations relating to pollution or protection of the environment or natural resources.

Federal Power Act shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a et seq.

FERC shall mean the Federal Energy Regulatory Commission or its successor.

Force Majeure shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include acts of negligence or intentional wrongdoing by the Party claiming Force Majeure.

Generating Facility shall mean Interconnection Customer's device for the production of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

Generating Facility Capacity shall mean the net capacity of the Generating Facility and the aggregate net capacity of the Generating Facility where it includes multiple energy production devices.

Good Utility Practice shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be acceptable practices, methods or acts generally accepted in the region.

Governmental Authority shall mean any Federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide and exercising or entitled to exercise any administrative, executive, police or taxing authority or power; provided however, that such term does not include Interconnection Customer, Transmission Provider, or any Affiliate thereof.

Hazardous Substances shall mean any chemicals, materials or substances defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "hazardous constituents," "restricted hazardous materials," "extremely hazardous substances," "toxic substances," "radioactive substances," "contaminants," "pollutants," "toxic pollutants" or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

Initial Synchronization Date shall mean the date upon which the Generating Facility is initially synchronized and upon which Trial Operation begins.

In-Service Date shall mean the date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Transmission Provider's Interconnection Facilities to obtain back feed power.

Interconnection Customer shall mean any entity, including the Transmission Provider, Transmission Owner or any of the Affiliates or subsidiaries of either, that proposes to interconnect its Generating Facility with the Transmission Provider's Transmission System.

Interconnection Customer's Interconnection Facilities shall mean all facilities and equipment, as identified in Appendix A of the LGIA, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the Transmission Provider's Transmission System. Interconnection Customer's Interconnection Facilities are sole use facilities.

Interconnection Facilities shall mean the Transmission Provider's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Transmission Provider's Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Interconnection Facilities Study shall mean a study conducted by the Transmission Provider or a third party consultant for the Interconnection Customer to determine a list of facilities (including Transmission Provider's Interconnection Facilities and Network Upgrades as identified in the Interconnection System Impact Study), the cost of those facilities and the time required to interconnect the Generating Facility with the Transmission Provider's Transmission System. The scope of the study is defined in Section 8 of the Standard Large Generator Interconnection Procedures (LGIP).

Interconnection Facilities Study Agreement shall mean the form of agreement contained in Appendix 4 of the LGIP for conducting the Interconnection Facilities Study.

Interconnection Feasibility Study shall mean a preliminary evaluation of the system impact and cost of interconnecting the Generating Facility to the Transmission Provider's Transmission System, the scope of which is described in Section 6 of the LGIP.

Interconnection Feasibility Study Agreement shall mean the form of agreement contained in Appendix 2 of the LGIP for conducting the Interconnection Feasibility Study.

Interconnection Request shall mean an Interconnection Customer's request, in the form of Appendix 1 to the LGIP, in accordance with the Tariff, to interconnect a new Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Generating Facility that is interconnected with the Transmission Provider's Transmission System.

Interconnection Service shall mean the service provided by the Transmission Provider associated with interconnecting the Interconnection Customer's Generating Facility to the Transmission Provider's Transmission System and enabling it to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the LGIA and, if applicable, the Transmission Provider's Tariff.

Interconnection Study shall mean any of the following studies: the Interconnection Feasibility Study, the Interconnection System Impact Study and the Interconnection Facilities Study described in the LGIP.

Interconnection System Impact Study shall mean an engineering study that evaluates the impact of the proposed interconnection on the safety and reliability of Transmission Provider's Transmission System and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were interconnected without project modifications or system modifications, focusing on the Adverse System Impacts identified in the Interconnection Feasibility Study, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the LGIP.

Interconnection System Impact Study Agreement shall mean the form of agreement contained in Appendix 3 of the LGIP for conducting the Interconnection System Impact Study.

Joint Operating Committee shall be a group made up of representatives from Interconnection Customers and the Transmission Provider to coordinate operating and technical considerations of Interconnection Service.

Large Generating Facility shall mean a Generating Facility having a Generating Facility Capacity of more than 20 MW.

Loss shall mean any and all losses relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees and all other obligations by or to third parties, arising out of or resulting from the other Party's performance, or non-performance of its obligations under the LGIA on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnifying Party.

Material Modification shall mean those modifications that have a material impact on the cost or timing of any Interconnection Request with a later queue priority date.

Metering Equipment shall mean all metering equipment installed or to be installed at the Generating Facility pursuant to the LGIA at the metering points, including but not limited to instrument transformers, MWh-meters, data acquisition equipment, transducers, remote terminal unit, communications equipment, phone lines and fiber optics.

NERC shall mean the North American Electric Reliability Council or its successor organization.

Network Resource shall mean any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

Network Resource Interconnection Service shall mean an Interconnection Service that allows the Interconnection Customer to integrate its Large Generating Facility with the Transmission Provider's Transmission System: (1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an RTO or ISO with market-based congestion management, in the same manner as Network Resources. Network Resource Interconnection Service in and of itself does not convey transmission service.

Network Upgrades shall mean the additions, modifications and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Interconnection Facilities connect to the Transmission Provider's Transmission System to accommodate the interconnection of the Large Generating Facility to the Transmission Provider's Transmission System.

Notice of Dispute shall mean a written notice of a dispute or claim that arises out of or in connection with the LGIA or its performance.

Optional Interconnection Study shall mean a sensitivity analysis based on assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement.

Optional Interconnection Study Agreement shall mean the form of agreement contained in Appendix 5 of the LGIP for conducting the Optional Interconnection Study.

Party or Parties shall mean Transmission Provider, Transmission Owner, Interconnection Customer or any combination of the above.

Point of Change of Ownership shall mean the point, as set forth in Appendix A to the LGIA, where the Interconnection Customer's Interconnection Facilities connect to the Transmission Provider's Interconnection Facilities.

Point of Interconnection shall mean the point, as set forth in Appendix A to the LGIA, where the Interconnection Facilities connect to the Transmission Provider's Transmission System.

Queue Position shall mean the order of a valid Interconnection Request, relative to all other pending valid Interconnection Requests, that is established based upon the date and time of receipt of the valid Interconnection Request by the Transmission Provider.

Reasonable Efforts shall mean, with respect to an action required to be attempted or taken by a Party under the LGIA, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.

Scoping Meeting shall mean the meeting between representatives of the Interconnection Customer and Transmission Provider conducted for the purpose of discussing alternative interconnection options, to exchange information including any transmission data and earlier study evaluations that would be reasonably expected to impact such interconnection options, to analyze such information and to determine the potential feasible Points of Interconnection.

Site Control shall mean documentation reasonably demonstrating: (1) ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the Generating Facility; (2) an option to purchase or acquire a leasehold site for such purpose; or (3) an exclusivity or other business relationship between Interconnection Customer and the entity having the right to sell, lease or grant Interconnection Customer the right to possess or occupy a site for such purpose.

Small Generating Facility shall mean a Generating Facility that has a Generating Facility Capacity of no more than 20 MW.

Stand Alone Network Upgrades shall mean Network Upgrades that an Interconnection Customer may construct without affecting day-to-day operations of the Transmission System during their construction. Both the Transmission Provider and the Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify them in Appendix A to the LGIA.

Standard Large Generator Interconnection Agreement (LGIA) shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to a Large Generating Facility that is included in the Transmission Provider's Tariff.

Standard Large Generator Interconnection Procedures (LGIP) shall mean the interconnection procedures applicable to an Interconnection Request pertaining to a Large Generating Facility that are included in the Transmission Provider's Tariff.

System Protection Facilities shall mean the equipment, including necessary protection signal communications equipment, required to protect: (1) the Transmission Provider's Transmission System from faults or other electrical disturbances occurring at the Generating Facility, and (2) the Generating Facility from faults or other electrical system disturbances occurring on the Transmission Provider's Transmission System or on other delivery systems or other generating systems to which the Transmission Provider's Transmission System is directly connected.

Tariff shall mean the Transmission Provider's Tariff through which open access transmission service and Interconnection Service are offered, as filed with FERC, and as amended or supplemented from time to time, or any successor Tariff.

Transmission Owner shall mean an entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System at the Point of Interconnection and may be a Party to the Standard LGIA to the extent necessary.

Transmission Provider shall mean the public utility (or its designated agent) that owns, controls or operates transmission or distribution facilities used for the transmission of electricity in interstate commerce and provides transmission service under the Tariff. The term Transmission Provider should be read to include the Transmission Owner when the Transmission Owner is separate from the Transmission Provider.

Transmission Provider's Interconnection Facilities shall mean all facilities and equipment owned, controlled or operated by the Transmission Provider from the Point of Change of Ownership to the Point of Interconnection as identified in Appendix A to the Standard LGIA, including any modifications, additions or upgrades to such facilities and equipment. Transmission Provider's Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.

Transmission System shall mean the facilities owned, controlled or operated by the Transmission Provider or Transmission Owner that are used to provide transmission service under the Tariff.

Trial Operation shall mean the period during which Interconnection Customer is engaged in on-site test operations and commissioning of the Generating Facility prior to Commercial Operation.

Article 2. Effective Date, Term and Termination

2.1 Effective Date.
This LGIA shall become effective upon execution by the Parties, or if filed unexecuted, upon the date specified by FERC.

2.2 Term of Agreement.
Subject to the provisions of Article 2.3, this LGIA shall remain in effect for a period of ten (10) years from the Effective Date and shall be automatically renewed for each successive one-year period thereafter.

2.3 Termination Procedures.

2.3.1 Written Notice.
This LGIA may be terminated by Interconnection Customer after giving Transmission Provider ninety (90) Calendar Days advance written notice or by Transmission Provider notifying FERC after the Generating Facility permanently ceases Commercial Operation.

2.3.2 Default.
Either Party may terminate this LGIA in accordance with Article 17.

2.3.3 Notwithstanding Articles 2.3.1 and 2.3.2, no termination shall become effective until the Parties have complied with all Applicable Laws and Regulations applicable to such termination.

2.4 Termination Costs.
If a Party elects to terminate this Agreement pursuant to Article 2.3 above, each Party shall pay all costs incurred (including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment) or charges assessed by the other Party, as of the date of the other Party's receipt of such notice of termination, for which it is responsible under this LGIA. In the event of termination by a Party, the Parties shall use commercially Reasonable Efforts to mitigate the costs, damages and charges arising as a consequence of termination.

2.4.1 With respect to any portion of Transmission Provider's Interconnection Facilities that have not yet been constructed or installed, Transmission Provider shall, to the extent possible and with Interconnection Customer's authorization, cancel any pending orders of, or return, any materials or equipment for, or contracts for construction of, such facilities; provided that in the event Interconnection Customer elects not to authorize such cancellation, Interconnection Customer shall assume all payment obligations with respect to such materials, equipment and contracts and Transmission Provider shall deliver such material and equipment; and, if necessary, assign such contracts, to Interconnection Customer as soon as practicable, at Interconnection Customer's expense. To the extent that Interconnection Customer has already paid Transmission Provider for any or all such costs of materials or equipment not taken by Interconnection Customer, Transmission Provider shall promptly refund such amounts to Interconnection Customer, less any costs, including penalties incurred by Transmission Provider to cancel any pending orders of or return such materials, equipment or contracts.

If an Interconnection Customer terminates this LGIA, it shall be responsible for all costs incurred in association with that Interconnection Customer's interconnection, including any cancellation costs relating to orders or contracts for Interconnection Facilities and equipment and other expenses including any Network Upgrades for which Transmission Provider has incurred expenses and has not been reimbursed by Interconnection Customer.

2.4.2 Transmission Provider may, at its option, retain any portion of such materials, equipment or facilities that Interconnection Customer chooses not to accept delivery of, in which case Transmission Provider shall be responsible for all costs associated with procuring such materials, equipment or facilities.

2.4.3 With respect to any portion of the Interconnection Facilities and any other facilities already installed or constructed pursuant to the terms of this LGIA, Interconnection Customer shall be responsible for all costs associated with the removal, relocation or other disposition or retirement of such materials, equipment or facilities.

2.5 Disconnection.
Upon termination of this LGIA, the Parties will take all appropriate steps to disconnect the Large Generating Facility from the Transmission System. All costs required to effectuate such disconnection shall be borne by the terminating Party, unless such termination resulted from the non-terminating Party's Default of this LGIA or such non-terminating Party otherwise is responsible for these costs under this LGIA.

2.6 Survival.
This LGIA shall continue in effect after termination to the extent necessary to provide for final billings and payments and for costs incurred hereunder, including billings and payments pursuant to this LGIA; to permit the determination and enforcement of liability and indemnification obligations arising from acts or events that occurred while this LGIA was in effect; and to permit each Party to have access to the lands of the other Party pursuant to this LGIA or other applicable agreements, to disconnect, remove or salvage its own facilities and equipment.

Article 3. Regulatory Filings

3.1 Filing.

Transmission Provider shall file this LGIA (and any amendment hereto) with the appropriate Governmental Authority, if required. Interconnection Customer may request that any information so provided be subject to the confidentiality provisions of Article 22. If Interconnection Customer has executed this LGIA, or any amendment thereto, Interconnection Customer shall reasonably cooperate with Transmission Provider with respect to such filing and to provide any information reasonably requested by Transmission Provider needed to comply with applicable regulatory requirements.

Article 4. Scope of Service

4.1 Interconnection Product Options.

Interconnection Customer has selected the following type of Interconnection Service:

4.1.1 Energy Resource Interconnection Service.

4.1.1.1 The Product.

Energy Resource Interconnection Service allows Interconnection Customer to connect the Large Generating Facility to the Transmission System and be eligible to deliver the Large Generating Facility's output using the existing firm or non-firm capacity of the Transmission System on an "as available" basis. To the extent Interconnection Customer wants to receive Energy Resource Interconnection Service, Transmission Provider shall construct facilities identified in Appendix A.

4.1.1.2 Transmission Delivery Service Implications.

Under Energy Resource Interconnection Service, Interconnection Customer will be eligible to inject power from the Large Generating Facility into and deliver power across the interconnecting Transmission Provider's Transmission System on an "as available" basis up to the amount of MWs identified in the applicable stability and steady state studies to the extent the upgrades initially required to qualify for Energy Resource Interconnection Service have been constructed. Where eligible to do so (e.g., PJM, ISO-NE, NYISO), Interconnection Customer may place a bid to sell into the market up to the maximum identified Large Generating Facility output, subject to any conditions specified in the interconnection service approval and the Large Generating Facility will be dispatched to the extent Interconnection Customer's bid clears. In all other instances, no transmission delivery service from the Large Generating Facility is assured, but Interconnection Customer may obtain Point-to-Point Transmission Service, Network Integration Transmission Service or be used for secondary network transmission service, pursuant to Transmission Provider's Tariff, up to the maximum output identified in the stability and steady state studies. In those instances, in order for Interconnection Customer to obtain the right to deliver or inject energy beyond the Large Generating Facility Point of Interconnection or to improve its ability to do so, transmission delivery service must be obtained pursuant to the provisions of Transmission Provider's Tariff. The Interconnection Customer's ability to inject its Large Generating Facility output beyond the Point of Interconnection, therefore, will depend on the existing capacity of Transmission Provider's Transmission System at such time as a transmission service request is made that would accommodate such delivery. The provision of firm Point-to-Point Transmission Service or Network Integration Transmission Service may require the construction of additional Network Upgrades.

4.2 Provision of Service.
Transmission Provider shall provide Interconnection Service for the Large Generating Facility at the Point of Interconnection.

4.3 Performance Standards.
Each Party shall perform all of its obligations under this LGIA in accordance with Applicable Laws and Regulations, Applicable Reliability Standards and Good Utility Practice and to the extent a Party is required or prevented or limited in taking any action by such regulations and standards, such Party shall not be deemed to be in Breach of this LGIA for its compliance therewith.

4.3.1 Compliance with WECC Reliability Criteria.

4.3.1.1 Compliance.
Interconnection Customer shall comply with the provisions of the WECC Reliability Criteria Agreement that are applicable to generators. All provisions of the WECC Reliability Criteria Agreement are hereby incorporated by reference into this LGIA as though set forth fully herein. Interconnection Customer shall for all purposes be considered a Participant as defined in the WECC Reliability Criteria Agreement and shall be entitled to all of the rights and privileges and be subject to all of the obligations of a generator that is a Participant to that agreement, including but not limited to the rights, privileges and obligations set forth in Section 5 (Determination of Compliance), Section 6 (Review of RCC Determination) and Section 10 (Remedies) of the WECC Reliability Criteria Agreement.

4.3.1.2 Payment of Sanctions.
Interconnection Customer shall be responsible for payment of any monetary sanction assessed against Interconnection Customer by WECC pursuant to the WECC Reliability Criteria Agreement. Any such payment shall be made pursuant to the procedures specified in the WECC Reliability Criteria Agreement.

4.3.1.3 WECC Remedy.
Transmission Provider and Interconnection Customer expressly intend that WECC is a third-party beneficiary to this LGIA for purposes of this Article 4.3.1. The WECC shall have the right to seek to enforce against Interconnection Customer any provision of this Article 4.3.1, **provided** that specific performance shall be the sole remedy available to the WECC for enforcement of the provisions of this Article 4.3.1, other than payment to the WECC of monetary sanctions under the WECC Reliability Criteria Agreement.

4.3.1.4 Termination.
Interconnection Customer may terminate its obligations under this Article 4.3.1 (other than its obligations under Article 4.3.1.5):

(a) if after the Effective Date of this LGIA, the requirements of the WECC Reliability Criteria Agreement applicable to Interconnection Customer are amended so as to adversely affect Interconnection Customer, **provided** that, within forty-five (45) days of the date of issuance of a FERC order accepting such amendment for filing, Interconnection Customer gives fifteen (15) days' written notice of such termination to Transmission Provider and the WECC; **and provided further** that such forty-five (45) day period may be extended by Interconnection Customer for an additional forty-five (45) days if Interconnection Customer gives written notice to Transmission Provider of such requested extension within the initial forty-five (45) day period; or

(b) for any reason on one year's written notice to Transmission Provider and the WECC.

4.3.1.5 Replacement Terms.
If Interconnection Customer exercises its right to terminate its obligations under this Article 4.3.1, Interconnection Customer and Transmission Provider shall use good faith efforts to negotiate an amendment to this LGIA imposing obligations on Interconnection Customer to meet reliability criteria satisfactory to Transmission Provider.

4.3.1.6 **Consent.**
Interconnection Customer consents to the release by the WECC of information related to Interconnection Customer's compliance with this LGIA, **provided** that such information is released in accordance with the WECC Reliability Criteria Agreement.

4.3.1.7 **Definitions.**

(a) WECC shall mean the Western Electricity Coordinating Council or its successor.

(b) WECC Reliability Criteria Agreement shall mean the WECC Reliability Criteria Agreement dated June 18, 1999, among the WECC and certain of its member transmission operators, as such may be amended or replaced from time to time.

4.4 No Transmission Delivery Service.
The execution of this LGIA does not constitute a request for, nor the provision of, any transmission delivery service under Transmission Provider's Tariff and does not convey any right to deliver electricity to any specific customer or point of delivery.

4.5 Interconnection Customer Provided Services.
The services provided by Interconnection Customer under this LGIA are set forth in Article 9.6 and Article 13.5.1. Interconnection Customer shall be paid for such services in accordance with Article 11.6.

Article 5. Interconnection Facilities Engineering, Procurement and Construction

5.1 Options.
Unless otherwise mutually agreed to between the Parties, Interconnection Customer shall select the In-Service Date, Initial Synchronization Date and Commercial Operation Date, and either Standard Option or Alternate Option set forth below for completion of Transmission Provider's Interconnection Facilities and Network Upgrades as set forth in Appendix A, Interconnection Facilities and Network Upgrades and such dates and selected option shall be set forth in Appendix B, Milestones.

5.1.1 Standard Option.
Transmission Provider shall design, procure and construct Transmission Provider's Interconnection Facilities and Network Upgrades, using Reasonable Efforts to complete Transmission Provider's Interconnection Facilities and Network Upgrades by the dates set forth in Appendix B, Milestones. Transmission Provider shall not be required to undertake any action which is inconsistent with its standard safety practices, its material and equipment specifications, its design criteria and construction procedures, its labor agreements and Applicable Laws and Regulations. In the event

Transmission Provider reasonably expects that it will not be able to complete Transmission Provider's Interconnection Facilities and Network Upgrades by the specified dates, Transmission Provider shall promptly provide written notice to Interconnection Customer and shall undertake Reasonable Efforts to meet the earliest dates thereafter.

5.1.2 Alternate Option.
If the dates designated by Interconnection Customer are acceptable to Transmission Provider, Transmission Provider shall so notify Interconnection Customer within thirty (30) Calendar Days and shall assume responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities by the designated dates.

If Transmission Provider subsequently fails to complete Transmission Provider's Interconnection Facilities by the In-Service Date, to the extent necessary to provide back feed power; or fails to complete Network Upgrades by the Initial Synchronization Date to the extent necessary to allow for Trial Operation at full power output, unless other arrangements are made by the Parties for such Trial Operation; or fails to complete the Network Upgrades by the Commercial Operation Date, as such dates are reflected in Appendix B, Milestones; Transmission Provider shall pay Interconnection Customer liquidated damages in accordance with Article 5.3, Liquidated Damages, provided, however, the dates designated by Interconnection Customer shall be extended day for day for each day that the applicable RTO or ISO refuses to grant clearances to install equipment.

5.1.3 Option to Build.
If the dates designated by Interconnection Customer are not acceptable to Transmission Provider, Transmission Provider shall so notify Interconnection Customer within thirty (30) Calendar Days; and unless the Parties agree otherwise, Interconnection Customer shall have the option to assume responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades on the dates specified in Article 5.1.2. Transmission Provider and Interconnection Customer must agree as to what constitutes Stand Alone Network Upgrades and identify such Stand Alone Network Upgrades in Appendix A. Except for Stand Alone Network Upgrades, Interconnection Customer shall have no right to construct Network Upgrades under this option.

5.1.4 Negotiated Option.
If Interconnection Customer elects not to exercise its option under Article 5.1.3, Option to Build, Interconnection Customer shall so notify Transmission Provider within thirty (30) Calendar Days and the Parties shall in good faith attempt to negotiate terms and conditions (including revision of the specified dates and liquidated damages, the provision of incentives or the procurement and construction of a portion of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades by Interconnection Customer)

pursuant to which Transmission Provider is responsible for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Network Upgrades. If the Parties are unable to reach agreement on such terms and conditions, Transmission Provider shall assume responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Network Upgrades pursuant to Article 5.1.1, Standard Option.

5.2 General Conditions Applicable to Option to Build.
If Interconnection Customer assumes responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades:

5.2.1 Interconnection Customer shall engineer, procure equipment and construct Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades (or portions thereof) using Good Utility Practice and using standards and specifications provided in advance by Transmission Provider;

5.2.2 Interconnection Customer's engineering, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades shall comply with all requirements of law to which Transmission Provider would be subject in the engineering, procurement or construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades;

5.2.3 Transmission Provider shall review and approve the engineering design, equipment acceptance tests and the construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades;

5.2.4 prior to commencement of construction, Interconnection Customer shall provide to Transmission Provider a schedule for construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades, and shall promptly respond to requests for information from Transmission Provider;

5.2.5 at any time during construction, Transmission Provider shall have the right to gain unrestricted access to Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades and to conduct inspections of the same;

5.2.6 at any time during construction, should any phase of the engineering, equipment procurement or construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades not meet the standards and specifications provided by Transmission Provider, Interconnection Customer shall be obligated to remedy deficiencies in that portion of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades;

5.2.7 (Intentionally Omitted);

5.2.8 Interconnection Customer shall transfer control of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades to Transmission Provider;

5.2.9 unless Parties otherwise agree, Interconnection Customer shall transfer ownership of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades to Transmission Provider;

5.2.10 Transmission Provider shall approve and accept for operation and maintenance Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades to the extent engineered, procured and constructed in accordance with this Article 5.2; and

5.2.11 Interconnection Customer shall deliver to Transmission Provider "as-built" drawings, information and any other documents that are reasonably required by Transmission Provider to assure that the Interconnection Facilities and Stand Alone Network Upgrades are built to the standards and specifications required by Transmission Provider.

5.3 Liquidated Damages.
The actual damages to Interconnection Customer, in the event Transmission Provider's Interconnection Facilities or Network Upgrades are not completed by the dates designated by Interconnection Customer and accepted by Transmission Provider pursuant to Subparagraphs 5.1.2 or 5.1.4 above, may include Interconnection Customer's fixed operation and maintenance costs and lost opportunity costs. Such actual damages are uncertain and impossible to determine at this time. Because of such uncertainty, any liquidated damages paid by Transmission Provider to Interconnection Customer in the event that Transmission Provider does not complete any portion of Transmission Provider's Interconnection Facilities or Network Upgrades by the applicable dates, shall be an amount equal to one-half of 1 percent per day of the actual cost of Transmission Provider's Interconnection Facilities and Network Upgrades, in the aggregate, for which Transmission Provider has assumed responsibility to design, procure and construct.

However, in no event shall the total liquidated damages exceed twenty (20) percent of the actual cost of Transmission Provider's Interconnection Facilities and Network Upgrades for which Transmission Provider has assumed responsibility to design, procure and construct. The foregoing payments will be made by Transmission Provider to Interconnection Customer as just compensation for the damages caused to Interconnection Customer, which actual damages are uncertain and impossible to determine at this time; and as reasonable liquidated damages, but not as a penalty or a method to secure performance of this LGIA. Liquidated damages, when the Parties agree to them, are the exclusive remedy for the Transmission Provider's failure to meet its schedule.

No liquidated damages shall be paid to Interconnection Customer if: (1) Interconnection Customer is not ready to commence use of Transmission Provider's Interconnection Facilities or Network Upgrades to take the delivery of power for the Large Generating Facility's Trial Operation or to export power from the Large Generating Facility on the specified dates, unless Interconnection Customer would have been able to commence use of Transmission Provider's Interconnection Facilities or Network Upgrades to take the delivery of power for Large Generating Facility's Trial Operation or to export power from the Large Generating Facility, but for Transmission Provider's delay; (2) Transmission Provider's failure to meet the specified dates is the result of the action or inaction of Interconnection Customer or any other Interconnection Customer who has entered into an LGIA with Transmission Provider or any cause beyond Transmission Provider's reasonable control or reasonable ability to cure; (3) the Interconnection Customer has assumed responsibility for the design, procurement and construction of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades; or (4) the Parties have otherwise agreed.

5.4 Power System Stabilizers.
The Interconnection Customer shall procure, install, maintain and operate Power System Stabilizers in accordance with the guidelines and procedures established by the Applicable Reliability Council. Transmission Provider reserves the right to reasonably establish minimum acceptable settings for any installed Power System Stabilizers, subject to the design and operating limitations of the Large Generating Facility. If the Large Generating Facility's Power System Stabilizers are removed from service or not capable of automatic operation, Interconnection Customer shall immediately notify Transmission Provider's system operator or its designated representative. The requirements of this paragraph shall not apply to wind generators.

5.5 Equipment Procurement.
If responsibility for construction of Transmission Provider's Interconnection Facilities or Network Upgrades is to be borne by Transmission Provider, then Transmission Provider shall commence design of Transmission Provider's Interconnection Facilities or Network Upgrades and procure necessary equipment as soon as practicable after all of the following conditions are satisfied, unless the Parties otherwise agree in writing:

5.5.1 Transmission Provider has completed the Facilities Study pursuant to the Facilities Study Agreement;

5.5.2 Transmission Provider has received written authorization to proceed with design and procurement from Interconnection Customer by the date specified in Appendix B, Milestones; and

5.5.3 Interconnection Customer has provided security to Transmission Provider in accordance with Article 11.5 by the dates specified in Appendix B, Milestones.

5.6 Construction Commencement.
Transmission Provider shall commence construction of Transmission Provider's Interconnection Facilities and Network Upgrades for which it is responsible as soon as practicable after the following additional conditions are satisfied:

5.6.1 Approval of the appropriate Governmental Authority has been obtained for any facilities requiring regulatory approval;

5.6.2 Necessary real property rights and rights-of-way have been obtained, to the extent required for the construction of a discrete aspect of Transmission Provider's Interconnection Facilities and Network Upgrades;

5.6.3 Transmission Provider has received written authorization to proceed with construction from Interconnection Customer by the date specified in Appendix B, Milestones; and

5.6.4 Interconnection Customer has provided security to Transmission Provider in accordance with Article 11.5 by the dates specified in Appendix B, Milestones.

5.7 Work Progress.
The Parties will keep each other advised periodically as to the progress of their respective design, procurement and construction efforts. Either Party may, at any time, request a progress report from the other Party. If, at any time, Interconnection Customer determines that the completion of Transmission Provider's Interconnection Facilities will not be required until after the specified In-Service Date, Interconnection Customer will provide written notice to Transmission Provider of such later date upon which the completion of Transmission Provider's Interconnection Facilities will be required.

5.8 Information Exchange.
As soon as reasonably practicable after the Effective Date, the Parties shall exchange information regarding the design and compatibility of the Parties' Interconnection Facilities and compatibility of the Interconnection Facilities with Transmission Provider's Transmission System, and shall work diligently and in good faith to make any necessary design changes.

5.9 Limited Operation.
If any of Transmission Provider's Interconnection Facilities or Network Upgrades are not reasonably expected to be completed prior to the Commercial Operation Date of the Large Generating Facility, Transmission Provider shall, upon the request and at the expense of Interconnection Customer, perform operating studies on a timely basis to determine the extent to which the Large Generating Facility and

Interconnection Customer's Interconnection Facilities may operate prior to the completion of Transmission Provider's Interconnection Facilities or Network Upgrades consistent with Applicable Laws and Regulations, Applicable Reliability Standards, Good Utility Practice and this LGIA. Transmission Provider shall permit Interconnection Customer to operate the Large Generating Facility and Interconnection Customer's Interconnection Facilities in accordance with the results of such studies.

5.10 Interconnection Customer's Interconnection Facilities (ICIF).
Interconnection Customer shall, at its expense, design, procure, construct, own and install the ICIF, as set forth in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades.

5.10.1 Interconnection Customer's Interconnection Facility Specifications.
Interconnection Customer shall submit initial specifications for the ICIF, including System Protection Facilities, to Transmission Provider at least one hundred eighty (180) Calendar Days prior to the Initial Synchronization Date, and final specifications for review and comment at least ninety (90) Calendar Days prior to the Initial Synchronization Date. Transmission Provider shall review such specifications to ensure that the ICIF are compatible with the technical specifications, operational control and safety requirements of Transmission Provider and comment on such specifications within thirty (30) Calendar Days of Interconnection Customer's submission. All specifications provided hereunder shall be deemed confidential.

5.10.2 Transmission Provider's Review.
Transmission Provider's review of Interconnection Customer's final specifications shall not be construed as confirming, endorsing or providing a warranty as to the design, fitness, safety, durability or reliability of the Large Generating Facility, or the ICIF. Interconnection Customer shall make such changes to the ICIF as may reasonably be required by Transmission Provider, in accordance with Good Utility Practice, to ensure that the ICIF are compatible with the technical specifications, operational control and safety requirements of Transmission Provider.

5.10.3 ICIF Construction.
The ICIF shall be designed and constructed in accordance with Good Utility Practice. Within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, Interconnection Customer shall deliver to Transmission Provider "as-built" drawings, information and documents for the ICIF, such as: a one-line diagram, a site plan showing the Large Generating Facility and the ICIF, plan and elevation drawings showing the layout of the ICIF, a relay functional diagram, relaying AC and DC schematic wiring diagrams and relay settings for all facilities associated with Interconnection Customer's step-up transformers, the facilities

connecting the Large Generating Facility to the step-up transformers and the ICIF, and the impedances (determined by factory tests) for the associated step-up transformers and the Large Generating Facility. The Interconnection Customer shall provide Transmission Provider specifications for the excitation system, automatic voltage regulator, Large Generating Facility control and protection settings, transformer tap settings and communications, if applicable.

5.11 Transmission Provider's Interconnection Facilities Construction.
Transmission Provider's Interconnection Facilities shall be designed and constructed in accordance with Good Utility Practice. Upon request, within one hundred twenty (120) Calendar Days after the Commercial Operation Date, unless the Parties agree on another mutually acceptable deadline, Transmission Provider shall deliver to Interconnection Customer the following "as-built" drawings, information and documents for Transmission Provider's Interconnection Facilities: drawings, diagrams, and other information reasonably related to the specifications set forth in Appendix A.

Transmission Provider will obtain control of Transmission Provider's Interconnection Facilities and Stand Alone Network Upgrades upon completion of such facilities.

5.12 Access Rights.
Upon reasonable notice and supervision by a Party, and subject to any required or necessary regulatory approvals, a Party ("Granting Party") shall furnish <u>at no cost</u> to the other Party ("Access Party") any rights of use, licenses, rights of way and easements with respect to lands owned or controlled by the Granting Party, its agents (if allowed under the applicable agency agreement), or any Affiliate, that are necessary to enable the Access Party to obtain ingress and egress to construct, operate, maintain, repair, test (or witness testing), inspect, replace or remove facilities and equipment to: (1) interconnect the Large Generating Facility with the Transmission System; (2) operate and maintain the Large Generating Facility, the Interconnection Facilities and the Transmission System; and (3) disconnect or remove the Access Party's facilities and equipment upon termination of this LGIA. In exercising such licenses, rights of way and easements, the Access Party shall not unreasonably disrupt or interfere with normal operation of the Granting Party's business and shall adhere to the safety rules and procedures established in advance, as may be changed from time to time, by the Granting Party and provided to the Access Party.

5.13 Lands of Other Property Owners.
If any part of Transmission Provider or Transmission Owner's Interconnection Facilities and/or Network Upgrades is to be installed on property owned by persons other than Interconnection Customer or Transmission Provider or Transmission Owner, Transmission Provider or Transmission Owner shall at Interconnection Customer's expense use efforts similar in nature and extent to those that it typically undertakes on its own behalf or on behalf of its Affiliates, including use of its eminent domain authority, and to the extent consistent with Federal law, to procure

from such persons any rights of use, licenses, rights of way and easements that are necessary to construct, operate, maintain, test, inspect, replace or remove Transmission Provider or Transmission Owner's Interconnection Facilities and/or Network Upgrades upon such property.

5.14 Permits.
Transmission Provider or Transmission Owner and Interconnection Customer shall cooperate with each other in good faith in obtaining all permits, licenses and authorizations that are necessary to accomplish the interconnection in compliance with Applicable Laws and Regulations. With respect to this paragraph, Transmission Provider or Transmission Owner shall provide permitting assistance to Interconnection Customer comparable to that provided to Transmission Provider's own, or an Affiliate's generation.

5.15 Early Construction of Base Case Facilities.
Interconnection Customer may request Transmission Provider to construct, and Transmission Provider shall construct, using Reasonable Efforts to accommodate Interconnection Customer's In-Service Date, all or any portion of any Network Upgrades required for Inter-connection Customer to be interconnected to the Transmission System which are included in the Base Case of the Facilities Study for Interconnection Customer, and which also are required to be constructed for another Interconnection Customer, but where such construction is not scheduled to be completed in time to achieve Interconnection Customer's In-Service Date.

5.16 Suspension.
Interconnection Customer reserves the right, upon written notice to Transmission Provider, to suspend at any time all work by Transmission Provider associated with the construction and installation of Transmission Provider's Interconnection Facilities and/or Network Upgrades required under this LGIA with the condition that Transmission System shall be left in a safe and reliable condition in accordance with Good Utility Practice and Transmission Provider's safety and reliability criteria. In such event, Interconnection Customer shall be responsible for all reasonable and necessary costs which Transmission Provider: (1) has incurred pursuant to this LGIA prior to the suspension; and (2) incurs in suspending such work, including any costs incurred to perform such work as may be necessary to ensure the safety of persons and property and the integrity of the Transmission System during such suspension and, if applicable, any costs incurred in connection with the cancellation or suspension of material, equipment and labor contracts which Transmission Provider cannot reasonably avoid; provided however, that prior to canceling or suspending any such material, equipment or labor contract, Transmission Provider shall obtain Interconnection Customer's authorization to do so.

Transmission Provider shall invoice Interconnection Customer for such costs pursuant to Article 12 and shall use due diligence to minimize its costs. In the event Interconnection Customer suspends work by Transmission Provider required under this LGIA pursuant to this Article 5.16, and has not requested Transmission Provider to recommence the work required under this LGIA on or before the expiration of three (3) years following commencement of such suspension, this LGIA shall be deemed terminated. The three-year period shall begin on the date the suspension is requested, or the date of the written notice to Transmission Provider, if no effective date is specified.

5.17 (Intentionally Omitted).

5.18 Tax Status.
The Transmission Provider shall cooperate with the Interconnection Customer to maintain the Interconnection Customer's tax status. Nothing in this LGIA is intended to adversely affect any Transmission Provider's tax exempt status with respect to the issuance of bonds including, but not limited to, Local Furnishing Bonds.

5.19 Modification.

5.19.1 General.
Either Party may undertake modifications to its facilities. If a Party plans to undertake a modification that reasonably may be expected to affect the other Party's facilities, that Party shall provide to the other Party sufficient information regarding such modification so that the other Party may evaluate the potential impact of such modification prior to commencement of the work. Such information shall be deemed to be confidential hereunder and shall include information concerning the timing of such modifications and whether such modifications are expected to interrupt the flow of electricity from the Large Generating Facility. The Party desiring to perform such work shall provide the relevant drawings, plans and specifications to the other Party at least ninety (90) Calendar Days in advance of the commencement of the work or such shorter period upon which the Parties may agree, which agreement shall not unreasonably be withheld, conditioned or delayed.

In the case of Large Generating Facility modifications that do not require Interconnection Customer to submit an Interconnection Request, Transmission Provider shall provide, within thirty (30) Calendar Days (or such other time as the Parties may agree), an estimate of any additional modifications to the Transmission System, Transmission Provider's Interconnection Facilities or Network Upgrades necessitated by such Interconnection Customer modification and a good faith estimate of the costs thereof.

5.19.2 Standards.
Any additions, modifications or replacements made to a Party's facilities shall be designed, constructed and operated in accordance with this LGIA and Good Utility Practice.

5.19.3 Modification Costs.
Interconnection Customer shall not be directly assigned for the costs of any additions, modifications or replacements that Transmission Provider makes to Transmission Provider's Interconnection Facilities or the Transmission System to facilitate the interconnection of a third party to Transmission Provider's Interconnection Facilities or the Transmission System, or to provide transmission service to a third party under Transmission Provider's Tariff. Interconnection Customer shall be responsible for the costs of any additions, modifications or replacements to Interconnection Customer's Interconnection Facilities that may be necessary to maintain or upgrade such Interconnection Customer's Interconnection Facilities consistent with Applicable Laws and Regulations, Applicable Reliability Standards or Good Utility Practice.

Article 6. Testing and Inspection

6.1 Pre-Commercial Operation Date Testing and Modifications.
Prior to the Commercial Operation Date, Transmission Provider shall test Transmission Provider's Interconnection Facilities and Network Upgrades and Interconnection Customer shall test the Large Generating Facility and Interconnection Customer's Interconnection Facilities to ensure their safe and reliable operation. Similar testing may be required after initial operation. Each Party shall make any modifications to its facilities that are found to be necessary as a result of such testing. Interconnection Customer shall bear the cost of all such testing and modifications. Interconnection Customer shall generate test energy at the Large Generating Facility only if it has arranged for the delivery of such test energy.

6.2 Post-Commercial Operation Date Testing and Modifications.
Each Party shall at its own expense perform routine inspection and testing of its facilities and equipment in accordance with Good Utility Practice as may be necessary to ensure the continued interconnection of the Large Generating Facility with the Transmission System in a safe and reliable manner. Each Party shall have the right, upon advance written notice, to require reasonable additional testing of the other Party's facilities, at the requesting Party's expense, as may be in accordance with Good Utility Practice.

6.3 Right to Observe Testing.
Each Party shall notify the other Party in advance of its performance of tests of its Interconnection Facilities. The other Party has the right, at its own expense, to observe such testing.

6.4 Right to Inspect.
Each Party shall have the right, but shall have no obligation to: (1) observe the other Party's tests and/or inspection of any of its System Protection Facilities and other protective equipment, including Power System Stabilizers; (2) review the settings of the other Party's System Protection Facilities and other protective equipment; and (3) review the other Party's maintenance records relative to the

Interconnection Facilities, the System Protection Facilities and other protective equipment. A Party may exercise these rights from time to time as it deems necessary upon reasonable notice to the other Party. The exercise or non-exercise by a Party of any such rights shall not be construed as an endorsement or confirmation of any element or condition of the Interconnection Facilities or the System Protection Facilities or other protective equipment or the operation thereof, or as a warranty as to the fitness, safety, desirability or reliability of same. Any information that a Party obtains through the exercise of any of its rights under this Article 6.4 shall be deemed to be Confidential Information and treated pursuant to Article 22 of this LGIA.

Article 7. Metering

7.1 General.

Each Party shall comply with the Applicable Reliability Council requirements. Unless otherwise agreed by the Parties, Transmission Provider shall install Metering Equipment at the Point of Interconnection prior to any operation of the Large Generating Facility and shall own, operate, test and maintain such Metering Equipment. Power flows to and from the Large Generating Facility shall be measured at or, at Transmission Provider's option, compensated to, the Point of Interconnection. Transmission Provider shall provide metering quantities, in analog and/or digital form, to Interconnection Customer upon request. Interconnection Customer shall bear all reasonable documented costs associated with the purchase, installation, operation, testing and maintenance of the Metering Equipment.

7.2 Check Meters.

Interconnection Customer, at its option and expense, may install and operate, on its premises and on its side of the Point of Interconnection, one or more check meters to check Transmission Provider's meters. Such check meters shall be for check purposes only and shall not be used for the measurement of power flows for purposes of this LGIA, except as provided in Article 7.4 below. The check meters shall be subject at all reasonable times to inspection and examination by Transmission Provider or its designee. The installation, operation and maintenance thereof shall be performed entirely by Interconnection Customer in accordance with Good Utility Practice.

7.3 Standards.

Transmission Provider shall install, calibrate and test revenue quality Metering Equipment in accordance with applicable ANSI standards.

7.4 Testing of Metering Equipment.

Transmission Provider shall inspect and test all Transmission Provider-owned Metering Equipment upon installation and at least once every two (2) years thereafter. If requested to do so by Interconnection Customer, Transmission Provider shall, at Interconnection Customer's expense, inspect or test Metering Equipment more frequently than every two (2) years. Transmission Provider shall give reasonable notice of the time when any inspection or test shall take place, and Interconnection Customer may have representatives present at the test or inspection. If at any time Metering Equipment is found to be inaccurate or defective, it shall be adjusted, repaired or replaced at Interconnection Customer's expense, in order to provide accurate metering, unless the inaccuracy or defect is due to Transmission Provider's failure to maintain, then Transmission Provider shall pay. If Metering Equipment fails to register, or if the measurement made by Metering Equipment during a test varies by more than two (2) percent from the measurement made by the standard meter used in the test, Transmission Provider shall adjust the measurements by correcting all measurements for the period during which Metering Equipment was in error by using Interconnection Customer's check meters, if installed. If no such check meters are installed or if the period cannot be reasonably ascertained, the adjustment shall be for the period immediately preceding the test of the Metering Equipment equal to one-half the time from the date of the last previous test of the Metering Equipment.

7.5 Metering Data.
At Interconnection Customer's expense, the metered data shall be telemetered to one or more locations designated by Transmission Provider and one or more locations designated by Interconnection Customer. Such telemetered data shall be used, under normal operating conditions, as the official measurement of the amount of energy delivered from the Large Generating Facility to the Point of Interconnection.

Article 8. Communications

8.1 Interconnection Customer Obligations.
Interconnection Customer shall maintain satisfactory operating communications with Transmission Provider's Transmission System dispatcher or representative designated by Transmission Provider. Interconnection Customer shall provide standard voice line, dedicated voice line and facsimile communications at its Large Generating Facility control room or central dispatch facility through use of either the public telephone system, or a voice communications system that does not rely on the public telephone system. Interconnection Customer shall also provide the dedicated data circuit(s) necessary to provide Interconnection Customer data to Transmission Provider as set forth in Appendix D, Security Arrangements Details. The data circuit(s) shall extend from the Large Generating Facility to the location(s) specified by Transmission Provider. Any required maintenance of such communications equipment shall be performed by Interconnection Customer. Operational communications shall be activated and maintained under, but not be limited to, the following events: system paralleling or separation, scheduled and unscheduled shutdowns, equipment clearances and hourly and daily load data.

8.2 Remote Terminal Unit.
Prior to the Initial Synchronization Date of the Large Generating Facility, a Remote Terminal Unit or equivalent data collection and transfer equipment acceptable to the Parties, shall be installed by Interconnection Customer, or by Transmission Provider at Interconnection Customer's expense, to gather accumulated and instantaneous data to be telemetered to the location(s) designated by Transmission Provider through use of a dedicated point-to-point data circuit(s) as indicated in

Article 8.1. The communication protocol for the data circuit(s) shall be specified by Transmission Provider. Instantaneous bi-directional analog real power and reactive power flow information must be telemetered directly to the location(s) specified by Transmission Provider.

Each Party will promptly advise the other Party if it detects or otherwise learns of any metering, telemetry or communications equipment errors or malfunctions that require the attention and/or correction by the other Party. The Party owning such equipment shall correct such error or malfunction as soon as reasonably feasible.

8.3 No Annexation.
Any and all equipment placed on the premises of a Party shall be and remain the property of the Party providing such equipment regardless of the mode and manner of annexation or attachment to real property, unless otherwise mutually agreed by the Parties.

Article 9. Operations

9.1 General.
Each Party shall comply with the Applicable Reliability Council requirements. Each Party shall provide to the other Party all information that may reasonably be required by the other Party to comply with Applicable Laws and Regulations and Applicable Reliability Standards.

9.2 Control Area Notification.
At least three (3) months before Initial Synchronization Date, Interconnection Customer shall notify Transmission Provider in writing of the Control Area in which the Large Generating Facility will be located. If Interconnection Customer elects to locate the Large Generating Facility in a Control Area other than the Control Area in which the Large Generating Facility is physically located, and if permitted to do so by the relevant transmission tariffs, all necessary arrangements, including but not limited to those set forth in Article 7 and Article 8 of this LGIA, and remote Control Area generator interchange agreements, if applicable, and the appropriate measures under such agreements, shall be executed and implemented prior to the placement of the Large Generating Facility in the other Control Area.

9.3 Transmission Provider Obligations.
Transmission Provider shall cause the Transmission System and Transmission Provider's Interconnection Facilities to be operated, maintained and controlled in a safe and reliable manner and in accordance with this LGIA. Transmission Provider may provide operating instructions to Interconnection Customer consistent with this LGIA and Transmission Provider's operating protocols and procedures as they may change from time to time. Transmission Provider will consider changes to its operating protocols and procedures proposed by Interconnection Customer.

9.4 Interconnection Customer Obligations.
Interconnection Customer shall at its own expense operate, maintain and control the Large Generating Facility and Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA. Interconnection Customer shall operate the Large Generating Facility and Interconnection Customer's Interconnection Facilities in accordance with all applicable requirements of the Control Area of which it is part, as such requirements are set forth in Appendix C, Interconnection Details, of this LGIA. Appendix C, Interconnection Details, will be modified to reflect changes to the requirements as they may change from time to time. Either Party may request that the other Party provide copies of the requirements set forth in Appendix C, Interconnection Details, of this LGIA.

9.5 Start-Up and Synchronization.
Consistent with the Parties' mutually acceptable procedures, Interconnection Customer is responsible for the proper synchronization of the Large Generating Facility to Transmission Provider's Transmission System.

9.6 Reactive Power.

9.6.1 Power Factor Design Criteria.
Interconnection Customer shall design the Large Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the minimum range of 0.95 leading to 0.95 lagging, unless Transmission Provider has established different requirements that apply to all generators in the Control Area on a comparable basis. The requirements of this paragraph shall not apply to wind generators.

9.6.2 Voltage Schedules.
Once Interconnection Customer has synchronized the Large Generating Facility with the Transmission System, Transmission Provider shall require Interconnection Customer to operate the Large Generating Facility to produce or absorb reactive power within the design limitations of the Large Generating Facility set forth in Article 9.6.1 (Power Factor Design Criteria). Transmission Provider's voltage schedules shall treat all sources of reactive power in the Control Area in an equitable and not unduly discriminatory manner. Transmission Provider shall exercise Reasonable Efforts to provide Interconnection Customer with such schedules at least one (1) day in advance and may make changes to such schedules as necessary to maintain the reliability of the Transmission System. Interconnection Customer shall operate the Large Generating Facility to maintain the specified output voltage or power factor at the Point of Interconnection within the design limitations of the Large Generating Facility set forth in Article 9.6.1 (Power Factor Design Criteria). If Interconnection Customer is unable to maintain the specified voltage or power factor, it shall promptly notify the System Operator.

9.6.2.1 Governors and Regulators.

Whenever the Large Generating Facility is operated in parallel with the Transmission System and the speed governors (if installed on the generating unit pursuant to Good Utility Practice) and voltage regulators are capable of operation, Interconnection Customer shall operate the Large Generating Facility with its speed governors and voltage regulators in automatic operation. If the Large Generating Facility's speed governors and voltage regulators are not capable of such automatic operation, Interconnection Customer shall immediately notify Transmission Provider's system operator, or its designated representative, and ensure that such Large Generating Facility's reactive power production or absorption (measured in MVARs) are within the design capability of the Large Generating Facility's generating unit(s) and steady state stability limits. Interconnection Customer shall not cause its Large Generating Facility to disconnect automatically or instantaneously from the Transmission System or trip any generating unit comprising the Large Generating Facility for an under- or over-frequency condition unless the abnormal frequency condition persists for a time period beyond the limits set forth in ANSI/IEEE Standard C37.106, or such other standard as applied to other generators in the Control Area on a comparable basis.

9.6.3 Payment for Reactive Power.

Transmission Provider is required to pay Interconnection Customer for reactive power that Interconnection Customer provides or absorbs from the Large Generating Facility when Transmission Provider requests Interconnection Customer to operate its Large Generating Facility outside the range specified in Article 9.6.1, provided that if Transmission Provider pays its own or affiliated generators for reactive power service within the specified range, it must also pay Interconnection Customer. Payments shall be pursuant to Article 11.6 or such other agreement to which the Parties have otherwise agreed.

9.7 Outages and Interruptions.

9.7.1 Outages.

9.7.1.1 Outage Authority and Coordination.

Each Party may in accordance with Good Utility Practice in coordination with the other Party remove from service any of its respective Interconnection Facilities or Network Upgrades that may impact the other Party's facilities as necessary to perform maintenance or testing or to install or replace equipment. Absent an Emergency Condition, the Party scheduling a removal of such facility(ies) from service will use Reasonable Efforts to schedule such removal on a date and time mutually acceptable to the

Parties. In all circumstances, any Party planning to remove such facility(ies) from service shall use Reasonable Efforts to minimize the effect on the other Party of such removal.

9.7.1.2 Outage Schedules.
Transmission Provider shall post scheduled outages of its transmission facilities on the Open Access Same-Time Information System (OASIS). Interconnection Customer shall submit its planned maintenance schedules for the Large Generating Facility to Transmission Provider for a minimum of a rolling twenty-four (24) month period. Interconnection Customer shall update its planned maintenance schedules as necessary. Transmission Provider may request Interconnection Customer to reschedule its maintenance as necessary to maintain the reliability of the Transmission System; provided however, adequacy of generation supply shall not be a criterion in determining Transmission System reliability. Transmission Provider shall compensate Interconnection Customer for any additional direct costs that Interconnection Customer incurs as a result of having to reschedule maintenance, including any additional overtime, breaking of maintenance contracts or other costs above and beyond the cost Interconnection Customer would have incurred absent Transmission Provider's request to reschedule maintenance. Interconnection Customer will not be eligible to receive compensation, if during the twelve (12) months prior to the date of the scheduled maintenance, Interconnection Customer had modified its schedule of maintenance activities.

9.7.1.3 Outage Restoration.
If an outage on a Party's Interconnection Facilities or Network Upgrades adversely affects the other Party's operations or facilities, the Party that owns or controls the facility that is out of service shall use Reasonable Efforts to promptly restore such facility(ies) to a normal operating condition consistent with the nature of the outage. The Party that owns or controls the facility that is out of service shall provide the other Party, to the extent such information is known, information on the nature of the Emergency Condition, an estimated time of restoration, and any corrective actions required. Initial verbal notice shall be followed up as soon as practicable with written notice explaining the nature of the outage.

9.7.2 Interruption of Service.
If required by Good Utility Practice to do so, Transmission Provider may require Interconnection Customer to interrupt or reduce deliveries of electricity if such delivery of electricity could adversely affect Transmission Provider's ability to perform such activities as are necessary to safely and reliably operate and maintain the Transmission System. The following provisions shall apply to any interruption or reduction permitted under this Article 9.7.2:

9.7.2.1 The interruption or reduction shall continue only for so long as reasonably necessary under Good Utility Practice.

9.7.2.2 Any such interruption or reduction shall be made on an equitable, non-discriminatory basis with respect to all generating facilities directly connected to the Transmission System.

9.7.2.3 The Parties shall cooperate and coordinate with each other to the extent necessary in order to restore the Large Generating Facility, Interconnection Facilities and the Transmission System to their normal operating state, consistent with system conditions and Good Utility Practice.

9.7.3 Under-Frequency and Over-Frequency Conditions.
The Transmission System is designed to automatically activate a load-shed program as required by the Applicable Reliability Council in the event of an under-frequency system disturbance. Interconnection Customer shall implement under-frequency and over-frequency relay set points for the Large Generating Facility as required by the Applicable Reliability Council to ensure "ride through" capability of the Transmission System. Large Generating Facility response to frequency deviations of pre-determined magnitudes, both under-frequency and over-frequency deviations, shall be studied and coordinated with Transmission Provider in accordance with Good Utility Practice. The term "ride through" as used herein shall mean the ability of a Generating Facility to stay connected to and synchronized with the Transmission System during system disturbances within a range of under-frequency and over-frequency conditions, in accordance with Good Utility Practice.

9.7.4 System Protection and Other Control Requirements.

9.7.4.1 System Protection Facilities.
Interconnection Customer shall, at its expense, install, operate and maintain System Protection Facilities as a part of the Large Generating Facility or Interconnection Customer's Interconnection Facilities. Transmission Provider shall install at Interconnection Customer's expense any System Protection Facilities that may be

required on Transmission Provider's Interconnection Facilities or the Transmission System as a result of the interconnection of the Large Generating Facility and Interconnection Customer's Interconnection Facilities.

9.7.4.2 Each Party's protection facilities shall be designed and coordinated with other systems in accordance with Good Utility Practice.

9.7.4.3 Each Party shall be responsible for protection of its facilities consistent with Good Utility Practice.

9.7.4.4 Each Party's protective relay design shall incorporate the necessary test switches to perform the tests required in Article 6. The required test switches will be placed such that they allow operation of lockout relays while preventing breaker failure schemes from operating and causing unnecessary breaker operations and/or the tripping of Interconnection Customer's units.

9.7.4.5 Each Party will test, operate and maintain System Protection Facilities in accordance with Good Utility Practice.

9.7.4.6 Prior to the In-Service Date, and again prior to the Commercial Operation Date, each Party or its agent shall perform a complete calibration test and functional trip test of the System Protection Facilities. At intervals suggested by Good Utility Practice and following any apparent malfunction of the System Protection Facilities, each Party shall perform both calibration and functional trip tests of its System Protection Facilities. These tests do not require the tripping of any in-service generation unit. These tests do, however, require that all protective relays and lockout contacts be activated.

9.7.5 Requirements for Protection.
In compliance with Good Utility Practice, Interconnection Customer shall provide, install, own and maintain relays, circuit breakers and all other devices necessary to remove any fault contribution of the Large Generating Facility to any short circuit occurring on the Transmission System not otherwise isolated by Transmission Provider's equipment, such that the removal of the fault contribution shall be coordinated with the protective requirements of the Transmission System. Such protective equipment shall include, without limitation, a disconnecting device or switch with load-interrupting capability located between the Large Generating Facility and the Transmission System at a site selected upon mutual agreement (not to be unreasonably withheld, conditioned or delayed) of the Parties. Interconnection Customer shall be responsible for protection of the Large Generating Facility and Interconnection Customer's other equipment from such conditions as negative sequence currents, over- or under-frequency, sudden load rejection, over- or under-voltage and generator loss-of-field.

Interconnection Customer shall be solely responsible to disconnect the Large Generating Facility and Interconnection Customer's other equipment if conditions on the Transmission System could adversely affect the Large Generating Facility.

9.7.6 Power Quality.
Neither Party's facilities shall cause excessive voltage flicker nor introduce excessive distortion to the sinusoidal voltage or current waves as defined by ANSI Standard C84.1-1989, in accordance with IEEE Standard 519, or any applicable superseding electric industry standard. In the event of a conflict between ANSI Standard C84.1-1989, or any applicable superseding electric industry standard, ANSI Standard C84.1-1989, or the applicable superseding electric industry standard, shall control.

9.8 Switching and Tagging Rules.
Each Party shall provide the other Party a copy of its switching and tagging rules that are applicable to the other Party's activities. Such switching and tagging rules shall be developed on a non-discriminatory basis. The Parties shall comply with applicable switching and tagging rules, as amended from time to time, in obtaining clearances for work or for switching operations on equipment.

9.9 Use of Interconnection Facilities by Third Parties.

9.9.1 Purpose of Interconnection Facilities.
Except as may be required by Applicable Laws and Regulations, or as otherwise agreed to among the Parties, the Interconnection Facilities shall be constructed for the sole purpose of interconnecting the Large Generating Facility to the Transmission System and shall be used for no other purpose.

9.9.2 Third Party Users.
If required by Applicable Laws and Regulations or if the Parties mutually agree, such agreement not to be unreasonably withheld, to allow one or more third parties to use Transmission Provider's Interconnection Facilities, or any part thereof, Interconnection Customer will be entitled to compensation for the capital expenses it incurred in connection with the Interconnection Facilities based upon the pro rata use of the Interconnection Facilities by Transmission Provider, all third party users and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually agreed upon methodology. In addition, cost responsibility for ongoing costs, including operation and maintenance costs associated with the Interconnection Facilities, will be allocated between Interconnection Customer and any third party users based upon the pro rata use of the Interconnection Facilities by Transmission Provider, all third party users and Interconnection Customer, in accordance with Applicable Laws and Regulations or upon some other mutually agreed upon methodology. If the issue of such compensation or allocation cannot be resolved through such negotiations, it shall be submitted to FERC for resolution.

9.10 Disturbance Analysis Data Exchange.
The Parties will cooperate with one another in the analysis of disturbances to either the Large Generating Facility or Transmission Provider's Transmission System by gathering and providing access to any information relating to any disturbance, including information from oscillography, protective relay targets, breaker operations and sequence of events records and any disturbance information required by Good Utility Practice.

Article 10. Maintenance

10.1 Transmission Provider Obligations.
Transmission Provider shall maintain the Transmission System and Transmission Provider's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA.

10.2 Interconnection Customer Obligations.
Interconnection Customer shall maintain the Large Generating Facility and Interconnection Customer's Interconnection Facilities in a safe and reliable manner and in accordance with this LGIA.

10.3 Coordination.
The Parties shall confer regularly to coordinate the planning, scheduling and performance of preventive and corrective maintenance on the Large Generating Facility and the Interconnection Facilities.

10.4 Secondary Systems.
Each Party shall cooperate with the other in the inspection, maintenance and testing of control or power circuits that operate below 600 volts, AC or DC, including, but not limited to, any hardware, control or protective devices, cables, conductors, electric raceways, secondary equipment panels, transducers, batteries, chargers and voltage and current transformers that directly affect the operation of a Party's facilities and equipment which may reasonably be expected to impact the other Party. Each Party shall provide advance notice to the other Party before undertaking any work on such circuits, especially on electrical circuits involving circuit breaker trip and close contacts, current transformers or potential transformers.

10.5 Operating and Maintenance Expenses.
Subject to the provisions herein addressing the use of facilities by others, and except for operations and maintenance expenses associated with modifications made for providing interconnection or transmission service to a third party and such third party pays for such expenses, Interconnection Customer shall be responsible for all reasonable expenses including overheads, associated with: (1) owning, operating, maintaining, repairing and replacing Interconnection Customer's Interconnection Facilities; and (2) operation, maintenance, repair and replacement of Transmission Provider's Interconnection Facilities.

Article 11. Performance Obligation

11.1 Interconnection Customer Interconnection Facilities.

Interconnection Customer shall design, procure, construct, install, own and/or control Interconnection Customer Interconnection Facilities described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades, at its sole expense.

11.2 Transmission Provider's Interconnection Facilities.

Transmission Provider or Transmission Owner shall design, procure, construct, install, own and/or control the Transmission Provider's Interconnection Facilities described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades, at the sole expense of the Interconnection Customer.

11.3 Network Upgrades and Distribution Upgrades.

Transmission Provider or Transmission Owner shall design, procure, construct, install and own the Network Upgrades and Distribution Upgrades described in Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades. The Interconnection Customer shall be responsible for all costs related to Distribution Upgrades. Unless Transmission Provider or Transmission Owner elects to fund the capital for the Network Upgrades, they shall be solely funded by Interconnection Customer.

11.4 Transmission Credits.

11.4.1 Repayment of Amounts Advanced for Network Upgrades.

Interconnection Customer shall be entitled to a cash repayment, equal to the total amount paid to Transmission Provider and Affected System Operator, if any, for the Network Upgrades, to be paid to Interconnection Customer on a dollar-for-dollar basis for the non-usage sensitive portion of transmission charges, as payments are made under Transmission Provider's Tariff and Affected System's Tariff for transmission services with respect to the Large Generating Facility. Any repayment shall include interest calculated at the rate for ten-year bonds posted on Bloomberg, L.P., under the United States Government Agency fair market yield curve (yield curve number 84) as in effect on the first day of the month during which the Transmission Provider receives the first payment for Network Upgrades, such interest to accrue from the date of any payment for Network Upgrades through the date on which the Interconnection Customer receives a repayment of such payment pursuant to this subparagraph. Interconnection Customer may assign such repayment rights to any person.

Notwithstanding the foregoing, Interconnection Customer, Transmission Provider and Affected System Operator may adopt any alternative payment schedule that is mutually agreeable so long as Transmission Provider and Affected System Operator take one of the following actions no later than five (5) years from the Commercial Operation Date:

(1) return to Interconnection Customer any amounts advanced for Network Upgrades not previously repaid; or (2) declare in writing that Transmission Provider or Affected System Operator will continue to provide payments to Interconnection Customer on a dollar-for-dollar basis for the non-usage sensitive portion of transmission charges, or develop an alternative schedule that is mutually agreeable and provides for the return of all amounts advanced for Network Upgrades not previously repaid; however, full reimbursement shall not extend beyond twenty (20) years from the Commercial Operation Date.

If the Large Generating Facility fails to achieve commercial operation, but it or another Generating Facility is later constructed and makes use of the Network Upgrades, Transmission Provider and Affected System Operator shall at that time reimburse Interconnection Customer for the amounts advanced for the Network Upgrades. Before any such reimbursement can occur, the Interconnection Customer, or the entity that ultimately constructs the Generating Facility, if different, is responsible for identifying the entity to which reimbursement must be made.

11.4.2 Special Provisions for Affected Systems.
Unless Transmission Provider provides, under the LGIA, for the repayment of amounts advanced to Affected System Operator for Network Upgrades, Interconnection Customer and Affected System Operator shall enter into an agreement that provides for such repayment. The agreement shall specify the terms governing payments to be made by Interconnection Customer to the Affected System Operator as well as the repayment by the Affected System Operator.

11.4.3 Notwithstanding any other provision of this LGIA, nothing herein shall be construed as relinquishing or foreclosing any rights, including but not limited to firm transmission rights, capacity rights, transmission congestion rights, or transmission credits, that Interconnection Customer, shall be entitled to, now or in the future under any other agreement or tariff as a result of, or otherwise associated with, the transmission capacity, if any, created by the Network Upgrades, including the right to obtain cash reimbursements or transmission credits for transmission service that is not associated with the Large Generating Facility.

11.5 Provision of Security.
At least thirty (30) Calendar Days prior to the commencement of the procurement, installation or construction of a discrete portion of a Transmission Provider's Interconnection Facilities, Network Upgrades or Distribution Upgrades, Interconnection Customer shall provide Transmission Provider, at Interconnection Customer's option, a guarantee, a surety bond, letter of credit or other form of security that is reasonably acceptable to Transmission Provider. Such security for

payment shall be in an amount sufficient to cover the costs for constructing, procuring and installing the applicable portion of Transmission Provider's Interconnection Facilities, Network Upgrades, or Distribution Upgrades and shall be reduced on a dollar-for-dollar basis for payments made to Transmission Provider for these purposes.

In addition:

11.5.1 The guarantee must be made by an entity that meets the creditworthiness requirements of Transmission Provider, and contain terms and conditions that guarantee payment of any amount that may be due from Interconnection Customer, up to an agreed-to maximum amount.

11.5.2 The letter of credit must be issued by a financial institution reasonably acceptable to Transmission Provider and must specify a reasonable expiration date.

11.5.3 The surety bond must be issued by an insurer reasonably acceptable to Transmission Provider and must specify a reasonable expiration date.

11.6 Interconnection Customer Compensation.
If Transmission Provider requests or directs Interconnection Customer to provide a service pursuant to Article 9.6.3, Payment for Reactive Power or Article 13.5.1 of this LGIA, Transmission Provider shall compensate Interconnection Customer in accordance with Interconnection Customer's applicable rate schedule then in effect unless the provision of such service(s) is subject to an RTO or ISO FERC-approved rate schedule. Interconnection Customer shall serve Transmission Provider or RTO or ISO with any filing of a proposed rate schedule at the time of such filing with FERC. To the extent that no rate schedule is in effect at the time the Interconnection Customer is required to provide or absorb any Reactive Power under this LGIA, Transmission Provider agrees to compensate Interconnection Customer in such amount as would have been due Interconnection Customer had the rate schedule been in effect at the time service commenced; provided however, that such rate schedule must be filed at FERC or other appropriate Governmental Authority within sixty (60) Calendar Days of the commencement of service.

11.6.1 Interconnection Customer Compensation for Actions during Emergency Condition.
Transmission Provider or RTO or ISO shall compensate Interconnection Customer for its provision of real and reactive power and other Emergency Condition services that Interconnection Customer provides to support the Transmission System during an Emergency Condition in accordance with Article 11.6.

Article 12. Invoice

12.1 General.
Each Party shall submit to the other Party, on a monthly basis, invoices of amounts due for the preceding month. Each invoice shall state the month to which the invoice applies and fully describe the services and equipment provided. The Parties may discharge mutual debts and payment obligations due and owing to each other on the same date through netting, in which case all amounts a Party owes to the other Party under this LGIA, including interest payments or credits, shall be netted so that only the net amount remaining due shall be paid by the owing Party.

12.2 Final Invoice.
Within six (6) months after completion of the construction of the Transmission Provider's Interconnection Facilities and the Network Upgrades, Transmission Provider shall provide an invoice of the final cost of the construction of the Transmission Provider's Interconnection Facilities and the Network Upgrades and shall set forth such costs in sufficient detail to enable Interconnection Customer to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. Transmission Provider shall refund to Interconnection Customer any amount by which the actual payment by Interconnection Customer for estimated costs exceeds the actual costs of construction within thirty (30) Calendar Days of the issuance of such final construction invoice.

12.3 Payment.
Invoices shall be rendered to the paying Party at the address specified in Appendix F, Addresses for Delivery of Notices and Billings. The Party receiving the invoice shall pay the invoice within thirty (30) Calendar Days of receipt. All payments shall be made in immediately available funds payable to the other Party, or by wire transfer to a bank named and account designated by the invoicing Party. Payment of invoices by either Party will not constitute a waiver of any rights or claims either Party may have under this LGIA.

12.4 Disputes.
In the event of a billing dispute between Transmission Provider and Interconnection Customer, Transmission Provider shall continue to provide Interconnection Service under this LGIA as long as Interconnection Customer: (1) continues to make all payments not in dispute; and (2) pays to Transmission Provider or into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If Interconnection Customer fails to meet these two requirements for continuation of service, then Transmission Provider may provide notice to Interconnection Customer of a Default pursuant to Article 17. Within thirty (30) Calendar Days after the resolution of the dispute, the Party that owes money to the other Party shall pay the amount due with interest calculated in accord with the methodology set forth in FERC's regulations at 18 CFR § 35.19a(a)(2)(iii).

Article 13. Emergencies

13.1 Definition.

"Emergency Condition" shall mean a condition or situation: (1) that in the judgment of the Party making the claim is imminently likely to endanger life or property; or (2) that, in the case of Transmission Provider, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to the Transmission System, Transmission Provider's Interconnection Facilities or the Transmission Systems of others to which the Transmission System is directly connected; or (3) that, in the case of Interconnection Customer, is imminently likely (as determined in a non-discriminatory manner) to cause a material adverse effect on the security of, or damage to, the Large Generating Facility or Interconnection Customer's Interconnection Facilities' System restoration and black start shall be considered Emergency Conditions; provided, that Interconnection Customer is not obligated by this LGIA to possess black start capability.

13.2 Obligations.

Each Party shall comply with the Emergency Condition procedures of the applicable ISO/RTO, NERC, the Applicable Reliability Council, Applicable Laws and Regulations and any emergency procedures agreed to by the Joint Operating Committee.

13.3 Notice.

Transmission Provider shall notify Interconnection Customer promptly when it becomes aware of an Emergency Condition that affects Transmission Provider's Interconnection Facilities or the Transmission System that may reasonably be expected to affect Interconnection Customer's operation of the Large Generating Facility or Interconnection Customer's Interconnection Facilities. Interconnection Customer shall notify Transmission Provider promptly when it becomes aware of an Emergency Condition that affects the Large Generating Facility or Interconnection Customer's Interconnection Facilities that may reasonably be expected to affect the Transmission System or Transmission Provider's Interconnection Facilities. To the extent information is known, the notification shall describe the Emergency Condition, the extent of the damage or deficiency, the expected effect on the operation of Interconnection Customer's or Transmission Provider's facilities and operations, its anticipated duration and the corrective action taken and/or to be taken.

13.4 Immediate Action.

Unless, in Interconnection Customer's reasonable judgment, immediate action is required, Interconnection Customer shall obtain the consent of Transmission Provider, such consent to not be unreasonably withheld, prior to performing any manual switching operations at the Large Generating Facility or Interconnection Customer's Interconnection Facilities in response to an Emergency Condition either declared by Transmission Provider or otherwise regarding the Transmission System.

13.5 Transmission Provider Authority.

13.5.1 General.
Transmission Provider may take whatever actions or inactions with regard to the Transmission System or Transmission Provider's Interconnection Facilities it deems necessary during an Emergency Condition in order to: (1) preserve public health and safety; (2) preserve the reliability of the Transmission System or Transmission Provider's Interconnection Facilities; (3) limit or prevent damage; and (4) expedite restoration of service.

Transmission Provider shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Large Generating Facility or Interconnection Customer's Interconnection Facilities. Transmission Provider may, on the basis of technical considerations, require the Large Generating Facility to mitigate an Emergency Condition by taking actions necessary and limited in scope to remedy the Emergency Condition, including, but not limited to, directing Interconnection Customer to shut-down, start-up, increase or decrease the real or reactive power output of the Large Generating Facility, implementing a reduction or disconnection pursuant to Article 13.5.2, directing Interconnection Customer to assist with black start (if available) or restoration efforts, or altering the outage schedules of the Large Generating Facility and Interconnection Customer's Interconnection Facilities. Interconnection Customer shall comply with all of Transmission Provider's operating instructions concerning Large Generating Facility real power and reactive power output within the manufacturer's design limitations of the Large Generating Facility's equipment that is in service and physically available for operation at the time, in compliance with Applicable Laws and Regulations.

13.5.2 Reduction and Disconnection.
Transmission Provider may reduce Interconnection Service or disconnect the Large Generating Facility or Interconnection Customer's Interconnection Facilities, when such, reduction or disconnection is necessary under Good Utility Practice due to Emergency Conditions. These rights are separate and distinct from any right of curtailment of Transmission Provider pursuant to Transmission Provider's Tariff. When Transmission Provider can schedule the reduction or disconnection in advance, Transmission Provider shall notify Interconnection Customer of the reasons, timing and expected duration of the reduction or disconnection. Transmission Provider shall coordinate with Interconnection Customer using Good Utility Practice to schedule the reduction or disconnection during periods of least impact to Interconnection Customer and Transmission Provider. Any reduction or

disconnection shall continue only for so long as reasonably necessary under Good Utility Practice. The Parties shall cooperate with each other to restore the Large Generating Facility, the Interconnection Facilities and the Transmission System to their normal operating state as soon as practicable consistent with Good Utility Practice.

13.6 Interconnection Customer Authority.
Consistent with Good Utility Practice and the LGIA and the LGIP, Interconnection Customer may take actions or inactions with regard to the Large Generating Facility or Interconnection Customer's Interconnection Facilities during an Emergency Condition in order to: (1) preserve public health and safety; (2) preserve the reliability of the Large Generating Facility or Interconnection Customer's Interconnection Facilities; (3) limit or prevent damage; and (4) expedite restoration of service. Interconnection Customer shall use Reasonable Efforts to minimize the effect of such actions or inactions on the Transmission System and Transmission Provider's Interconnection Facilities. Transmission Provider shall use Reasonable Efforts to assist Interconnection Customer in such actions.

13.7 Limited Liability.
Except as otherwise provided in Article 11.6.1 of this LGIA, neither Party shall be liable to the other for any action it takes in responding to an Emergency Condition so long as such action is made in good faith and is consistent with Good Utility Practice.

Article 14. Regulatory Requirements and Governing Law

14.1 Regulatory Requirements.
Each Party's obligations under this LGIA shall be subject to its receipt of any required approval or certificate from one or more Governmental Authorities in the form and substance satisfactory to the applying Party, or the Party making any required filings with, or providing notice to, such Governmental Authorities, and the expiration of any time period associated therewith. Each Party shall in good faith seek and use its Reasonable Efforts to obtain such other approvals. Nothing in this LGIA shall require Interconnection Customer to take any action that could result in its inability to obtain, or its loss of, status or exemption under the Federal Power Act, the Public Utility Holding Company Act of 1935, as amended, or the Public Utility Regulatory Policies Act of 1978.

14.2 Governing Law.

14.2.1 The validity, interpretation and performance of this LGIA and each of its provisions shall be governed by Federal law.

14.2.2 This LGIA is subject to all Applicable Laws and Regulations.

14.2.3 Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, rules or regulations of a Governmental Authority.

Article 15. Notices

15.1 General.

Unless otherwise provided in this LGIA, any notice, demand or request required or permitted to be given by either Party to the other and any instrument required or permitted to be tendered or delivered by either Party in writing to the other shall be effective when delivered and may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party, at the address set out in Appendix F, Addresses for Delivery of Notices and Billings.

Either Party may change the notice information in this LGIA by giving five (5) Business Days' written notice prior to the effective date of the change.

15.2 Billings and Payments.

Billings and payments shall be sent to the addresses set out in Appendix F, Addresses for delivery of Notices and Billings.

15.3 Alternative Forms of Notice.

Any notice or request required or permitted to be given by a Party to the other and not required by this LGIA to be given in writing may be so given by telephone, facsimile or email to the telephone numbers and email addresses set out in Appendix F, Addresses for delivery of Notices and Billings.

For any service interruptions, Emergency Conditions, operating instructions, curtailments, or dispatch orders, Transmission Provider may notify Interconnection Customer through any of the following methods: (1) by electronic signal pre-arranged between Interconnection Customer and Transmission Provider, (2) by telephone, facsimile or email to the telephone numbers and email addresses set out in Appendix F, Addresses for delivery of Notices and Billings, (3) by a change request to a transaction submitted according to the NERC e-Tag protocol, or (4) as otherwise agreed between Interconnection Customer and Transmission Provider. Transmission Provider is not responsible for ensuring that Interconnection Customer has the continuous ability to receive Transmission Provider's electronic signals.

15.4 Operations and Maintenance Notice.

Each Party shall notify the other Party in writing of the identity of the person(s) that it designates as the point(s) of contact with respect to the implementation of Articles 9 and 10.

Article 16. Force Majeure

16.1 Force Majeure.

16.1.1 Economic hardship is not considered a Force Majeure event.

16.1.2 Neither Party shall be considered to be in Default with respect to any obligation hereunder, (including obligations under Article 4), other than the obligation to pay money when due, if prevented from fulfilling such obligation by Force Majeure. A Party unable to fulfill any obligation hereunder (other than an obligation to pay money when due) by reason of Force Majeure shall give notice and the full particulars of such Force Majeure to the other Party in writing or by telephone as soon as reasonably possible after the occurrence of the cause relied upon. Telephone notices given pursuant to this article shall be confirmed in writing as soon as reasonably possible and shall specifically state full particulars of the Force Majeure, the time and date when the Force Majeure occurred and when the Force Majeure is reasonably expected to cease. The Party affected shall exercise due diligence to remove such disability with reasonable dispatch, but shall not be required to accede or agree to any provision not satisfactory to it in order to settle and terminate a strike or other labor disturbance.

Article 17. Default

17.1 Default.

17.1.1 General.
No Default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of Force Majeure as defined in this LGIA or the result of an act of omission of the other Party. Upon a Breach, the non-breaching Party shall give written notice of such Breach to the breaching Party. Except as provided in Article 17.1.2, the breaching Party shall have thirty (30) Calendar Days from receipt of the Default notice within which to cure such Breach; provided however, if such Breach is not capable of cure within thirty (30) Calendar Days, the breaching Party shall commence such cure within thirty (30) Calendar Days after notice and continuously and diligently complete such cure within ninety (90) Calendar Days from receipt of the Default notice; and, if cured within such time, the Breach specified in such notice shall cease to exist.

17.1.2 Right to Terminate.
If a Breach is not cured as provided in this article, or if a Breach is not capable of being cured within the period provided for herein, the non-breaching Party shall have the right to declare a Default and terminate this LGIA by written notice at any time until cure occurs, and be relieved of any further obligation hereunder and, whether or not that Party

terminates this LGIA, to recover from the breaching Party all amounts due hereunder, plus all other damages and remedies to which it is entitled at law or in equity. The provisions of this article will survive termination of this LGIA.

Article 18. Indemnity, Consequential Damages and Insurance

Article 18.1 applies only if, at the time of the action or inaction by a Party that gave rise to the Party's right to indemnification, either Transmission Provider or Interconnection Customer was not a party to the Agreement Limiting Liability among Western Interconnected Electric Systems.

18.1 Indemnity.

The Parties shall at all times indemnify and hold the other Party harmless from any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees and all other obligations by or to third parties, arising out of or resulting from the other Party's action or inaction of its obligations under this LGIA on behalf of the Indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the Indemnified Party.

18.1.1 Indemnified Person. (Intentionally Omitted)

18.1.2 Indemnified Party.

If an Indemnifying Party is obligated to indemnify and hold any Indemnified Person harmless under this Article 18, the amount owing to the Indemnified Person shall be the amount of such Indemnified Person's actual Loss, net of any insurance or other recovery.

18.1.3 Indemnity Procedures.

Promptly after receipt by an Indemnified Person of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in Article 18.1 may apply, the Indemnified Person shall notify the Indemnifying Party of such fact. Any failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the Indemnifying Party.

18.2 Consequential Damages.

Other than the Liquidated Damages heretofore described, in no event shall either Party be liable under any provision of this LGIA for any losses, damages, costs or expenses for any special, indirect, incidental, consequential or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability or any other theory of liability; provided however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental or consequential damages hereunder.

18.3 Insurance.

Interconnection Customer shall, at its own expense, maintain in force throughout the period of this LGIA, and until released by the Transmission Provider, the following minimum insurance coverage, with insurers authorized to do business in the state where the Point of Interconnection is located:

18.3.1 Employers' Liability and Workers' Compensation Insurance providing statutory benefits in accordance with the laws and regulations of the state in which the Point of Interconnection is located.

18.3.2 Commercial General Liability Insurance including premises and operations, personal injury, broad form property damage, broad form blanket contractual liability coverage (including coverage for the contractual indemnification) products and completed operations coverage, coverage for explosion, collapse and underground hazards, independent contractors coverage, coverage for pollution to the extent normally available and punitive damages to the extent normally available and a cross liability endorsement, with minimum limits of One Million Dollars ($1,000,000) per occurrence/One Million Dollars ($1,000,000) aggregate combined single limit for personal injury, bodily injury, including death and property damage.

18.3.3 Comprehensive Automobile Liability Insurance for coverage of owned and non-owned and hired vehicles, trailers or semi-trailers designed for travel on public roads, with a minimum, combined single limit of One Million Dollars ($1,000,000) per occurrence for bodily injury, including death and property damage.

18.3.4 Excess Public Liability Insurance over and above the Employers' Liability Commercial General Liability and Comprehensive Automobile Liability Insurance coverage, with a minimum combined single limit of Twenty Million Dollars ($20,000,000) per occurrence/Twenty Million Dollars ($20,000,000) aggregate.

18.3.5 The Commercial General Liability Insurance, Comprehensive Automobile Insurance and Excess Public Liability Insurance policies shall name the Transmission Provider, its parent, associated and Affiliate companies and their respective directors, officers, agents, servants and employees (Transmission Provider Party Group) as additional insured. All policies shall contain provisions whereby the insurers waive all rights of subrogation in accordance with the provisions of this LGIA against the Transmission Provider Party Group and provide thirty (30) Calendar Days advance written notice to the Transmission Provider Party Group prior to anniversary date of cancellation or any material change in coverage or condition.

18.3.6 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies shall contain provisions that specify that the polices are primary and shall apply to such extent without consideration for other policies separately carried and shall state that each insured is provided coverage as though a separate policy had been issued to each, except the insurer's liability shall not be increased beyond the amount for which the insurer would have been liable had only one insured been covered. Interconnection Customer shall be responsible for its respective deductibles or retentions.

18.3.7 The Commercial General Liability Insurance, Comprehensive Automobile Liability Insurance and Excess Public Liability Insurance policies, if written on a Claims First Made Basis, shall be maintained in full force and effect for two (2) years after termination of this LGIA, which coverage may be in the form of tail coverage or extended reporting period coverage if agreed by the Parties.

18.3.8 The requirements contained herein as to the types and limits of all insurance to be maintained by Interconnection Customer are not intended to and shall not in any manner, limit or qualify the liabilities and obligations assumed by Interconnection Customer under this LGIA.

18.3.9 Within ten (10) Calendar Days following execution of this LGIA, and as soon as practicable after the end of each fiscal year or at the renewal of the insurance policy and in any event within ninety (90) Calendar Days thereafter, Interconnection Customer shall provide certification of all insurance required in this LGIA, executed by each insurer or by an authorized representative of each insurer.

18.3.10 Notwithstanding the foregoing, Interconnection Customer may self-insure to meet the minimum insurance requirements of Articles 18.3.2 through 18.3.8 to the extent it maintains a self-insurance program; provided that, Interconnection Customer has an issuer credit rating or a senior unsecured debt rating of investment grade or better as rated by Standard & Poor's and that its self-insurance program meets the minimum insurance requirements of Articles 18.3.2 through 18.3.8. For any period of time that Interconnection Customer has no issuer credit rating and its senior unsecured debt is unrated by Standard & Poor's, or Interconnection Customer has an issuer credit rating or a senior unsecured debt rating of less than investment grade as rated by Standard & Poor's, Interconnection Customer shall comply with the insurance requirements applicable to it under Articles 18.3.2 through 18.3.9. In the event that Interconnection Customer is permitted to self-insure pursuant to this article, it shall notify the Transmission Provider that it meets the requirements to self-insure and that its self-insurance program meets the minimum insurance requirements in a manner consistent with that specified in Article 18.3.9.

18.3.11 The Parties agree to report to each other in writing as soon as practical all accidents or occurrences resulting in injuries to any person, including death, and any property damage arising out of this LGIA.

Article 19. Assignment

19.1 Assignment.

This LGIA may be assigned by either Party only with the written consent of the other, provided that either Party may assign this LGIA without the consent of the other Party to any Affiliate of the assigning Party with an equal or greater credit rating and with the legal authority and operational ability to satisfy the obligations of the assigning Party under this LGIA; and provided further, that Interconnection Customer shall have the right to assign this LGIA, without the consent of Transmission Provider, for collateral security purposes to aid in providing financing for the Large Generating Facility, provided that Interconnection Customer will promptly notify Transmission Provider of any such assignment. Any financing arrangement entered into by Interconnection Customer pursuant to this article will provide that prior to or upon the exercise of the secured party's, trustee's or mortgagee's assignment rights pursuant to said arrangement, the secured creditor, the trustee or mortgagee will notify Transmission Provider of the date and particulars of any such exercise of assignment right(s), including providing the Transmission Provider with proof that it meets the requirements of Articles 11.5 and 18.3. Any attempted assignment that violates this article is void and ineffective. Any assignment under this LGIA shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

Article 20. Severability

20.1 Severability.

If any provision in this LGIA is finally determined to be invalid, void or unenforceable by any court or other Governmental Authority having jurisdiction, such determination shall not invalidate, void or make unenforceable any other provision, agreement or covenant of this LGIA; provided that if Interconnection Customer (or any third party, but only if such third party is not acting at the direction of Transmission Provider) seeks and obtains such a final determination with respect to any provision of the Alternate Option (Article 5.1.2), or the Negotiated Option (Article 5.1.4), then none of these provisions shall thereafter have any force or effect and the Parties' rights and obligations shall be governed solely by the Standard Option (Article 5.1.1).

Article 21. Comparability

21.1 Comparability. (Intentionally Omitted)

Article 22. Confidentiality

22.1 Confidentiality.

Confidential Information shall include, without limitation, all information relating to a Party's technology, research and development, business affairs and pricing, and any information supplied by either of the Parties to the other prior to the execution of this LGIA.

Information is Confidential Information only if it is clearly designated or marked in writing as confidential on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Party receiving the information that the information is confidential.

If requested by either Party, the other Party shall provide in writing, the basis for asserting that the information referred to in this Article 22 warrants confidential treatment, and the requesting Party may disclose such writing to the appropriate Governmental Authority. Each Party shall be responsible for the costs associated with affording confidential treatment to its information.

22.1.1 Term.

During the term of this LGIA, and for a period of three (3) years after the expiration or termination of this LGIA, except as otherwise provided in this Article 22, each Party shall hold in confidence and shall not disclose to any person Confidential Information.

22.1.2 Scope.

Confidential Information shall not include information that the receiving Party can demonstrate: (1) is generally available to the public other than as a result of a disclosure by the receiving Party; (2) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (3) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (4) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (5) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of this LGIA; or (6) is required, in accordance with Article 22.1.7 of the LGIA, Order of Disclosure, to be disclosed by any Governmental Authority or is otherwise required to be disclosed by law or subpoena, including the Freedom of Information Act, 5 U.S.C. § 552, as amended, or is necessary in any legal proceeding establishing rights and obligations under this LGIA. Information designated as Confidential Information will no longer be deemed confidential if the Party that designated the information as confidential notifies the other Party that it no longer is confidential.

22.1.3 **Release of Confidential Information.**
Neither Party shall release or disclose Confidential Information to any other person, except to its Affiliates (limited by the Standards of Conduct requirements), sub-contractors, employees, consultants or to parties who may be or considering providing financing to or equity participation with Interconnection Customer, or to potential purchasers or assignees of Interconnection Customer, on a need-to-know basis in connection with this LGIA, unless such person has first been advised of the confidentiality provisions of this Article 22 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Article 22.

22.1.4 **Rights.**
Each Party retains all rights, title and interest in the Confidential Information that each Party discloses to the other Party. The disclosure by each Party to the other Party of Confidential Information shall not be deemed a waiver by either Party or any other person or entity of the right to protect the Confidential Information from public disclosure.

22.1.5 **No Warranties.**
By providing Confidential Information, neither Party makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, neither Party obligates itself to provide any particular information or Confidential Information to the other Party nor to enter into any further agreements or proceed with any other relationship or joint venture.

22.1.6 **Standard of Care.**
Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to the other Party under this LGIA or its regulatory requirements.

22.1.7 **Order of Disclosure.**
If a court or a Government Authority or entity with the right, power and apparent authority to do so requests or requires either Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the other Party with prompt notice of such request(s) or requirement(s) so that the other Party may seek an appropriate protective order or waive compliance with the terms of this LGIA. Notwithstanding the absence of a protective order or waiver, the

Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

22.1.8 Termination of Agreement.
Upon termination of this LGIA for any reason, each Party shall, within ten (10) Calendar Days of receipt of a written request from the other Party, use Reasonable Efforts to destroy, erase or delete (with such destruction, erasure and deletion certified in writing to the other Party) or return to the other Party, without retaining copies thereof, any and all written or electronic Confidential Information received from the other Party.

22.1.9 Remedies.
The Parties agree that monetary damages would be inadequate to compensate a Party for the other Party's Breach of its obligations under this Article 22. Each Party accordingly agrees that the other Party shall be entitled to equitable relief, by way of injunction or otherwise, if the first Party Breaches or threatens to Breach its obligations under this Article 22, which equitable relief shall be granted without bond or proof of damages, and the receiving Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the Breach of this Article 22, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Article 22.

22.1.10 Disclosure to FERC, its Staff, or a State.
Notwithstanding anything in this Article 22 to the contrary, and pursuant to 18 CFR § 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to this LGIA, the Party shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party must, consistent with 18 CFR § 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party to this LGIA prior to the release of the Confidential Information to FERC or its staff. The Party shall notify the other Party to the LGIA when it is notified by FERC or its staff that a request to release Confidential Information has been received by FERC,

at which time either of the Parties may respond before such information would be made public, pursuant to 18 CFR § 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.

22.1.11 Subject to the exception in Article 22.1.10, any information that a Party claims is competitively sensitive, commercial or financial information under this LGIA ("Confidential Information") shall not be disclosed by the other Party to any person not employed or retained by the other Party, except to the extent disclosure is: (1) required by law; (2) reasonably deemed by the disclosing Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (3) otherwise permitted by consent of the other Party, such consent not to be unreasonably withheld; or (4) necessary to fulfill its obligations under this LGIA or as a transmission service provider or a Control Area operator including disclosing the Confidential Information to an RTO or ISO or to a regional or national reliability organization. The Party asserting confidentiality shall notify the other Party in writing of the information it claims is confidential. Prior to any disclosures of the other Party's Confidential Information under this subparagraph, or if any third party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the disclosing Party agrees to promptly notify the other Party in writing and agrees to assert confidentiality and cooperate with the other Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

Article 23. Environmental Releases

23.1 Each Party shall remediate all releases of Hazardous Substances brought to, or created at, real property it owns underlying the Large Generating Facility or Interconnection Facilities, and any Hazardous Substances migrating from real property it owns at the Large Generating Facility site. The Party that caused the release shall bear the costs of the remediation, which shall meet applicable state and Federal environmental standards at the time of the remediation. Such costs may include, but are not limited to, state and Federal supervision, remedial action plans, removal and remedial actions, and negotiation of voluntary and judicial agreements required to meet such environmental standards.

23.2 Each Party shall notify the other Party as promptly as practicable of any significant release of Hazardous Substances by the first Party. Each Party shall cooperate with the other Party in accommodating any necessary remedial activities of the other Party with respect to property occupied by such other Party.

23.3 The Parties agree to comply fully with the substantive requirements of all applicable Federal, state and local environmental laws in the performance of their obligations hereunder, and to mitigate and abate adverse environmental impacts accordingly.

Article 24. Information Requirements

24.1 Information Acquisition.
Transmission Provider and Interconnection Customer shall submit specific information regarding the electrical characteristics of their respective facilities to each other as described below and in accordance with Applicable Reliability Standards.

24.2 Information Submission by Transmission Provider.
The initial information submission by Transmission Provider shall occur no later than one hundred eighty (180) Calendar Days prior to Trial Operation and shall include Transmission System information necessary to allow Interconnection Customer to select equipment and meet any system protection and stability requirements, unless otherwise agreed to by the Parties. On a monthly basis Transmission Provider shall provide Interconnection Customer a status report on the construction and installation of Transmission Provider's Interconnection Facilities and Network Upgrades, including, but not limited to, the following information: (1) progress to date; (2) a description of the activities since the last report; (3) a description of the action items for the next period; and (4) the delivery status of equipment ordered.

24.3 Updated Information Submission by Interconnection Customer.
The updated information submission by Interconnection Customer, including manufacturer information, shall occur no later than one hundred eighty (180) Calendar Days prior to the Trial Operation. Interconnection Customer shall submit a completed copy of the Large Generating Facility data requirements contained in Appendix 1 to the LGIP. It shall also include any additional information provided to Transmission Provider for the Feasibility and Facilities Study. Information in this submission shall be the most current Large Generating Facility design or expected performance data. Information submitted for stability models shall be compatible with Transmission Provider standard models. If there is no compatible model, Interconnection Customer will work with a consultant mutually agreed to by the Parties to develop and supply a standard model and associated information.

If Interconnection Customer's data is materially different from what was originally provided to Transmission Provider pursuant to the Interconnection Study Agreement between Transmission Provider and Interconnection Customer, then Transmission Provider will conduct appropriate studies to determine the impact on Transmission Provider Transmission System based on the actual data submitted pursuant to this Article 24.3. The Interconnection Customer shall not begin Trial Operation until such studies are completed.

24.4 Information Supplementation.
Prior to the Operation Date, the Parties shall supplement their information submissions described above in this Article 24 with any and all "as-built" Large Generating Facility information or "as-tested" performance information that differs from the initial submissions or, alternatively, written confirmation that no such differences exist. The Interconnection Customer shall conduct tests on the Large Generating Facility as required by Good Utility Practice such as an open circuit "step voltage" test on the Large Generating Facility to verify proper operation of the Large Generating Facility's automatic voltage regulator.

Unless otherwise agreed, the test conditions shall include: (1) Large Generating Facility at synchronous speed; (2) automatic voltage regulator on and in voltage control mode; and (3) a five percent change in Large Generating Facility terminal voltage initiated by a change in the voltage regulators reference voltage. Interconnection Customer shall provide validated test recordings showing the responses of Large Generating Facility terminal and field voltages. In the event that direct recordings of these voltages is impractical, recordings of other voltages or currents that mirror the response of the Large Generating Facility's terminal or field voltage are acceptable if information necessary to translate these alternate quantities to actual Large Generating Facility terminal or field voltages is provided. Large Generating Facility testing shall be conducted and results provided to Transmission Provider for each individual generating unit in a station.

Subsequent to the Operation Date, Interconnection Customer shall provide Transmission Provider any information changes due to equipment replacement, repair or adjustment. Transmission Provider shall provide Interconnection Customer any information changes due to equipment replacement, repair or adjustment in the directly connected substation or any adjacent Transmission Provider-owned substation that may affect Interconnection Customer's Interconnection Facilities equipment ratings, protection or operating requirements. The Parties shall provide such information no later than thirty (30) Calendar Days after the date of the equipment replacement, repair or adjustment.

Article 25. Information Access and Audit Rights

25.1 Information Access.
Each Party (the "disclosing Party") shall make available to the other Party information that is in the possession of the disclosing Party and is necessary in order for the other Party to: (1) verify the costs incurred by the disclosing Party for which the other Party is responsible under this LGIA; and (2) carry out its obligations and responsibilities under this LGIA. The Parties shall not use such information for purposes other than those set forth in this Article 25.1 and to enforce their rights under this LGIA.

25.2 Reporting of Non-Force Majeure Events.
Each Party (the "notifying Party") shall notify the other Party when the notifying Party becomes aware of its inability to comply with the provisions of this LGIA for a reason other than a Force Majeure event. The Parties agree to cooperate with each

other and provide necessary information regarding such inability to comply, including the date, duration, reason for the inability to comply and corrective actions taken or planned to be taken with respect to such inability to comply. Notwithstanding the foregoing, notification, cooperation or information provided under this article shall not entitle the Party receiving such notification to allege a cause for anticipatory breach of this LGIA.

25.3 Audit Rights.
Subject to the requirements of confidentiality under Article 22 of this LGIA, each Party shall have the right, during normal business hours, and upon prior reasonable notice to the other Party, to audit at its own expense the other Party's accounts and records pertaining to either Party's performance or either Party's satisfaction of obligations under this LGIA. Such audit rights shall include audits of the other Party's costs, calculation of invoiced amounts, Transmission Provider's efforts to allocate responsibility for the provision of reactive support to the Transmission System, Transmission Provider's efforts to allocate responsibility for interruption or reduction of generation on the Transmission System, and each Party's actions in an Emergency Condition. Any audit authorized by this article shall be performed at the offices where such accounts and records are maintained and shall be limited to those portions of such accounts and records that relate to each Party's performance and satisfaction of obligations under this LGIA. Each Party shall keep such accounts and records for a period equivalent to the audit rights periods described in Article 25.4.

25.4 Audit Rights Periods.

25.4.1 Audit Rights Period for Construction-Related Accounts and Records.
Accounts and records related to the design, engineering, procurement and construction of Transmission Provider's Interconnection Facilities and Network Upgrades shall be subject to audit for a period of twenty-four (24) months following Transmission Provider's issuance of a final invoice in accordance with Article 12.2.

25.4.2 Audit Rights Period for All Other Accounts and Records.
Accounts and records related to either Party's performance or satisfaction of all obligations under this LGIA other than those described in Article 25.4.1 shall be subject to audit as follows: (1) for an audit relating to cost obligations, the applicable audit rights period shall be twenty-four (24) months after the auditing Party's receipt of an invoice giving rise to such cost obligations; and (2) for an audit relating to all other obligations, the applicable audit rights period shall be twenty-four (24) months after the event for which the audit is sought.

25.5 Audit Results.
If an audit by a Party determines that an overpayment or an underpayment has occurred, a notice of such overpayment or underpayment shall be given to the other Party together with those records from the audit which support such determination.

Article 26. Subcontractors

26.1 General.
Nothing in this LGIA shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this LGIA; provided however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this LGIA in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

26.2 Responsibility of Principal.
The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this LGIA. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided however, that in no event shall Transmission Provider be liable for the actions or inactions of Interconnection Customer or its subcontractors with respect to obligations of Interconnection Customer under Article 5 of this LGIA. Any applicable obligation imposed by this LGIA upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

26.3 No Limitation by Insurance.
The obligations under this Article 26 will not be limited in any way by any limitation of subcontractor's insurance.

Article 27. Disputes

27.1 Submission.
In the event either Party has a dispute, or asserts a claim, that arises out of or in connection with this LGIA or its performance, such Party (the "disputing Party") shall provide the other Party with written notice of the dispute or claim ("Notice of Dispute"). Such dispute or claim shall be referred to a designated senior representative of each Party for resolution on an informal basis as promptly as practicable after receipt of the Notice of Dispute by the other Party. In the event the designated representatives are unable to resolve the claim or dispute through unassisted or assisted negotiations within thirty (30) Calendar Days of the other Party's receipt of the Notice of Dispute, such claim or dispute may, upon mutual agreement of the Parties, be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below. In the event the Parties do not agree to submit such claim or dispute to arbitration, each Party may exercise whatever rights and remedies it may have in equity or at law consistent with the terms of this LGIA.

27.2 External Arbitration Procedures.
Any arbitration initiated under this LGIA shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) Calendar Days of the submission of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member

arbitration panel. The two arbitrators so chosen shall within twenty (20) Calendar Days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association ("Arbitration Rules") and any applicable FERC regulations or RTO rules; provided however, in the event of a conflict between the Arbitration Rules and the terms of this Article 27, the terms of this Article 27 shall prevail.

27.3 Arbitration Decisions.

Unless otherwise agreed by the Parties, the arbitrator(s) shall render a decision within ninety (90) Calendar Days of appointment and shall notify the Parties in writing of such decision and the reasons therefore. The arbitrator(s) shall be authorized only to interpret and apply the provisions of this LGIA and shall have no power to modify or change any provision of this Agreement in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with FERC if it affects jurisdictional rates, terms and conditions of service, Interconnection Facilities or Network Upgrades.

27.4 Costs.

Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable: (1) the cost of the arbitrator chosen by the Party to sit on the three-member panel and one-half of the cost of the third arbitrator chosen; or (2) one-half the cost of the single arbitrator jointly chosen by the Parties.

Article 28. Representations, Warranties and Covenants

28.1 General.

Each Party makes the following representations, warranties and covenants:

28.1.1 Good Standing.

Interconnection Customer is duly organized, validly existing and in good standing under the laws of the state in which it is organized, formed or incorporated, as applicable; that it is qualified to do business in the state or states in which the Large Generating Facility, Interconnection Facilities and Network Upgrades owned by such Party, as applicable, are located; and that it has the corporate power and authority to own its properties, to carry on its business as now being conducted and to enter into this LGIA and carry out the transactions contemplated hereby and perform and carry out all covenants and obligations on its part to be performed under and pursuant to this LGIA.

28.1.2 Authority.
Such Party has the right, power and authority to enter into this LGIA, to become a Party hereto and to perform its obligations hereunder. This LGIA is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

28.1.3 No Conflict.
The execution, delivery and performance of this LGIA does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of such Party, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon such Party or any of its assets.

28.1.4 Consent and Approval.
Such Party has sought or obtained; or, in accordance with this LGIA will seek or obtain, each consent, approval, authorization, order or acceptance by any Governmental Authority in connection with the execution, delivery and performance of this LGIA, and it will provide to any Governmental Authority notice of any actions under this LGIA that are required by Applicable Laws and Regulations.

Article 29. Joint Operating Committee

29.1 Joint Operating Committee.
Except in the case of ISOs and RTOs, Transmission Provider shall constitute a Joint Operating Committee to coordinate operating and technical considerations of Interconnection Service. At least six (6) months prior to the expected Initial Synchronization Date, Interconnection Customer and Transmission Provider shall each appoint one representative and one alternate to the Joint Operating Committee. Each Interconnection Customer shall notify Transmission Provider of its appointment in writing. Such appointments may be changed at any time by similar notice. The Joint Operating Committee shall meet as necessary, but not less than once each calendar year, to carry out the duties set forth herein. The Joint Operating Committee shall hold a meeting at the request of either Party, at a time and place agreed upon by the representatives. The Joint Operating Committee shall perform all of its duties consistent with the provisions of this LGIA. Each Party

shall cooperate in providing to the Joint Operating Committee all information required in the performance of the Joint Operating Committee's duties. All decisions and agreements, if any, made by the Joint Operating Committee, shall be evidenced in writing. The duties of the Joint Operating Committee shall include the following:

29.1.1 Establish data requirements and operating record requirements.

29.1.2 Review the requirements, standards and procedures for data acquisition equipment, protective equipment and any other equipment or software.

29.1.3 Annually review the one (1) year forecast of maintenance and planned outage schedules of Transmission Provider's and Interconnection Customer's facilities at the Point of Interconnection.

29.1.4 Coordinate the scheduling of maintenance and planned outages on the Interconnection Facilities, the Large Generating Facility and other facilities that impact the normal operation of the interconnection of the Large Generating Facility to the Transmission System.

29.1.5 Ensure that information is being provided by each Party regarding equipment availability.

29.1.6 Perform such other duties as may be conferred upon it by mutual agreement of the Parties.

Article 30. Miscellaneous

30.1 Binding Effect.
This LGIA and the rights and obligations hereof, shall be binding upon and shall inure to the benefit of the successors and assigns of the Parties hereto.

30.2 Conflicts.
In the event of a conflict between the body of this LGIA and any attachment, appendices or exhibits hereto, the terms and provisions of the body of this LGIA shall prevail and be deemed the final intent of the Parties.

30.3 Rules of Interpretation.
This LGIA, unless a clear contrary intention appears, shall be construed and interpreted as follows: (1) the singular number includes the plural number and vice versa; (2) reference to any person includes such person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this LGIA, and reference to a person in a particular capacity excludes such person in any other capacity or individually; (3) reference to any agreement (including this LGIA), document, instrument or tariff means such agreement, document, instrument or tariff as amended or modified and in effect from time to time in accordance with the terms thereof; and if applicable, the terms hereof; (4) reference to any Applicable Laws and Regulations means such Applicable Laws and Regulations as amended,

modified, codified or reenacted, in whole or in part, and in effect from time to time, including, if applicable, rules and regulations promulgated thereunder; (5) unless expressly stated otherwise, reference to any Article, Section or Appendix means such Article of this LGIA or such Appendix to this LGIA, or such Section to the LGIP or such Appendix to the LGIP, as the case may be; (6) "hereunder," "hereof," "herein," "hereto" and words of similar import shall be deemed references to this LGIA as a whole and not to any particular Article or other provision hereof or thereof; (7) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (8) relative to the determination of any period of time, "from" means "from and including," "to" means "to but excluding" and "through" means "through and including."

30.4 Entire Agreement.
This LGIA, including all Appendices and Schedules attached hereto, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this LGIA. There are no other agreements, representations, warranties or covenants which constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this LGIA.

30.5 No Third Party Beneficiaries.
Except as provided in Article 4.3.1.3, this LGIA is not intended to and does not create rights, remedies or benefits of any character whatsoever in favor of any persons, corporations, associations or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and, where permitted, their assigns.

30.6 Waiver.
The failure of a Party to this LGIA to insist, on any occasion, upon strict performance of any provision of this LGIA will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

Any waiver at any time by either Party of its rights with respect to this LGIA shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this LGIA. Termination or Default of this LGIA for any reason by Interconnection Customer shall not constitute a waiver of Interconnection Customer's legal rights to obtain an interconnection from Transmission Provider. Any waiver of this LGIA shall, if requested, be provided in writing.

30.7 Headings.
The descriptive headings of the various Articles of this LGIA have been inserted for convenience of reference only and are of no significance in the interpretation or construction of this LGIA.

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30.8 Multiple Counterparts.
This LGIA may be executed in two (2) or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

30.9 Amendment.
The Parties may by mutual agreement amend this LGIA by a written instrument duly executed by the Parties.

30.10 Modification by the Parties.
The Parties may by mutual agreement amend the Appendices to this LGIA by a written instrument duly executed by the Parties. Such amendment shall become effective and a part of this LGIA upon satisfaction of all Applicable Laws and Regulations.

30.11 Reservation of Rights. (Intentionally Omitted)

30.12 No Partnership.
This LGIA shall not be interpreted or construed to create an association, joint venture, agency relationship or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

IN WITNESS WHEREOF, the Parties have executed this Agreement as of the last date indicated below.

EUGENE WATER & ELECTRIC BOARD	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
[redacted] (b) (6)	[redacted] (b) (6)
By:	By:
Name: Dave Churchman (Print/Type)	Name: G. Doug Johnson (Print/Type)
Title: Interim General Manager	Title: Transmission Account Executive
Date: 4/22/16	Date: 4/27/16

APPENDIX A
INTERCONNECTION FACILITIES, NETWORK UPGRADES AND DISTRIBUTION UPGRADES FOR 38.27 MW SMITH CREEK HYDROELECTRIC PROJECT

*Reference generation interconnection request number **G0511 (38.27 MW)** for related studies.*

1. **TRANSMISSION PROVIDER INTERCONNECTION FACILITIES**
   Transmission Provider's Interconnection Facilities are shown in Appendix A, Attachment 2.

2. **NETWORK UPGRADES**
   None. The existing facilities are sufficient for the Generating Facility.

3. **TEMPORARY NETWORK UPGRADES AND TRANSMISSION PROVIDER'S INTERCONNECTION FACILITIES**
   Not applicable.

4. **INTERCONNECTION CUSTOMER'S INTERCONNECTION FACILITIES**
   Interconnection Customer's Interconnection Facilities are shown in Appendix A, Attachment 2.

5. **AFFECTED SYSTEM NETWORK UPGRADES**
   Not applicable.

6. **STAND ALONE NETWORK UPGRADES**
   Not applicable.

7. **POINT OF INTERCONNECTION**
   The Point of Interconnection is the point where Interconnection Customer's Interconnection Facilities connects to the Transmission Provider's Bonners Ferry Substation, further depicted in Appendix A, Attachment 2.

8. **POINT OF CHANGE OF OWNERSHIP**
   The Point of Change of Ownership is the same as the Point of Interconnection.

9. **DISTRIBUTION UPGRADES**
   Not applicable.

10. **DUTIES OF TRANSMISSION PROVIDER**
    Transmission Provider shall own, maintain, and operate the Transmission Provider's Interconnection Facilities.

11. DUTIES OF INTERCONNECTION CUSTOMER

Interconnection Customer shall:

(a) Coordinate testing and energization of the Generating Facility, as necessary, and Interconnection Customer's Interconnection Facilities with Transmission Provider;

(b) Provide space in the temperature controlled control building(s) of Interconnection Customer's substation(s) for Transmission Provider's equipment with a separate Transmission Provider lockable area (consistent with NERC and Critical Infrastructure Protection security requirements) for Transmission Provider's communications equipment;

(c) Comply with the Transmission Provider's requirements contained in: (1) Transmission Provider Technical Requirements for Interconnection (Technical Requirements), (2) Metering Application Guide, (3) Transmission Provider's scheduling procedures as posted on Transmission Provider's Open Access Same Time Information System (OASIS), and (4) Transmission Provider's business practices. Transmission Provider may unilaterally amend its Technical Requirements, scheduling procedures, and business practices. The Transmission Provider Technical Requirements are incorporated herein by reference;

(d) Provide Transmission Provider personnel direct access to all Transmission Provider facilities at the Interconnection Customer's substations via Transmission Provider lock(s) or equivalent system;

(e) Own, maintain, and operate all Interconnection Facilities except the Transmission Provider's Interconnection Facilities;

(f) Provide as built technical data on the Generating Facility and Interconnection Customer's Interconnection Facilities as required by Transmission Provider for generation owner or operator NERC and WECC compliance; and

(g) Cooperate on relay testing in compliance with NERC and WECC regulations.

12. O&M COSTS ASSIGNED TO INTERCONNECTION CUSTOMER

Not applicable.

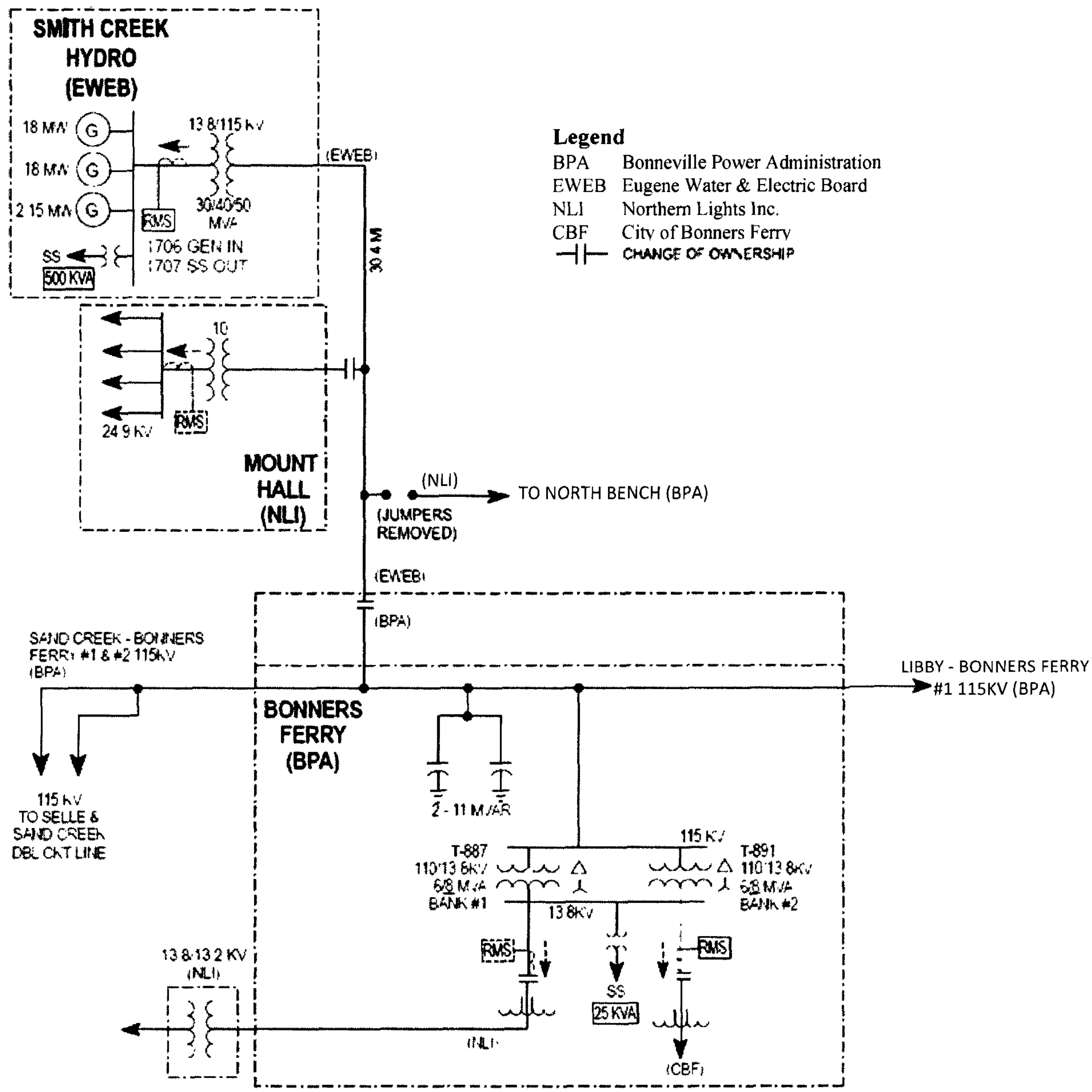
13. TRANSMISSION CREDITS FOR FUNDS ADVANCED FOR NETWORK UPGRADES

Not applicable.

APPENDIX A
ATTACHMENT 1
COST ESTIMATE SUMMARY
SMITH CREEK HYDROELECTRIC PROJECT

This Appendix A, Attachment 1 is not applicable. See Appendix B, Section 1.

APPENDIX A
ATTACHMENT 2
SIMPLIFIED ONE LINE DIAGRAM



Legend

BPA	Bonneville Power Administration
EWEB	Eugene Water & Electric Board
NLI	Northern Lights Inc.
CBF	City of Bonners Ferry
─┤├─	CHANGE OF OWNERSHIP

APPENDIX B
MILESTONES

1. **IN-SERVICE DATE OF INTERCONNECTION CUSTOMER'S SWITCHYARD**
   In-Service Date is December 1, 1989.

2. **INITIAL SYNCHRONIZATION DATE**
   Initial Synchronization Date is December 1, 1989.

3. **COMMERCIAL OPERATION DATE**
   The Commercial Operation date of the Generating Facility is December 1, 1989.

4. **STANDARD OPTION**
   Standard Option is selected as per Article 5.1.

5. **SECURITY**
   Intentionally left blank.

6. **PAYMENT SCHEDULE**
   Not Applicable. See Section 1 of this Appendix B.

APPENDIX C
INTERCONNECTION DETAILS AND OPERATING REQUIREMENTS FOR SMITH CREEK HYDROELECTRIC PROJECT

*Reference generation interconnection request number **G0511 (38.27 MW)** for related studies.*

1. **TOTAL INSTALLED GENERATING FACILITY CAPACITY**
Interconnection Customer's net Generating Facility Capacity shall not exceed 38.27 MW at the Point of Interconnection. Net Generating Facility capacity is the Nameplate rating less losses to the Point of Interconnection.

2. **IDENTIFICATION OF THE LARGE GENERATING FACILITY**
The Generating Facility consists of Unit 1: Horizontal Pelton 18.06 MW hydro turbine generator; Unit 2: Horizontal Pelton18.06 MW hydro turbine generator; Unit 3: Horizontal Pelton 2.15 MW hydro turbine generator. Total installed Generating Facility Capacity is 38.27 MW.

3. **CONTROL AREA OBLIGATION FOR INTERCONNECTION CUSTOMER**

(a) As specified in Article 9.4, Interconnection Customer is responsible for compliance with Control Area requirements. This includes the WECC Reliability Criteria referenced in Article 4.3.1.1. The Joint Operating Committee described in Article 29 will address past performance issues and future compliance requirements.

(b) The Interconnection Customer shall operate the Project as directed by the Transmission Provider and comply with all Transmission Provider's orders in accordance with Transmission Provider's Open Access Transmission Tariff, including, but not limited to, orders to reduce generation in accordance with the Oversupply Management Protocol, and other Dispatcher Standing Orders or operational procedures and their successors.

(c) Interconnection Customer must provide as built technical data (such as equipment characteristics and system data) on the Generating Facility and Interconnection Customer's Interconnection Facilities to Transmission Provider as required by the NERC Reliability Standards.

4. **INTERCONNECTION GENERATION METERING**

(a) **Generation Metering:** Transmission Provider will provide metering capable of measuring and recording real and reactive power into (IN) the Transmission Provider's system and separately out (OUT) to the Generating Facility, connecting to the Interconnection Customer's Smith Creek Substation. When sufficient generation is available, the Generating Facility is required to self-supply all Station Service and Parasitic (plant auxiliary power) load. The generation IN metering will measure the Generating

Facility's output less the Station Service and Parasitic loads (net metering). There will be loss factor adjustments from Smith Creek Substation point of metering to the Point of Interconnection on Transmission Provider's 115 kV Bonners Ferry Substation.

Voltage: 13.8 kV.

(b) **Generation Facility Load Metering:** Transmission Provider's generation **OUT** metering will measure the Generation Facility substation service load and the Parasitic Load of the Generating Facility, delivered by Transmission Provider's system, when Interconnection Customer's equipment is connected to the Transmission Provider's system. Interconnection Customer shall arrange for any alternate power source required for the Generation Facility when connection to Transmission Provider's system is interrupted and any other local load service required for facilities not connected to Transmission Provider's system. The alternate power source(s) shall be provided by others and separate metering is required. There will be loss factor adjustments from Smith Creek Substation points of metering to the Point of Interconnection at Transmission Provider's 115 kV Bonners Ferry Substation.

Voltage: 13.8 kV.

5. VOLTAGE SCHEDULES AND REACTIVE POWER

As set forth in Article 9.6.2, the following provides Interconnection Customer the information for voltage schedules.

There are no current voltage schedule and reactive power requirements. Transmission Provider will provide written notice to Interconnection Customer of any future voltage schedule and reactive power requirements as system conditions warrant, and Interconnection Customer will comply with those requirements.

6. REMEDIAL ACTION SCHEME

(a) There are no current RAS requirements. Transmission Provider will provide written notice to Interconnection Customer of any future RAS requirements as system conditions warrant, and Interconnection Customer will comply with those requirements.

(b) Information exchange on the RAS design and operation will be performed as part of the duties of the Joint Operating Committee as described in Article 29.

7. REQUIRED CONTROL AREA SERVICES

Unless otherwise stated below, the Interconnection Customer is subject to the Ancillary Service Rate Schedule, or successor rate schedule and General Rate Schedule Provisions, including any new or modified Control Area services rate or general rate schedule provision that Transmission Provider adopts after the date of execution of the LGIA.

As of the Effective Date of this LGIA, Interconnection Customer is subject to the following services provided by Transmission Provider:

	Provided By	Contract No.
Generation Imbalance Service	As Applicable[1]	16TX-16224
Operating Reserves – Spinning Reserve Service	Transmission Provider[2]	16TX-16224
Operating Reserves – Supplemental Reserve Service	Transmission Provider[2]	16TX-16224
Dispatchable Energy Resource Balancing Service	As Applicable[3]	16TX-16224

Subject to Transmission Provider's consent, which shall not be unreasonably withheld, Interconnection Customer may self-supply, or acquire from a third party, any of the Control Area services that Transmission Provider provides under this LGIA, if such Control Area services are (1) comparable to the Control Area services Transmission Provider is providing, and (2) consistent with the Tariff and Transmission Provider's associated business practices. Interconnection Customer may also, subject to Transmission Provider's consent, which shall not be unreasonably withheld, move out of Transmission Provider's Control Area, at which point Interconnection Customer will be responsible for providing its own Control Area services. No later than the date (Change Date) on which Interconnection Customer begins self-supplying such Control Area services, taking such Control Area services from a third party, or when Interconnection customer moves out of Transmission Provider's Control Area, Interconnection Customer must compensate Transmission Provider for any costs to modify the Transmission System that Transmission Provider incurs because of such self-supply, third-party supply, or Control Area move. After the Change Date the Interconnection Customer must also continue to pay Transmission Provider for Control Area Services taken under this Section 7 of Appendix C until the end of the Transmission Provider's rate period for such Control Area Services.

[1] Generation Imbalance is applicable subject to the Ancillary Service Rate Schedule, or successor Rate Schedule and General Rate Schedule Provisions.

[2] Unless otherwise provided for under a Transmission Provider Transmission Service Agreement consistent with Transmission Provider's Open Access Transmission Tariff and associated business practices.

[3] Dispatchable Energy Resource Balancing Service is subject to the Ancillary Service Rate Schedule, or successor Rate Schedule and General Rate Schedule Provisions.

APPENDIX D
SECURITY ARRANGEMENTS DETAILS

This Appendix D is intentionally left blank.

APPENDIX E
COMMERCIAL OPERATION DATE

COMMERCIAL OPERATION DATE

Commercial Operation date of the Generating Facility is December 1, 1989.

APPENDIX F
ADDRESSES FOR DELIVERY OF NOTICES AND BILLINGS

1. ADMINISTRATIVE CONTACTS

If to Interconnection Customer:

Eugene Water & Electric Board
4200 Roosevelt Boulevard
Eugene, OR 97402
Attention: Dave Churchman
Title: Power Operations Manager
Phone: (541) 685-7598
Fax: (541) 685-7598
E-mail: dave.churchman@eweb.org

If to Transmission Provider:

Attention: Transmission Account Executive for Eugene Water & Electric Board – TSE/TPP-2
Phone: (360) 619-6016
Fax: (360) 619-6940

If by First Class Mail:
Bonneville Power Administration
P.O. Box 61409
Vancouver, WA 98666-1409

If by Overnight Delivery Service:
Bonneville Power Administration – TSE/TPP-2
905 NE 11th Avenue
Portland, OR 97232

2. OPERATIONAL CONTACTS

If to Interconnection Customer:

Outage Coordination:
Eugene Water & Electric Board
4200 Roosevelt Boulevard
Eugene, OR 97402
Attention: Kevin Cardoza
Title: Real Time Supervisor
Phone: (541) 685-7338
Fax: (541) 685-7338
E-mail: kevin.cardoza@eweb.org

Plant Operator:
Eugene Water & Electric Board
Attention: Real Time Generation Desk
Phone: (541) 685-7555
Fax: (541) 685-7555

If to Transmission Provider:

Operational Primary:
Munro Dispatch
Phone: (509) 465-1820
Fax: (503)219-9009

Alternate & Local Subgrid:
Dittmer Dispatch
Phone: (360) 418-2280 or 418-2281
Fax: (360) 418-2938

Planned Outages:
Dittmer Control Center
Phone: (360) 418-2274
Fax: (360) 418-2214

3. CHANGES IN CONTACTS

If either Party changes its contact(s), that Party shall notify the other Party by voice phone, facsimile transmission, or other means as soon as possible. The Party asking for the change shall send written notice of the change to the other Party as soon as practical. Transmission Provider shall revise this Appendix F upon such notice.

APPENDIX G
INTERCONNECTION REQUIREMENTS FOR A WIND GENERATING PLANT

This Appendix G is intentionally left blank.

APPENDIX H
OPERATION, MAINTENANCE, REPAIR AND REPLACEMENT OF NETWORK UPGRADES

This Appendix H is intentionally left blank.

Contract No. 19TP-11686

TRANSMISSION OPERATOR SERVICES AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

EUGENE WATER & ELECTRIC BOARD

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Exhibit A BES Equipment Subject to this Agreement

Exhibit B Billing Determinants

Exhibit C Notices

Exhibit D Implementation Plan

This TRANSMISSION OPERATOR SERVICES AGREEMENT (Agreement) is entered into by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (BPA), and EUGENE WATER & ELECTRIC BOARD (Customer), hereinafter individually referred to as "Party" and collectively as "Parties".

RECITALS

WHEREAS, the Energy Policy Act of 2005 (Act) authorized the Federal Energy Regulatory Commission (FERC) to approve mandatory Reliability Standards with which users, owners and operators of the bulk power system (which includes the Bulk Electric System (BES)) are required to comply (mandatory Reliability Standards);

WHEREAS, FERC has approved certain mandatory Reliability Standards and associated requirements applicable to Transmission Operator(s) (TOP) proposed by the Electric Reliability Organization authorized by the Act to develop such standards (currently, the North American Electric Reliability Corporation (NERC));

WHEREAS, FERC, NERC and the Regional Reliability Organization (currently, the Western Electricity Coordinating Council (WECC)) have authority under the Act to enforce compliance with such mandatory Reliability Standards and associated requirements;

WHEREAS, Customer is registered as the TOP for its BES equipment specified herein, Customer plans to deregister as a TOP, and BPA is willing to register and act as the TOP for that BES equipment; and

WHEREAS, the Parties agree that the arrangements contained herein provide for BPA to register as and perform the TOP function in a manner that will satisfy the mandatory Reliability Standards and associated requirements applicable to TOPs, and take responsibility for enforcement actions for non-compliance with such standards.

In consideration of the promises and mutual covenants and agreements herein contained, the Parties agree as follows:

1. TERM OF AGREEMENT

This Agreement shall become effective on the date that the Agreement has been signed by both Parties (Effective Date) and shall continue in effect for no longer than five years after the Effective Date unless otherwise terminated by the Parties.

This Agreement may be terminated 90 days after written notice by Customer. BPA may terminate this Agreement after 90 days' written notice under the following circumstances:

(a) Customer fails to follow operating orders or instructions from BPA;

(b) Customer independently takes an action that results in BPA's non-compliance with any mandatory Reliability Standard applicable to the TOP, except when doing so would prevent a risk to life or safety;

(c) Customer independently takes an action that results in a safety or reliability issue;

(d) Customer modifies BES equipment without notifying BPA;

(e) Customer fails to maintain its BES equipment for which BPA is the TOP; or

(f) Customer fails to pay for TOP services according to the terms in Section 7 below.

2. EXHIBITS

The following Exhibits are hereby incorporated into and made part of this Agreement:

(a)	Exhibit A	BES Equipment Subject to this Agreement
(b)	Exhibit B	Billing Determinants
(c)	Exhibit C	Notices
(d)	Exhibit D	Implementation Plan

3. DEFINITIONS

When used in this Agreement, the following terms have the meaning shown below. Capitalized terms that are not listed below shall have the meaning stated in the most recent Glossary of Terms used in NERC Reliability Standards.

(a) "Business Day" means any day that is normally observed by the Federal Government as a workday.

(b) "Mitigation Plan" for non-compliance with a mandatory Reliability Standard has the same meaning as the term defined in the most current version of Appendix 2 of the NERC Rules of Procedure, or successor document.

(c) "Gap Resolution Team Implementation Plan" or "Implementation Plan" is a series of tasks that once accomplished brings BPA and Customer into full compliance and defines the associated time period that will be allowed for BPA to incorporate Customer into BPA's functional responsibilities for compliance purposes.

(d) "Transmission Operator Integrated Compendium" or "TOPIC" documents TOP procedures necessary in order to provide BPA with the ability to carry out its TOP responsibilities as they relate to Customer's BES equipment listed in Exhibit A.

4. BPA RESPONSIBILITIES

(a) BPA shall register as and perform the TOP function on behalf of Customer for the Customer's BES equipment listed in Exhibit A. Registration as and performance of Customer's TOP function shall begin upon Customer's successful deregistration as a TOP. BPA's responsibilities shall include, but are not limited to:

(1) Compliance with all mandatory Reliability Standards and associated processes applicable to the TOP function;

(2) Maintaining documentation and other evidence required to demonstrate compliance with all mandatory Reliability Standards applicable to the TOP function;

(3) Responding to audits, data requests, or other inquiries from FERC, NERC, or WECC regarding compliance matters applicable to the TOP function;

(4) Responding to and defending all enforcement actions applicable to the TOP function; and

(5) Acting as the primary contact for communications with or requests from the Reliability Coordinator for TOP functions provided under this Agreement.

(b) BPA shall develop TOP procedures that are contained in the TOPIC and incorporated by reference into this Agreement in order to provide BPA with the ability to carry out TOP responsibilities as they relate to Customer's BES equipment listed in Exhibit A. BPA shall provide outreach and training to ensure Customer can successfully implement the TOP procedures.

(1) These TOP procedures are required in order to: (1) allow BPA to implement TOP authority over the BES equipment listed in Exhibit A and, (2) demonstrate compliance with certain mandatory Reliability Standards and requirements. These procedures will contain, but are not limited to:

(A) Actions which must be taken by Customer prior to changing the status of, or taking actions that could impact the control or protection of, the BES transmission system associated with the transmission lines owned by Customer;

(B) Orders, instructions, and other requests BPA may issue and Customer must follow in order for BPA to fulfill its TOP obligations.

(2) BPA shall update and provide to Customer the most current edition of the TOPIC, or successor document, within ten Business Days after updates are made.

(c) BPA agrees to provide to Customer a letter stating that BPA performed the TOP function as described in Section 4 no later than March 31st for the previous calendar year in which BPA performed TOP services under this Agreement.

(d) If BPA determines that it may be non-compliant with any mandatory Reliability Standards with respect to the TOP function for the BES equipment listed in Exhibit A, BPA may elect to self-report pursuant to WECC's Compliance Monitoring and Enforcement Program (CMEP). BPA will notify Customer prior to filing a self-report to the extent practicable.

(1) BPA may coordinate with Customer as appropriate to develop a Mitigation Plan for submission to WECC. BPA will submit the Mitigation Plan and all related required documentation to WECC.

(2) BPA will notify Customer within ten Business Days of any WECC action, including any Notice of Alleged Violation issued pursuant to the CMEP.

5. CUSTOMER RESPONSIBILITIES

(a) Customer shall register for all other applicable NERC functions for which it qualifies, except for the TOP function provided for under this Agreement, and shall be responsible for mandatory Reliability Standards applicable to those functions.

(b) As the owner of the equipment listed in Exhibit A, Customer shall be responsible for compliance with the Critical Infrastructure Protection Reliability Standards, including the identification and categorization of BES Cyber Systems and Cyber Assets.

(c) No later than January 31st each year, Customer shall provide BPA an attestation that, to the best of Customer's knowledge, for the previous calendar year, it is:

(1) In compliance with all applicable mandatory Reliability Standards; or

(2) If non-compliant with any applicable mandatory Reliability Standards, under a WECC-approved Mitigation Plan.

(d) Customer shall assist BPA in responding to an audit by FERC, NERC, or WECC, by using reasonable efforts to provide any additional documentation required.

(e) Customer shall provide BPA with a current one-line diagram including BES equipment listed in Exhibit A and covered under this Agreement, and Customer shall provide an updated one-line diagram at least 90 days prior to modifying its BES equipment.

(f) Customer shall notify BPA in accordance with Exhibit C within seven days of self-reports for non-TOP functions associated with BES equipment listed in Exhibit A.

(g) Customer shall provide all data required by BPA to perform the TOP function pursuant to this Agreement within specified timeframes.

(h) Customer shall provide BPA with information, maintain its BES equipment listed in Exhibit A and supporting equipment, follow all orders and instructions from BPA, and perform other activities necessary for BPA to comply with its obligations as the TOP. Customer's obligations, and the processes and procedures that Customer must follow to meet its obligations under this provision, will be set forth in the TOPIC, or successor document.

(i) Customer shall mark and identify any Critical Electric Infrastructure Information in accordance with regulations adopted by BPA, FERC or the Department of Energy.

(j) Customer has a 24-hour control center and shall maintain it to monitor Customer's system and respond to any orders, instructions, and other requests issued by BPA.

6. CUSTOMER TOP IMPLEMENTATION PLAN

BPA and Customer shall identify all actions needed in order for BPA to provide TOP services that are fully compliant with applicable mandatory Reliability Standards. Milestones, timelines, and the Party responsible for these preparatory actions shall be specified in Exhibit D, Implementation Plan.

7. BILLING AND PAYMENT

(a) **Billing**

BPA shall bill Customer monthly for the annual costs. BPA may send Customer an estimated bill followed by a final bill. The Issue Date is the date BPA electronically sends the bill to Customer. If electronic transmittal of the entire bill is not practical, BPA shall transmit a summary electronically, and send the entire bill by United States mail.

(b) **Payment**

Customer shall pay all bills electronically in accordance with instructions on the bill. Payment of all bills, whether estimated or final, must be received by the 20^{th} day after the Issue Date of the bill (Due Date). If the 20^{th} day is a Saturday, Sunday, or federal holiday, then the Due Date is the next Business Day. If Customer has made payment on an estimated bill then:

(1) If the amount of the final bill exceeds the amount of the estimated bill, Customer shall pay BPA the difference between the estimated bill and final bill by the final bill's Due Date; or

(2) If the amount of the final bill is less than the amount of the estimated bill, BPA shall pay Customer the difference between the estimated bill and final bill by the 20^{th} day after the final bill's Issue Date. If the 20^{th} day is a Saturday, Sunday, or federal holiday, the difference shall be paid by the next Business Day.

(c) **Late Payments**

After the Due Date, a late payment charge equal to the higher of:

(1) The Prime Rate (as reported in the Wall Street Journal or successor publication, in the first issue published during the month in which payment was due) plus four (4) percent, divided by 365; or

(2) The Prime Rate times 1.5, divided by 365;

shall be applied each day to any unpaid balance.

(d) **Termination**
If Customer has not paid its bill in full by the Due Date, it shall have 45 days to cure its non-payment by making payment in full. If, Customer does not provide payment within three Business Days after receipt of an additional written notice from BPA, and BPA determines in its sole discretion that Customer is unable to make the payments owed, then BPA may terminate this Agreement consistent with Section 1 above. Written notices sent under this Section 7(d) must comply with Exhibit C.

(e) **Disputed Bills**

(1) If Customer disputes any portion of a charge or credit on Customer's estimated or final bills, Customer shall provide written notice to BPA with a copy of the bill noting the disputed amounts. Notwithstanding whether any portion of the bill is in dispute, Customer shall pay the entire bill by the Due Date. This Section 7(e)(1) does not allow Customer to challenge the validity of any BPA rate.

(2) Unpaid amounts on a bill (including both disputed and undisputed amounts) are subject to the late payment charges provided above. Notice of a disputed charge on a bill does not constitute BPA's agreement that a valid claim under contract law has been stated.

(3) If the Parties agree, or if after a final determination of a dispute pursuant to Section 9(c), Customer is entitled to a refund of any portion of the disputed amount, then BPA shall make such refund with simple interest computed from the date of receipt of the disputed payment to the date the refund is made. The daily interest rate shall equal the Prime Rate (as reported in the Wall Street Journal or successor publication in the first issue published during the month in which payment was due) divided by 365.

8. LIABILITY
In no event shall either Party, including its officers, employees, agents or representatives, be liable for any lost or prospective profits or for any other special, punitive, exemplary, consequential, incidental or indirect losses or damages (in tort, contract or otherwise) under or in respect of this Agreement.

9. STANDARD PROVISIONS

(a) **Amendments**
Except where this Agreement explicitly allows one Party to unilaterally amend a provision or revise an exhibit, no amendment or exhibit revision to this Agreement shall be of any force or effect unless set forth in a written instrument signed by authorized representatives of each Party.

(b) **Assignment**
This Agreement is binding on any successors and assigns of the Parties. Neither Party may otherwise transfer or assign this Agreement, in whole or in part, without the other Party's written consent. Such consent shall not be unreasonably withheld.

(c) **Dispute Resolution**

(1) In the event of a dispute arising out of this Agreement, the Parties shall negotiate in good faith to reach an acceptable and timely resolution. If the Parties are unable to resolve the dispute to their mutual satisfaction within five Business Days, or any other mutually acceptable time period after negotiation begins, the Parties shall attempt in good faith to resolve the dispute through non-binding mediation.

(2) Each Party shall be responsible for its own expenses and one-half of the expenses of the mediator.

(d) **Entire Agreement**
This Agreement, including documents expressly incorporated by reference, constitutes the entire agreement between the Parties. It supersedes all previous communications, representations, or contracts, either written or oral, which purport to describe or embody the subject matter of this Agreement.

(e) **Freedom of Information Act (FOIA)**
BPA may release information provided by Customer to comply with FOIA or if required by any other Federal law or court order. For information that Customer designates in writing as proprietary, BPA will limit the use and dissemination of that information within BPA to employees who need the information for purposes of this Agreement.

(f) **Governing Law**
This Agreement shall be interpreted, construed and enforced in accordance with Federal law.

(g) **No Third Party Beneficiaries**
This Agreement is made and entered into for the sole benefit of the Parties, and the Parties intend that no other person or entity shall be a direct or indirect beneficiary of this Agreement.

(h) **Section Headings**
Section headings and subheadings appearing in this Agreement are inserted for convenience only and are not to be construed as interpretations of text.

(i) **Several Obligations**

Except where specifically stated in this Agreement, the duties, obligations and liabilities of the Parties are intended to be several and not joint or collective.

(j) **Uncontrollable Forces**

The Parties shall not be in breach of their respective obligations to the extent the failure to fulfill any obligation is due to an Uncontrollable Force. "Uncontrollable Force" means an event beyond the reasonable control of, and without the fault or negligence of, the Party claiming the Uncontrollable Force that prevents that Party from performing its contractual obligations under this Agreement and which, by exercise of that Party's reasonable care, diligence and foresight, such Party was unable to avoid. Uncontrollable Forces include, but are not limited to:

(1) Strikes or work stoppage;

(2) Floods, earthquakes, or other natural disasters; terrorist acts; and

(3) Final orders or injunctions issued by a court or regulatory body having competent subject matter jurisdiction which the Party claiming the Uncontrollable Force, after diligent efforts, was unable to have stayed, suspended, or set aside pending review by a court of competent subject matter jurisdiction.

Neither the unavailability of funds or financing, nor conditions of national or local economies or markets shall be considered an Uncontrollable Force. The economic hardship of either Party shall not constitute an Uncontrollable Force. Nothing contained in this provision shall be construed to require either Party to settle any strike or labor dispute in which it may be involved.

If an Uncontrollable Force prevents a Party from performing any of its obligations under this Agreement, such Party shall: (1) immediately notify the other Party of such Uncontrollable Force by any means practicable and confirm such notice in writing as soon as reasonably practicable; (2) use its best efforts to mitigate the effects of such Uncontrollable Force, remedy its inability to perform, and resume full performance of its obligation hereunder as soon as reasonably practicable; (3) keep the other Party apprised of such efforts on an ongoing basis; and (4) provide written notice of the resumption of performance. Written notices sent under this section must comply with Exhibit C.

(k) **Waivers**

No waiver of any provision or breach of this Agreement shall be effective unless such waiver is in writing and signed by the waiving Party, and any such waiver shall not be deemed a waiver of any other provision of this Agreement or any other breach of this Agreement.

10. SIGNATURES

This Agreement may be executed in several counterparts, all of which taken together will constitute one single agreement, and may be executed by electronic signature and delivered electronically. The Parties have executed this Agreement as of the last date indicated below.

EUGENE WATER & ELECTRIC BOARD	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: Rodney Price — Dig tally signed by Rodney Price DN cn Rodney Price, o EWEB, ou Electric Division, email rod.price@eweb.org, c US Date 2019.04.09 12 03 22 -07'00'	By: MICHELLE CATHCART — Digitally signed by MICHELLE CATHCART Date: 2019 04.08 15:35:23 -07'00'
Title: Chief Operations and Engineerin	Title: Vice President Transmission System Operations

If opting out of the electronic signature:

By: ____________________

Name: ____________________
(Print/Type)

Title: ____________________

Date: ____________________

EXHIBIT A
BES EQUIPMENT SUBJECT TO THIS AGREEMENT

BPA will perform TOP responsibilities for Customer's BES equipment that is listed below in accordance with the TOP procedures that are contained in the TOPIC. Customer is not charged for BPA owned equipment. This exhibit contains a complete listing of the BES equipment.

1. DESCRIPTION OF BES EQUIPMENT SUBJECT TO THIS AGREEMENT

Line	Line Terminal		Line Section	Line Terminal	
McKenzie-Willakenzie 115 kV line	McKenzie Substation	**Bus** McKenzie 115 kV **Breaker** 6672 **Disconnects** BSD6672 LSD6672 TBD6673	McKenzie-Willakenzie 115 kV line	Willakenzie Substation	**Bus** Willakenzie 115 kV **Breaker** 5072 **Disconnects** BSD5072 LSD5072 TBD5073
McKenzie-Gateway (SUB) 115 kV line	McKenzie Substation	**Bus** McKenzie 115 kV **Breaker** 6680 **Disconnects** BSD6680 LSD6680 TBD6681	McKenzie-Gateway (SUB) 115 kV line	EWEB/SUB change of ownership after sixth span out of McKenzie	
Coburg-McKenzie 115 kV line	Coburg Substation	**Bus** Coburg 115 kV **Breaker** 6850 **Disconnects** BSD6850 LSD6850 AS6863 AS6861	Coburg-McKenzie 115 kV line	McKenzie Substation	**Bus** McKenzie 115 kV **Breaker** 6670 **Disconnects** BSD6670 LSD6670 TBD6671

Line	Line Terminal		Line Section	Line Terminal	
Coburg-Spring Creek (EWEB) 115 kV line	Coburg Substation	**Bus** Coburg 115 kV **Breaker** 6800 **Disconnects** BSD6800 LSD6800	Coburg-Spring Creek (EWEB) 115 kV line	Spring Creek (EWEB) Substation	**Bus** Spring Creek (EWEB) 115 kV **Breaker** 5470 **Disconnects** BSD5470 LSD5470
Danebo-Prairie (EWEB) 115 kV line	Danebo Substation	**Bus** Danebo 115 kV **Breaker** 4950 **Disconnects** BSD4950 LSD4950 AS4975	*Danebo-Jessen section of Danebo-Prairie (EWEB) 115 kV line **Disconnects** IS5871 *Jessen-Prairie (EWEB) section of Danebo-Prairie (EWEB) 115 kV line **Disconnects** AS5853 IS5873	Prairie (EWEB) Substation	**Bus** Prairie (EWEB) 115 kV **Breaker** 5672 **Disconnects** BSD5672 LSD5672
Danebo-Lane 115 kV line	Danebo Substation	**Bus** Danebo 115 kV **Breaker** 4900 **Disconnects** BSD4900 LSD4900 AS4973	Danebo-Lane 115 kV line	Lane Substation (BPA)	All BES equipment at Lane Substation is owned and operated by BPA

Line	Line Terminal		Line Section	Line Terminal	
Westmoreland -Willow Creek 115 kV line	Westmoreland Substation	**Bus** Westmoreland 115 kV **Breaker** 5172 **Disconnects** BSD5172 LSD5172	Westmoreland -Willow Creek 115 kV line	Willow Creek Substation	**Bus** Willow Creek 115 kV **Breaker** 5774 5778 **Disconnects** LSD5775 LSD5778 BSD5778
Hyundai-Willow Creek #1 115 kV line	Hyundai Substation	**Bus** Hyundai 115 kV **Breaker** 6750 **Disconnects** LSD6751 BYD6760 BYD6750 XSD6753 XSD6761 XSD6763	Hyundai-Willow Creek #1 115 kV line	Willow Creek Substation	**Bus** Willow Creek 115 kV **Breaker** 5764 5768 **Disconnects** LSD5765 LSD5768 BSD5768
Hyundai-Willow Creek #2 115 kV line	Hyundai Substation	**Bus** Hyundai 115 kV **Breaker** 6790 **Disconnects** LSD6793 BYD6790 XSD6791 XSD6783 XSD6781 XSD6773 XSD6771 BYD6780 BYD6770	Hyundai-Willow Creek #2 115 kV line	Willow Creek Substation	**Bus** Willow Creek 115 kV **Breaker** 5770 5774 **Disconnects** LSD5773 LSD5770 BSD5770

<table>
<tr><th>Line</th><th colspan="2">Line Terminal</th><th>Line Section</th><th colspan="2">Line Terminal</th></tr>
<tr><td>Willow Creek-Lane 115 kV line</td><td>Willow Creek Substation</td><td><u>Bus</u>
Willow Creek 115 kV
<u>Breaker</u>
5760
5764
<u>Disconnects</u>
LSD5760
LSD5763
BSD5760</td><td>Willow Creek-Lane 115 kV line</td><td>Lane Substation (BPA)</td><td>All BES equipment at Lane Substation is owned and operated by BPA
-</td></tr>
<tr><td>Seneca-Westmoreland 115 kV line</td><td>Seneca Substation</td><td><u>Bus</u>
Seneca 115 kV
<u>Breaker</u>
4350
<u>Disconnects</u>
BSD4350
LSD4350
AS4351</td><td>Seneca-Westmoreland 115 kV line</td><td>Westmoreland Substation</td><td><u>Bus</u>
Westmoreland 115kV
<u>Breaker</u>
5180
<u>Disconnects</u>
BSD5180
LSD5180</td></tr>
<tr><td>Seneca-Bertelsen 115kV line</td><td>Seneca Substation</td><td><u>Bus</u>
Seneca 115kV
<u>Breaker</u>
4300
<u>Disconnects</u>
BSD4300
LSD4300</td><td>Seneca-Bertelsen 115kV line</td><td>Bertelsen Substation</td><td><u>Bus</u>
Bertelsen 115kV
<u>Breaker</u>
6470
<u>Disconnects</u>
BSD6470
LSD6470</td></tr>
</table>

Line	Line Terminal		Line Section	Line Terminal	
Currin-Willakenzie 115kV line	Currin Substation	**Bus** Currin 115kV **Breaker** 4590 **Disconnects** BSD4590 LSD4590 TBD4591	Currin-Willakenzie 115kV line	Willakenzie Substation	**Bus** Willakenzie 115kV **Breaker** 5080 **Disconnects** BSD5080 LSD5080 TBD5081
Cal Young-Willakenzie 115 kV line	Cal Young Substation	**Bus** Cal Young 115 kV **Breaker** 4870 **Disconnects** BSD4870 LSD4870 AS4871	Cal Young-Willakenzie 115 kV line	Willakenzie Substation	**Bus** Willakenzie 115 kV **Breaker** 5078 **Disconnects** BSD5078 LSD5078 TBD5079
Cal Young-Santa Clara 115 kV line	Cal Young Substation	**Bus** Cal Young 115 kV **Breaker** 4872 **Disconnects** BSD4872 LSD4872	Cal Young-Santa Clara 115 kV line	Santa Clara Substation	**Bus** Santa Clara 115 kV **Breaker** 4670 **Disconnects** BSD4670 LSD4670 XSD4663
Prairie (EWEB)-Santa Clara 115 kV line	Prairie (EWEB) Substation	**Bus** Prairie (EWEB) 115 kV **Breaker** 5670 **Disconnects** BSD5670 LSD5670 AS5671	Prairie (EWEB)-Santa Clara 115 kV line	Santa Clara Substation	**Bus** Santa Clara 115 kV **Breaker** 4650 **Disconnects** BSD4650 LSD4650 XSD 4661
Alvey-Currin 115 kV line	Alvey Substation (BPA)	All BES equipment at Alvey Substation is owned and operated by BPA	Alvey-Currin 115 kV line	Currin Substation	**Bus** Currin 115 kV **Breaker** 4580 **Disconnects** BSD4580 LSD4580 TBD4581

Line	Line Terminal		Line Section	Line Terminal	
Currin-Laurel 115 kV line	Currin Substation	**Bus** Currin 115 kV **Breaker** 4578 **Disconnects** BSD4578 LSD4578	Currin-Laurel 115 kV line	Laurel Substation	**Bus** Laurel 115 kV **Breaker** 5200 **Disconnects** BSD5200 LSD5200
Hilyard-Laurel 115 kV line	Hilyard Substation	**Bus** Hilyard 115 kV **Breaker** 4150 **Disconnects** BSD4150 LSD4150 AS4151	Hilyard-Laurel 115 kV line	Laurel Substation	**Bus** Laurel 115 kV **Breaker** 5250 **Disconnects** BSD5250 LSD5250
Dillard-Hilyard 115 kV line	Dillard Substation	**Bus** Dillard 115 kV **Breaker** 4750 **Disconnects** BSD4750 LSD4750 AS4705	Dillard-Hilyard 115 kV line	Hilyard Substation	**Bus** Hilyard 115 kV **Breaker** 4152 **Disconnects** BSD4152 LSD4152
Hilyard-Monroe (EWEB) 115 kV line	Hilyard Substation	**Bus** Hilyard 115 kV **Breaker** 4100 **Disconnects** BSD4100 LSD4100	Hilyard-Monroe (EWEB) 115 kV line	Monroe (EWEB) Substation	**Bus** Monroe (EWEB) 115 kV **Breaker** 3700 **Disconnects** BSD3700 LSD3700 AS3751
Jefferson-Monroe (EWEB) 115 kV line	Jefferson Substation	**Bus** Jefferson 115 kV **Breaker** 6590 **Disconnects** BSD6590 LSD6590	Jefferson-Monroe (EWEB) 115 kV line	Monroe (EWEB) Substation	**Bus** Monroe (EWEB) 115 kV **Breaker** 3750 **Disconnects** BSD3750 LSD3750

Line	Line Terminal		Line Section	Line Terminal	
Jefferson-Westmoreland 115 kV line	Jefferson Substation	**Bus** Jefferson 115 kV **Breaker** 6570 6580 **Disconnects** BSD6570 LSD6570 BSD6581 BSD6583	Jefferson-Westmoreland 115 kV line	Westmoreland Substation	**Bus** Westmoreland 115 kV **Breaker** 5174 **Disconnects** BSD5174 LSD5174
University-Willamette 115 kV line	University Substation	**Bus** University 115 kV **Breaker** 7070 7060 **Disconnects** MOD7073 MOD7071 MOD7063	University-Willamette 115 kV line	Willamette Substation	**Bus** Willamette 115 kV **Breaker** 6050 **Disconnects** MOD6049 MOD6051 MOD6053 MOD6061
Adams-University 115 kV line	Adams Substation	**Bus** Adams 115 kV **Breaker** 3800 **Disconnects** BSD3800 LSD3800	Adams-University 115 kV line	University Substation	**Bus** University 115 kV **Breaker** 7050 **Disconnects** MOD7049 MOD7051 MOD7053 MOD7061
Adams-Bethel (EWEB) 115 kV line	Adams Substation	**Bus** Adams 115 kV **Breaker** 3850 **Disconnects** BSD3850 LSD3850	Adams-Bethel (EWEB) 115 kV line	Bethel (EWEB) Substation	**Bus** Bethel (EWEB) 115 kV **Breaker** 4200 **Disconnects** BSD4200 LSD4200

Line	Line Terminal		Line Section	Line Terminal	
Bethel (EWEB)-Eugene 115 kV line	Bethel (EWEB) Substation	**Bus** Bethel (EWEB) 115 kV **Breaker** 4270 **Disconnects** BSD4270 LSD4270 AS4251	Bethel (EWEB)-Eugene 115 kV line	Eugene Substation (BPA)	All BES equipment at Eugene Substation is owned and operated by BPA
Delta-Oakway 115 kV line	Delta Substation	**Bus** Delta 115 kV **Breaker** 5372 **Disconnects** LSD5372 AS5373 AS5371	Delta-Oakway 115 kV line	Oakway Substation	**Bus** Oakway 115 kV **Breaker** 5900 **Disconnects** BSD5900 LSD5900 AS5953
Delta-River Road (EWEB) 115 kV line	Delta Substation	**Bus** Delta 115 kV **Breaker** 5370 **Disconnects** BSD5370 LSD5370	Delta-River Road (EWEB) 115 kV line	River Road (EWEB) Substation	**Bus** River Road (EWEB) 115 kV **Breaker** 5500 **Disconnects** BSD5500 LSD5500
River Road (EWEB)-Eugene 115 kV line	River Road (EWEB) Substation	**Bus** River Road (EWEB) 115 kV **Breaker** 5550 **Disconnects** BSD5550 LSD5550	River Road (EWEB)-Eugene 115 kV line	Eugene Substation (BPA)	All BES equipment at Eugene Substation is owned and operated by BPA

Line	Line Terminal		Line Section	Line Terminal	
Currin-Hayden Bridge Switching Station 115 kV line	Currin Substation	**Bus** Currin 115 kV **Breaker** 4586 **Disconnects** BSD4586 LSD4586 TBD4587	Currin-Hayden Bridge Switching Station 115 kV line	Hayden Bridge Switching Station	**Bus** Hayden Bridge Switching Station 115 kV **Breaker** 2690 **Disconnects** BSD2690 LSD2690 TBD2691
Hayden Bridge-Hayden Bridge Switching Station 115 kV line	Hayden Bridge Substation	**Bus** Hayden Bridge 115 kV[1]	Hayden Bridge-Hayden Bridge Switching Station 115 kV line	Hayden Bridge Switching Station	**Bus** Hayden Bridge Switching Station 115 kV **Breaker** 2670 **Disconnects** BSD2670 LSD2670 TBD2671
Hayden Bridge Switching Station-Weyco 3 115 kV line	Hayden Bridge Switching Station	**Bus** Hayden Bridge Switching Station 115 kV **Breaker** 2680 **Disconnects** BSD2680 LSD2680 TBD2681	Hayden Bridge Switching Station-Weyco 3 115 kV line	Weyco 3 Substation	**Bus** Weyco 3 115 kV **Breaker** 2700 2720 **Disconnects** BSD2700 LSD2700 AS2751 AS2719 AS2721 BYD2720

[1] TOP jurisdiction ends on the high side of 115/69 kV transformer.

Line	Line Terminal		Line Section	Line Terminal	
Weyco 1-Weyco 3 115 kV line	Weyco 1 Substation	**Bus** Weyco 1 115 kV **Breaker** 2820 **Disconnects** BSD2820 LSD2820	Weyco 1-Weyco 3 115 kV line	Weyco 3 Substation	**Bus** Weyco 3 115 kV **Breaker** 2740 2730 **Disconnects** BSD2740 LSD2740 AS2731 AS2729 BYD2730
Thurston-Weyco 1 115 kV line	Thurston Substation	**Bus** Thurston 115 kV **Breaker** 2350 **Disconnects** BSD2350 LSD2350 AS2361	Thurston-Weyco 1 115 kV line	Weyco 1 Substation	**Bus** Weyco 1 115 kV **Breaker** 2830 **Disconnects** BSD2830 LSD2830
Dillard Tap to Eugene-Alvey #2 115 kV line	Dillard Substation	**Bus** Dillard 115 kV **Breaker** 4700 **Disconnects** BSD4700 LSD4700	Dillard Tap to Eugene-Alvey #2 115 kV line	Dillard Tap (BPA)	All BES equipment at Dillard Tap is owned and operated by BPA
Carmen Smith Tap to Cougar-Holden Creek #1 115 kV line	Carmen Smith Substation	**Bus** Carmen Smith 115 kV **Breaker** 1000 **Disconnects** BSD1000 LSD1000	Carmen Smith Tap to Cougar-Holden Creek #1 115 kV line	Carmen Smith Tap	**Disconnects** AS1051

Line	Line Terminal		Line Section	Line Terminal	
McKenzie Tap to Alvey-Diamond Hill (PACW) #3 230 kV line	McKenzie Substation	**Bus** McKenzie 230 kV **Breaker** 6692 **Disconnects** BSD6692 LSD6692 AS6698 1M33 1M34 1M35 1M513 1M514 **Other** 230/115 kV 150/200/250 MVA Transformer #2 (EWEB)	McKenzie Tap to Alvey-Diamond Hill (PACW) #3 230 kV line	McKenzie Substation	**Bus** McKenzie 115 kV **Breaker** 6676 **Disconnects** BSD6676 LSD6676 TBD6677
Thurston-McKenzie #1 115 kV Line (BPA)	McKenzie Substation	**Bus** McKenzie 115 kV **Breaker** 6682 **Disconnects** BSD6682 LSD6682 TBD6683	Thurston-McKenzie #1 115 kV Line (BPA)	Thurston Substation	**Bus** Thurston 115 kV **Breaker** 2300 **Disconnects** BSD2300 LSD2300
Cougar-Holden Creek #1 115 kV line (BPA)	Cougar Substation (BPA)	All BES equipment at Cougar Substation is owned and operated by BPA	Cougar-Holden Creek #1 115 kV line (BPA)	Holden Creek Substation	**Bus** Holden Creek 115 kV **Breaker** 7160 7170 7180 **Disconnects** BSD7170 LSD7170 BSD7180 LSD7180 AS7161 AS7163

Line	Line Terminal		Line Section	Line Terminal	
Holden Creek-Thurston #1 115 kV line (BPA)	Holden Creek Substation	**Bus** Holden Creek 115 kV **Breaker** 7150 7190 **Disconnects** BSD7150 LSD7150 BSD7190 LSD7190	Holden Creek-Thurston #1 115 kV line (BPA)	Thurston Substation	**Bus** Thurston 115 kV **Breaker** 2360 **Disconnects** BSD2360 LSD2360 BYD2360
Eugene-Bertelsen #1 115 kV line (BPA)	Eugene Substation (BPA)	All BES equipment at Eugene Substation is owned and operated by BPA	Eugene-Bertelsen #1 115 kV line (BPA)	Bertelsen Substation	**Bus** Bertelsen 115 kV **Breaker** 6450 **Disconnects** BSD 6450 LSD 6450 AS6453
Bertelsen-Willow Creek #1 115 kV line (BPA)	Bertelsen Substation	**Bus** Bertelsen 115 kV **Breaker** 6400 **Disconnects** BSD6400 LSD6400	Bertelsen-Willow Creek #1 115 kV line (BPA)	Willow Creek Substation	**Bus** Willow Creek 115 kV **Breaker** 5750 5754 **Disconnects** BSD5750 LSD5750 LSD5753 LSD5755
Willow Creek-Hawkins #1 115 kV line (BPA)	Willow Creek Substation	**Bus** Willow Creek 115 kV **Breaker** 5754 5758 **Disconnects** LSD5753 LSD5755 BSD5758 LSD5758	Willow Creek-Hawkins #1 115 kV line (BPA)	Hawkins Substation	**Bus** Hawkins 115 kV **Breaker** 6172 **Disconnects** BSD6172 LSD6172 AS6173

Line	Line Terminal		Line Section	Line Terminal	
Hawkins-Alvey #1 115 kV line (BPA)	Hawkins Substation	**Bus** Hawkins 115 kV **Breaker** 6170 **Disconnects** BSD6170 LSD6170	Hawkins-Alvey #1 115 kV line (BPA)	Alvey Substation (BPA)	All BES equipment at Alvey Substation is owned and operated by BPA

Notes: **The following facilities and associated equipment are three terminal lines. The lines are normally operated with all 3 terminals in service, but can be operated with one terminal out of service and the other two terminals in service. This type of configuration occurs for maintenance of breaker and associated equipment.**

Line	Line Terminal		Line Terminal		Line Terminal	
Enid Rd-Prairie (EWEB)-Spring Creek (EWEB) 115 kV line	Enid Rd Substation	**Bus** Enid Rd 115 kV **Breaker** 6900 **Disconnects** LSD6900	Prairie (EWEB) Substation	**Bus** Prairie (EWEB) 115 kV **Breaker** 5674 **Disconnects** BSD5674 LSD5674 AS5613	Spring Creek (EWEB) Substation	**Bus** Spring Creek (EWEB) 115 kV **Breaker** 5472 **Disconnects** BSD5472 LSD5472 AS5471 AS5473
Currin-Oakway-Willamette 115 kV line	Currin Substation	**Bus** Currin 115 kV **Breaker** 4584 **Disconnects** BSD4584 LSD4584 TBD4585	Willamette Substation	**Bus** Willamette 115 kV **Breaker** 6070 6060 **Disconnects** MOD6075 MOD6073 MOD6071 MOD6063	Oakway Substation	**Bus** Oakway 115 kV **Breaker** 5950 **Disconnects** BSD5950 LSD5950

2. REVISIONS

Customer shall notify BPA in writing when updates to this exhibit are necessary to accurately reflect the facilities over which BPA will carry out TOP responsibilities. Customer shall also inform BPA as early in the planning process as practicable, but no later than 90 days before changes are made, when Customer identifies the need for equipment changes. The Parties shall revise this exhibit to reflect such changes. The Parties shall mutually agree on any such exhibit revisions. The effective date of any revision to this exhibit shall be the later of the date the actual circumstances described by the revision occur or the date necessary visibility and control equipment is installed.

ONE LINE DIAGRAM

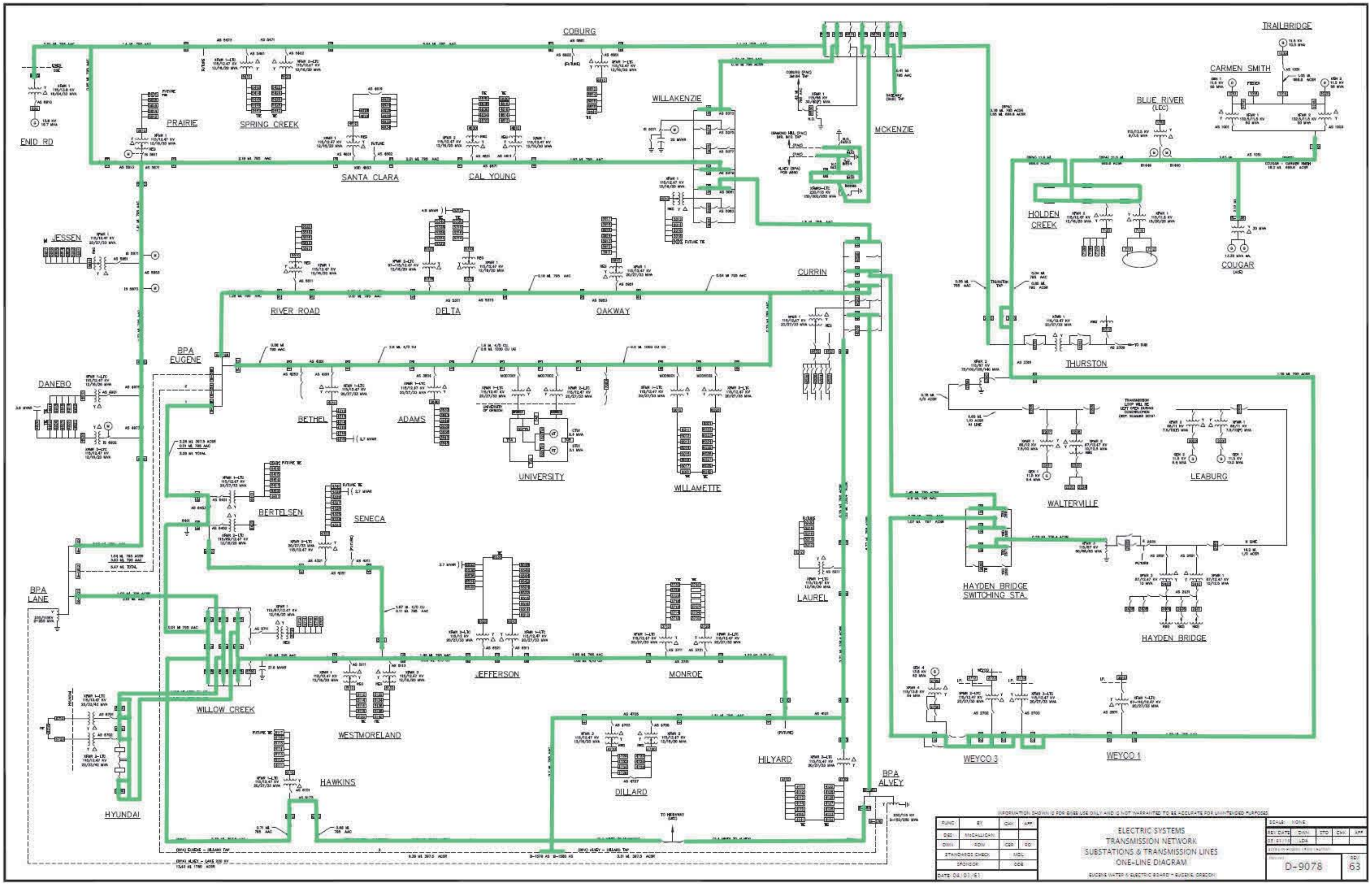

EXHIBIT B
BILLING DETERMINANTS

This Exhibit B provides an adjusted calendar year 2019 prorated cost beginning in May of 2019.

1. COST

2019 cost from May – December is comprised of:

Base Charge:		$30,000
Annual Load:	524 MW x $58.30	$30,549
# of Lines:	40 x $5,426	$217,040
# of Buses:	36 x $2,713	$97,668
Total annual charge for 2019		$375,257
Total cost / 8 months remaining in 2019		$250,171
Total monthly charge for 2019[1]		$31,271

2. REVISIONS

Upon 90 days written notice, BPA may unilaterally revise Exhibit B pursuant to the following:

This exhibit may change if BPA's cost basis needs to be adjusted based on but not limited to:

(a) Annual cost allocation review.
(b) Number of requirements.
(c) Number of participating customers.
(d) Change in facilities.
(e) Change in customer load.

[1] The monthly charges will be the annual cost divided by the remainder of the whole calendar months within the calendar year. Customer's annual cost will be divided by 8 months with an expected execution date of May 1, 2019.

EXHIBIT C
NOTICES

1. ADMINISTRATIVE NOTICES

Any notice or other communication related to this Agreement, other than notices of an operating nature (Section 2 below) shall be delivered in person, or with proof of receipt by email, facsimile, First Class mail or overnight delivery service. Notices are effective on the date received. Either Party may change the contact information by providing notice of such change to the following person and address:

To Eugene Water & Electric Board:

4200 Roosevelt Blvd
Eugene, OR 97402
Attention: Michele Klemp
Title: Engineering & Operations Administrative Assistant III
Phone: (541) 685-7325
Fax: (541) 685-7325
Email: Michele.klemp@eweb.org
NERCReliability@eweb.org

To Bonneville Power Administration:

Attention: Customer Service Reliability Program – TPCR/TPP-4
Phone: (360) 418-8777
Email: csrp@bpa.gov

First Class Mail:
Bonneville Power Administration
P.O. Box 61409
Vancouver, WA 98666

Overnight Delivery Service:
Bonneville Power Administration
905 NE 11th Avenue
Portland, OR 97232

2. OPERATIONAL NOTICES

Any notice, request, or demand of an operating nature by BPA or Customer shall be deemed to have been received if delivered in person, in writing, by email, facsimile, First Class mail or overnight delivery service. Notices are effective on the date received.

To Eugene Water & Electric Board:

Primary Contact:
EWEB Primary Control Center
Phone: (541) 342-1033
Phone: (541) 342-1034
Fax: (541) 685-7517

Secondary Contact:
If primary contacts are unreachable
Emergency contact devices as follows:
VOIP Line: (541) 685-7517
Emergency Cell: (541) 206-0583
Emergency Satellite: (1-480) 768-2500
881622446473

To Bonneville Power Administration:

Primary Contact:
Munro Dispatch
Phone: (509) 465-1836/ (509) 465-1820
DATS: 900-172
Fax: (509) 466-2444

Secondary Contact:
Dittmer Dispatch
Phone: (360) 418-2281
Fax: (360) 418-2938

Outage Coordination:
Munro Control Center Outage Office
Phone: (509) 466-2409
Fax: (509) 466-2444

3. EMERGENCY CONTACTS

In the event of an emergency which requires either Party to open, close, or otherwise alter the position of switches or affect the control or protection related to the Facilities referenced in Exhibit A, the acting Party shall call the other Party as soon as possible.

BPA Munro Control Center Dispatcher: (509) 465-1836, (877) 836-6632 or DATS 900-172

BPA Munro Control Center Outage Dispatcher: (509) 466-2409 or DATS 900-176

In the event of inability to contact Munro Control Center, use the following numbers to contact the Dittmer Control Center Dispatcher:

BPA Dittmer Control Center System Dispatcher: (360) 418-2281 or DATS 922-113

BPA Dittmer Control Center Outage Dispatcher: (360) 418-2274 or DATS 922-148

EWEB EMERGENCY CONTACTS

EWEB Primary Control Center (541) 342-1033, (541) 342-1034
PCC Back up communication devices:
VOIP Line: (541) 685-7571
Emergency Cell: (541) 206-0583
Emergency Satellite: (1-480) 768-2500 881622446473

4. LAW ENFORCEMENT CONTACTS

Eugene Police Department: 911 or non-emergency (541) 682-5111

Lane County Sheriff: 911 or non-emergency (541) 682-4150

Springfield Police Department 911 or non-emergency (541) 726-3714

EWEB Security: (541) 685-7911

EWEB Building Maintenance & Security Supervisor: Office (541) 685-7672, Cell (541) 579-9359

5. FOR REPORTING OF COMPLIANCE DOCUMENTATION

To Eugene Water & Electric Board:

4200 Roosevelt Blvd
Eugene, OR 97402
Attention: Michele Klemp
Title: Engineering & Operations
Administrative Assistant III
Phone: (541) 685-7325
Fax: (541) 685-7325
Email: Michele.klemp@eweb.org
NERCReliability@eweb.org

To Bonneville Power Administration:

Attention: Customer Service Reliability
Program – TPCR/TPP-4
Phone: (360) 418-8777
Email: csrp@bpa.gov

First Class Mail:
Bonneville Power Administration
P.O. Box 61409
Vancouver, WA 98666

Overnight Delivery Service:
Bonneville Power Administration
905 NE 11th Avenue
Portland, OR 97232

6. REVISIONS TO NOTICES

If either Party revises its contact information, that Party shall notify the other Party within 3 business days and such notice shall be deemed to have been received if delivered in person, in writing, by email, facsimile, First Class mail or overnight delivery service. BPA shall revise this exhibit upon such notice.

EXHIBIT D
IMPLEMENTATION PLAN

This is intentionally left blank

Contract No. 20PM-16075

AGREEMENT TO ENABLE RESALE OF TRANSMISSION

executed by the

BONNEVILLE POWER ADMINISTRATION

and

EUGENE WATER & ELECTRIC BOARD

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Exhibit A	BPA Transmission Services Business Practice for Resale of Transmission
Exhibit B	Sample of BPA Confirmation Agreement
Exhibit C	Notices and Contact Information

This AGREEMENT TO ENABLE RESALE OF TRANSMISSION (Agreement) is executed by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (BPA), and Eugene Water & Electric Board (Customer), a corporation incorporated under the laws of the State of Oregon. BPA and Customer are sometimes referred to individually as "Party" and collectively as "Parties."

RECITALS

BPA has functionally separated its organization in order to separate the administration and decision-making activities of BPA's power and transmission functions. References in this Agreement to Power Services (PS) or Transmission Services (TS) are solely for the purpose of clarifying which BPA function is responsible for administrative activities that are jointly performed.

The Parties wish to provide a contractual mechanism for Resale of scheduling rights on existing BPA Transmission Service reservation(s) which the Parties may agree from time to time to make available as specified below.

The Parties agree as follows:

1. TERM

This Agreement shall become effective at 2400 hours on the date of execution (Effective Date), and shall terminate three years from the Effective Date, unless terminated earlier in accordance with the termination provisions specified in Section 7. All obligations and liabilities accrued hereunder are preserved until satisfied.

2. DEFINITIONS

Capitalized terms in this Agreement shall have the meanings defined below.

2.1 "Assignee" means an existing customer of TS with an executed Point-to-Point (PTP) Transmission Service Agreement (TSA) that receives PTP Transmission Service rights and obligations from a Reseller through a Resale.

2.2 "Confirmation Agreement" means the agreement under which the Parties specify the terms by which the Reseller will agree to assign its scheduling rights to the Assignee. See Exhibit B for an example of a Confirmation Agreement.

2.3 "Power Services" or "PS" means the organization, or its successor organization, within BPA that is responsible for the management and sale of federal power.

2.4 "Resale" or "Resale of Transmission" means the assignment of <u>only scheduling rights</u> associated with a Transmission Service reservation, for a specific term, to the Assignee in accordance with the TS Resale of Transmission Service Business Practice (Exhibit A).

2.5 "Reseller" means the Party that holds PTP Transmission Service rights and assigns all or a portion of the scheduling rights and obligations to the Assignee.

2.6 "Start of Term" means the initial utilization date by the Assignee of the transmission acquired through the Resale of Transmission under this Agreement.

2.7 "Transmission Services" or "TS" means the organization or its successor organization, within BPA that is responsible for the management and sale of transmission service on the Federal Columbia River Transmission System (FCRTS).

3. REVISION OF EXHIBITS; INTERPRETATION

3.1 **Exhibit A**
Exhibit A, BPA's TS Resale of Transmission Service Practice, shall include any future revisions, additions, or updates to BPA's TS Resale of Transmission Service Business Practice.

3.2 **Exhibit B**
Exhibit B, Sample of BPA Confirmation Agreement, shall include any future revisions, additions, or updates to BPA's standard Confirmation Agreement.

3.3 **Exhibit C**
Either Party may change the name or address for delivery in Exhibit C, Notices and Contact Information, by providing notice of such change or other mutually agreed method.

3.4 **Interpretation**
In the event of a conflict between the terms of any Exhibit and the terms of the body of this Agreement, the terms of the body of this Agreement shall prevail.

4. RESALE OF TRANSMISSION

This Agreement shall only be used in conjunction with a Confirmation Agreement. The specifics of any particular Resale of Transmission transaction will be provided in a Confirmation Agreement. This Agreement is not a Resale of Transmission, or a purchase or sale of any other product or service, and does not constitute any advance agreement or obligation for any Party to make available or to resell any amount of transmission or transmission scheduling rights, or any other products and services.

Any Resale of Transmission under this Agreement will comply with the requirements specified in the TS Resale of Transmission Service Business Practice, as incorporated by reference in Exhibit A (Exhibit A). The Parties have read the terms of the current Resale of Transmission Service Business Practice and agree to the incorporation of the terms in this Agreement.

4.1 The Assignee shall be entitled to use the resold transmission in any manner permitted under Exhibit A, including non-firm and firm Redirects. All applicable terms and conditions under BPA's Open Access Transmission Tariff (OATT) shall apply to the Resale of Transmission.

4.2 During the term of the Resale, any changes to the resold transmission (e.g., POR or POD) made by the Assignee that result in additional costs billed by TS will be paid by the Assignee.

4.3 The Assignee shall provide the Reseller its Sale Ref number (as defined in Exhibit A) for each Resale. The Reseller shall provide a new A-Ref (as defined in Exhibit A) to the Assignee for the purpose of scheduling electronic tag(s).

5. SCHEDULING

All transactions under this Agreement shall be scheduled by the Assignee. The Assignee may only schedule transactions under a Resale using the Sale Ref number provided by the Assignee to the Reseller, which will be used to generate a new A-Ref. The new A-Ref shall be used by the Assignee on the electronic scheduling tag.

6. BILLING AND PAYMENT

6.1 Billing

Each Party shall be billed by TS, per the business practices described in Exhibit A, during the term of the Resale, and each Party shall pay the billing obligation in accordance with Exhibit A, provided, however, the Assignee shall be responsible for any additional charges incurred by the Reseller as specified in Section 4.2 above. Reseller shall bill Assignee monthly for resold transmission provided during the preceding month(s). Reseller may send Assignee an estimated bill followed by a final bill. The Issue Date is the date Reseller electronically sends the bill to Assignee.

6.2 Payment

Assignee shall pay all bills electronically in accordance with instructions on the bill. Payment of all bills, whether estimated or final, must be received by the 20th day after the Issue Date of the bill (Due Date). If the 20th day is a Saturday, Sunday, or federal holiday, then the Due Date is the next Business Day.

If Assignee has made payment on an estimated bill then:

(a) if the amount of the final bill exceeds the amount of the estimated bill, then Assignee shall pay Reseller the difference between the estimated bill and final bill by the final bill's Due Date; or

(b) if the amount of the final bill is less than the amount of the estimated bill, then Reseller shall pay Assignee the difference between the estimated bill and final bill by the final bill's Due Date.

6.3 Late Payments

After the Due Date, a late payment charge equal to the higher of:

(a) the Prime Rate (as reported in the Wall Street Journal or successor publication in the first issue published during the month in which payment was due) plus four percent, divided by 365; or

(b) the Prime Rate times 1.5, divided by 365;

shall be applied each day to any unpaid balance.

If Assignee has not paid its bill in full by the Due Date, it shall have 30 days to cure its nonpayment by making payment in full. If Assignee does not provide payment within the 30 day cure period, the Assignee is in Default and Section 10 shall apply.

6.4 **Disputed Bills**

6.4.1 If Assignee disputes any portion of a charge or credit on Assignee's estimated or final bills, Assignee shall provide written notice to Reseller with a copy of the bill noting the disputed amounts. Notwithstanding whether any portion of the bill is in dispute, Assignee shall pay the entire bill by the Due Date.

6.4.2 Unpaid amounts on a bill (including both disputed and undisputed amounts) are subject to the late payment charges provided above. Notice of a disputed charge on a bill does not constitute Reseller's agreement to the validity of the claim.

6.4.3 If the Parties agree, or if after a final determination of a dispute, Assignee is entitled to a refund of any portion of the disputed amount, then Reseller shall make such refund with simple interest computed from the date of receipt of the disputed payment to the date the refund is made. The daily interest rate shall equal the Prime Rate (as reported in the Wall Street Journal or successor publication in the first issue published during the month in which payment was due) divided by 365.

6.5 **Netting**

Payment amounts under this Agreement shall be netted in accordance with the Parties' Netting Agreement (BPA Contract No. 19PM-15466).

7. TERMINATION

Each Party shall have the right to terminate this Agreement upon 30 calendar days' written notice to the other Party; ***provided, however***, that if any Confirmation Agreement between the Parties remains in effect after the termination date of this Agreement and incorporates by reference, individually or generally, provisions of this Agreement, such provisions shall survive the termination of this Agreement and be binding on the Parties until after the termination of the last such agreement.

8. CREDITWORTHINESS

Should an Assignee's creditworthiness, financial responsibility, or performance viability become unsatisfactory to BPA in its reasonably exercised discretion with regard to any transaction pursuant to this Agreement and any Confirmation, BPA may require that the Assignee provide, at Assignee's option and with BPA's consent, such consent not to be unreasonably withheld or delayed, one of the following:

1. the posting of a Letter of Credit,
2. a cash prepayment,
3. the posting of other acceptable collateral or security by Assignee,
4. a Guarantee Agreement executed by a creditworthy entity, or
5. some other mutually agreeable method of satisfying BPA.

The Assignee's obligations under this Section shall be limited to a reasonable estimate of the damages to BPA if the Assignee were to fail to perform its obligations. Events which may trigger BPA questioning the Assignee's creditworthiness, financial responsibility, or performance viability include, but are not limited to, the following:

1. BPA has knowledge that the Assignee (or its Guarantor if applicable) is failing to perform or defaulting under other contracts.
2. The Assignee or its Guarantor has debt which is rated as investment grade and that debt falls below the investment grade rating by at least one rating agency or is below investment grade and the rating of that debt is downgraded further by at least one rating agency.
3. Other material adverse changes in the Assignee's financial condition occur.

If the Assignee fails to provide such reasonably satisfactory assurances of its ability to perform a transaction hereunder within three Business Days of demand, that will be considered an event of Default under Section 10 of this Agreement and BPA shall have the right to exercise any of the remedies provided for under Section 10.

9. UNCONTROLLABLE FORCES

Uncontrollable forces (force majeure) shall be defined and treated pursuant to Section 10 of BPA's Open Access Transmission Tariff.

10. DEFAULT

Failure to comply with the business practices specified in Exhibit A, the terms of a Confirmation Agreement entered into pursuant to this Agreement, or failure to pay as described in Section 6 above shall be considered a Default, if such failure is not remedied within three Business Days after written notice of such failure is given to the Defaulting Party by the other Party ("Non-Defaulting Party").

In the event of a Default, the Non-Defaulting Party shall have the right, upon written notice to terminate all Confirmations between the Parties made under this Agreement. Such termination(s) shall be effective immediately upon receipt of termination notice. If the Non-Defaulting Party is the Reseller, then the Defaulting Party shall reassign back to the Reseller all remaining transmission upon receipt of the termination notice. Termination of related Confirmation Agreements shall be the sole and exclusive remedy for the Non-Defaulting Party.

Upon termination, the Non-Defaulting Party may withhold any payments it owes the Defaulting Party for obligations incurred prior to termination under this Agreement or Confirmation(s) and to call on any credit support provided by the Defaulting Party to cover costs resulting from the Default.

11. APPLICABLE LAW

All transactions under this Agreement shall be subject to Federal law

12. LIABILITY AND DAMAGES

No Party or its directors, members of its governing bodies, officers or employees shall be liable to any other Party or Parties for any loss or damage to property, loss of earnings, or revenues, personal injury, or any other direct, indirect, or consequential damages or injury, or punitive damages, which may occur or result from the performance or non-performance of this Agreement (including any applicable Confirmation), including any negligence arising hereunder. Any liability or damages incurred by an officer or employee of a Federal agency or by that agency that would result from the operation of this provision shall not be inconsistent with Federal law. Any Party due monies under this Agreement, the amounts of which are not in dispute or if disputed have been the subject of a decision awarding monies, (i) shall have the right to seek payment of such monies in any forum having competent jurisdiction and (ii) shall possess the right to seek relief directly from that forum without first utilizing the mediation or arbitration provisions under Section 13 of this Agreement and without exercising termination rights under Section 10.

13. DISPUTE RESOLUTION

If the Parties elect to pursue binding arbitration of any dispute arising out of this Agreement, the Parties shall draft and sign an agreement which shall meet the requirements of the Administrative Disputes Resolution Act of 1996, 5 U.S.C. §§ 571-584, including the requirements to set forth the precise issue in dispute, the amount in controversy and the maximum monetary award allowed. Under no circumstances shall specific performance be an available remedy against BPA in arbitration.

14. NOTICES

Any notice, demand, request, or other communication shall be provided pursuant to Exhibit C.

15. ENTIRE AGREEMENT

This Agreement, including documents expressly incorporated by reference, constitutes the entire agreement between the Parties. It supersedes all previous communications, representations, or agreements, either written or oral, which purport to describe or embody the subject matter of this Agreement. This Agreement is intended to serve as an Enabling Agreement for the Resale of Transmission scheduling rights. The specific terms of such Resale shall be included in Confirmation Agreements that incorporate this Agreement by reference.

16. SIGNATURES

The Parties have executed this Agreement as of the last date indicated below.

EUGENE WATER & ELECTRIC BOARD	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By [redacted]	By [redacted]
Name Kevin J. Cardoza *(Print/Type)*	Name Debra J. Malin *(Print/Type)*
Title Real Time Supervisor	Title Account Executive
Date 10/28/2019	Date 10/22/2019

EXHIBIT A
BPA TRANSMISSION SERVICES BUSINESS PRACTICE FOR RESALE OF TRANSMISSION

The current Resale of Transmission Service Business Practice is posted on the TS Website at:
https://www.bpa.gov/transmission/Doing%20Business/bp/Pages/Business-Practices.aspx

EXHIBIT B
SAMPLE OF BPA CONFIRMATION AGREEMENT

BONNEVILLE POWER ADMINISTRATION

Department of Energy
Bonneville Power Administration
Power Services

CONFIRMATION AGREEMENT

From: Bonneville Power Administration
P O Box 3621
Portland, OR 97208-3621
BPA Preschedule: 503-230-3813
BPA Real Time: 503-230-3341

To: COUNTERPARTY COMPANY NAME
Fax: COUNTERPARTY FAX

BPA Contract: YYPM-XXXXX
Trade Date: DATE

The following memorializes the terms of a transaction agreed to by Bonneville Power Administration (BPA) and COUNTERPARTY NAME (ACRONYM). Transactions hereunder are in accordance with Agreement YYPB-XXXXX.

Buyer: ACRONYM FOR BUYER

Seller: ACRONYM FOR SELLER

Point of Receipt: LOCATION

COUNTERPARTY Trader: TRADER NAME
Phone: COUNTERPARTY PHONE #
BPA Trader: BPA TRADER NAME
Phone: BPA TRADER PHONE #
Point of Delivery: LOCATION

Product: Resale of Transmission of Firm Point to Point (or intertie) transmission as defined in the Transmission Services' Business Practice entitled Resale of Transmission Service, Version 1, (<http://www.transmission.bpa.gov/includes/get.cfm?ID=1630>) as revised.

Start Date	End Date	Transmission Limit	Transmission Price $/MWh	Hours	Amount MWh / hr	Total MWh	Revenue / Cost
DATE	DATE	MW	$PRICE	HOURS TYPE	MW	QUANTITY	$REV/COST
			Transaction Total			**QUANTITY**	**$REV/COST**

Transaction will be shown in Pacific Prevailing Time.
HLHs are defined as HE 0700 - HE 2200, Monday through Saturday (excludes Sundays and NERC holidays).
LLHs are defined as HE 0100 - HE 0600, HE 2300 and HE 2400, Monday through Saturday and all day Sunday and NERC holidays.
Flat is defined as HE 0100 - HE 2400.

This confirmation agreement is intended to memorialize the terms of an existing oral agreement.

We are pleased to have this agreed upon transaction. Please confirm the terms by signing and returning an executed copy of this Confirmation via fax to BPA 503-230-7463.

AGREED AND ACCEPTED

Bonneville Power Administration

____

Alex Spain

Trading Floor Manager Date: __________

COUNTERPARTY COMPANY NAME

____

Print Name: ____________________

Title: __________ Date: __________

Exhibit C
NOTICES AND CONTACT INFORMATION

Any notice required under this Agreement that requires such notice to be provided under the terms of this section shall be provided in writing to the other Party in one of the following ways:

(1) delivered in person;

(2) by a nationally recognized delivery service with proof of receipt;

(3) by United States Certified Mail with return receipt requested;

(4) electronically, if both Parties have means to verify the electronic notice's origin, date, time of transmittal and receipt; or

(5) by another method agreed to by the Parties.

Notices are effective when received. Either Party may change the name or address for delivery of notice by providing notice of such change or other mutually agreed method. The Parties shall deliver notices to the following person and address:

If to Eugene Water & Electric Board:

Eugene Water & Electric Board
500 East 4th Avenue
Eugene, OR 97440
Attn: Kevin Cardoza
Real Time Supervisor
Phone: 541-685-7338
E-Mail: kevin.cardoza@eweb.org

If to BPA:

Bonneville Power Administration
905 NE 11th Ave.
P.O. Box 3621
Portland, OR 97208-3621
Attn: Debra J. Malin – PTL-5
Account Executive
Phone: 503-230-5701
FAX: 503-230-3681
E-Mail: djmalin@bpa.gov

Contract No. 20TX-16939

NETWORK OPERATING AGREEMENT
executed by the
UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
acting by and through the
BONNEVILLE POWER ADMINISTRATION
and
EUGENE WATER & ELECTRIC BOARD

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Exhibit A Related Agreements
Exhibit B Other Operational or Technical Requirements
Exhibit C Remedial Action Schemes and Relay Schemes

This NETWORK OPERATING AGREEMENT (Agreement) is entered into by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Transmission Provider) and EUGENE WATER & ELECTRIC BOARD (Network Customer), hereinafter individually also referred to as "Party" and collectively as "Parties."

The Transmission Provider provides Network Integration Transmission Service under the Transmission Provider's Open Access Transmission Tariff (Tariff) as it may be amended or replaced from time to time.

The Parties have entered into a Service Agreement for Network Integration Transmission Service (Service Agreement), on the 1st day of December 2001, and amended or replaced from time to time in which the Transmission Provider will provide Network Integration Transmission Service for the Network Customer.

The provision of Ancillary Services will be addressed in the Service Agreement.

The Network Customer shall either: (i) operate as a Balancing Authority Area under applicable requirements of NERC, WECC, and NWPP, and satisfy its own Balancing Authority Area Requirements, including all necessary Ancillary Services; (ii) satisfy its Balancing Authority Area requirements, including all necessary Ancillary Services, by contracting with the Transmission Provider, or (iii) satisfy its Balancing Authority Area requirements, including all necessary Ancillary Services, by contracting with another entity which satisfies the applicable reliability requirements of NERC, WECC, and NWPP.

The Parties recognize that the Transmission Provider's Transmission System is directly or indirectly interconnected with Transmission Systems owned or operated by others and the flow of power and energy between such systems shall be controlled by the physical and electrical characteristics of the facilities involved and the manner in which they are operated.

Part of the power and energy being delivered under this Agreement and the Service Agreement may flow through such other systems rather than through the Transmission Provider's facilities.

The Transmission Provider has established technical standards, guidelines, policies, and procedures (Standards) for planning, construction, maintenance, and operation of the Transmission Provider's grid, interties, and interconnections in accordance with the Tariff. Standards are available from the Transmission Provider and may be amended from time to time. Standards include, but are not limited to, the following documents or their successors:

- Technical Requirements for Interconnection to the BPA Transmission Grid;
- Metering Application Guide (MAG);
- Responsibilities and Technical Requirements Guide for Transmission Customer Owned Meters;
- BPA's Facility Ownership and Cost Assignment Guidelines; and
- BPA Outage Planning and Coordination Policy.

The Transmission Provider has established business practices (Practices) in accordance with the Tariff. Practices are available on the Transmission Provider's Website. Practices may be amended from time to time in accordance with the Transmission Provider's business practice process.

There is a need to identify operational requirements related to Network Integration Transmission Service over the Transmission Provider's Transmission System.

The Parties therefore agree as follows:

1. TERM OF AGREEMENT

This Agreement will be effective at 0000 hours on the date that this Agreement has been signed by both Parties (Effective Date), and shall remain in effect through the term of the Service Agreement.

In the event that the Agreement is terminated, all liabilities incurred hereunder are hereby preserved until satisfied.

2. EXHIBITS

The following Exhibits are hereby incorporated as part of this Agreement:

(a) Exhibit A Related Agreements

(b) Exhibit B Other Operational or Technical Requirements

(c) Exhibit C Remedial Action Schemes (RAS) and Relay Schemes

3. OBLIGATIONS OF THE PARTIES

The Parties to this Agreement shall:

(a) Agree to adhere to Good Utility Practice as defined in the Tariff, including all applicable reliability criteria as observed in the region;

(b) Determine methods and take appropriate actions to assure capability for delivery of power and energy at the points of receipt and delivery, and at additional or alternate points of receipt and delivery as established by the Parties;

(c) Operate and maintain equipment necessary for interconnecting the Network Customer with the Transmission Provider's Transmission System including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment. Each party is expected to maintain their own equipment unless otherwise agreed to;

(d) Transfer data as required to maintain reliability of the Transmission Provider's Transmission System;

(e) Use software programs required for data links and constraint dispatching for operational needs;

(f) Exchange data on forecasted loads and resources, and technical data necessary for planning and operation; and

(g) Address other technical and operational considerations required for Tariff implementation, including scheduling protocols.

4. DEFINITIONS

Unless otherwise defined herein, capitalized terms refer to terms defined in the Tariff, Rate Schedules, or *Glossary of Terms Used in NERC Reliability Standards* in effect at the time.

(a) "NERC" means North American Electric Reliability Corporation, or its successor.

(b) "NWPP" means the Northwest Power Pool, or its successor.

(c) "Operational Constraints" means limitations on the ability of the Transmission Provider's Transmission System to operate due to any system emergency, loading condition, or maintenance outage on the Transmission Provider facilities, or on facilities of an interconnected utility, that makes it prudent to reduce Transmission Provider's Transmission System loadings, whether or not all facilities are in service.

(d) "WECC" means the Western Electricity Coordinating Council, or its successor.

5. INTERCONNECTED FACILITY REQUIREMENTS[1]

(a) **Ownership**

(1) Equipment and facilities owned by one Party and installed on the property of the other Party shall remain the property of the owner, except as noted in this Agreement.

(2) A Party must identify its equipment and facilities installed on the other Party's property. Identification of ownership must be made by affixing suitable markers with the owner's name. The Parties may jointly prepare an itemized list of the aforementioned equipment and facilities.

[1] See Exhibits for additional customer-specific agreements or requirements.

(3) Each Party agrees to be responsible for the cost of complying with all applicable Federal, State, and local environmental laws for its own equipment and facilities.

(b) **Safety Design**
The Transmission Provider requires clearance of equipment during maintenance, modification, and testing. In accordance with the Transmission Provider's Standards and Practices, facility interconnections between the Transmission Provider and the Network Customer are to be designed and constructed to allow clearance of equipment using isolation devices. Isolation devices must produce a visible air gap between the energized facilities and the equipment to be maintained, modified, or tested. Any operating procedures associated with this interconnection must comply with OSHA Standard 29 CFR 1910.269(m) and also the ANSI/IEEE National Electric Safety Code as amended or replaced from time to time.

(c) **Access**

(1) Each Party grants permission, subject to site requirements, to the other to enter its property to perform operations, maintenance, meter reading, inspection, or removal of their respective equipment and facilities installed on the other Party's property.

(2) If unescorted access is prohibited, the Parties shall allow escorted access during normal business hours. Unescorted access shall be facilitated through separate agreement.

(3) Within the limitations of applicable law, in accessing equipment or facilities on the property of another, each Party is responsible for injury or damage to person or property from the intentional actions or negligent acts of its own employees and agents.

6. RESOURCE AND INTERCONNECTION PRINCIPLES AND REQUIREMENTS

(a) **Plan, Construct, Operate and Maintain Facilities**
The Network Customer shall plan, construct, operate and maintain its facilities and system that interconnect with the Transmission Provider's Transmission System in accordance with Good Utility Practice, including, but not limited to, all applicable requirements of (1) NERC, WECC, NWPP, and any other applicable reliability authority; and (2) the Transmission Provider's Standards and Practices.

(b) **System Protection**
The Parties acknowledge their obligations to respond to contingencies on the Transmission Provider's Transmission System and on systems directly and indirectly interconnected with the Transmission Provider's Transmission System, in accordance with the Transmission Provider's Tariff, Standards, and Practices. The Parties intend to meet this obligation by implementing

RAS or other relay schemes which may be identified in the attached Exhibit C.

7. CUSTOMER INFORMATION REQUIREMENT

Network Customer shall provide annually to the Transmission Provider, plans of any expansions of, or upgrades to, its owned generation or transmission facilities (lines, transformers, reactive equipment, load forecasts, etc.) for each of the subsequent ten years.

Requested information may include:

(a) **Annual and Ongoing Data Coordination Requirements:**

(1) Annual updates of load and resource forecasts.

(2) Any additional information required from the Network Customer as required by applicable reliability standards, or specified by the Transmission Provider's Tariff, Standards, and Practices.

(b) **Annual Data Exchange Technical Data Details:**
The Network Customer shall review, validate, and respond to the Transmission Provider's annual data exchange requests that are applicable to the Network Customer:

(1) The Network Customer must respond on or before the reasonable deadlines set by the Transmission Provider.

(2) Technical data requirements may include the following:

(A) Steady-State, Dynamics, Geomagnetic Induced Current (GIC), and Short Circuit data.

(B) One lines, facility ratings, facility rating methodology.

(C) Date of data validation, notification of latest version of files on record.

(D) Other information reasonably requested for modeling purposes.

8. POWER QUALITY

Requirements and information regarding Power Quality can be found in the Transmission Provider's Standards and Practices.

9. SERVICE INTERRUPTIONS

Outage Coordination
Parties must request and coordinate outages in accordance with the Tariff and the Transmission Provider's Standards and Practices.

10. EMERGENCY PLANNING AND OPERATION

(a) The Transmission Provider shall be responsible for planning, coordinating, and implementing emergency operation (NERC EOP) schemes including Disturbance Reporting (EOP-4), System Restoration (EOP-5), Geomagnetic Disturbances (EOP-10), and the Emergency Operating Plan (EOP-11). There may be additional schemes that meet the NWPP, WECC, and applicable reliability authority planning objectives. If the Transmission Provider identifies reliability objectives beyond the NWPP, WECC, and applicable reliability authority planning objectives, they shall be communicated to the Network Customer.

(b) **The Network Customer shall:**

(1) Participate in the development and implementation of Load Shedding programs for system security;

(2) Install and maintain the required Load Shedding relays, including under-frequency and under-voltage relays as reasonably determined by Transmission Provider to meet compliance obligations, provided, that the Network Customer can instead request that the Transmission Provider install such relays on the Transmission Provider's facilities that serve the Network Customer; and

(3) Participate in system restoration planning.

(c) Additional information regarding Emergency Planning and Operation can be found in the Transmission Provider's Standards and Practices.

11. METERING INFORMATION, COSTS, AND REQUIREMENTS

(a) The Network Customer shall review information and follow requirements related to metering found in the Transmission Provider's Standards and Practices.

(b) **Metering of Existing Facilities:**
The Transmission Provider shall be responsible for costs of all Transmission Provider-required new meter installation or meter replacements at a Network Customer's facility/ies existing on the Effective Date of this Agreement. The Network Customer may assume this responsibility by mutual agreement of the Parties.

The Network Customer shall be responsible for the costs of:

(1) Any meter replacement or new installation at points of delivery which are not required to achieve the best overall plan of service (convenience points of delivery as defined in the Transmission Provider's Standards and Practices);

(2) Any meters needed because the Network Customer changes Balancing Authorities or is displacing transmission from the Transmission Provider;

(3) Any meters requested by the Network Customer; and

(4) The supporting equipment to the metering system associated with supplying the Transmission Provider funded meter, including, but not limited to the instrument transformers for voltage potential and current flow (potential transformers and current transformers) and associated interconnected cabling, terminal blocks, and switches.

(c) Network Customer is required to notify the Transmission Provider if there are any changes to the supporting equipment to the metering system (instrument transformers specifically), or to the meter the customer has assumed responsibility for, that may affect the meter readings in any way prior to installing the new components so that updated billing arrangements can be implemented.

(d) Metering of New Network Customer Facilities:
The Transmission Provider shall be responsible for costs associated with installation of the Transmission Provider-approved metering at new facilities established after the Effective Date of this Agreement that are connected to the Transmission Provider's Transmission System.

The Network Customer shall be responsible for the costs of the Transmission Provider approved metering for:

(1) All points of resource integration;

(2) All Automatic Generation Control (AGC) interchange points; and

(3) All other points of electrical interconnection, including convenience points of delivery.

12. COMMUNICATIONS

Requirements and information regarding communications can be found in the Transmission Provider's Standards and Practices.

13. NETWORK OPERATING COMMITTEE

(a) **Membership**
The Network Operating Committee shall be composed of at least one representative from each participating Network Customer and the Transmission Provider or their designated agents.

(b) **Responsibilities**
The Network Operating Committee shall meet at least once per year to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Part 3 of the Tariff.

14. STANDARD PROVISIONS

(a) **Notices**
Notices or requests made by either Party regarding these provisions shall be made to the representative of the other Party as indicated in the Service Agreement.

(b) **Administration of The Provisions**
The Tariff and Service Agreement, as they are amended from time to time, are incorporated herein and made a part hereof, and are to be read together with this Agreement to determine the rights of the parties. In the event of any irreconcilable differences between the Tariff and this Agreement, the language of the Tariff shall govern.

(c) **Amendments**
Except where this Agreement explicitly allows one Party to unilaterally amend a provision or revise an exhibit, no amendment or exhibit revision to this Agreement shall be of any force or effect unless set forth in a written instrument signed by authorized representatives of each Party.

(d) **Assignment**
This Agreement is binding on any successors and assigns of the Parties. Neither Party may otherwise transfer or assign this Agreement, in whole or in part, without the other Party's written consent. Such consent shall not be unreasonably withheld.

(e) **Dispute Resolution**
Disputes arising under this Agreement are subject to the dispute resolution procedures set forth in the Tariff.

(f) **Entire Agreement**
This Agreement, including documents expressly incorporated by reference, constitutes the entire agreement between the Parties. It supersedes all previous communications, representations, or contracts, either written or oral, which purport to describe or embody the subject matter of this Agreement.

(g) **Freedom of Information Act (FOIA)**
The Transmission Provider may release information provided by the Network Customer to comply with FOIA or if required by any other Federal law or court order. Prior to releasing any such information, the Transmission Provider shall follow its then applicable procedures for notifying Parties that their information is subject to a FOIA request. For information that the

Network Customer designates in writing as proprietary or marks as Critical Energy/Electric Infrastructure Information (CEII) according to applicable rules and regulations, the Transmission Provider will limit the use and dissemination of that information within the Transmission Provider to employees who need the information for purposes of this Agreement.

(h) **Governing Law**
This Agreement shall be interpreted, construed, and enforced in accordance with Federal law.

(i) **No Third Party Beneficiaries**
This Agreement is made and entered into for the sole benefit of the Parties, and the Parties intend that no other person or entity shall be a direct or indirect beneficiary of this Agreement.

(j) **Section Headings**
Section headings and subheadings appearing in this Agreement are inserted for convenience only and are not be construed as interpretations of text.

(k) **Uncontrollable Forces**
The Parties shall not be in breach of their respective obligations to the extent the failure to fulfill any obligation is due to an Uncontrollable Force. “Uncontrollable Force” means an event beyond the reasonable control of, and without the fault or negligence of, the Party claiming the Uncontrollable Force that prevents that Party from performing its contractual obligations under this Agreement and which, by exercise of that Party’s reasonable care, diligence and foresight, such Party was unable to avoid. Uncontrollable Forces include, but are not limited to:

(1) strikes or work stoppage;

(2) floods, earthquakes, fire, or other natural disasters, terrorist acts, epidemics, pandemics; and

(3) final orders or injunctions issued by a court or regulatory body having competent subject matter jurisdiction which the Party claiming the Uncontrollable Force, after diligent efforts, was unable to have stayed, suspended, or set aside pending review by a court of competent subject matter jurisdiction.

Neither the unavailability of funds or financing, nor conditions of national or local economies or markets shall be considered an Uncontrollable Force. The economic hardship of either Party shall not constitute an Uncontrollable Force. Nothing contained in this provision shall be construed to require either Party to settle any strike or labor dispute in which it may be involved.

If an Uncontrollable Force prevents a Party from performing any of its obligations under this Agreement, such Party shall: (1) immediately notify the other Party of such Uncontrollable Force by any means practicable and confirm such notice in writing as soon as reasonably practicable; (2) use its best efforts to mitigate the effects of such Uncontrollable Force, remedy its inability to perform, and resume full performance of its obligation hereunder as soon as reasonably practicable; (3) keep the other Party apprised of such efforts on an ongoing basis; and (4) provide written notice of the resumption of performance. Written notices sent under this section shall be made as indicated in the Service Agreement.

(l) **Waivers**
No waiver of any provision or breach of this Agreement shall be effective unless such waiver is in writing and signed by the waiving Party, and any such waiver shall not be deemed a waiver of any other provision of this Agreement or any other breach of this Agreement.

15. SIGNATURES
This Agreement may be executed in several counterparts, all of which taken together will constitute one single agreement, and may be executed by electronic signature and delivered electronically. The Parties have executed this Agreement as of the last date indicated below.

EUGENE WATER & ELECTRIC BOARD	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: ____________________	By: ____________________
Title: Trading Operations Supervisor	Title: Transmission Account Executive

If opting out of the electronic signature:

By: ____________________

Name: ____________________
(Print / Type)

Title: ____________________

Date: ____________________

EXHIBIT A
RELATED AGREEMENTS

This Exhibit A identifies agreements between the Parties which may contain additional obligations related to this Network Operating Agreement. Agreements identified in this exhibit are for reference only.

Table 1 Related Agreements

Related Agreement	**Contract No.**
Network Integration Transmission Services Agreement	02TX-10793
Operations Delegation Agreement	07TX-12876
Transmission Operator Agreement	19TP-11686
Facilities Ownership and O&M Responsibilties Agreement	01TX-10766
Mutual Assistance Agreement	16TX-16342

EXHIBIT B
OTHER OPERATIONAL OR TECHNICAL REQUIREMENTS

This Exhibit B identifies additional requirements and obligations that may be unique to the Network Customer.

Operational and Technical Requirements

(a) BPA owned Cougar-Holden Creek #1 115kV line and Holden Creek-Thurston #1 115kV line are EWEB dispatched.

(b) EWEB and BPA share breaker status, and analog operational data via ICCP across respective SCADA systems.

EXHIBIT C
REMEDIAL ACTION SCHEMES AND RELAY SCHEMES

This Exhibit C identifies Remedial Action Schemes (RAS) and Relay Schemes that the Network Customer participates in.

Transmission Provider will provide written notice to Network Customer of any future RAS or Relay Scheme requirements as system conditions warrant, and Network Customer will comply with those requirements.

Table #1 Remedial Action Schemes

Action (e.g. load, gen, reconfigure)	Related Contract No.
Not applicable	Not applicable

Table #2 Relay Schemes

Description or Action	Related Contract No.
Eugene-Alvey #2: 3-terminal Permissive and direct mirror bit transfer trip on SEL-321 set #1. Current differential RFL9300 on set #2. Mirror bit transfer trip is back to back at EWEB's Dillard substation, where EWEB owns the relaying. Communication circuits on EWEB's communication system.	Not applicable
Alvey-Hawkins #1: Permissive mirror bit transfer trip on SEL-321 set #1. Current differential RFL9300 on set #2. EWEB owns the relaying at EWEB's Hawkins substation. Communication circuits on EWEB's communication system.	Not applicable
Eugene-Bethel #1 and Eugene-EWEB #3 River Road: Permissive mirror bit transfer trip on SEL-311 set #1. Current differential SEL-311L on set #2. EWEB owns the remote terminals. Communication circuits on EWEB's communication system.	Not applicable
Alvey-Currin #1 and Eugene-Bertelsen #1: Pilot wire relaying where BPA owns one terminal and EWEB owns the other. Communication circuits on EWEB's communication system. Pilot wire signal converted to digital.	Not applicable
EWEB owns and operates relays at Thurston and Holden Creek that protect BPA owned 115kV transmission lines. Auto-sectionalizing at Blue River Tap affects EWEB's upriver Carmen Smith Generation. Upriver section from the Tap can be islanded.	Not applicable
Alvey-Mckenzie-Diamond Hill #1 230kV: three terminal line with direct tripping via carrier current transfer trip. Communications owned and maintained by Pacificorp.	Not applicable

Description or Action	**Related Contract No.**
UFLS relay action for 59.3Hz underfrequency event: ▪ Currin Substation breaker 4582 ▪ Spring Creek Substation breakers 5410 & 5420 ▪ Coburg Substation breaker 6810	Not applicable
UFLS relay action for 59.2Hz underfrequency event: ▪ Westmoreland Substation breaker 5110 ▪ Dillard Substation breaker 4730 ▪ Seneca Substation breaker 4320	Not applicable
UFLS relay action for 59.0Hz underfrequecny event: ▪ Bethel Substation breaker 4210 ▪ Adams Substation breaker 3840 ▪ River Rd Substation breaker 5510	Not applicable
UFLS relay action for 58.8Hz underfrequency event: ▪ Danebo Substation breaker 4920 ▪ Willow Creek Substation breaker 5710 ▪ Bertelsen Substation breaker 6410 ▪ Monroe Substation breakers 3710 & 3720	Not applicable
UFLS relay action for 58.6Hz underfrequency event: ▪ Holden Creek Substation breakers 7120 & 7130	Not applicable
UVLS relay action for 103.2kV undervoltage event: ▪ Bertelsen Substation breaker 6410 ▪ Currin Substation breaker 4532	Not applicable
UVLS relay action for 105.1kV undervoltage event: ▪ Spring Creek Substation breakers 5410 & 5420	Not applicable
UVLS relay action for 105.8kV undervoltage event: ▪ Dillard Substation breakers 4720 & 4730	Not applicable

Department of Energy

Bonneville Power Administration
P.O. Box 61409
Vancouver, WA 98666-1409

TRANSMISSION SERVICES

March 10, 2023

In reply refer to: TSE/TPP2

Ms. Megan Capper, Energy Resources Manager
Eugene Water & Electric Board
4200 Roosevelt Boulevard
Eugene, OR 97402

Dear Ms. Capper:

Enclosed for signature is one signed original of Operations and Maintenance Agreement (O&M Agreement), Contract No. 22TX-17178, between Bonneville Power Administration and Eugene Water & Electric Board (EWEB).

Please electronically sign the flagged signature field in the enclosed document and return by email to txsalescontracts@bpa.gov by Close of Business on March 27, 2023. Alternatively, EWEB may print, sign and scan the document into a PDF file and return by email or send a paper copy of the document to my attention at one of the following addresses by the date stated above:

First Class Mail	Overnight Delivery Service
Bonneville Power Administration	Bonneville Power Administration
Mail Stop: TSE/TPP-2	Mail Stop: TSE/TPP-2
P.O. Box 61409	905 NE 11th Avenue
Vancouver, WA 98666-1409	Portland, OR 97232

If you have any questions regarding this letter, please call me at (360) 619-6017.

Sincerely,

(b) (6) [redacted]

Christopher Lockman
2023.03.10 09:56:57
-08'00'

Contract No. 22TX-17178

OPERATIONS AND MAINTENANCE AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

EUGENE WATER & ELECTRIC BOARD

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Exhibit A **Ownership of Facilities and Equipment and Operation and Maintenance Responsibilities**

Exhibit B **Notices**

This OPERATIONS AND MAINTENANCE AGREEMENT (Agreement) is entered into by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (BPA), and EUGENE WATER & ELECTRIC BOARD (Customer), hereinafter individually referred to as "Party" and collectively as "Parties".

RECITALS

On September 27, 2001, BPA and Customer entered into Facilities Ownership and Operations and Maintenance (O&M) Responsibilities Agreement No. 01TX-10766 (Original Agreement).

The purpose of the Original Agreement was to: 1) terminate agreements that required ongoing administration, tracking, and periodic updating of O&M charges; 2) realign ownership of facilities at points of interconnection between the electrical systems of the Parties and on jointly owned facilities; and 3) realign and clarify O&M responsibilities for certain electrical facilities.

On October 1, 2021 the Original Agreement expired by operation of the terms of that agreement. However, the Parties did not wish for the Original Agreement to terminate.

The Parties want to enter into an agreement providing for the maintenance and ownership of equipment as detailed in this Agreement;

BPA and Customer Transmission Systems have many unique connection points where both Parties own facilities and equipment. This agreement describes the specific ownership boundary point on the Transmission System and the associated equipment that each Party operates and maintains.

The Energy Policy Act of 2005 (Act) authorized the Federal Energy Regulatory Commission (FERC) to approve Electric Reliability Standards with which users, owners and operators of the bulk power system are required to comply (Electric Reliability Standards);

Customer's maintenance activities on BPA equipment may be subject to the Electric Reliability Standards, and Customer agrees to be retained by BPA to perform and report to BPA on those activities in accordance with the applicable Electric Reliability Standards;

BPA is the Registered Entity with compliance responsibility for the Electric Reliability Standards applicable to the equipment described herein; and

Customer is authorized pursuant to law to operate and maintain transmission facilities and equipment and to enter into agreements to carry out such authority.

In consideration of the promises and mutual covenants and agreements herein contained, the Parties agree as follows:

1. **TERM OF AGREEMENT**

This Agreement shall become effective at 0000 hours on the first calendar day of the month following the date that the Agreement has been signed by both Parties (Effective Date) and shall continue in effect for no longer than 30 years after the Effective Date unless otherwise terminated by the Parties.

This Agreement may be terminated by 6 months prior written notice by either Party.

In the event that the Agreement is terminated, all liabilities incurred hereunder are hereby preserved until satisfied.

2. **DEFINITIONS**

When used in this Agreement, the following terms have the meaning shown below:

(a) "Business Day" means any day that is normally observed by the Federal Government as a workday.

(b) "Good Utility Practice" means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act section 215(d).

(c) "FERC" is the Federal Energy Regulatory Commission.

(d) "NERC" is the North American Electric Reliability Corporation.

(e) "WECC" is the Western Electricity Coordinating Council.

3. **EXHIBITS**

The following Exhibits are hereby incorporated into and made part of this Agreement:

(a) Exhibit A Equipment Maintained by BPA or Customer

(b) Exhibit B Notices

4. **REVISION OF EXHIBITS**

(a) Any requests for revisions to Exhibit A should be made pursuant to the notice requirements in Exhibit B to:

(1) document replacement or removal of equipment undertaken pursuant to Section 6; and

(2) upon ninety (90) days written notice, incorporate revisions to charges described in Exhibit A.

(b) BPA shall issue a revision to Exhibit A within thirty (30) days after receiving notice of such revision pursuant to Exhibit B, and such revisions shall take effect upon issuance of the revision.

(c) BPA shall issue a revision to Exhibit A within thirty (30) days of providing notice of such revisions pursuant to Exhibit B, and such revisions shall take effect upon issuance of the revision.

5. OWNERSHIP OF EQUIPMENT

(a) Unless joint ownership is indicated in Exhibit A, the Party listed on Exhibit A is the sole owner and holds title to all equipment listed in Exhibit A. When joint ownership is indicated, all jointly owned equipment, facilities, and capital spare parts will be identified as such with co-ownership tags and signs.

(b) Replacement and removal costs and the proceeds from the disposal of jointly owned equipment will be consistent with the ownership share percentages specified in Exhibit A.

6. MAINTENANCE AND REMOVAL OF BPA OWNED EQUIPMENT BY CUSTOMER

(a) Customer shall comply with its own safety and security requirements and shall provide reasonable notice to BPA of any outages of BPA equipment that must be taken to enable Customer to perform its obligations hereunder, pursuant to Exhibit A.

(b) Customer shall,

(1) maintain the BPA owned equipment described in Exhibit A in the same manner in which Customer operates and maintains similar equipment owned by Customer and in accordance with the applicable Electric Reliability Standards;

(2) maintain Customer's power system control facilities (e.g.: Supervisory Control and Data Acquisition {SCADA}) which are necessary to integrate the BPA owned equipment described in Exhibit A with Customer’s control system and, from time to time when Customer determines it is necessary, modify or replace such Customer power system control facilities.

(c) In the event of a major failure or functional obsolescence of any of the equipment described in Exhibit A, the Parties shall negotiate and execute a mutually acceptable agreement providing for the replacement, repair, or removal of such equipment with the expenses to be paid by BPA as the equipment owner. In the event of joint ownership, expenses will be shared by the Parties in accordance with the ownership percentages specified in Exhibit A.

(d) BPA agrees to pay the cost of modifying or replacing any of the power system control equipment associated with the equipment specified in Exhibit A if and when Customer notifies BPA that such action is necessary to make the operation of BPA's equipment compatible with the operation of Customer's equipment. Such costs will be shared in accordance with the ownership percentages specified in Exhibit A. Customer shall provide reasonable written notice to BPA consistent with the availability of budgetary planning and funding. Any such modification or replacement of power system control equipment will be required only: (1) when Customer, in keeping with prudent utility practice, replaces or modifies similar equipment owned by Customer at the same location, (2) as a part of a programmed project involving a significant portion of Customer's system, or (3) by mutual agreement of the Parties.

(e) If requested by BPA, Customer shall, at BPA's expense, remove and return to BPA some or all of the salvable facilities and equipment which are owned by BPA as described in Exhibit A. After such removal, Customer may, at BPA's expense, return the Customer facilities altered under the installation contract described in Exhibit A, to the configuration (1) existing before such contract was executed, or (2) as mutually agreed by the Parties.

7. LIABILITY

(a) BPA's liability to Customer, its affiliates, its respective Boards of Directors, officers, employees, agents, or representatives, for any loss or damage to property or injury to persons resulting from any acts or omissions shall be in accordance with the provisions of the Federal Tort Claims Act, 28 U.S.C 2671.

(b) BPA and Customer assert that neither Party is the agent or principal for the other, nor are they partners or joint ventures; and the Parties agree that they shall not represent to any other Party that they act in the capacity of agent or principal for the other.

8. ADDITIONAL COMMITMENTS

(a) For BPA equipment that Customer maintains pursuant to Exhibit A, Customer agrees to provide to BPA in quarter 4 of each calendar year:

(1) Letter certifying Customer has maintained equipment listed in Exhibit A in accordance with Customer's maintenance procedures.

(2) Copy of Customer's maintenance procedures applicable to equipment listed in Exhibit A.

(3) Copy of maintenance performed as applicable to equipment listed in Exhibit A.

(b) At BPA's request in order to respond to an Electric Reliability Standard audit, Customer shall use reasonable efforts to provide all items listed in 8(a) and any additional documentation required on an as-needed basis.

(c) Customer shall follow the metering requirements in BPA's Transmission Services Standard, Meter Application Guide STD-DC-000005, as amended.

9. FAILURE TO PERFORM

(a) If Customer determines that it may not be in compliance with one or more of the requirements in Section 6(b), it shall notify BPA within three (3) Business Days of such determination.

(b) If BPA determines that any Electric Reliability Standards may have been violated with respect to facilities and/or equipment listed in Exhibit A, BPA will notify Customer within ten (10) Business Days. BPA may elect to self report pursuant to WECC's Compliance Monitoring and Enforcement Program (CMEP).

(c) BPA will coordinate with Customer to create any Mitigation Plan that BPA prepares for submission to WECC. BPA will submit the Mitigation Plan and all related, required documentation to WECC.

(d) BPA will notify Customer within ten (10) Business Days when a Notice of Alleged Violation (NOAV) is issued pursuant to the CMEP and provide Customer a copy of the NOAV. Customer shall treat the NOAV as confidential and it shall not be disclosed, except to Customer's employees, including executives and managers, legal advisors, consultants, and other representatives on a need to know basis. Customer shall not disclose the NOAV to any other parties without BPA's consent.

(e) BPA will not oppose any attempts by Customer to intervene in CMEP proceedings conducted by WECC, NERC, or FERC.

(f) BPA shall have the sole discretion to decide whether to proceed through the Settlement Process or the Hearing Process under the CMEP.

10. STANDARD PROVISIONS

(a) **Amendments**
Except where this Agreement explicitly allows one Party to unilaterally amend a provision or revise an exhibit, no amendment or exhibit revision of this Agreement shall be of any force or effect unless set forth in a written instrument signed by authorized representatives of each Party.

(b) **Assignment**
This Agreement is binding on any successors and assigns of the Parties. Neither Party may otherwise transfer or assign this Agreement, in whole or in part, without the other Party's written consent. Such consent shall not be unreasonably withheld.

(c) **Dispute Resolution**

(1) Except as provided in Section 10(g) of this Agreement, in the event of a dispute arising out of this Agreement, the Parties shall negotiate in good faith to reach an acceptable and timely resolution. If the Parties are unable to resolve the dispute to their mutual satisfaction within five Business days, or any other mutually acceptable time period after negotiation begins, the Parties shall attempt in good faith to resolve the dispute through nonbinding mediation.

(2) Except as provided in Section 10(g) of this Agreement, each Party shall be responsible for its own expenses and one-half of the expenses of the mediator.

(d) **Freedom of Information Act (FOIA)**
BPA may release information provided by Customer to comply with FOIA or if required by any other federal law or court order. For information that Customer provides pursuant to Section 10(d), or designates in writing as proprietary, BPA will limit the use and dissemination of that information within BPA to employees who need the information for purposes of this Agreement.

(e) **Governing Law**
This Agreement shall be interpreted, construed and enforced in accordance with Federal law.

(f) **No Third Party Beneficiaries**
This Agreement is made and entered into for the sole benefit of the Parties, and the Parties intend that no other person or entity shall be a direct or indirect beneficiary of this Agreement.

(g) **Relationship of the Parties**
The Parties agree that Customer is an independent contractor to BPA in the performance of Customer's obligations under Section 7 of this Agreement.

Neither Party is the agent or principal of the other, nor are they partners or joint venturers. Each Party agrees that it will not represent that, in performing its obligations hereunder, it acts in the capacity of agent or principal of the other Party, nor that it is a partner or joint venturer with the other Party with respect to the subject matter of this Agreement.

(h) **Section Headings**

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

(i) **Several Obligations**

Except where specifically stated in this Agreement, the duties, obligations and liabilities of the Parties are intended to be several and not joint or collective.

(j) **Uncontrollable Forces**

The Parties shall not be in breach of their respective obligations to the extent the failure to fulfill any obligation is due to an Uncontrollable Force. "Uncontrollable Force" means an event beyond the reasonable control of, and without the fault or negligence of, the Party claiming the Uncontrollable Force that prevents that Party from performing its contractual obligations under this Agreement and which, by exercise of that Party's reasonable care, diligence and foresight, such Party was unable to avoid. Uncontrollable Forces include, but are not limited to:

(1) strikes or work stoppage;

(2) floods, earthquakes, or other natural disasters; terrorist acts; epidemics, pandemics and

(3) final orders or injunctions issued by a court or regulatory body having competent subject matter jurisdiction which the Party claiming the Uncontrollable Force, after diligent efforts, was unable to have stayed, suspended, or set aside pending review by a court of competent subject matter jurisdiction.

Neither the unavailability of funds or financing, nor conditions of national or local economies or markets shall be considered an Uncontrollable Force. The economic hardship of either Party shall not constitute an Uncontrollable Force. Nothing contained in this provision shall be construed to require either Party to settle any strike or labor dispute in which it may be involved.

If an Uncontrollable Force prevents a Party from performing any of its obligations under this Agreement, such Party shall: (1) immediately notify the other Party of such Uncontrollable Force by any means practicable and confirm such notice in writing as soon as reasonably practicable; (2) use its best efforts to mitigate the effects of such Uncontrollable Force, remedy its inability to perform, and resume full performance of its obligation hereunder as soon as reasonably practicable; (3) keep the other Party apprised of such efforts on an ongoing basis; and (4) provide written notice of the resumption of performance. Written notices sent under this section must comply with Exhibit B.

(k) **Waivers**
No waiver of any provision or breach of this Agreement shall be effective unless such waiver is in writing and signed by the waiving Party, and any such waiver shall not be deemed a waiver of any other provision of this Agreement or any other breach of this Agreement.

11. SIGNATURES
This Agreement may be executed in several counterparts, all of which taken together will constitute one single agreement, and the Agreement may be executed and delivered electronically. The Parties have executed this Agreement as of the last date indicated below.

EUGENE WATER & ELECTRIC BOARD		UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration	
By:	[redacted]	By:	[redacted]
Name:	Megan Capper *(Print/Type)*	Name:	Chris Lockman *(Print/Type)*
Title:	Energy Resources Manager	Title:	Transmission Account Executive
Date:	3/29/2023	Date:	03.10.2023

EXHIBIT A
OWNERSHIP OF FACILITIES AND EQUIPMENT AND O&M RESPONSIBILITIES

TABLE 1
BPA'S ALVEY SUBSTATION

1. ALVEY-CURRIN 115 KV LINE TERMINAL

Facilities and Equipment Ownership Demarcation: the point on BPA's 115 kV steel lattice dead-end structure where BPA's insulators and attachment hardware meet the terminal span of Customer's Alvey-Currin 115 kV transmission line.

Facilities and Equipment Ownership, Operation, and Maintenance Responsibilities:

(a) BPA shall own, operate, and maintain its:

(1) 115 kV power circuit breaker B-590 and associated disconnect switches;

(2) 115 kV jumpers, insulators, and attachment hardware;

(3) Protection relays associated with B-590;

(4) SCADA and telemetry equipment for B-590;

(5) Revenue meter and instrument transformers.

(b) Customer shall own, operate, and maintain its:

(1) 115 kV transmission line conductor and terminal structure.

2. ALVEY-CURRIN FIBER OPTIC CABLE

Facilities and Equipment Ownership, Operation, and Maintenance Responsibilities:

(a) Customer shall own, operate and maintain its:

(1) Fiber optic cable up to the splice case in the Customer Fiber Interface Vaults ALVY 1CV and ALVY 2CV.

(2) J-MUX Rack, RTU equipment, and fiber optic patch panel located in the Alvey Substation control house basement.

(b) **BPA shall own, operate and maintain its:**

(1) Fiber optic cable from Customer Fiber Interface Vaults ALVY 1CV and ALVY 2CV to Customer's fiber optic patch panel located in the Alvey Substation control house basement.

EXHIBIT A
OWNERSHIP OF FACILITIES AND EQUIPMENT AND O&M RESPONSIBILITIES

TABLE 2
BPA'S LANE SUBSTATION

1. **LANE-WILLOW CREEK 115 kV LINE TERMINAL**

Facilities and Equipment Ownership Demarcation: the point on BPA's 115 kV steel lattice dead-end structure where BPA's insulators and attachment hardware meet the terminal span of Customer's Lane-Willow Creek 115 kV transmission line.

Facilities and Equipment Ownership, Operation, and Maintenance Responsibilities:

(a) BPA shall own, operate, and maintain its:

(1) 115 kV power circuit breaker B-1621 and associated disconnect switches.

(2) 115 kV jumpers, insulators, and attachment hardware.

(3) Protection relays associated with B-1621

(4) SCADA and telemetry equipment for B-1621.

(5) Revenue meter and instrument transformers.

(b) Customer shall own, operate, and maintain its:

(1) 115 kV transmission line conductor and terminal structure.

2. **LANE-DANEBO 115 KV LINE TERMINAL**

Facilities and Equipment Ownership Demarcation: the point on BPA's 115 kV steel lattice dead-end structure where BPA's insulators and attachment hardware meet the terminal span of Customer's Lane-Danebo 115 kV transmission line.

(a) BPA shall own, operate, and maintain its:

(1) 115 kV power circuit breaker B-1620 and associated disconnect switches.

(2) 115 kV jumpers, insulators, and attachment hardware.

(3) Protection relays associated with B-1620.

(4) SCADA and telemetry equipment for B-1620.

(5) Revenue meter and instrument transformers.

(b) Customer shall own, operate, and maintain its:

(1) 115 kV transmission line conductor and terminal structure.

3. LANE-DANEBO FIBER OPTIC CABLE

Facilities and Equipment Ownership, Operation, and Maintenance Responsibilities:

(a) Customer shall own, operate and maintain its:

(1) Fiber optic cable up to the splice case in the Customer Fiber Interface Vaults LANE 4CV.

(2) J-MUX Rack, RTU equipment, and fiber optic patch panel located in the Lane Substation control house basement.

(b) BPA shall own, operate and maintain its:

(1) Fiber optic cable from Customer Fiber Interface Vault LANE 4CV to Customer's fiber optic patch panel located in the Lane Substation control house basement.

EXHIBIT A
OWNERSHIP OF FACILITIES AND EQUIPMENT AND OPERATIONS AND MAINTENANCE RESPONSIBILITIES

TABLE 3
BPA'S EUGENE SUBSTATION

1. EUGENE-RIVER ROAD 115 kV LINE TERMINAL

Facilities and Equipment Ownership Demarcation: the point on BPA's 115 kV steel lattice dead-end structure where BPA's insulators and attachment hardware meet the terminal span of Customer's Eugene-River Road 115 kV transmission line.

Facilities and Equipment Ownership, Operation, and Maintenance Responsibilities:

(a) BPA shall own, operate, and maintain its:

(1) 115 kV power circuit breaker B-1198 and associated disconnect switches.

(2) 115 kV jumpers, insulators, and attachment hardware.

(3) Protection relays associated with B-1198.

(4) SCADA and telemetry equipment for B-1198.

(5) Revenue meter and instrument transformers.

(b) Customer shall own, operate, and maintain its:

(1) 115 kV transmission line conductor and terminal structure.

2. EUGENE-BETHEL 115 kV LINE TERMINAL

Facilities and Equipment Ownership Demarcation: the point on BPA's 115 kV steel lattice dead-end structure where BPA's insulators and attachment hardware meet the terminal span of Customer's Eugene-Bethel 115 kV transmission line.

Facilities and Equipment Ownership, Operation, and Maintenance Responsibilities:

(a) BPA shall own, operate, and maintain its:

(1) 115 kV power circuit breaker B-552 and associated disconnect switches.

(2) 115 kV jumpers, insulators, and attachment hardware.

(3) Protection relays associated with B-552.

(4) SCADA and telemetry equipment for B-552.

(5) Revenue meter and instrument transformers.

(b) Customer shall own, operate, and maintain its:

(1) 115 kV transmission line conductor and terminal structure.

3. FIBER OPTIC CABLE AND TRANSFER TRIP CIRCUITS

Facilities and Equipment Ownership, Operation, and Maintenance Responsibilities:

(a) Customer shall own, operate and maintain its:

(1) Fiber optic cable up to the splice case in the Customer Fiber Interface Vaults EUGE 3CV.

(2) J-MUX Rack, RTU equipment, and fiber optic patch panel located in the Eugene Substation control house.

(3) Two 4-conductor shielded control cables between Customer's Bethel Substation and BPA's Eugene Substation.

(b) BPA shall own, operate and maintain its:

(1) Fiber optic cable from Customer Fiber Interface Vault EUGE 3CV to Customer's Fiber optic patch panel located in the Eugene Substation control house.

EXHIBIT A
OWNERSHIP OF FACILITIES AND EQUIPMENT
AND OPERATIONS AND MAINTENANCE RESPONSIBILITIES

TABLE 4
CUSTOMER'S MCKENZIE SUBSTATION

1. THURSTON-MCKENZIE NO. 1 115 KV LINE TERMINAL

Facilities and Equipment Ownership Demarcation: the point on Customer's 115 kV dead-end structure where Customer's insulators and attachment hardware meet the terminal span of BPA's Thurston-McKenzie No. 1 115 kV transmission line.

Facilities and Equipment Ownership, Operation, and Maintenance Responsibilities:

(a) BPA shall own, operate, and maintain its:

(1) 115 kV transmission line conductor and terminal structure.

(2) Revenue meter.

(b) Customer shall own, operate, and maintain its:

(1) 115 kV power circuit breaker 6682 and associated disconnect switches.

(2) 115 kV jumpers, insulators, and attachment hardware.

(3) Protection relays associated with 6682.

(4) SCADA and telemetry equipment for 6682.

(5) Revenue metering instrument transformers.

2. GATEWAY TAP

Facilities and Equipment Ownership, Operation, and Maintenance Responsibilities:

(a) BPA shall own, operate, and maintain its:

(1) Revenue meter.

(b) Customer shall own, operate, and maintain its:

(1) Revenue metering instrument transformers.

3. COBURG TAP

Facilities and Equipment Ownership, Operation, and Maintenance Responsibilities:

(a) BPA shall own, operate, and maintain its:

(1) Revenue meter.

(b) Customer shall own, operate, and maintain its:

(1) Revenue metering instrument transformers.

EXHIBIT A
OWNERSHIP OF FACILITIES AND EQUIPMENT AND OPERATIONS AND MAINTENANCE RESPONSIBILITIES

TABLE 5
CUSTOMER'S THURSTON SUBSTATION

1. THURSTON-MCKENZIE NO. 1 115 KV LINE TERMINAL

Facilities and Equipment Ownership Demarcation: the point on Customer's 115 kV Thurston line tap where Customer's jumpers and attachment hardware meet BPA's Thurston-McKenzie No. 1 115 kV transmission line at BPA structure 1/11.

Facilities and Equipment Ownership, Operation, and Maintenance Responsibilities:

(a) BPA shall own, operate, and maintain its:

(1) 115 kV transmission line conductor and structure 1/11.

(2) Revenue meter.

(b) Customer shall own, operate, and maintain its:

(1) 115 kV power circuit breaker 2300 and associated disconnect switches.

(2) 115 kV 0.85mile line tap conductor, structures, jumpers, insulators, and attachment hardware.

(3) Protection relays associated with 2300.

(4) SCADA and telemetry equipment for 2300.

(5) Revenue metering instrument transformers.

2. HOLDEN CREEK-THURSTON NO. 1 115 KV LINE TERMINAL

Facilities and Equipment Ownership Demarcation: the point on Customer's 115 kV Thurston line tap where Customer's jumpers and attachment hardware meet BPA's Holden Creek-Thurston No. 1 115 kV transmission line at BPA structure 12/5.

Facilities and Equipment Ownership, Operation, and Maintenance Responsibilities:

(a) BPA shall own, operate, and maintain its:

(1) 115 kV transmission line conductor and structure 12/5.

(2) Revenue meter.

(b) Customer shall own, operate, and maintain its:

(1) 115 kV power circuit breaker 2360 and associated disconnect switches.

(2) 115 kV 0.85mile line tap conductor, structures, jumpers, insulators, and attachment hardware.

(3) Protection relays associated with 2360.

(4) SCADA and telemetry equipment for 2360. Revenue metering instrument transformers.

EXHIBIT A
OWNERSHIP OF FACILITIES AND EQUIPMENT AND OPERATIONS AND MAINTENANCE RESPONSIBILITIES

TABLE 6
CUSTOMER'S HOLDEN CREEK SUBSTATION

1. HOLDEN CREEK-THURSTON NO. 1 115 kV LINE TERMINAL

Facilities and Equipment Ownership Demarcation: the point on Customer's 115 kV dead-end structure where Customer's insulators and attachment hardware meet the terminal span of BPA's Holden Creek-Thurston No. 1 115 kV transmission line.

Facilities and Equipment Ownership, Operation, and Maintenance Responsibilities:

(a) BPA shall own, operate, and maintain its:

(1) 115 kV transmission line conductor.

(b) Customer shall own, operate, and maintain its:

(1) 115 kV power circuit breakers 7150, 7190, and associated disconnect switches.

(2) 115 kV jumpers, insulators, and attachment hardware.

(3) Protection relays associated with 7150 and 7190.

(4) SCADA and telemetry equipment for 7150 and 7190.

2. COUGAR-HOLDEN CREEK NO. 1 115 kV LINE TERMINAL

Facilities and Equipment Ownership Demarcation: the point on Customer's 115 kV dead-end structure where Customer's insulators and attachment hardware meet the terminal span of BPA's Cougar-Holden Creek No. 1 115 kV transmission line.

Facilities and Equipment Ownership, Operation, and Maintenance Responsibilities:

(a) BPA shall own, operate, and maintain its:

(1) 115 kV transmission line conductor.

(b) Customer shall own, operate, and maintain its:

(1) 115 kV power circuit breakers 7170, 7180, and associated disconnect switches.

(2) 115 kV jumpers, insulators, and attachment hardware.

(3) Protection relays associated with 7170 and 7180.

(4) SCADA and telemetry equipment for 7170 and 7180.

3. TRANSFORMER BANKS #2 AND #3

Facilities and Equipment Ownership, Operation, and Maintenance Responsibilities:

(a) BPA shall own, operate, and maintain its:

(1) Revenue meters.

(b) Customer shall own, operate, and maintain its:

(1) 115/12.5 kV transformer banks.

(2) Revenue metering instrument transformers.

EXHIBIT A
OWNERSHIP OF FACILITIES AND EQUIPMENT AND OPERATIONS AND MAINTENANCE RESPONSIBILITIES

TABLE 7
CUSTOMER'S BERTELSEN SUBSTATION

1. EUGENE-BERTELSEN NO. 1 115 KV LINE TERMINAL

Facilities and Equipment Ownership Demarcation: the point on Customer's 115 kV vertical break disconnect switch where Customer's insulators and attachment hardware meet the terminal span of BPA's Eugene-Bertelsen No. 1 115 kV transmission line.

Facilities and Equipment Ownership, Operation, and Maintenance Responsibilities:

(a) BPA shall own, operate, and maintain its:

(1) 115 kV transmission line conductor, terminal pads, and armor rod.

(b) Customer shall own, operate, and maintain its:

(1) 115 kV power circuit breaker 6450 and associated disconnect switches.

(2) 115 kV jumpers, insulators, and attachment hardware.

(3) 115 kV line support posts, post insulators, and conductor clamps.

(4) Protection relays associated with 6450.

(5) SCADA and telemetry equipment for 6450.

2. BERTELSEN-WILLOW CREEK NO. 1 115 kV LINE TERMINAL

Facilities and Equipment Ownership Demarcation: the point on Customer's 115 kV vertical break disconnect switch where Customer's insulators and attachment hardware meet the terminal span of BPA's Bertelsen-Willow Creek No. 1 115 kV transmission line.

Facilities and Equipment Ownership, Operation, and Maintenance Responsibilities:

(a) BPA shall own, operate, and maintain its:

(1) 115 kV transmission line conductor, terminal pads, and armor rod.

(b) Customer shall own, operate, and maintain its:

(1) 115 kV power circuit breaker 6400 and associated disconnect switches.

(2) 115 kV jumpers, insulators, and attachment hardware.

(3) 115 kV line support posts, post insulators, and conductor clamps.

(4) Protection relays associated with 6400.

(5) SCADA and telemetry equipment for 6400.

EXHIBIT A
OWNERSHIP OF FACILITIES AND EQUIPMENT AND OPERATIONS AND MAINTENANCE RESPONSIBILITIES

TABLE 8
CUSTOMER'S WILLOW CREEK SUBSTATION

1. BERTELSEN-WILLOW CREEK NO. 1 115 KV LINE TERMINAL

Facilities and Equipment Ownership Demarcation: the point on Customer's 115 kV dead-end structure where Customer's insulators and attachment hardware meet the terminal span of BPA's Bertelsen-Willow Creek No. 1 115 kV transmission line.

Facilities and Equipment Ownership, Operation, and Maintenance Responsibilities:

(a) BPA shall own, operate, and maintain its:

(1) 115 kV transmission line conductor.

(b) Customer shall own, operate, and maintain its:

(1) 115 kV power circuit breakers 5750, 5754 and associated disconnect switches.

(2) 115 kV jumpers, insulators, and attachment hardware.

(3) Protection relays associated with 5750 and 5754.

(4) SCADA and telemetry equipment for 5750 and 5754.

2. WILLOW CREEK-HAWKINS NO. 1 115 KV LINE TERMINAL

Facilities and Equipment Ownership Demarcation: the point on Customer's 115 kV dead-end structure where Customer's insulators and attachment hardware meet the terminal span of BPA's Willow Creek-Hawkins No. 1 115 kV transmission line.

Facilities and Equipment Ownership, Operation, and Maintenance Responsibilities:

(a) BPA shall own, operate, and maintain its:

(1) 115 kV transmission line conductor.

(b) Customer shall own, operate, and maintain its:

(1) 115 kV power circuit breaker 5758 and associated disconnect switches.

(2) 115 kV jumpers, insulators, and attachment hardware.

(3) Protection relays associated with 5758.

(4) SCADA and telemetry equipment for 5758.

EXHIBIT A
OWNERSHIP OF FACILITIES AND EQUIPMENT
AND OPERATIONS AND MAINTENANCE RESPONSIBILITIES

TABLE 9
CUSTOMER'S HAWKINS SUBSTATION

1. WILLOW CREEK-HAWKINS NO. 1 115 KV LINE TERMINAL

Facilities and Equipment Ownership Demarcation: the point on Customer's 115 kV Hawkins line tap where Customer's jumpers and attachment hardware meet BPA's Willow Creek-Hawkins No. 1 115 kV transmission line at BPA structure 3/6.

Facilities and Equipment Ownership, Operation, and Maintenance Responsibilities:

(a) BPA shall own, operate, and maintain its:

(1) 115 kV transmission line conductor and structure 3/6.

(b) Customer shall own, operate, and maintain its:

(1) 115 kV power circuit breaker 6172 and associated disconnect switches.

(2) 115 kV 0.71 mile line tap conductor, structures, jumpers, insulators, and attachment hardware.

(3) Protection relays associated with 6172.

(4) SCADA and telemetry equipment for 6172.

2. HAWKINS-ALVEY NO. 1 115 KV LINE TERMINAL

Facilities and Equipment Ownership Demarcation: the point on Customer's 115 kV Hawkins line tap where Customer's jumpers and attachment hardware meet BPA's Hawkins-Alvey No. 1 115 kV transmission line at BPA structure 1/1.

Facilities and Equipment Ownership, Operation, and Maintenance Responsibilities:

(a) BPA shall own, operate, and maintain its:

(1) 115 kV transmission line conductor and structure 1/1.

(b) Customer shall own, operate, and maintain its:

(1) 115 kV power circuit breaker 6170 and associated disconnect switches.

(2) 115 kV 0.68 mile line tap conductor, structures, jumpers, insulators, and attachment hardware.

(3) Protection relays associated with 6170.

(4) SCADA and telemetry equipment for 6170.

EXHIBIT A
OWNERSHIP OF FACILITIES AND EQUIPMENT
AND OPERATIONS AND MAINTENANCE RESPONSIBILITIES

TABLE 10
CUSTOMER'S CARMEN SMITH SUBSTATION

1. CARMEN SMITH LINE TAP

Facilities and Equipment Ownership Demarcation: the point on Customer's 115 kV Carmen Smith line tap where Customer's jumpers and attachment hardware meet BPA's Cougar-Holden Creek No. 1 115 kV transmission line at BPA structure 2/5.

Facilities and Equipment Ownership, Operation, and Maintenance Responsibilities:

(a) BPA shall own, operate, and maintain its:

(1) 115 kV transmission line conductor and structure 2/5.

(2) Metering and telemetry equipment.

(b) Customer shall own, operate, and maintain its:

(1) 115 kV power circuit breaker 1000 and associated disconnect switches.

(2) 115 kV 18 mile line tap conductor, structures, jumpers, insulators, and attachment hardware.

(3) Protection relays associated with 1000.

(4) Metering instrument transformers.

EXHIBIT A
OWNERSHIP OF FACILITIES AND EQUIPMENT AND OPERATIONS AND MAINTENANCE RESPONSIBILITIES

TABLE 11
CUSTOMER'S DILLARD SUBSTATION

1. DILLARD LINE TAP

Facilities and Equipment Ownership Demarcation: the point on Customer's 115 kV Dillard line tap where Customer's terminal span meets BPA's Eugene-Alvey No. 2 115 kV transmission line jumpers and attachment hardware at BPA structures 10/3 and 10/4.

Facilities and Equipment Ownership, Operation, and Maintenance Responsibilities:

(a) BPA shall own, operate, and maintain its:

(1) 115 kV transmission line conductor and structure 10/3 and 10/4.

(2) 115 kV jumpers, insulators, and attachment hardware.

(3) 115 kV disconnect switches B1579 and 1580.

(4) Revenue meter.

(b) Customer shall own, operate, and maintain its:

(1) 115 kV power circuit breaker 4700 and associated disconnect switches.

(2) 115 kV 0.70 mile line tap conductor, structures, jumpers, insulators, and attachment hardware.

(3) Protection relays associated with 4700.

(4) Metering instrument transformers.

EXHIBIT A
OWNERSHIP OF FACILITIES AND EQUIPMENT AND OPERATIONS AND MAINTENANCE RESPONSIBILITIES

TABLE 12
DOUBLE CIRCUIT - BPA EUGENE-LANE NO. 1 115 KV LINE AND CUSTOMER LANE-DANEBO 115 KV LINE

1. BPA EUGENE-LANE NO. 1 115 KV LINE AND CUSTOMER LANE-DANEBO 115 KV LINE

Facilities and Equipment Ownership Demarcation: the point on Customer's 115 kV line structures (Customer structure 4/10 through structure 1/1 [BPA structure 2/6 through structure 6/6]) where Customer's davit arms and horizontal cross members meet BPA's Eugene-Lane No. 1 115 kV transmission line insulators and attachment hardware.

Facilities and Equipment Ownership, Operation, and Maintenance Responsibilities:

(a) BPA shall own and operate its:

(1) 115 kV 3-phase circuit.

(b) BPA shall maintain at its expense its:

(2) Right-of-way occupied by the double-circuit line.

(c) Customer shall own, operate, and maintain its:

(3) 115 kV 3-phase circuit and line structures.

(d) Customer shall maintain at its expense:

(4) BPA's 115 kV 3-phase circuit conductor, insulators, and attachment hardware; materials to be provided by BPA.

EXHIBIT A
OWNERSHIP OF FACILITIES AND EQUIPMENT AND OPERATIONS AND MAINTENANCE RESPONSIBILITIES

TABLE 13
DOUBLE CIRCUIT - BPA EUGENE-ALVEY NO. 2 115 KV LINE AND CUSTOMER LANE-WILLOW CREEK 115 KV LINE

1. BPA EUGENE-ALVEY NO. 2 115 KV LINE AND CUSTOMER LANE-WILLOW CREEK 115 KV LINE

Facilities and Equipment Ownership Demarcation: the point on Customer's 115 kV line structures (Customer structure 1/12 through structure 1/3 [BPA structure 3/4 through structure 4/3]) where Customer's davit arms and horizontal cross members meet BPA's Eugene-Alvey No. 2 115 kV transmission line insulators and attachment hardware.

Facilities and Equipment Ownership, Operation, and Maintenance Responsibilities:

(a) BPA shall own and operate its:

(1) 115 kV 3-phase circuit.

(b) BPA shall maintain at its expense its:

(2) Right-of-way occupied by the double circuit line.

(c) Customer shall own, operate, and maintain its:

(3) 115 k V 3-phase circuit and line structures.

(d) Customer shall maintain at its expense:

(4) BPA's 115 kV 3-phase circuit conductor, insulators, and attachment hardware; materials to be provided by BPA.

EXHIBIT B
NOTICES

1. NOTICES RELATING TO PROVISIONS OF THE AGREEMENT

Any notice or other communication related to this Agreement, other than notices of an operating nature (Section 2 below), shall be delivered in person, or with proof of receipt by email, facsimile, First Class mail or overnight delivery service. Notices are effective on the date received. Either Party may change the contact information by providing notice of such change to the following person and address:

To Eugene Water & Electric Board:

Eugene Water & Electric Board
4200 Roosevelt BLVD
Eugene, OR 97402-6520
Attention: Tyler Nice
Title: Electric Division Manager
Phone: (541) 685-7419
E-mail: Tyler.Nice@eweb.org

To Bonneville Power Administration:

Attention: Transmission Account Executive for Eugene Water & Electric Board – TSE/TPP-2
Phone: (360) 619-6017
Fax: (360) 619-6940
Email: txsalescontracts@bpa.gov

If by First Class Mail:
Bonneville Power Administration
P.O. Box 61409
Vancouver, WA 98666-1409

If by Overnight Delivery Service:
Bonneville Power Administration – TSE/TPP-2
905 NE 11th Avenue
Portland, OR 97232

2. NOTICES OF AN OPERATING NATURE

The Company shall provide BPA with the name (or title), address, voice phone number and fax number for routine operational activities performed under this Agreement. Such operational activities shall include, but are not limited to outage coordination, generation dispatch and system dispatch. Any notice, request or demand of an operating nature between BPA and the Company shall be deemed to have been received if delivered in person, by email, facsimile, First Class mail or overnight delivery service.

To Eugene Water & Electric Board:

Eugene Water & Electric Board
4200 Roosevelt BLVD
Eugene, OR 97402-6520
Attention: Larry Longworth
Title: T&D Dispatch Supervisor
Phone: (541) 685-7197
E-mail: Larry.Longworth@eweb.org

To Bonneville Power Administration:

Primary Contact:
Dittmer Dispatch:
Phone: (360) 418-2281 or 418-2280
or (503) 283-8501
Fax: (360) 418-2938

Secondary Contact:
Munro Dispatch:
Phone: (509) 465-1820
or (888) 835-9590
Fax: (509) 466-2444

Outage Coordination:
Dittmer Control Center Outage Office
Phone: (360) 418-2274
or (360) 418-2275
Fax: (360) 418-2214

3. FOR REPORTING OF COMPLIANCE DOCUMENTATION

To the Customer Reliability:

E-mail: eweb.NERCReliability@eweb.org

E-mail: Jessica.Markovich@eweb.org
NERC Compliance Specialist II

To the BPA Reliability Program:

E-mail: CSReliabilityProgram@bpa.gov

If by First Class Mail:
Bonneville Power Administration
Attention: Transmission Reliability Program – TPC/TPP-4
P.O. Box 61409
Vancouver, WA 98666-0491

If by Overnight Delivery Service:
Bonneville Power Administration
Attention: Transmission Reliability Program – TPC/TPP-4
905 NE 11th Avenue
Portland, OR 97232

EXHIBIT A, REVISION NO. 2
BES EQUIPMENT SUBJECT TO THIS AGREEMENT

This Exhibit A, Revision No. 2 (Exhibit A) updates Section 1 to reflect the removal of the McKenzie-Gateway 115 kV line. This Exhibit A supersedes the previous version in its entirety.

BPA will perform TOP responsibilities for Customer's BES equipment that is listed below in accordance with the TOP procedures that are contained in the TOPIC. Customer is not charged for BPA owned equipment. This exhibit contains a complete listing of the BES equipment.

1. DESCRIPTION OF BES EQUIPMENT SUBJECT TO THIS AGREEMENT

Line	Line Terminal		Line Section	Line Terminal	
McKenzie-Willakenzie 115 kV line	McKenzie Substation	**Bus** McKenzie 115 kV **Breaker** 6672 **Disconnects** BSD6672 LSD6672 TBD6673	McKenzie-Willakenzie 115 kV line	Willakenzie Substation	**Bus** Willakenzie 115 kV **Breaker** 5072 **Disconnects** BSD5072 LSD5072 TBD5073
Coburg-McKenzie 115 kV line	Coburg Substation	**Bus** Coburg 115 kV **Breaker** 6850 **Disconnects** BSD6850 LSD6850 AS6863 AS6861	Coburg-McKenzie 115 kV line	McKenzie Substation	**Bus** McKenzie 115 kV **Breaker** 6670 **Disconnects** BSD6670 LSD6670 TBD6671

Line	Line Terminal		Line Section	Line Terminal	
Coburg-Spring Creek (EWEB) 115 kV line	Coburg Substation	**Bus** Coburg 115 kV **Breaker** 6800 **Disconnects** BSD6800 LSD6800	Coburg-Spring Creek (EWEB) 115 kV line	Spring Creek (EWEB) Substation	**Bus** Spring Creek (EWEB) 115 kV **Breaker** 5470 **Disconnects** BSD5470 LSD5470
Danebo-Prairie (EWEB) 115 kV line	Danebo Substation	**Bus** Danebo 115 kV **Breaker** 4950 **Disconnects** BSD4950 LSD4950 AS4975	*Danebo-Jessen section of Danebo-Prairie (EWEB) 115 kV line **Disconnects** IS5871 *Jessen-Prairie (EWEB) section of Danebo-Prairie (EWEB) 115 kV line **Disconnects** AS5853 IS5873	Prairie (EWEB) Substation	**Bus** Prairie (EWEB) 115 kV **Breaker** 5672 **Disconnects** BSD5672 LSD5672
Danebo-Lane 115 kV line	Danebo Substation	**Bus** Danebo 115 kV **Breaker** 4900 **Disconnects** BSD4900 LSD4900 AS4973	Danebo-Lane 115 kV line	Lane Substation (BPA)	All BES equipment at Lane Substation is owned and operated by BPA

Line	Line Terminal		Line Section	Line Terminal	
Westmoreland -Willow Creek 115 kV line	Westmoreland Substation	**Bus** Westmoreland 115 kV **Breaker** 5172 **Disconnects** BSD5172 LSD5172	Westmoreland -Willow Creek 115 kV line	Willow Creek Substation	**Bus** Willow Creek 115 kV **Breaker** 5774 5778 **Disconnects** LSD5775 LSD5778 BSD5778
Hyundai-Willow Creek #1 115 kV line	Hyundai Substation	**Bus** Hyundai 115 kV **Breaker** 6750 **Disconnects** LSD6751 BYD6760 BYD6750 XSD6753 XSD6761 XSD6763	Hyundai-Willow Creek #1 115 kV line	Willow Creek Substation	**Bus** Willow Creek 115 kV **Breaker** 5764 5768 **Disconnects** LSD5765 LSD5768 BSD5768
Hyundai-Willow Creek #2 115 kV line	Hyundai Substation	**Bus** Hyundai 115 kV **Breaker** 6790 **Disconnects** LSD6793 BYD6790 XSD6791 XSD6783 XSD6781 XSD6773 XSD6771 BYD6780 BYD6770	Hyundai-Willow Creek #2 115 kV line	Willow Creek Substation	**Bus** Willow Creek 115 kV **Breaker** 5770 5774 **Disconnects** LSD5773 LSD5770 BSD5770

Line	Line Terminal		Line Section	Line Terminal	
Willow Creek-Lane 115 kV line	Willow Creek Substation	**<u>Bus</u>** Willow Creek 115 kV **<u>Breaker</u>** 5760 5764 **<u>Disconnects</u>** LSD5760 LSD5763 BSD5760	Willow Creek-Lane 115 kV line	Lane Substation (BPA)	All BES equipment at Lane Substation is owned and operated by BPA -
Seneca-Westmoreland 115 kV line	Seneca Substation	**<u>Bus</u>** Seneca 115 kV **<u>Breaker</u>** 4350 **<u>Disconnects</u>** BSD4350 LSD4350 AS4351	Seneca-Westmoreland 115 kV line	Westmoreland Substation	**<u>Bus</u>** Westmoreland 115 kV **<u>Breaker</u>** 5180 **<u>Disconnects</u>** BSD5180 LSD5180
Seneca-Bertelsen 115 kV line	Seneca Substation	**<u>Bus</u>** Seneca 115 kV **<u>Breaker</u>** 4300 **<u>Disconnects</u>** BSD4300 LSD4300	Seneca-Bertelsen 115 kV line	Bertelsen Substation	**<u>Bus</u>** Bertelsen 115 kV **<u>Breaker</u>** 6470 **<u>Disconnects</u>** BSD6470 LSD6470

Line	Line Terminal		Line Section	Line Terminal	
Currin-Willakenzie 115 kV line	Currin Substation	**Bus** Currin 115 kV **Breaker** 4590 **Disconnects** BSD4590 LSD4590 TBD4591	Currin-Willakenzie 115 kV line	Willakenzie Substation	**Bus** Willakenzie 115 kV **Breaker** 5080 **Disconnects** BSD5080 LSD5080 TBD5081
Cal Young-Willakenzie 115 kV line	Cal Young Substation	**Bus** Cal Young 115 kV **Breaker** 4870 **Disconnects** BSD4870 LSD4870 AS4871	Cal Young-Willakenzie 115 kV line	Willakenzie Substation	**Bus** Willakenzie 115 kV **Breaker** 5078 **Disconnects** BSD5078 LSD5078 TBD5079
Cal Young-Santa Clara 115 kV line	Cal Young Substation	**Bus** Cal Young 115 kV **Breaker** 4872 **Disconnects** BSD4872 LSD4872	Cal Young-Santa Clara 115 kV line	Santa Clara Substation	**Bus** Santa Clara 115 kV **Breaker** 4670 **Disconnects** BSD4670 LSD4670 XSD4663
Prairie (EWEB)-Santa Clara 115 kV line	Prairie (EWEB) Substation	**Bus** Prairie (EWEB) 115 kV **Breaker** 5670 **Disconnects** BSD5670 LSD5670 AS5671	Prairie (EWEB)-Santa Clara 115 kV line	Santa Clara Substation	**Bus** Santa Clara 115 kV **Breaker** 4650 **Disconnects** BSD4650 LSD4650 XSD 4661
Alvey-Currin 115 kV line	Alvey Substation (BPA)	All BES equipment at Alvey Substation is owned and operated by BPA	Alvey-Currin 115 kV line	Currin Substation	**Bus** Currin 115 kV **Breaker** 4580 **Disconnects** BSD4580 LSD4580 TBD4581

Line	Line Terminal		Line Section	Line Terminal	
Currin-Laurel 115 kV line	Currin Substation	**Bus** Currin 115 kV **Breaker** 4578 **Disconnects** BSD4578 LSD4578	Currin-Laurel 115 kV line	Laurel Substation	**Bus** Laurel 115 kV **Breaker** 5200 **Disconnects** BSD5200 LSD5200
Hilyard-Laurel 115 kV line	Hilyard Substation	**Bus** Hilyard 115 kV **Breaker** 4150 **Disconnects** BSD4150 LSD4150 AS4151	Hilyard-Laurel 115 kV line	Laurel Substation	**Bus** Laurel 115 kV **Breaker** 5250 **Disconnects** BSD5250 LSD5250
Dillard-Hilyard 115 kV line	Dillard Substation	**Bus** Dillard 115 kV **Breaker** 4750 **Disconnects** BSD4750 LSD4750 AS4705	Dillard-Hilyard 115 kV line	Hilyard Substation	**Bus** Hilyard 115 kV **Breaker** 4152 **Disconnects** BSD4152 LSD4152
Hilyard-Monroe (EWEB) 115 kV line	Hilyard Substation	**Bus** Hilyard 115 kV **Breaker** 4100 **Disconnects** BSD4100 LSD4100	Hilyard-Monroe (EWEB) 115 kV line	Monroe (EWEB) Substation	**Bus** Monroe (EWEB) 115 kV **Breaker** 3700 **Disconnects** BSD3700 LSD3700 AS3751
Jefferson-Monroe (EWEB) 115 kV line	Jefferson Substation	**Bus** Jefferson 115 kV **Breaker** 6590 **Disconnects** BSD6590 LSD6590	Jefferson-Monroe (EWEB) 115 kV line	Monroe (EWEB) Substation	**Bus** Monroe (EWEB) 115 kV **Breaker** 3750 **Disconnects** BSD3750 LSD3750

Line	Line Terminal		Line Section	Line Terminal	
Jefferson-Westmoreland 115 kV line	Jefferson Substation	**Bus** Jefferson 115 kV **Breaker** 6570 6580 **Disconnects** BSD6570 LSD6570 BSD6581 BSD6583	Jefferson-Westmoreland 115 kV line	Westmoreland Substation	**Bus** Westmoreland 115 kV **Breaker** 5174 **Disconnects** BSD5174 LSD5174
University-Willamette 115 kV line	University Substation	**Bus** University 115 kV **Breaker** 7070 7060 **Disconnects** MOD7073 MOD7071 MOD7063	University-Willamette 115 kV line	Willamette Substation	**Bus** Willamette 115 kV **Breaker** 6050 **Disconnects** MOD6049 MOD6051 MOD6053 MOD6061
Adams-University 115 kV line	Adams Substation	**Bus** Adams 115 kV **Breaker** 3800 **Disconnects** BSD3800 LSD3800	Adams-University 115 kV line	University Substation	**Bus** University 115 kV **Breaker** 7050 **Disconnects** MOD7049 MOD7051 MOD7053 MOD7061
Adams-Bethel (EWEB) 115 kV line	Adams Substation	**Bus** Adams 115 kV **Breaker** 3850 **Disconnects** BSD3850 LSD3850	Adams-Bethel (EWEB) 115 kV line	Bethel (EWEB) Substation	**Bus** Bethel (EWEB) 115 kV **Breaker** 4200 **Disconnects** BSD4200 LSD4200

Line	Line Terminal		Line Section	Line Terminal	
Bethel (EWEB)-Eugene 115 kV line	Bethel (EWEB) Substation	**Bus** Bethel (EWEB) 115 kV **Breaker** 4270 **Disconnects** BSD4270 LSD4270 AS4251	Bethel (EWEB)-Eugene 115 kV line	Eugene Substation (BPA)	All BES equipment at Eugene Substation is owned and operated by BPA
Delta-Oakway 115 kV line	Delta Substation	**Bus** Delta 115 kV **Breaker** 5372 **Disconnects** LSD5372 AS5373 AS5371	Delta-Oakway 115 kV line	Oakway Substation	**Bus** Oakway 115 kV **Breaker** 5900 **Disconnects** BSD5900 LSD5900 AS5953
Delta-River Road (EWEB) 115 kV line	Delta Substation	**Bus** Delta 115 kV **Breaker** 5370 **Disconnects** BSD5370 LSD5370	Delta-River Road (EWEB) 115 kV line	River Road (EWEB) Substation	**Bus** River Road (EWEB) 115 kV **Breaker** 5500 **Disconnects** BSD5500 LSD5500
River Road (EWEB)-Eugene 115 kV line	River Road (EWEB) Substation	**Bus** River Road (EWEB) 115 kV **Breaker** 5550 **Disconnects** BSD5550 LSD5550	River Road (EWEB)-Eugene 115 kV line	Eugene Substation (BPA)	All BES equipment at Eugene Substation is owned and operated by BPA

Line	Line Terminal		Line Section	Line Terminal	
Currin-Hayden Bridge Switching Station 115 kV line	Currin Substation	**Bus** Currin 115 kV **Breaker** 4586 **Disconnects** BSD4586 LSD4586 TBD4587	Currin-Hayden Bridge Switching Station 115 kV line	Hayden Bridge Switching Station	**Bus** Hayden Bridge Switching Station 115 kV **Breaker** 2690 **Disconnects** BSD2690 LSD2690 TBD2691
Hayden Bridge-Hayden Bridge Switching Station 115 kV line	Hayden Bridge Substation	**Bus** Hayden Bridge 115 kV[1]	Hayden Bridge-Hayden Bridge Switching Station 115 kV line	Hayden Bridge Switching Station	**Bus** Hayden Bridge Switching Station 115 kV **Breaker** 2670 **Disconnects** BSD2670 LSD2670 TBD2671
Hayden Bridge Switching Station-Weyco 3 115 kV line	Hayden Bridge Switching Station	**Bus** Hayden Bridge Switching Station 115 kV **Breaker** 2680 **Disconnects** BSD2680 LSD2680 TBD2681	Hayden Bridge Switching Station-Weyco 3 115 kV line	Weyco 3 Substation	**Bus** Weyco 3 115 kV **Breaker** 2700 2720 **Disconnects** BSD2700 LSD2700 AS2751 AS2719 AS2721 BYD2720

[1] TOP jurisdiction ends on the high side of 115/69 kV transformer.

Line	Line Terminal		Line Section	Line Terminal	
Weyco 1-Weyco 3 115 kV line	Weyco 1 Substation	**Bus** Weyco 1 115 kV **Breaker** 2820 **Disconnects** BSD2820 LSD2820	Weyco 1-Weyco 3 115 kV line	Weyco 3 Substation	**Bus** Weyco 3 115 kV **Breaker** 2740 2730 **Disconnects** BSD2740 LSD2740 AS2731 AS2729 BYD2730
Thurston-Weyco 1 115 kV line	Thurston Substation	**Bus** Thurston 115 kV **Breaker** 2350 **Disconnects** BSD2350 LSD2350 AS2361	Thurston-Weyco 1 115 kV line	Weyco 1 Substation	**Bus** Weyco 1 115 kV **Breaker** 2830 **Disconnects** BSD2830 LSD2830
Dillard Tap to Eugene-Alvey #2 115 kV line	Dillard Substation	**Bus** Dillard 115 kV **Breaker** 4700 **Disconnects** BSD4700 LSD4700	Dillard Tap to Eugene-Alvey #2 115 kV line	Dillard Tap (BPA)	All BES equipment at Dillard Tap is owned and operated by BPA
Carmen Smith Tap to Cougar-Holden Creek #1 115 kV line	Carmen Smith Substation	**Bus** Carmen Smith 115 kV **Breaker** 1000 **Disconnects** BSD1000 LSD1000	Carmen Smith Tap to Cougar-Holden Creek #1 115 kV line	Carmen Smith Tap	**Disconnects** AS1051

Line	Line Terminal		Line Section	Line Terminal	
McKenzie Tap to Alvey-Diamond Hill (PACW) #3 230 kV line	McKenzie Substation	**Bus** McKenzie 230 kV **Breaker** 6692 **Disconnects** BSD6692 LSD6692 AS6698 1M33 1M34 1M35 1M513 1M514 **Other** 230/115 kV 150/200/250 MVA Transformer #2 (EWEB)	McKenzie Tap to Alvey-Diamond Hill (PACW) #3 230 kV line	McKenzie Substation	**Bus** McKenzie 115 kV **Breaker** 6676 **Disconnects** BSD6676 LSD6676 TBD6677
Thurston-McKenzie #1 115 kV Line (BPA)	McKenzie Substation	**Bus** McKenzie 115 kV **Breaker** 6682 **Disconnects** BSD6682 LSD6682 TBD6683	Thurston-McKenzie #1 115 kV Line (BPA)	Thurston Substation	**Bus** Thurston 115 kV **Breaker** 2300 **Disconnects** BSD2300 LSD2300
Cougar-Holden Creek #1 115 kV line (BPA)	Cougar Substation (BPA)	All BES equipment at Cougar Substation is owned and operated by BPA	Cougar-Holden Creek #1 115 kV line (BPA)	Holden Creek Substation	**Bus** Holden Creek 115 kV **Breaker** 7160 7170 7180 **Disconnects** BSD7170 LSD7170 BSD7180 LSD7180 AS7161 AS7163

Line	Line Terminal		Line Section	Line Terminal	
Holden Creek-Thurston #1 115 kV line (BPA)	Holden Creek Substation	**Bus** Holden Creek 115 kV **Breaker** 7150 7190 **Disconnects** BSD7150 LSD7150 BSD7190 LSD7190	Holden Creek-Thurston #1 115 kV line (BPA)	Thurston Substation	**Bus** Thurston 115 kV **Breaker** 2360 **Disconnects** BSD2360 LSD2360 BYD2360
Eugene-Bertelsen #1 115 kV line (BPA)	Eugene Substation (BPA)	All BES equipment at Eugene Substation is owned and operated by BPA	Eugene-Bertelsen #1 115 kV line (BPA)	Bertelsen Substation	**Bus** Bertelsen 115 kV **Breaker** 6450 **Disconnects** BSD 6450 LSD 6450 AS6453
Bertelsen-Willow Creek #1 115 kV line (BPA)	Bertelsen Substation	**Bus** Bertelsen 115 kV **Breaker** 6400 **Disconnects** BSD6400 LSD6400	Bertelsen-Willow Creek #1 115 kV line (BPA)	Willow Creek Substation	**Bus** Willow Creek 115 kV **Breaker** 5750 5754 **Disconnects** BSD5750 LSD5750 LSD5753 LSD5755
Willow Creek-Hawkins #1 115 kV line (BPA)	Willow Creek Substation	**Bus** Willow Creek 115 kV **Breaker** 5754 5758 **Disconnects** LSD5753 LSD5755 BSD5758 LSD5758	Willow Creek-Hawkins #1 115 kV line (BPA)	Hawkins Substation	**Bus** Hawkins 115 kV **Breaker** 6172 **Disconnects** BSD6172 LSD6172 AS6173

Line	Line Terminal		Line Section	Line Terminal	
Hawkins-Alvey #1 115 kV line (BPA)	Hawkins Substation	**Bus** Hawkins 115 kV **Breaker** 6170 **Disconnects** BSD6170 LSD6170	Hawkins-Alvey #1 115 kV line (BPA)	Alvey Substation (BPA)	All BES equipment at Alvey Substation is owned and operated by BPA

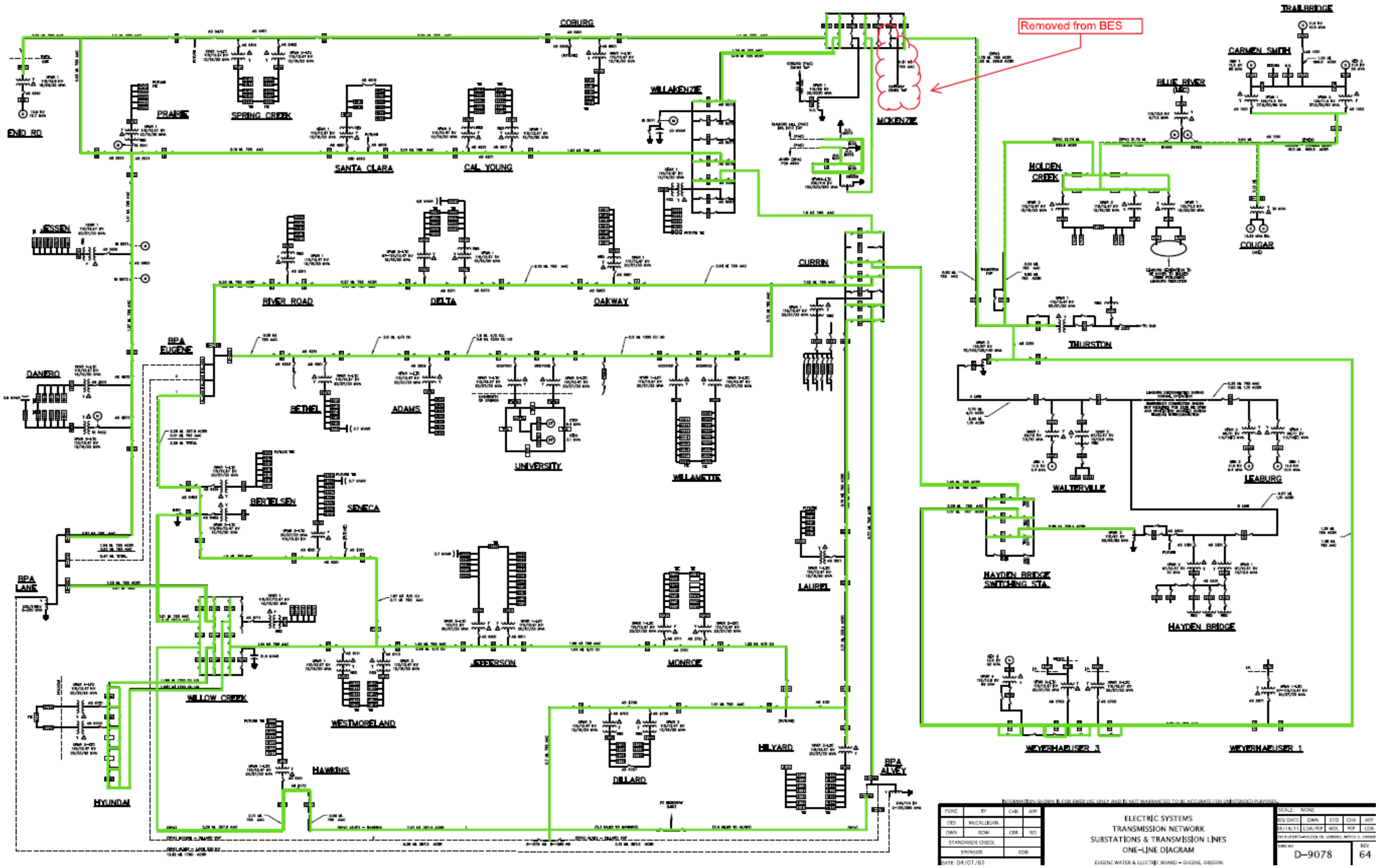
Notes: **The following facilities and associated equipment are three terminal lines. The lines are normally operated with all 3 terminals in service, but can be operated with one terminal out of service and the other two terminals in service. This type of configuration occurs for maintenance of breaker and associated equipment.**

Line	Line Terminal		Line Terminal		Line Terminal	
Enid Rd-Prairie (EWEB)-Spring Creek (EWEB) 115 kV line	Enid Rd Substation	**Bus** Enid Rd 115 kV **Breaker** 6900 **Disconnects** LSD6900	Prairie (EWEB) Substation	**Bus** Prairie (EWEB) 115 kV **Breaker** 5674 **Disconnects** BSD5674 LSD5674 AS5613	Spring Creek (EWEB) Substation	**Bus** Spring Creek (EWEB) 115 kV **Breaker** 5472 **Disconnects** BSD5472 LSD5472 AS5471 AS5473
Currin-Oakway-Willamette 115 kV line	Currin Substation	**Bus** Currin 115 kV **Breaker** 4584 **Disconnects** BSD4584 LSD4584 TBD4585	Willamette Substation	**Bus** Willamette 115 kV **Breaker** 6070 6060 **Disconnects** MOD6075 MOD6073 MOD6071 MOD6063	Oakway Substation	**Bus** Oakway 115 kV **Breaker** 5950 **Disconnects** BSD5950 LSD5950

2. REVISIONS

Customer shall notify the BPA Customer Service Reliability Program (CSRP) by submitting the Equipment Update Form when updates to this exhibit are necessary to accurately reflect the facilities over which BPA will carry out BPA's assigned TP responsibilities. Customer shall also inform CSRP as early in the planning process as practicable, but no later than 120 days before changes are made, when Customer identifies the need for equipment changes. The Parties shall revise this exhibit to reflect such changes. The Parties shall mutually agree on any such exhibit revisions. The effective date of any revision to this exhibit shall be the latter of the date the actual circumstances described by the revision occur or the date necessary visibility and control equipment is installed, or as otherwise agreed to by the Parties.

ONE LINE DIAGRAM



3. SIGNATURES

This Revision may be executed in several counterparts, all of which taken together will constitute one single agreement, and may be executed by electronic signature and delivered electronically. The parties have executed this Revision as of the last date indicated below.

EUGENE WATER & ELECTRIC BOARD	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: ______________________	By: ______________________
Title: Trading Operations Supervisor	Title: Manager, Customer Service Engineering

If opting out of the electronic signature:

By: ______________________

Name: ______________________
(Print/Type)

Title: ______________________

Date: ______________________

Contract No. 20TX-16939

NETWORK OPERATING AGREEMENT
executed by the
UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
acting by and through the
BONNEVILLE POWER ADMINISTRATION
and
EUGENE WATER & ELECTRIC BOARD

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Exhibit A Related Agreements
Exhibit B Other Operational or Technical Requirements
Exhibit C Remedial Action Schemes and Relay Schemes

This NETWORK OPERATING AGREEMENT (Agreement) is entered into by the UNITED STATES OF AMERICA, Department of Energy, acting by and through the BONNEVILLE POWER ADMINISTRATION (Transmission Provider) and EUGENE WATER & ELECTRIC BOARD (Network Customer), hereinafter individually also referred to as "Party" and collectively as "Parties."

The Transmission Provider provides Network Integration Transmission Service under the Transmission Provider's Open Access Transmission Tariff (Tariff) as it may be amended or replaced from time to time.

The Parties have entered into a Service Agreement for Network Integration Transmission Service (Service Agreement), on the 1st day of December 2001, and amended or replaced from time to time in which the Transmission Provider will provide Network Integration Transmission Service for the Network Customer.

The provision of Ancillary Services will be addressed in the Service Agreement.

The Network Customer shall either: (i) operate as a Balancing Authority Area under applicable requirements of NERC, WECC, and NWPP, and satisfy its own Balancing Authority Area Requirements, including all necessary Ancillary Services; (ii) satisfy its Balancing Authority Area requirements, including all necessary Ancillary Services, by contracting with the Transmission Provider, or (iii) satisfy its Balancing Authority Area requirements, including all necessary Ancillary Services, by contracting with another entity which satisfies the applicable reliability requirements of NERC, WECC, and NWPP.

The Parties recognize that the Transmission Provider's Transmission System is directly or indirectly interconnected with Transmission Systems owned or operated by others and the flow of power and energy between such systems shall be controlled by the physical and electrical characteristics of the facilities involved and the manner in which they are operated.

Part of the power and energy being delivered under this Agreement and the Service Agreement may flow through such other systems rather than through the Transmission Provider's facilities.

The Transmission Provider has established technical standards, guidelines, policies, and procedures (Standards) for planning, construction, maintenance, and operation of the Transmission Provider's grid, interties, and interconnections in accordance with the Tariff. Standards are available from the Transmission Provider and may be amended from time to time. Standards include, but are not limited to, the following documents or their successors:

- Technical Requirements for Interconnection to the BPA Transmission Grid;
- Metering Application Guide (MAG);
- Responsibilities and Technical Requirements Guide for Transmission Customer Owned Meters;
- BPA's Facility Ownership and Cost Assignment Guidelines; and
- BPA Outage Planning and Coordination Policy.

The Transmission Provider has established business practices (Practices) in accordance with the Tariff. Practices are available on the Transmission Provider's Website. Practices may be amended from time to time in accordance with the Transmission Provider's business practice process.

There is a need to identify operational requirements related to Network Integration Transmission Service over the Transmission Provider's Transmission System.

The Parties therefore agree as follows:

1. TERM OF AGREEMENT

This Agreement will be effective at 0000 hours on the date that this Agreement has been signed by both Parties (Effective Date), and shall remain in effect through the term of the Service Agreement.

In the event that the Agreement is terminated, all liabilities incurred hereunder are hereby preserved until satisfied.

2. EXHIBITS

The following Exhibits are hereby incorporated as part of this Agreement:

(a) Exhibit A Related Agreements

(b) Exhibit B Other Operational or Technical Requirements

(c) Exhibit C Remedial Action Schemes (RAS) and Relay Schemes

3. OBLIGATIONS OF THE PARTIES

The Parties to this Agreement shall:

(a) Agree to adhere to Good Utility Practice as defined in the Tariff, including all applicable reliability criteria as observed in the region;

(b) Determine methods and take appropriate actions to assure capability for delivery of power and energy at the points of receipt and delivery, and at additional or alternate points of receipt and delivery as established by the Parties;

(c) Operate and maintain equipment necessary for interconnecting the Network Customer with the Transmission Provider's Transmission System including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment. Each party is expected to maintain their own equipment unless otherwise agreed to;

(d) Transfer data as required to maintain reliability of the Transmission Provider's Transmission System;

(e) Use software programs required for data links and constraint dispatching for operational needs;

(f) Exchange data on forecasted loads and resources, and technical data necessary for planning and operation; and

(g) Address other technical and operational considerations required for Tariff implementation, including scheduling protocols.

4. DEFINITIONS

Unless otherwise defined herein, capitalized terms refer to terms defined in the Tariff, Rate Schedules, or *Glossary of Terms Used in NERC Reliability Standards* in effect at the time.

(a) "NERC" means North American Electric Reliability Corporation, or its successor.

(b) "NWPP" means the Northwest Power Pool, or its successor.

(c) "Operational Constraints" means limitations on the ability of the Transmission Provider's Transmission System to operate due to any system emergency, loading condition, or maintenance outage on the Transmission Provider facilities, or on facilities of an interconnected utility, that makes it prudent to reduce Transmission Provider's Transmission System loadings, whether or not all facilities are in service.

(d) "WECC" means the Western Electricity Coordinating Council, or its successor.

5. INTERCONNECTED FACILITY REQUIREMENTS[1]

(a) **Ownership**

(1) Equipment and facilities owned by one Party and installed on the property of the other Party shall remain the property of the owner, except as noted in this Agreement.

(2) A Party must identify its equipment and facilities installed on the other Party's property. Identification of ownership must be made by affixing suitable markers with the owner's name. The Parties may jointly prepare an itemized list of the aforementioned equipment and facilities.

[1] See Exhibits for additional customer-specific agreements or requirements.

(3) Each Party agrees to be responsible for the cost of complying with all applicable Federal, State, and local environmental laws for its own equipment and facilities.

(b) **Safety Design**
The Transmission Provider requires clearance of equipment during maintenance, modification, and testing. In accordance with the Transmission Provider's Standards and Practices, facility interconnections between the Transmission Provider and the Network Customer are to be designed and constructed to allow clearance of equipment using isolation devices. Isolation devices must produce a visible air gap between the energized facilities and the equipment to be maintained, modified, or tested. Any operating procedures associated with this interconnection must comply with OSHA Standard 29 CFR 1910.269(m) and also the ANSI/IEEE National Electric Safety Code as amended or replaced from time to time.

(c) **Access**

(1) Each Party grants permission, subject to site requirements, to the other to enter its property to perform operations, maintenance, meter reading, inspection, or removal of their respective equipment and facilities installed on the other Party's property.

(2) If unescorted access is prohibited, the Parties shall allow escorted access during normal business hours. Unescorted access shall be facilitated through separate agreement.

(3) Within the limitations of applicable law, in accessing equipment or facilities on the property of another, each Party is responsible for injury or damage to person or property from the intentional actions or negligent acts of its own employees and agents.

6. RESOURCE AND INTERCONNECTION PRINCIPLES AND REQUIREMENTS

(a) **Plan, Construct, Operate and Maintain Facilities**
The Network Customer shall plan, construct, operate and maintain its facilities and system that interconnect with the Transmission Provider's Transmission System in accordance with Good Utility Practice, including, but not limited to, all applicable requirements of (1) NERC, WECC, NWPP, and any other applicable reliability authority; and (2) the Transmission Provider's Standards and Practices.

(b) **System Protection**
The Parties acknowledge their obligations to respond to contingencies on the Transmission Provider's Transmission System and on systems directly and indirectly interconnected with the Transmission Provider's Transmission System, in accordance with the Transmission Provider's Tariff, Standards, and Practices. The Parties intend to meet this obligation by implementing

RAS or other relay schemes which may be identified in the attached Exhibit C.

7. CUSTOMER INFORMATION REQUIREMENT

Network Customer shall provide annually to the Transmission Provider, plans of any expansions of, or upgrades to, its owned generation or transmission facilities (lines, transformers, reactive equipment, load forecasts, etc.) for each of the subsequent ten years.

Requested information may include:

(a) **Annual and Ongoing Data Coordination Requirements:**

(1) Annual updates of load and resource forecasts.

(2) Any additional information required from the Network Customer as required by applicable reliability standards, or specified by the Transmission Provider's Tariff, Standards, and Practices.

(b) **Annual Data Exchange Technical Data Details:**
The Network Customer shall review, validate, and respond to the Transmission Provider's annual data exchange requests that are applicable to the Network Customer:

(1) The Network Customer must respond on or before the reasonable deadlines set by the Transmission Provider.

(2) Technical data requirements may include the following:

(A) Steady-State, Dynamics, Geomagnetic Induced Current (GIC), and Short Circuit data.

(B) One lines, facility ratings, facility rating methodology.

(C) Date of data validation, notification of latest version of files on record.

(D) Other information reasonably requested for modeling purposes.

8. POWER QUALITY

Requirements and information regarding Power Quality can be found in the Transmission Provider's Standards and Practices.

9. SERVICE INTERRUPTIONS

Outage Coordination

Parties must request and coordinate outages in accordance with the Tariff and the Transmission Provider's Standards and Practices.

10. EMERGENCY PLANNING AND OPERATION

(a) The Transmission Provider shall be responsible for planning, coordinating, and implementing emergency operation (NERC EOP) schemes including Disturbance Reporting (EOP-4), System Restoration (EOP-5), Geomagnetic Disturbances (EOP-10), and the Emergency Operating Plan (EOP-11). There may be additional schemes that meet the NWPP, WECC, and applicable reliability authority planning objectives. If the Transmission Provider identifies reliability objectives beyond the NWPP, WECC, and applicable reliability authority planning objectives, they shall be communicated to the Network Customer.

(b) **The Network Customer shall:**

(1) Participate in the development and implementation of Load Shedding programs for system security;

(2) Install and maintain the required Load Shedding relays, including under-frequency and under-voltage relays as reasonably determined by Transmission Provider to meet compliance obligations, provided, that the Network Customer can instead request that the Transmission Provider install such relays on the Transmission Provider's facilities that serve the Network Customer; and

(3) Participate in system restoration planning.

(c) Additional information regarding Emergency Planning and Operation can be found in the Transmission Provider's Standards and Practices.

11. METERING INFORMATION, COSTS, AND REQUIREMENTS

(a) The Network Customer shall review information and follow requirements related to metering found in the Transmission Provider's Standards and Practices.

(b) **Metering of Existing Facilities:**
The Transmission Provider shall be responsible for costs of all Transmission Provider-required new meter installation or meter replacements at a Network Customer's facility/ies existing on the Effective Date of this Agreement. The Network Customer may assume this responsibility by mutual agreement of the Parties.

The Network Customer shall be responsible for the costs of:

(1) Any meter replacement or new installation at points of delivery which are not required to achieve the best overall plan of service (convenience points of delivery as defined in the Transmission Provider's Standards and Practices);

(2) Any meters needed because the Network Customer changes Balancing Authorities or is displacing transmission from the Transmission Provider;

(3) Any meters requested by the Network Customer; and

(4) The supporting equipment to the metering system associated with supplying the Transmission Provider funded meter, including, but not limited to the instrument transformers for voltage potential and current flow (potential transformers and current transformers) and associated interconnected cabling, terminal blocks, and switches.

(c) Network Customer is required to notify the Transmission Provider if there are any changes to the supporting equipment to the metering system (instrument transformers specifically), or to the meter the customer has assumed responsibility for, that may affect the meter readings in any way prior to installing the new components so that updated billing arrangements can be implemented.

(d) Metering of New Network Customer Facilities:
The Transmission Provider shall be responsible for costs associated with installation of the Transmission Provider-approved metering at new facilities established after the Effective Date of this Agreement that are connected to the Transmission Provider's Transmission System.

The Network Customer shall be responsible for the costs of the Transmission Provider approved metering for:

(1) All points of resource integration;

(2) All Automatic Generation Control (AGC) interchange points; and

(3) All other points of electrical interconnection, including convenience points of delivery.

12. COMMUNICATIONS

Requirements and information regarding communications can be found in the Transmission Provider's Standards and Practices.

13. NETWORK OPERATING COMMITTEE

(a) **Membership**
The Network Operating Committee shall be composed of at least one representative from each participating Network Customer and the Transmission Provider or their designated agents.

(b) **Responsibilities**
The Network Operating Committee shall meet at least once per year to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Part 3 of the Tariff.

14. STANDARD PROVISIONS

(a) **Notices**
Notices or requests made by either Party regarding these provisions shall be made to the representative of the other Party as indicated in the Service Agreement.

(b) **Administration of The Provisions**
The Tariff and Service Agreement, as they are amended from time to time, are incorporated herein and made a part hereof, and are to be read together with this Agreement to determine the rights of the parties. In the event of any irreconcilable differences between the Tariff and this Agreement, the language of the Tariff shall govern.

(c) **Amendments**
Except where this Agreement explicitly allows one Party to unilaterally amend a provision or revise an exhibit, no amendment or exhibit revision to this Agreement shall be of any force or effect unless set forth in a written instrument signed by authorized representatives of each Party.

(d) **Assignment**
This Agreement is binding on any successors and assigns of the Parties. Neither Party may otherwise transfer or assign this Agreement, in whole or in part, without the other Party's written consent. Such consent shall not be unreasonably withheld.

(e) **Dispute Resolution**
Disputes arising under this Agreement are subject to the dispute resolution procedures set forth in the Tariff.

(f) **Entire Agreement**
This Agreement, including documents expressly incorporated by reference, constitutes the entire agreement between the Parties. It supersedes all previous communications, representations, or contracts, either written or oral, which purport to describe or embody the subject matter of this Agreement.

(g) **Freedom of Information Act (FOIA)**
The Transmission Provider may release information provided by the Network Customer to comply with FOIA or if required by any other Federal law or court order. Prior to releasing any such information, the Transmission Provider shall follow its then applicable procedures for notifying Parties that their information is subject to a FOIA request. For information that the

Network Customer designates in writing as proprietary or marks as Critical Energy/Electric Infrastructure Information (CEII) according to applicable rules and regulations, the Transmission Provider will limit the use and dissemination of that information within the Transmission Provider to employees who need the information for purposes of this Agreement.

(h) **Governing Law**
This Agreement shall be interpreted, construed, and enforced in accordance with Federal law.

(i) **No Third Party Beneficiaries**
This Agreement is made and entered into for the sole benefit of the Parties, and the Parties intend that no other person or entity shall be a direct or indirect beneficiary of this Agreement.

(j) **Section Headings**
Section headings and subheadings appearing in this Agreement are inserted for convenience only and are not be construed as interpretations of text.

(k) **Uncontrollable Forces**
The Parties shall not be in breach of their respective obligations to the extent the failure to fulfill any obligation is due to an Uncontrollable Force. "Uncontrollable Force" means an event beyond the reasonable control of, and without the fault or negligence of, the Party claiming the Uncontrollable Force that prevents that Party from performing its contractual obligations under this Agreement and which, by exercise of that Party's reasonable care, diligence and foresight, such Party was unable to avoid. Uncontrollable Forces include, but are not limited to:

(1) strikes or work stoppage;

(2) floods, earthquakes, fire, or other natural disasters, terrorist acts, epidemics, pandemics; and

(3) final orders or injunctions issued by a court or regulatory body having competent subject matter jurisdiction which the Party claiming the Uncontrollable Force, after diligent efforts, was unable to have stayed, suspended, or set aside pending review by a court of competent subject matter jurisdiction.

Neither the unavailability of funds or financing, nor conditions of national or local economies or markets shall be considered an Uncontrollable Force. The economic hardship of either Party shall not constitute an Uncontrollable Force. Nothing contained in this provision shall be construed to require either Party to settle any strike or labor dispute in which it may be involved.

If an Uncontrollable Force prevents a Party from performing any of its obligations under this Agreement, such Party shall: (1) immediately notify the other Party of such Uncontrollable Force by any means practicable and confirm such notice in writing as soon as reasonably practicable; (2) use its best efforts to mitigate the effects of such Uncontrollable Force, remedy its inability to perform, and resume full performance of its obligation hereunder as soon as reasonably practicable; (3) keep the other Party apprised of such efforts on an ongoing basis; and (4) provide written notice of the resumption of performance. Written notices sent under this section shall be made as indicated in the Service Agreement.

(l) **Waivers**
No waiver of any provision or breach of this Agreement shall be effective unless such waiver is in writing and signed by the waiving Party, and any such waiver shall not be deemed a waiver of any other provision of this Agreement or any other breach of this Agreement.

15. SIGNATURES
This Agreement may be executed in several counterparts, all of which taken together will constitute one single agreement, and may be executed by electronic signature and delivered electronically. The Parties have executed this Agreement as of the last date indicated below.

EUGENE WATER & ELECTRIC BOARD	UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration
By: ______________________	By: ______________________
Title: Trading Operations Supervisor	Title: Transmission Account Executive

If opting out of the electronic signature:

By: ______________________

Name: ______________________
(Print / Type)

Title: ______________________

Date: ______________________

EXHIBIT A
RELATED AGREEMENTS

This Exhibit A identifies agreements between the Parties which may contain additional obligations related to this Network Operating Agreement. Agreements identified in this exhibit are for reference only.

Table 1 Related Agreements

Related Agreement	Contract No.
Network Integration Transmission Services Agreement	02TX-10793
Operations Delegation Agreement	07TX-12876
Transmission Operator Agreement	19TP-11686
Facilities Ownership and O&M Responsibilties Agreement	01TX-10766
Mutual Assistance Agreement	16TX-16342

EXHIBIT B
OTHER OPERATIONAL OR TECHNICAL REQUIREMENTS

This Exhibit B identifies additional requirements and obligations that may be unique to the Network Customer.

Operational and Technical Requirements

(a) BPA owned Cougar-Holden Creek #1 115kV line and Holden Creek-Thurston #1 115kV line are EWEB dispatched.

(b) EWEB and BPA share breaker status, and analog operational data via ICCP across respective SCADA systems.

EXHIBIT C
REMEDIAL ACTION SCHEMES AND RELAY SCHEMES

This Exhibit C identifies Remedial Action Schemes (RAS) and Relay Schemes that the Network Customer participates in.

Transmission Provider will provide written notice to Network Customer of any future RAS or Relay Scheme requirements as system conditions warrant, and Network Customer will comply with those requirements.

Table #1 Remedial Action Schemes

Action (e.g. load, gen, reconfigure)	Related Contract No.
Not applicable	Not applicable

Table #2 Relay Schemes

Description or Action	Related Contract No.
Eugene-Alvey #2: 3-terminal Permissive and direct mirror bit transfer trip on SEL-321 set #1. Current differential RFL9300 on set #2. Mirror bit transfer trip is back to back at EWEB's Dillard substation, where EWEB owns the relaying. Communication circuits on EWEB's communication system.	Not applicable
Alvey-Hawkins #1: Permissive mirror bit transfer trip on SEL-321 set #1. Current differential RFL9300 on set #2. EWEB owns the relaying at EWEB's Hawkins substation. Communication circuits on EWEB's communication system.	Not applicable
Eugene-Bethel #1 and Eugene-EWEB #3 River Road: Permissive mirror bit transfer trip on SEL-311 set #1. Current differential SEL-311L on set #2. EWEB owns the remote terminals. Communication circuits on EWEB's communication system.	Not applicable
Alvey-Currin #1 and Eugene-Bertelsen #1: Pilot wire relaying where BPA owns one terminal and EWEB owns the other. Communication circuits on EWEB's communication system. Pilot wire signal converted to digital.	Not applicable
EWEB owns and operates relays at Thurston and Holden Creek that protect BPA owned 115kV transmission lines. Auto-sectionalizing at Blue River Tap affects EWEB's upriver Carmen Smith Generation. Upriver section from the Tap can be islanded.	Not applicable
Alvey-Mckenzie-Diamond Hill #1 230kV: three terminal line with direct tripping via carrier current transfer trip. Communications owned and maintained by Pacificorp.	Not applicable

Description or Action	Related Contract No.
UFLS relay action for 59.3Hz underfrequency event: ▪ Currin Substation breaker 4582 ▪ Spring Creek Substation breakers 5410 & 5420 ▪ Coburg Substation breaker 6810	Not applicable
UFLS relay action for 59.2Hz underfrequency event: ▪ Westmoreland Substation breaker 5110 ▪ Dillard Substation breaker 4730 ▪ Seneca Substation breaker 4320	Not applicable
UFLS relay action for 59.0Hz underfrequecny event: ▪ Bethel Substation breaker 4210 ▪ Adams Substation breaker 3840 ▪ River Rd Substation breaker 5510	Not applicable
UFLS relay action for 58.8Hz underfrequency event: ▪ Danebo Substation breaker 4920 ▪ Willow Creek Substation breaker 5710 ▪ Bertelsen Substation breaker 6410 ▪ Monroe Substation breakers 3710 & 3720	Not applicable
UFLS relay action for 58.6Hz underfrequency event: ▪ Holden Creek Substation breakers 7120 & 7130	Not applicable
UVLS relay action for 103.2kV undervoltage event: ▪ Bertelsen Substation breaker 6410 ▪ Currin Substation breaker 4532	Not applicable
UVLS relay action for 105.1kV undervoltage event: ▪ Spring Creek Substation breakers 5410 & 5420	Not applicable
UVLS relay action for 105.8kV undervoltage event: ▪ Dillard Substation breakers 4720 & 4730	Not applicable