Oregon
Kate Brown, Governor

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June 20, 2016

Via Electronic Filing

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX: 1088
SALEM OR 97308-1088

RE: Docket No. UE 308 – In the Matter of
PORTLAND GENERAL ELECTRIC COMPANY,
2017 Annual Power Cost Update Tariff (Schedule 125).

Enclosed for electronic filing in the above-captioned docket is Staff's Opening Testimony.

Exhibit 102 is voluminous and is included with the CD.

Confidential pages for Exhibit 100 are pages 2, 9 and 10.
Confidential pages for Exhibit 200 are pages 7 and 8.
Confidential pages for Exhibit 300 are [ages 3, 6 to 13.

Exhibit 103, 104, 105, 202, 302, 303, 304 and 306 are confidential.
Exhibit 306 has confidential work paper.

/s/ Kay Barnes
Kay Barnes
PUC- Utility Program
(503) 378-5763
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CASE: UE 308
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

<u>REDACTED</u>
Opening Testimony

June 20, 2016

Q. Please state your name, and business address.

A. My name is Scott Gibbens. I am a Senior Economist for the Public Utility Commission of Oregon (Commission or OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your background and work experience.

A. My witness qualification statement is found in exhibit Staff/101.

Q. On whose behalf are you testifying in this proceeding?

A. Staff of the Public Utility Commission of Oregon.

Q. What topics will Staff testimony address?

A. Staff addresses Portland General Electric Company's (PGE)'s updated forecasted of net variable power costs (NVPC) in 2017 for its Automatic Update Tariff (AUT) (Schedule 125). Staff discusses its review of PGE's forecasted NVPC for 2017 and proposes adjustments related to:

(1) the forced outage rate at PGE's Coyote Springs natural gas plant;

(2) penalties that PGE incurs when it does not meet the minimum delivery requirements of its coal transportation contracts with BNSF Railway Company (BNSF) and Union Pacific Railroad Company (UP) and PGE's system optimization to avoid penalties;

(3) PGE's calculation of net benefits resulting from transactions at the California-Oregon Border (COB) market that PGE may make utilizing its firm transmission rights, and;

(4) cost and benefits related to PGE's participation in the Energy Imbalance Market (EIM), which starts the fourth quarter of 2017.

Staff also proposes that PGE defer any revenue that PGE may receive in 2017 related to the termination of its Power Hydroelectric Project (PHP) Power Sales Agreement with the City of Portland rather than allowing the revenue to flow through to customers through the Power Cost Adjustment Mechanism that trues up PGE's forecasted NVPC to its actual NVPC subject to a deadband, sharing, and earnings test. Finally, Staff addresses PGE's proposal to include forecasted federal production tax credits in forecasted NVPC for 2017. Staff does not address the proposed long-term gas hedge PGE discusses in supplemental direct testimony filed on June 3, 2016. Staff will address the long-term hedge in testimony filed on August 12, 2016.[1]

Q. Please summarize Staff's adjustments in this docket.

A. Below is a table summarizing the Staff adjustments found in Staff testimony.

Adjustment	Amount	Testimony Ref
California trading margins	[redacted]	Kaufman 300/2-6
Boardman coal mgmt.	[redacted]	Kaufman 300/7-13
Coyote Springs FOR	($1,700,000)	Crider 200/9-11
EIM net benefits	[redacted]	Crider 200/6-8
Portland Hydro contract	[redacted]	Gibbens 100/9-10
TOTAL	[redacted]	

Q. Which issues do you address?

A. I provide testimony on MONET model parameters, the impact of PGE's wind integration choice (BPA VERBS), and issues related to the Portland Hydro Project. Staff witness Crider will discuss the issues related to EIM, the federal

[1] See April 18, 2016 Prehearing Conference Memorandum bifurcating consideration of long-term gas hedge from the remainder of AUT issues.

wind production credits and the forced outage rate calculation for Coyote Springs (Exhibit 200). Staff witness Kaufman will discuss the California-Oregon trading margins and management of Boardman coal (Exhibit 300).

Q. How is your testimony organized?

A. The testimony is organized as follows:

ISSUE 1, MINIMUM FILING REQUIREMENTS AND MONET INPUTS

Q. What is PGE's forecasted NVPC for 2017?

A. PGE's initial 2017 NVPC forecast, excluding PGE's forecast of PTCs, is $499.8 million, based on contracts and forward curves as of February 25, 2016. This initial forecast represents a reduction of $32.3 million relative to the final 2016 NVPC forecast.[2] PGE's forecasted NVPC, including PTCs valued at $76.2 million, is $423.6 million.

PGE states that its forecast of 2017 NVPC includes all the updates required under Schedule 125, and specifically addresses only a few significant adjustments in testimony.[3]

Q. Did the filing conform to applicable Minimum Filing Requirements (MFRs)?

A. Yes, the filing includes all MFRs. Commission Order No. 08-505 (Order) contains a list of MFRs for PGE in AUT filings. Staff utilized the MFRs during our analysis of PGE's NVPC. From a high level, the supporting documents contain:

- Summary Documents (Items 1-6)
- MONET Input Supporting Docs
- Historical Data

Q. Please describe what MONET inputs the Company updated.

A. The Company updated the following inputs:

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[2] PGE/400, Niman-Peshka-Hager/1.
[3] PGE/400, Niman-Peshka-Hager/6.

a. Forward Price Curves;

b. Load Forecasts;

c. Heat rates;

d. Pacific Northwest Coordination Agreement Headwater Benefit Study;

e. Contracts for wholesale power and power purchases and sales;

f. Wind availability forecast;

g. PURPA contract expenses; and

h. Maintenance and Forced Outage rates.

Q, Did Staff check the validity and reasonableness of the updated input parameters?

A. Yes, Staff reviewed every updated input group used in the AUT. In general, the values seem reasonable and in line with both previous filings and last year's actual parameter values. Staff currently has pending several Data Requests that are intended to clarify a few outliers. Potential issues associated with input parameters are discussed later in testimony.

Q. Did PGE perform the prescribed calculations properly?

A. Yes, Staff has found no errors associated with the calculations used in the AUT. The Company adhered to pertinent Commission orders in every calculation.

<u>ISSUE 2, VARIABLE ENERGY RESOURCE BALANCING SERVICE (VERBS)</u>

Q. What is VERBS?

A. Variable Energy Resource Balancing Service (VERBS) is a Control Area Service offered by Bonneville Power Administration (BPA) to all Variable Energy Resources (VERs) that are within BPA's Balancing Authority Area (BAA) in order for the VERs to satisfy its reliability obligation. Located in BPA's BAA are PGE's Biglow Canyon and Tucannon River Wind Farms, which provide a variable amount of power at any given moment based on wind speed and direction. BPA offers utilities the option to select a VERBS product to balance the variable energy at four different levels based on the frequency of energy schedules submitted and the generation signal persistence used to calculate the schedules. The products currently offered are referred to as "30/60", "40/15", "30/15", and "Uncommitted", where the first number is the number of minutes preceding the scheduling period for which the persistence value (one-minute average of the actual generation) is calculated, and the second number is the length of the scheduling period. Under the Uncommitted Scheduling, a party can either 1) use the BPA supplied wind generation forecast as the schedule, or 2) they can opt to use a different forecast for an additional fee.

Q. What is PGE's current election?

A. PGE currently is utilizing the 30/15 VERBS product. The fifteen minute scheduling means that the Company provides four wind schedules per hour to BPA. This is the lowest cost VERBS product available from BPA.

Q. If it is the lowest cost, why is this an issue for Staff?

A. Beginning in October 2017, PGE will be joining CAISO's EIM. The EIM will effectively replace VERBS to provide moment-to-moment balancing of PGE's VERs. PGE plans to “pseudo-tie” their wind resources out of BPA's BAA and fully self-integrate.[4] However, according to the Company, BPA has been reticent to commit to a timeline for when the pseudo-tie could take place. Due to this, PGE has chosen to continue to include the cost of VERBS through the end of the year. PGE states in testimony that there is no net effect to NVPC as part of modeling the 30/15 throughout the year; however, fully self-integrating for the last quarter of the year may provide a power cost reduction.[5]

Q. If PGE will no longer be utilizing BPA services, why are they included in MONET?

A. Staff currently has pending Date Requests in order to further understand the situation. Based on Staff’s reading of the BPA tariff sheet, PGE should be able to qualify for one of the two exceptions listed in the tariff that will allow self-integration.[6] It states:

> Individual rate components under section 2.a.(1)-(5) above will not apply to a Variable Energy Resource, or portion of a Variable Energy Resource, that, in BPA’s determination, has put in place, tested, and successfully

[4] A pseudo tie is a telemetered reading or value that is updated in real time and used as a tie line flow in the Automatic Generation Control/Area Control Error (AGC/ACE) equation but for which no physical tie or energy metering actually exists.
[5] PGE/400, Niman-Peshka-Hager/15.
[6] Staff/102.

> implemented in conformance to criteria specified in BPA business practices, no later than the 15th day of the month prior to the billing month, self-supply of that component of Balancing Service, including by contractual arrangements for third-party supply.

Staff will continue to investigate the apparent discrepancy between BPA's timeline stated in tariffs and timeline stated to PGE.

Q. What is Staff's estimation of the apparent reduction in costs?

A. When looking at a conservative estimation of costs associated with complete self-integration (No EIM benefit), Staff finds that there are no apparent cost savings at this time.[7] In light of this fact, Staff finds no impetus for adjustment to NVPC.

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[7] Staff/103.

ISSUE 3, PORTLAND HYDRO PROJECT

Q. What is the Portland Hydroelectric Project (PHP)?

A. The PHP is a hydroelectric power generating facility located in the Bull Run watershed owned by the City of Portland. The project was completed and commercial generation was initiated in 1982. The City sells the power output to PGE who operates and maintains the facilities.

Q. Please describe the issue related to the PHP Power Purchase Agreement (PPA).

A. The PPA between the City of Portland and PGE expires August 31, 2017. Under that PPA, PGE could receive a disbursement in 2017 from a Renewal and Replacement (R&R) Fund created under the PPA.[8] PGE's receipt of a disbursement is not certain however, and therefore not included in PGE's forecasted NVPC.[9]

Q. How does Staff propose to treat the possible disbursement?

A. Staff proposes that 100 percent of any disbursement PGE receives in 2017 in connection with termination of the PHP PPA be flowed through to customers. To accomplish this, Staff recommends deferring any disbursement rather than capturing it in the PCAM, which trues up forecasted NVPC to actual.

Q. How is the PHP contract modeled in MONET?

A. In the current MONET model, the contract is modeled with the existing terms until the expiration of the [redacted]

[8] See Confidential Staff/104 (PGE Confidential Response to ICNU DR 8 Attachment A).
[9] See Confidential Staff/104 (PGE Confidential Response to ICNU DR 8 Attachment A).

[redacted]. In the confidential workpapers supporting the use of this value, the Company states that the number included in the MONET model is a placeholder that does not reflect the true (to-be-determined) price but instead is based upon the 2016 AUT price.

Q. Does Staff agree with this treatment of the contract price?

A. No. Staff notes that the Company's forward market projection shows energy [redacted]. This is not a reasonable assumption even for a placeholder. Current market conditions must be taken into account.

Q. What alternative does Staff propose?

A. Staff proposes that the Company replace the placeholder value with the price of market energy for the four months (September thru December 2017) for which an executed agreement does not currently exist. This results in a [redacted] to NVPC.[10] If the PPA is renewed before settlement of this AUT, Staff proposes the Company update the value to reflect actual contract terms.

Q. Does this conclude your testimony?

A. Yes.

[10] Staff/105.

CASE: UE 308
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 101

Witness Qualifications Statement

June 20, 2016

WITNESS QUALIFICATION STATEMENT

NAME:	Scott Gibbens
EMPLOYER:	Public Utility Commission Of Oregon
TITLE:	Senior Economist Energy Rates, Finance and Audit
ADDRESS:	201 High St. SE Ste. 100 Salem, OR 97301-3612
EDUCATION:	Bachelor of Science, Economics, University of Oregon Masters of Science, Economics, University of Oregon
EXPERIENCE:	I have been employed at the Oregon Public Utility Commission (Commission) since August of 2015. My current responsibilities include analysis and technical support for electric power cost recovery proceedings with a focus in model evaluation. I also handle analysis and decision making of affiliated interest and property sale filings, rate spread and rate design, as well as operational auditing and evaluation. Prior to working for the OPUC I was the operations director at Bracket LLC. My responsibilities at Bracket included quarterly financial analysis, product pricing, cost study analysis, and production streamlining. Previous to working for Bracket, I was a manager for US Bank in San Francisco where my responsibilities included coaching and team leadership, branch sales and campaign oversight, and customer experience management.

CASE: UE 308
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

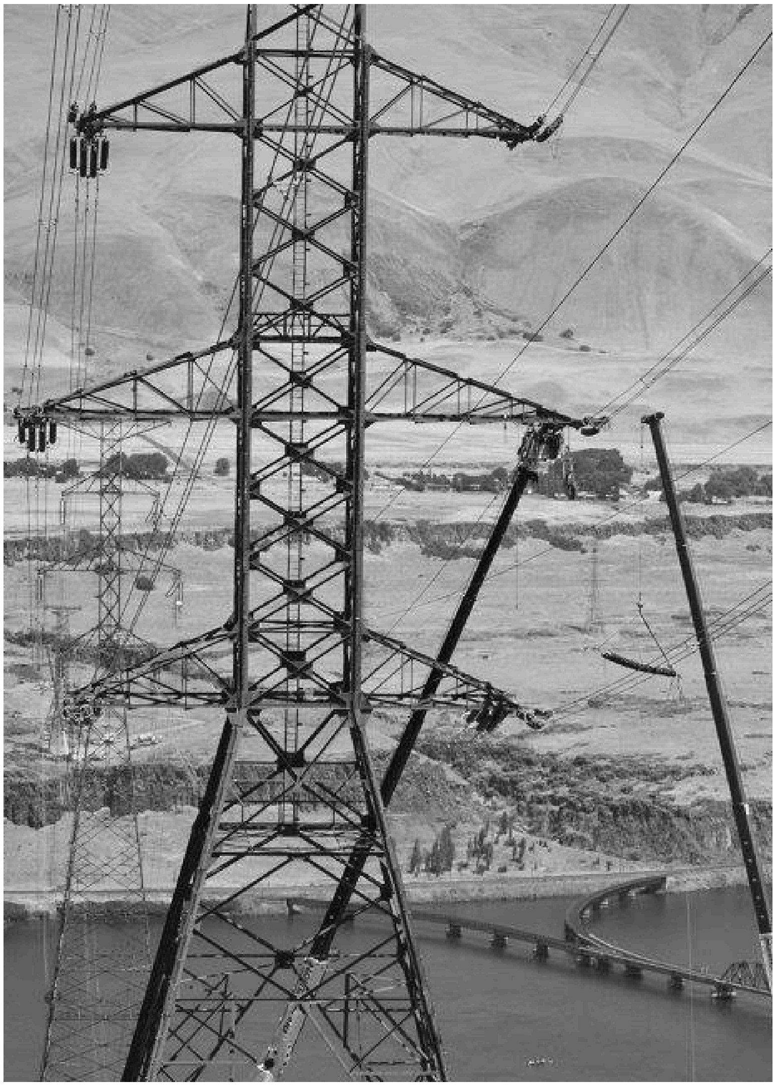
STAFF EXHIBIT 102

Exhibits in Support
Of Opening Testimony

June 20, 2016

B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

2016 Transmission, Ancillary, and Control Area Service Rate Schedules and General Rate Schedule Provisions (FY 2016–2017)



October 2015

United States Department of Energy
Bonneville Power Administration
905 N.E. 11th Avenue
Portland, OR 97232

Bonneville Power Administration's 2016 Transmission, Ancillary, and Control Area Service Rate Schedules and General Rate Schedule Provisions, effective October 1, 2015, and contained herein, were approved on an interim basis by the Federal Energy Regulatory Commission on September 17, 2015. *U.S. Dep't of Energy – Bonneville Power Admin.,* 152 FERC ¶ 61,201 (2015).

These Transmission, Ancillary, and Control Area Service Rate Schedules and General Rate Schedule Provisions reflect all errata corrections, if any, as of the date of publication.

BONNEVILLE POWER ADMINISTRATION

2016 TRANSMISSION, ANCILLARY, AND CONTROL AREA SERVICE RATE SCHEDULES AND GENERAL RATE SCHEDULE PROVISIONS

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TRANSMISSION, ANCILLARY, AND CONTROL AREA SERVICE RATE SCHEDULES

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FPT-16.1
FORMULA POWER TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes the FPT-14.1 rate schedule for all firm transmission agreements that provide for application of FPT rates that may be adjusted not more frequently than once a year. This schedule is applicable only to such transmission agreements executed prior to October 1, 1996. It is available for firm transmission of non-Federal power using the Main Grid and/or Secondary System of the Federal Columbia River Transmission System. This schedule is for full-year and partial-year service and for either continuous or intermittent service when firm transmission service is required. For facilities at voltages lower than the Secondary System, a different rate schedule may be specified. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATES

The monthly charge per kilowatt (kW) shall be one-twelfth of the sum of the Main Grid Charge and the Secondary System Charge, as applicable and as specified in the agreement.

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

$$\left(1 + \frac{GSR_q}{\$1.634/\text{kW/mo}}\right) * \text{ FPT Base Charges}$$

Where:

GSR_q	=	The ACS-16 Reactive Supply and Voltage Control From Generation Sources Service Rate for Long-Term Firm PTP Transmission Service and NT Service, section II.B.1.a., that is effective for the quarter for which the FPT rate is being calculated, in \$/kW/mo.
FPT Base Charges	=	The following annual Main Grid and Secondary System charges:

MAIN GRID CHARGES		
1.	Main Grid Distance	$0.0700 per mile
2.	Main Grid Interconnection Terminal	$0.73/kW
3.	Main Grid Terminal	$0.81/kW
4.	Main Grid Miscellaneous Facilities	$3.99/kW
SECONDARY SYSTEM CHARGES		
1.	Secondary System Distance	$0.6884 per mile
2.	Secondary System Transformation	$7.53/kW
3.	Secondary System Intermediate Terminal	$2.91/kW
4.	Secondary System Interconnection Terminal	$2.06/kW

Main Grid Distance and Secondary System Distance charges shall be calculated to four decimal places. All other Main Grid and Secondary System charges shall be calculated to two decimal places.

The Main Grid Charge per kilowatt shall be the sum of one or more of the Main Grid annual charges, as specified in the agreement. The Secondary System Charge per kilowatt shall be the sum of one or more of the Secondary System annual charges, as specified in the agreement.

SECTION III. BILLING FACTORS

Unless otherwise stated in the agreement, the Billing Factor for the rates specified in section II shall be the largest of:

A. The Transmission Demand;

B. The highest hourly Scheduled Demand for the month; or

C. The Ratchet Demand.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Ancillary Services that may be required to support FPT transmission service are available under the ACS rate schedule. FPT customers do not pay the ACS charges for Scheduling, System Control, and Dispatch Service or Reactive Supply and Voltage Control from Generation Sources Service, because these services are included in FPT service.

B. FAILURE TO COMPLY PENALTY

Customers taking service under this rate schedule are subject to the Failure to Comply Penalty Charge, specified in GRSP II.B.

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FPT-16.3
FORMULA POWER TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes the FPT-14.3 rate schedule for all firm transmission agreements that provide for application of FPT rates that may be adjusted not more frequently than once every three years. This schedule is applicable only to such transmission agreements executed prior to October 1, 1996. It is available for firm transmission of non-Federal power using the Main Grid and/or Secondary System of the Federal Columbia River Transmission System. This schedule is for full-year and partial-year service and for either continuous or intermittent service when firm transmission service is required. For facilities at voltages lower than the Secondary System, a different rate schedule may be specified. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATES

A. FY 2016 Rates

The monthly charge per kilowatt (kW) shall be one-twelfth of the sum of the Main Grid Charge and the Secondary System Charge, as applicable and as specified in the agreement.

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

$$\left(1 + \frac{GSR_q}{\$1.666/\text{kW/mo}}\right) * \text{ FPT Base Charges}$$

Where:

GSR_q = The ACS-16 Reactive Supply and Voltage Control From Generation Sources Service Rate for Long-Term Firm PTP Transmission Service and NT Service, section II.B.1.a., that is effective for the quarter for which the FPT rate is being calculated, in $/kW/mo.

FPT Base Charges = The following annual Main Grid and Secondary System charges:

MAIN GRID CHARGES		
1.	Main Grid Distance	\$0.0679 per mile
2.	Main Grid Interconnection Terminal	\$0.71/kW
3.	Main Grid Terminal	\$0.79/kW
4.	Main Grid Miscellaneous Facilities	\$3.87/kW
SECONDARY SYSTEM CHARGES		
1.	Secondary System Distance	\$0.6676 per mile
2.	Secondary System Transformation	\$7.30/kW
3.	Secondary System Intermediate Terminal	\$2.82/kW
4.	Secondary System Interconnection Terminal	\$2.00/kW

Main Grid Distance and Secondary System Distance charges shall be calculated to four decimal places. All other Main Grid and Secondary System charges shall be calculated to two decimal places.

The Main Grid Charge per kilowatt shall be the sum of one or more of the Main Grid annual charges, as specified in the agreement. The Secondary System Charge per kilowatt shall be the sum of one or more of the Secondary System annual charges, as specified in the agreement.

B. FY 2017 Rates

The monthly charge per kilowatt (kW) shall be one-twelfth of the sum of the Main Grid Charge and the Secondary System Charge, as applicable and as specified in the agreement.

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

$$\left(1 + \frac{GSR_q}{\$1.634/kW/mo}\right) * \text{FPT Base Charges}$$

Where:

GSR_q = The ACS-16 Reactive Supply and Voltage Control From Generation Sources Service Rate for Long-Term Firm PTP Transmission Service and NT Service, section II.B.1.a., that is effective for the quarter for which the FPT rate is being calculated, in \$/kW/mo.

FPT Base Charges = The following annual Main Grid and Secondary System charges:

MAIN GRID CHARGES		
1.	Main Grid Distance	$0.0700 per mile
2.	Main Grid Interconnection Terminal	$0.73/kW
3.	Main Grid Terminal	$0.81/kW
4.	Main Grid Miscellaneous Facilities	$3.99/kW
SECONDARY SYSTEM CHARGES		
1.	Secondary System Distance	$0.6884 per mile
2.	Secondary System Transformation	$7.53/kW
3.	Secondary System Intermediate Terminal	$2.91/kW
4.	Secondary System Interconnection Terminal	$2.06/kW

Main Grid Distance and Secondary System Distance charges shall be calculated to four decimal places. All other Main Grid and Secondary System charges shall be calculated to two decimal places.

The Main Grid Charge per kilowatt shall be the sum of one or more of the Main Grid annual charges, as specified in the agreement. The Secondary System Charge per kilowatt shall be the sum of one or more of the Secondary System annual charges, as specified in the agreement.

SECTION III. BILLING FACTORS

Unless otherwise stated in the agreement, the Billing Factor for the rates specified in section II shall be the largest of:

A. The Transmission Demand;

B. The highest hourly Scheduled Demand for the month; or

C. The Ratchet Demand.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Ancillary Services that may be required to support FPT transmission service are available under the ACS rate schedule. FPT customers do not pay the ACS charges for Scheduling, System Control, and Dispatch Service or Reactive Supply and Voltage Control from Generation Sources Service, because these services are included in FPT service.

B. FAILURE TO COMPLY PENALTY

Customers taking transmission service under FPT agreements are subject to the Failure to Comply Penalty Charge, specified in GRSP II.B.

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IR-16
INTEGRATION OF RESOURCES RATE

SECTION I. AVAILABILITY

This schedule supersedes the IR-14 rate schedule and is available for transmission of non-Federal power for full-year firm transmission service and non-firm transmission service in amounts not to exceed the customer's total Transmission Demand using Federal Columbia River Transmission System Network and Delivery facilities. This schedule is applicable only to Integration of Resource (IR) agreements executed prior to October 1, 1996. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATES

The IR rates in sections A and B, below, are calculated each quarter. These rates shall be calculated to three decimal places. The monthly IR rate shall be as provided in section A or section B.

A. RATE

The rate shall be the sum of:

1. $1.790 per kilowatt per month ($/kW/mo); and

2. ACS-16 Reactive Supply and Voltage Control From Generation Sources Service Rate for Long-Term Firm PTP Transmission Service and NT Service, section II.B.1.a., effective for the quarter for which the IR rate is being calculated, in $/kW/mo.

B. SHORT DISTANCE DISCOUNT (SDD) RATE

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

1. $0.301/kW/mo; and

2. ACS-16 Reactive Supply and Voltage Control From Generation Sources Service Rate for Long-Term Firm PTP Transmission Service and NT Service, section II.B.1.a., effective for the quarter for which the IR rate is being calculated, in $/kW/mo; and

3. (0.6 + (0.4 * transmission distance/75)) * $1.489/kW/mo

Where:

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

SECTION III. BILLING FACTORS

The Billing Factor for rates specified in section II shall be the largest of:

A. The annual Transmission Demand, or, if defined in the agreement, the annual Total Transmission Demand;

B. The highest hourly Scheduled Demand for the month; or

C. The Ratchet Demand.

To the extent that the agreement provides for the IR customer to be billed for transmission service in excess of the Transmission Demand or Total Transmission Demand, as defined in the agreement, at an hourly non-firm rate, such excess transmission service shall not contribute to the Billing Factor for the IR rates in section II, provided that the IR customer requests such treatment and BPA approves such request in accordance with the prescribed provisions in the agreement. The rate for transmission service in excess of the Transmission Demand will be pursuant to the Point-to-Point Rate (PTP-16) for Hourly Non-Firm Service.

When the Scheduled Demand or Ratchet Demand is the Billing Factor, short-distance POIs shall be charged the Rate specified in section II.A. for the amount in excess of Transmission Demand.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Ancillary Services that may be required to support IR transmission service are available under the ACS rate schedule. IR customers do not pay the ACS charges for Scheduling, System Control, and Dispatch Service or Reactive Supply and Voltage Control from Generation Sources Service, because these services are included in IR service.

B. DELIVERY CHARGE

Customers taking service over Delivery facilities are subject to the Delivery Charge, specified in GRSP II.A.

C. FAILURE TO COMPLY PENALTY

Customers taking service under this rate schedule are subject to the Failure to Comply Penalty Charge, specified in GRSP II.B.

D. RATCHET DEMAND RELIEF

Under appropriate circumstances, BPA may waive or reduce the Ratchet Demand. An IR customer seeking a reduction or waiver must demonstrate good cause for relief, including a demonstration that:

1. The event that resulted in the Ratchet Demand:

   a. was the result of an equipment failure or outage that could not reasonably have been foreseen by the customer; and

   b. did not result in harm to BPA's transmission system or transmission services, or to any other Transmission Customer; or

2. The event that resulted in the Ratchet Demand:

   a. was inadvertent;

   b. could not have been avoided by the exercise of reasonable care;

   c. did not result in harm to BPA's transmission system or transmission services, or to any other Transmission Customer; and

   d. was not part of a recurring pattern of conduct by the IR customer.

If the IR customer causes a Ratchet Demand to be established in a series of months during which the IR customer has not received notice from BPA of such Ratchet Demands by billing or otherwise, and the Ratchet Demand(s) established after the first Ratchet Demand were due to the lack of notice, then BPA may establish a Ratchet Demand for the IR customer based on the highest Ratchet Demand in the series. This highest Ratchet Demand will be charged in the month it is established and the following 11 months. All other Ratchet Demands based on such a series (including the Ratchet Demand established in the first month if it is not the highest Ratchet Demand) will be waived.

Ratchet Demand Relief is not available in the month in which the Ratchet Demand was established. For that month, the Customer will be assessed charges based upon the highest hourly Scheduled Demand Billing Factor.

E. SELF-SUPPLY OF REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES SERVICE

A credit for self-supply of Reactive Supply and Voltage Control from Generation Sources Service will be available for IR customers on a basis equivalent to the credit for PTP Transmission Customers.

NT-16
NETWORK INTEGRATION RATE

SECTION I. AVAILABILITY

This schedule supersedes the NT-14 rate schedule. It is available to Transmission Customers taking Network Integration Transmission (NT) Service over Federal Columbia River Transmission System Network and Delivery facilities, including Conditional Firm (CF) Service. Terms and conditions of service are specified in the Open Access Transmission Tariff. This schedule is available also for transmission service of a similar nature that may be ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§ 824j and 824k). Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATE

$1.735 per kilowatt per month

SECTION III. BILLING FACTOR

The monthly Billing Factor shall be the customer's Network Load on the hour of the Monthly Transmission System Peak Load.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Customers taking service under this rate schedule are subject to the ACS Scheduling, System Control, and Dispatch Service Rate and the Reactive Supply and Voltage Control from Generation Sources Service Rate. Other Ancillary Services that are required to support NT Service are also available under the ACS rate schedule.

B. DELIVERY CHARGE

Customers taking NT Service over Delivery facilities are subject to the Delivery Charge, specified in GRSP II.A.

C. FAILURE TO COMPLY PENALTY

Customers taking NT Service under this rate schedule are subject to the Failure to Comply Penalty Charge, specified in GRSP II.B.

D. SHORT-DISTANCE DISCOUNT (SDD)

A Customer's monthly NT bill shall be adjusted to reflect a Short Distance Discount (SDD) when a Customer has a resource that (1) is designated as a Network Resource (DNR) in the customer's NT Service Agreement for at least 12 months, and (2) uses FCRTS facilities for less than 75 circuit miles for delivery to the Network Load. A DNR that is a system sale (the DNR is not associated with a specific generating resource) does not qualify for the SDD. Any DNR that is eligible for the SDD (DNR SD) must be noted as such in the NT Service Agreement.

The NT monthly bill will be reduced by a credit equal to:

$$\text{Avg. Generation of the DNR SD during HLH} \;*\; \text{NT Rate} \;*\; \frac{75 - \text{Tx Distance}}{75} \;*\; 0.4$$

Where:

Average Generation during HLH =	The output serving Network Load during HLH on a firm basis over the billing month, divided by the number of HLH during the month, multiplied by the ratio of the Qualifying Capacity of the DNR SD output serving the Customer's Point(s) of Delivery (POD) to the total DNR SD designated capacity. The output serving Network Load is: 1. in the case of a scheduled DNR SD, the sum of firm schedules to Network Load. 2. in the case of Behind the Meter Resources, the metered output of the resource.
NT Rate =	$1.735 per kilowatt per month

Tx Distance = The contractually specified distance measured in circuit miles between the DNR SD Point of Receipt (POR) and the Customer's nearest POD(s) within 75 circuit miles of the DNR SD.

1. BPA shall use the peak load for the prior calendar year for the POD nearest to the DNR SD to calculate how much of the DNR SD's designated capacity is allocated to that POD. If the peak load for the prior calendar year of the closest POD is less than the DNR SD's designated capacity, then BPA shall use the next nearest POD that is within 75 circuit miles of the DNR SD, continuing until the DNR SD's designated capacity is fully allocated to the qualifying PODs, subject to section 2 below. The Tx Distance shall be the sum of the distance from the DNR SD to each of the PODs, weighted by the DNR SD designated capacity allocated to each POD.
2. The amount of designated capacity from all DNR SD allocated to any POD may not exceed the POD's peak load.
3. For a DNR SD directly connected to the customer's system (including Behind the Meter Resources) or a DNR SD that does not use BPA's network facilities, the Tx Distance shall be zero.

Qualifying Capacity = The sum of all DNR SD designated capacity allocated to the Customer's POD(s).

For a DNR SD directly connected to the customer's system (including Behind the Meter Resources) or a DNR SD that does not use BPA's network facilities, the Qualifying Capacity shall be the total DNR SD designated capacity.

Behind the Meter Resource = A resource that is used solely to serve the NT Customer's Network Load and is internal to the NT Customer's system.

E. DIRECT ASSIGNMENT FACILITIES

BPA shall collect the capital and related costs of a Direct Assignment Facility under the Advance Funding (AF) rate or the Use-of-Facilities (UFT) rate. Other associated costs, including but not limited to operations, maintenance, and general plant costs, also shall be recovered from the Network Customer under an applicable rate schedule.

F. INCREMENTAL COST RATES

The rates specified in section II are applicable to service over available transmission capacity. Network Customers that integrate new Network Resources, new Member Systems, or new native load customers that would require BPA to construct Network Upgrades shall be subject to the higher of the rates specified in section II or incremental cost rates for service over such facilities. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

G. RATE ADJUSTMENT DUE TO FERC ORDER UNDER FPA § 212

Customers taking service under this rate schedule are subject to the Rate Adjustment Due to FERC Order under FPA § 212, specified in GRSP II.C.

PTP-16
POINT-TO-POINT RATE

SECTION I. AVAILABILITY

This schedule supersedes the PTP-14 rate schedule. It is available to Transmission Customers taking Point-to-Point (PTP) Transmission Service over Federal Columbia River Transmission System (FCRTS) Network and Delivery facilities, including Conditional Firm (CF) Transmission Service , and for hourly non-firm service over such FCRTS facilities for customers with Integration of Resources agreements. Terms and conditions of PTP are specified in the Open Access Transmission Tariff. This schedule is available also for transmission service of a similar nature that may be ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§ 824j and 824k). Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATES

A. LONG-TERM FIRM PTP TRANSMISSION SERVICE

$1.489 per kilowatt per month

B. SHORT-TERM FIRM AND NON-FIRM PTP TRANSMISSION SERVICE

For each reservation, the rates shall not exceed:

1. Monthly, Weekly, and Daily Firm and Non-Firm Service

a. **Days 1 through 5** $0.068 per kilowatt per day

b. **Day 6 and beyond** $0.049 per kilowatt per day

2. Hourly Firm and Non-Firm Service

4.28 mills per kilowatthour

SECTION III. BILLING FACTORS

A. ALL FIRM AND NON-FIRM SERVICE

The Billing Factor for each rate specified in sections II.A. and II.B. for all service shall be the Reserved Capacity, which is the greater of:

1. the sum of the capacity reservations at the Point(s) of Receipt (POR), or

2. the sum of the capacity reservations at the Point(s) of Delivery (POD).

B. REDIRECT SERVICE

Redirecting Long-Term Firm PTP to Short-Term Firm PTP service will not result in an additional charge if the capacity reservation does not exceed the amount reserved in the existing service agreement.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Customers taking service under this rate schedule are subject to the ACS Scheduling, System Control, and Dispatch Service Rate and the Reactive Supply and Voltage Control from Generation Sources Service Rate. Other Ancillary Services that are required to support PTP Transmission Service on the Network are available under the ACS rate schedule.

B. DELIVERY CHARGE

Customers taking PTP Transmission Service over Delivery facilities are subject to the Delivery Charge, specified in GRSP II.A.

C. FAILURE TO COMPLY PENALTY

Customers taking service under this rate schedule are subject to the Failure to Comply Penalty Charge, specified in GRSP II.B.

D. INTERRUPTION OF NON-FIRM PTP TRANSMISSION SERVICE

If daily, weekly, or monthly Non-Firm PTP Transmission Service is interrupted, the rates charged under section II.B.1. shall be prorated over the total hours in the day to give credit for the hours of such interruption.

For Hourly Non-Firm Service, the rates charged under section II.B.2. shall apply as follows:

1. If the need for curtailment is caused by conditions on the FCRTS, the Billing Factor will be as follows:

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

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

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

E. RESERVATION FEE

Customers that postpone the commencement of Long-Term Firm Point-To-Point Transmission Service by requesting an extension of the Service Commencement Date will be subject to the Reservation Fee, specified in GRSP II.D.

F. SHORT-DISTANCE DISCOUNT (SDD)

When a Point of Receipt and Point of Delivery use FCRTS facilities for a distance of less than 75 circuit miles and are designated as being short distance in the PTP Service Agreement, the monthly capacity reservations for the relevant POR and POD shall be adjusted, for the purpose of computing the monthly bill for annual service, by the following factor:

$$0.6 + (0.4 * \text{transmission distance} / 75)$$

Such adjusted monthly POR and POD reservations shall be used to compute the billing factors in section III.A. to calculate the monthly bill for Long-Term Firm PTP Transmission Service. The POD capacity reservation eligible for the SDD may be no larger than the POR capacity reservation. System sales do not qualify for SDD. The distance used to calculate the SDD will be contractually specified and based upon path(s) identified in power flow studies. If a set of contiguous PODs qualifies for an SDD, the transmission distance used in the calculation of the SDD shall be between the POR and the POD farthest from the POR.

If the customer requests secondary PORs or PODs that use SDD-adjusted capacity reservations for any period of time during a month, the SDD shall not be applied that month.

G. UNAUTHORIZED INCREASE CHARGE

Customers that exceed their capacity reservations at any POR or POD shall be subject to the Unauthorized Increase Charge, specified in GRSP II.F.

H. DIRECT ASSIGNMENT FACILITIES

BPA shall collect the capital and related costs of a Direct Assignment Facility under the Advance Funding (AF) rate or the Use-of-Facilities (UFT) rate. Other associated costs, including but not limited to operations, maintenance, and general plant costs, also shall be recovered from the PTP Transmission Customer under an applicable rate schedule.

I. INCREMENTAL COST RATES

The rates specified in section II are applicable to service over available transmission capacity. Customers requesting new or increased firm service that would require BPA to construct Network Upgrades to alleviate a capacity constraint may be subject to incremental cost rates for such service if incremental cost is higher than embedded cost. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

J. RATE ADJUSTMENT DUE TO FERC ORDER UNDER FPA § 212

Customers taking service under this rate schedule are subject to the Rate Adjustment Due to FERC Order under FPA § 212, specified in GRSP II.C.

IS-16
SOUTHERN INTERTIE RATE

SECTION I. AVAILABILITY

This schedule supersedes the IS-14 rate schedule. It is available to Transmission Customers taking Point-to-Point Transmission (PTP) Service over the Federal Columbia River Transmission System (FCRTS) Southern Intertie facilities. Terms and conditions of service are specified in the Open Access Transmission Tariff or, for customers that executed Southern Intertie agreements with BPA before October 1, 1996, will be as provided in the customer's agreement with BPA. This schedule is available also for transmission service of a similar nature that may be ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§ 824j and 824k). Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATES

A. LONG-TERM FIRM PTP TRANSMISSION SERVICE

$1.230 per kilowatt per month

B. SHORT-TERM FIRM AND NON-FIRM PTP TRANSMISSION SERVICE

For each reservation, the rates shall not exceed:

1. Monthly, Weekly, and Daily Firm and Non-Firm Service

a. Days 1 through 5 $0.057 per kilowatt per day

b. Day 6 and beyond $0.040 per kilowatt per day

2. Hourly Firm and Non-Firm Service

3.53 mills per kilowatthour

SECTION III. BILLING FACTORS

A. ALL FIRM SERVICE AND MONTHLY, WEEKLY, AND DAILY NON-FIRM SERVICE

The Billing Factor for each rate specified in sections II.A. and II.B. for all services shall be the Reserved Capacity, which is the greater of:

1. the sum of the capacity reservations at the Point(s) of Receipt (POR), or

2. the sum of the capacity reservations at the Point(s) of Delivery (POD).

For Southern Intertie transmission agreements executed prior to October 1, 1996, the Billing Factor shall be as specified in the agreement.

B. REDIRECT SERVICE

Redirecting Long-Term Firm PTP to Short-Term Firm PTP service will not result in an additional charge if the capacity reservation does not exceed the amount reserved in the existing service agreement.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Customers taking service under this rate schedule are subject to the ACS Scheduling, System Control, and Dispatch Service Rate and the Reactive Supply and Voltage Control from Generation Sources Service Rate. Other Ancillary Services that are required to support PTP Transmission Service on the Southern Intertie are available under the ACS rate schedule.

B. FAILURE TO COMPLY PENALTY

Customers taking service under this rate schedule are subject to the Failure to Comply Penalty Charge specified in GRSP II.B.

C. INTERRUPTION OF NON-FIRM PTP TRANSMISSION SERVICE

If daily, weekly, or monthly Non-Firm PTP Transmission Service is interrupted, the rates charged under section II.B.1. shall be prorated over the total hours in the day to give credit for the hours of such interruption.

For Hourly Non-Firm Service, the rates charged under section II.B.2. shall apply as follows:

1. If the need for curtailment is caused by conditions on the FCRTS, the Billing Factor will be as follows:

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

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

2. If the need for curtailment is caused by conditions on another transmission provider’s transmission system, the Billing Factor will be the Reserved Capacity.

D. RESERVATION FEE

Customers that postpone the commencement of Long-Term Firm Point-To-Point Transmission Service by requesting an extension of their Service Commencement Date will be subject to the Reservation Fee specified in GRSP II.D.

E. UNAUTHORIZED INCREASE CHARGE

Customers that exceed their capacity reservations at any POR or POD shall be subject to the Unauthorized Increase Charge, specified in GRSP II.F.

F. DIRECT ASSIGNMENT FACILITIES

BPA shall collect the capital and related costs of a Direct Assignment Facility under the Advance Funding (AF) rate or the Use-of-Facilities (UFT) rate. Other associated costs, including but not limited to operations, maintenance, and general plant costs, also shall be recovered from the Transmission Customer under an applicable rate schedule.

G. INCREMENTAL COST RATES

The rates specified in section II are applicable to service over available transmission capacity. Customers requesting new or increased firm service that would require BPA to construct new facilities or upgrades to alleviate a capacity constraint may be subject to incremental cost rates for such service if incremental cost is higher than embedded cost. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

H. RATE ADJUSTMENT DUE TO FERC ORDER UNDER FPA § 212

Customers taking service under this rate schedule are subject to the Rate Adjustment Due to FERC Order under FPA § 212, specified in GRSP II.C.

IM-16
MONTANA INTERTIE RATE

SECTION I. AVAILABILITY

This schedule supersedes the IM-14 rate schedule. It is available to Transmission Customers taking Point-to-Point (PTP) Transmission Service on the Eastern Intertie. Terms and conditions of service are specified in the Open Access Transmission Tariff. This schedule is available also for transmission service of a similar nature that may be ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§ 824j and 824k). Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATES

A. LONG-TERM FIRM PTP TRANSMISSION SERVICE

$0.598 per kilowatt per month

B. SHORT-TERM FIRM AND NON-FIRM PTP TRANSMISSION SERVICE

For each reservation, the rates shall not exceed:

1. Monthly, Weekly, and Daily Short-Term Firm and Non-Firm Service

a. Days 1 through 5 $0.028 per kilowatt per day

b. Day 6 and beyond $0.020 per kilowatt per day

2. Hourly Firm and Non-Firm Service

1.72 mills per kilowatthour

SECTION III. BILLING FACTORS

A. ALL FIRM SERVICE AND MONTHLY, WEEKLY, AND DAILY NON-FIRM SERVICE

The Billing Factor for each rate specified in section II.A. and II.B. for all services shall be the Reserved Capacity, which is the greater of:

1. the sum of the capacity reservations at the Point(s) of Receipt (POR), or

2. the sum of the capacity reservations at the Point(s) of Delivery (POD).

B. REDIRECT SERVICE

Redirecting Long-Term Firm PTP to Short-Term Firm PTP service will not result in an additional charge if the capacity reservation does not exceed the amount reserved in the existing service agreement.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Customers taking service under this rate schedule are subject to the ACS Scheduling, System Control, and Dispatch Service Rate and the Reactive Supply and Voltage Control from Generation Sources Service Rate. Other Ancillary Services that are required to support PTP Transmission Service on the Montana Intertie are available under the ACS rate schedule.

B. FAILURE TO COMPLY PENALTY CHARGE

Customers taking service under this rate schedule are subject to the Failure to Comply Penalty Charge, specified in GRSP II.B.

C. INTERRUPTION OF NON-FIRM PTP TRANSMISSION SERVICE

If daily, weekly, or monthly Non-Firm PTP Transmission Service is interrupted, the rates charged under section II.B.1. shall be prorated over the total hours in the day to give credit for the hours of such interruption.

For Hourly Non-Firm Service, the rates charged under section II.B.2. shall apply as follows:

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

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

   b. If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted after the close of the hourly non-firm scheduling window, the Billing Factor will be the Transmission Customer’s actual schedule for the hour.

2. If the need for curtailment is caused by conditions on another transmission provider’s transmission system, the Billing Factor will be the Reserved Capacity.

D. RESERVATION FEE

Customers that postpone the commencement of Long-Term Firm Point-To-Point Transmission Service by requesting an extension of their Service Commencement Date will be subject to the Reservation Fee, specified in GRSP II.D.

E. UNAUTHORIZED INCREASE CHARGE

Customers that exceed their capacity reservations at any POR or POD shall be subject to the Unauthorized Increase Charge, specified in GRSP II.F.

F. DIRECT ASSIGNMENT FACILITIES

BPA shall collect the capital and related costs of a Direct Assignment Facility under the Advance Funding (AF) rate or the Use-of-Facilities (UFT) rate. Other associated costs, including but not limited to operations, maintenance, and general plant costs, also shall be recovered from the Transmission Customer under an applicable rate schedule.

G. INCREMENTAL COST RATES

The rates specified in section II are applicable to service over available transmission capacity. Customers requesting new or increased firm service that would require BPA to construct new facilities or upgrades to alleviate a capacity constraint may be subject to incremental cost rates for such service if incremental cost is higher than embedded cost. Incremental cost rates would be developed pursuant to section 7(i) of the Northwest Power Act.

H. RATE ADJUSTMENT DUE TO FERC ORDER UNDER FPA § 212

Customers taking service under this rate schedule are subject to the Rate Adjustment Due to FERC Order under FPA § 212, specified in GRSP II.C.

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UFT-16
USE-OF-FACILITIES TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes the UFT-14 rate schedule unless otherwise provided in the agreement, and is available for firm transmission over specified Federal Columbia River Transmission System (FCRTS) facilities. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATE

The monthly charge per kilowatt of Transmission Demand/capacity reservations specified in the agreement shall be one-twelfth of the annual cost of capacity of the specified facilities divided by the sum of Transmission Demands/capacity reservations (in kilowatts) using such facilities. Such annual cost shall be determined in accordance with section III.

SECTION III. DETERMINATION OF TRANSMISSION RATE

A. From time to time, but not more often than once a year, BPA shall determine the following data for the facilities that have been constructed or otherwise acquired by BPA and that are used to transmit electric power:

   1. The annual cost of the specified FCRTS facilities, as determined from the capital cost of such facilities and annual cost ratios developed from the Federal Columbia River Power System financial statement, including interest and amortization, operation and maintenance, administrative and general, and general plant costs.

      The annual cost per kilowatt of facilities listed in the agreement that are owned by another entity and used by BPA for making deliveries to the transferee shall be determined from the costs specified in the agreement between BPA and such other entity.

   2. The yearly noncoincident peak demands of all users of such facilities or other reasonable measurement of the facilities' peak use.

B. The monthly charge per kilowatt of billing demand shall be one-twelfth of the sum of the annual cost of the FCRTS facilities used, divided by the sum of Transmission Demands/capacity reservations. The annual cost per kilowatt of Transmission

Demand/capacity reservation for a facility constructed or otherwise acquired by BPA shall be determined in accordance with the following formula:

$$\frac{A}{D}$$

Where:

A = The annual cost of such facility as determined in accordance with A.1. above.
D = The sum of the yearly noncoincident demands on the facility as determined in accordance with A.2. above.

For facilities used solely by one customer, BPA may charge a monthly amount equal to the annual cost of such sole-use facilities, determined in accordance with section III.A.1., divided by 12.

For facilities used by more than one customer, BPA may charge a monthly amount equal to the annual cost of such facilities prorated based on relative use of the facilities, divided by 12.

SECTION IV. DETERMINATION OF BILLING FACTORS

Unless otherwise stated in the agreement, the Billing Factor shall be the largest of:

A. The Transmission Demand/capacity reservation in kilowatts specified in the agreement;

B. The highest hourly Measured or Scheduled Demand for the month; or

C. The Ratchet Demand.

SECTION V. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Ancillary services that are required to support UFT transmission service are available under the ACS rate schedule.

B. FAILURE TO COMPLY PENALTY

Customers taking service under this rate schedule are subject to the Failure to Comply Penalty Charge, specified in GRSP II.B.

AF-16
ADVANCE FUNDING RATE

SECTION I. AVAILABILITY

This schedule supersedes the AF-14 rate schedule and is available to customers that execute an agreement that provides for BPA to collect capital and related costs through advance funding or other financial arrangement for specified BPA-owned Federal Columbia River Transmission System (FCRTS) facilities used for:

A. Interconnection or integration of resources and loads to the FCRTS;

B. Upgrades, replacements, or reinforcements of the FCRTS for transmission service; or

C. Other transmission service arrangements, as determined by BPA.

Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. CHARGE

The charge is:

A. The sum of the actual capital and related costs for specified FCRTS facilities, as provided in the agreement. Such actual capital and related costs include, but are not limited to, costs of design, materials, construction, overhead, spare parts, and all incidental costs necessary to provide service as identified in the agreement; or

B. An advance payment equal to the sum of the capital and related costs for specified FCRTS facilities, as provided in the agreement. A credit for some or all of the amount advanced will be applied against charges for transmission service, as provided in the agreement. The charges for transmission service shall be at the rate for the applicable transmission service.

SECTION III. PAYMENT

A. ADVANCE PAYMENT

Payment to BPA shall be specified in the agreement as one of the following options:

1. A lump sum advance payment;

2. Advance payments pursuant to a schedule of progress payments; or

3. Other payment arrangement, as determined by BPA.

Such advance payment or payments shall be based on an estimate of the capital and related costs for the specified FCRTS facilities as provided in the agreement.

B. ADJUSTMENT TO ADVANCE PAYMENT

For charges under section II.A., BPA shall determine the actual capital and related costs of the specified FCRTS facilities as soon as practicable after the date of commercial operation, as determined by BPA. The customer will either receive a refund from BPA or be billed for additional payment for the difference between the advance payment and the actual capital and related costs.

TGT-16
TOWNSEND-GARRISON TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes the TGT-14 rate schedule and is available to Companies that are parties to the Montana Intertie Agreement (Contract No. DE-MS79-81BP90210, as amended), which provides for firm transmission over BPA's section (Garrison to Townsend) of the Montana Intertie. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATE

The monthly charge shall be one-twelfth of the sum of the annual charges listed below, as applicable and as specified in the agreements for firm transmission. The Townsend-Garrison 500-kV lines and associated terminal, line compensation, and communication facilities are a separately identified portion of the Federal Columbia River Transmission System. Annual revenues plus credits for government use should equal annual costs of the facilities, but in any given year there may be a surplus or a deficit. Such surplus or deficit for any year shall be accounted for in the computation of annual costs for succeeding years. Revenue requirements for firm transmission use will be decreased by any revenues received from non-firm use and credits for all government use. The general methodology for determining the firm rate is to divide the revenue requirement by the total firm capacity requirements. Therefore, the higher the total capacity requirements, the lower the unit rate will be.

If BPA provides firm transmission service in its section of the Montana (Eastern) Intertie in exchange for firm transmission service in a customer's section of the Montana Intertie, the payment by BPA for such transmission services provided by such customer will be made in the form of a credit in the calculation of the Intertie Charge for such customer.

A. NON-FIRM TRANSMISSION CHARGE

This charge will be filed as a separate rate schedule, the Eastern intertie (IE) rate.

B. INTERTIE CHARGE FOR FIRM TRANSMISSION SERVICE

$$\text{Intertie Charge} = \left[\left((TAC / 12) - NFR \right) * \frac{(CR - EC)}{TCR} \right]$$

SECTION III. DEFINITIONS

A. TAC = Total Annual Costs of facilities associated with the Townsend-Garrison 500 kV Transmission line including terminals, and prior to extension of the 500 kV portion of the Federal Transmission System to Garrison, the 500/230 kV transformer at Garrison. Such annual costs are the total of: (1) interest and amortization of associated Federal investment and the appropriate allocation of general plant costs; (2) operation and maintenance costs; (3) allowance for BPA's general administrative costs that are appropriately allocable to such facilities, and (4) payments made pursuant to section 7(m) of Public Law 96-501 with respect to these facilities. Total Annual Costs shall be adjusted to reflect reductions to unpaid total costs as a result of any amounts received, under agreements for firm transmission service over the Montana Intertie, by BPA on account of any reduction in Transmission Demand, termination, or partial termination of any such agreement or otherwise to compensate BPA for the unamortized investment, annual cost, removal, salvage, or other cost related to such facilities.

B. NFR = Non-firm Revenues, which are equal to (1) the product of the Non-firm Transmission Charge described in II.A. above and the total non-firm energy transmitted over the Townsend-Garrison line segment under such charge during such month; plus (2) revenue received by BPA under any other rate schedules for non-firm transmission service in either direction over the Townsend-Garrison line segment during such month.

C. CR = Capacity Requirement of a customer on the Townsend-Garrison 500 kV transmission facilities as specified in its firm transmission agreement.

D. TCR = Total Capacity Requirement on the Townsend-Garrison 500-kV transmission facilities as calculated by adding (1) the sum of all Capacity Requirements (CR) specified in transmission agreements described in section I and (2) BPA's firm capacity requirement. BPA's firm capacity requirement shall be no less than the total of the amounts, if any, specified in firm transmission agreements for use of the Montana Intertie.

E. EC = Exchange Credit for each customer, which is the product of (1) the ratio of investment in the Townsend-Broadview 500 kV transmission line to the investment in the Townsend-Garrison 500 kV transmission line and (2) the capacity BPA obtains in the Townsend-Broadview 500 kV transmission line through exchange with such customer. If no exchange is in effect with a customer, the value of EC for such customer shall be zero.

PW-16
WECC AND PEAK SERVICE RATE

SECTION I. AVAILABILITY

The rate below applies to all loads in the BPA Control Area except for loads of customers billed directly by WECC or by Peak Reliability. The WECC and Peak Service rate recovers the costs billed to BPA by WECC and Peak Reliability based on loads in the BPA Control Area. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATES

A. WECC RATE

0.05 mills per kilowatthour

B. PEAK RATE

0.05 mills per kilowatthour

SECTION III. BILLING FACTORS

The Billing Factor is the customer's total load in the BPA Control Area, in kilowatthours.

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OS-16
OVERSUPPLY RATE

SECTION I. AVAILABILITY

This schedule supersedes the OS-14 rate schedule. The Oversupply Rate applies to generators in the BPA Balancing Authority Area that are specified as the source on transmission schedules for the hours that BPA displaces generation pursuant to the Open Access Transmission Tariff (OATT), Attachment P (Oversupply Event Hours), and to customers that purchase power under the Priority Firm Power, Industrial Firm Power, or New Resources Firm Power rate, for the charges to BPA Power Services under section II.C.

The Oversupply Charge shall collect the amounts paid pursuant to OATT Attachment P for the period October 1, 2015, through September 30, 2017. The Oversupply Charge shall remain in effect until all costs incurred pursuant to OATT Attachment P during the FY 2016-2017 rate period are billed and fully paid. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. CHARGE

A. OVERSUPPLY RATE

For each month, the Oversupply rate in dollars per megawatthour ($/MWh) shall be:

$$\frac{\textit{Displacement Cost}}{\sum \textit{Scheduled Generation}}$$

Where:

Displacement Cost = the amount BPA paid pursuant to OATT Attachment P to displace output from generating facilities for the calendar month, in dollars.

Scheduled Generation = For each generator in the BPA Balancing Authority Area, the sum of transmission schedules (e-Tags) during Oversupply Event Hours that specify such generator as the source, in megawatthours.

The after-the-fact schedule shall be used for power dynamically transferred out of BPA's Balancing Authority Area.

∑ *Scheduled Generation* = the sum of all Scheduled Generation, in megawatthours.

B. OVERSUPPLY BILLING FACTORS

The billing factor for the monthly Oversupply Rate is the sum of the customer's Scheduled Generation during the month.

C. OVERSUPPLY CHARGES TO BPA POWER SERVICES

Charges to BPA Power Services for its applicable Scheduled Generation under this rate schedule shall be billed to customers purchasing under the Priority Firm Power, Industrial Firm Power, or New Resources Firm Power rate schedules using a Modified TOCA. The charge for each such customer shall be the Oversupply Charge amount charged to BPA Power Services multiplied by each customer's Modified Tier 1 Cost Allocator (TOCA). The Modified TOCA for each customer for each fiscal year is specified in GRSP II.I.

SECTION III. BILLING

A. OVERSUPPLY CHARGE

The Oversupply charge shall be included on bills for the month after Displacement Costs are incurred, subject to the billing cap; *i.e.,* there will be a one-month lag between Scheduled Generation and billing the Oversupply charge. Any Displacement Cost not billed because of the billing cap, or because BPA was unable to determine the full amount of Displacement Cost for the month, shall be included on the following month's bill, subject to the billing cap, and on subsequent bills as necessary until all Displacement Costs have been billed.

B. BILLING CAP

Total billing to all customers for the Oversupply Charges may not exceed $8 million in any one month. If the total Oversupply Charges exceed $8 million in any month, the excess over $8 million shall be billed in the following month, subject to this billing cap. If the billing cap is exceeded in such following month, excess charges shall be billed in each subsequent month, subject to this billing cap, until all charges are billed.

C. BILLING FOR OVERSUPPLY CHARGES TO BPA POWER SERVICES

The charge for BPA Power Services costs (section II.C) shall be separately included on each applicable customer's transmission bill.

IE-16
EASTERN INTERTIE RATE

SECTION I. AVAILABILITY

This schedule supersedes the IE-14 rate schedule and is available to Companies that are parties to the Montana Intertie Agreement (Contract No. DE-MS79-81BP90210, as amended) for non-firm transmission service on the portion of Eastern Intertie capacity that exceeds BPA's firm transmission rights. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATE

The rate shall not exceed 1.48 mills per kilowatthour.

SECTION III. BILLING FACTOR

The Billing Factor shall be the scheduled kilowatthours, unless otherwise specified in the Montana Interie Agreement.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

Ancillary services that may be required to support IE transmission service are available under the ACS rate schedule.

B. FAILURE TO COMPLY PENALTY

Customers taking service under this rate schedule are subject to the Failure to Comply Penalty Charge, specified in GRSP II.B.

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ACS-16
ANCILLARY AND CONTROL AREA SERVICE RATES

SECTION I. AVAILABILITY

This schedule supersedes the ACS-14 rate schedule. It is available to all Transmission Customers taking service under the Open Access Transmission Tariff and other contractual arrangements. This schedule also is available for transmission service of a similar nature that may be ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§ 824j and 824k). Service under this schedule is subject to BPA's General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

A. ANCILLARY SERVICES

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. The Transmission Provider is required to provide, and the Transmission Customer is required to purchase, the following Ancillary Services: (a) Scheduling, System Control, and Dispatch, and (b) Reactive Supply and Voltage Control from Generation Sources.

In addition, the Transmission Provider is required to offer to provide the following Ancillary Services only to the Transmission Customer serving load within the Transmission Provider's Control Area: (a) Regulation and Frequency Response, and (b) Energy Imbalance. The Transmission Customer serving load within the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply.

The Transmission Provider is also required to offer to provide (a) Operating Reserve – Spinning and (b) Operating Reserve – Supplemental to the Transmission Customer in accordance with applicable NERC, WECC, and NWPP standards. The Transmission Customer taking these services in the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply in accordance with applicable NERC, WECC, and NWPP standards.

The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the Transmission Provider.

Ancillary Services available under this rate schedule are:

1. Scheduling, System Control, and Dispatch Service
2. Reactive Supply and Voltage Control from Generation Sources Service
3. Regulation and Frequency Response Service
4. Energy Imbalance Service
5. Operating Reserve – Spinning Reserve Service
6. Operating Reserve – Supplemental Reserve Service

B. CONTROL AREA SERVICES

Control Area Services are available to meet the Reliability Obligations of a party with resources or loads in the BPA Control Area. A party that is not satisfying all of its Reliability Obligations through the purchase or self-provision of Ancillary Services must purchase Control Area Services to meet its Reliability Obligations. Control Area Services are also available to parties with resources or loads in the BPA Control Area that have Reliability Obligations but do not have transmission agreements with BPA. Reliability Obligations for resources or loads in the BPA Control Area shall be determined consistent with the applicable NERC, WECC, and NWPP standards.

Control Area Services available under this rate schedule are:

1. Regulation and Frequency Response Service
2. Generation Imbalance Service
3. Operating Reserve – Spinning Reserve Service
4. Operating Reserve – Supplemental Reserve Service
5. Variable Energy Resource Balancing Service
6. Dispatchable Energy Resource Balancing Service

SECTION II. ANCILLARY SERVICE RATES

A. SCHEDULING, SYSTEM CONTROL, AND DISPATCH SERVICE

The rates below apply to Transmission Customers taking Scheduling, System Control, and Dispatch Service from BPA. These rates apply to both firm and non-firm transmission service. Transmission arrangements on the Network, on the Southern Intertie, and on the Montana Intertie are each charged separately for Scheduling, System Control, and Dispatch Service.

1. RATES

a. NT Service

The rate shall not exceed $0.350 per kilowatt per month.

b. Long-Term Firm PTP Transmission Service and IR Service

The rate shall not exceed $0.301 per kilowatt per month.

c. Short-Term Firm and Non-Firm PTP Transmission Service

For each reservation, the rates shall not exceed:

(1) Monthly, Weekly, and Daily Firm and Non-Firm Service

(a) Days 1 through 5 $0.014 per kilowatt per day

(b) Day 6 and beyond $0.010 per kilowatt per day

(2) Hourly Firm and Non-Firm Service

The rate shall not exceed 0.87 mills per kilowatthour.

2. BILLING FACTORS

a. Point-To-Point Transmission Service

For Transmission Customers taking Point-to-Point Transmission Service (PTP, IS, and IM rates), the Billing Factor for each rate specified in sections 1.b. and 1.c.(1) and for the Hourly Firm PTP Transmission Service rate specified in 1.c.(2) shall be the Reserved Capacity, which is the greater of:

(1) the sum of the capacity reservations at the Point(s) of Receipt, or

(2) the sum of the capacity reservations at the Point(s) of Delivery.

The Reserved Capacity for Firm PTP Transmission Service shall not be adjusted for any Short-Distance Discounts or for any modifications on a non-firm basis in determining the Scheduling, System Control, and Dispatch Service Billing Factor.

The Billing Factor for the rate specified in section 1.b.(2) for Hourly Non-Firm Service shall be the Reserved Capacity, and the following shall apply:

(1) If the need for curtailment is caused by conditions on the Federal Columbia River Transmission System, the Billing Factor will be as follows:

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

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

(2) If the need for curtailment is caused by conditions on another transmission provider's transmission system, the Billing Factor will be the Reserved Capacity.

These Billing Factors apply to all PTP transmission service under the Open Access Transmission Tariff regardless of whether the Transmission Customer actually uses (schedules) the transmission.

b. Network Integration Transmission Service

For Transmission Customers taking Network Integration Transmission Service, the Billing Factor for the rate specified in section 1.a. shall equal the NT rate Billing Factor determined pursuant to section III.A. of the Network Integration Rate Schedule (NT-16).

c. Adjustment for Customers Subject to the Unauthorized Increase Charge (UIC)

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

B. REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES SERVICE

The rates below apply to Transmission Customers taking Reactive Supply and Voltage Control from Generation Sources (GSR) Service from BPA. These rates apply to both firm and non-firm transmission service. Transmission arrangements on the Network, the Southern Intertie, and the Montana Intertie are each charged separately for Reactive Supply and Voltage Control from Generation Sources Service.

1. RATES

The rates for GSR Service will be set on a quarterly basis, beginning October 2015, according to the formulas below. Rates for Long-Term PTP and NT Service and for Short-Term Monthly, Weekly and Daily Service (sections a. and b.(1), below) shall be calculated to three decimal places. Rates for Hourly Service (section b.(2), below) shall be calculated to two decimal places.

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

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

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

Where:

bd = 513,961 MW-mo = Average of forecasted FY 2016 and FY 2017 GSR Service billing determinants. Each annual billing determinant is the sum of the 12 monthly billing determinants.

N_q = Non-Federal GSR cost ($) to be paid by BPA under a FERC-approved rate during the relevant quarter, as anticipated prior to the quarter.

U_{q-1} = Payments of non-Federal GSR cost ($) made in the preceding quarter(s) that were not included in the effective rate for the preceding quarter(s). Any refunds received by BPA would reduce this cost. U_{q-1} is a true-up for any deviation of non-Federal GSR costs from the amount used in a previous quarter's GSR rate calculation. For calculating the GSR rate effective October 1, 2015, U_{q-1} is zero.

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

Z_{q-1} = True-up ($) for under- or overstatement of reactive self-supply in rate calculations for the preceding quarter(s). For calculating the GSR rate effective October 1, 2015, Z_{q-1} is zero. Z_{q-1} will be calculated by multiplying the under- or overstated megawatt amount of self-supply by the GSR rate that was effective during the quarter of self-supply deviation.

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

b. Short-Term Firm and Non-Firm PTP Transmission Service

(1) Monthly, Weekly, and Daily Firm and Non-firm Service

For each reservation, the rates shall not exceed:

(a) Days 1 through 5 ($/kW/day)

$$\text{Long-Term Service Rate} \quad * \quad \frac{\text{12 months}}{\text{52 weeks * 5 days}}$$

(b) Day 6 and beyond ($/kW/day)

$$\text{Long-Term Service Rate} \quad * \quad \frac{\text{12 months}}{\text{52 weeks * 7 days}}$$

(2) Hourly Firm and Non-Firm Service (mills/kilowatthour)

The rate shall not exceed:

$$\text{Long-Term Service Rate} \quad * \quad \frac{\text{12 months}}{\text{52 weeks * 5 days * 16 hours}}$$

Where:

The "Long-Term Service Rate" specified in the formulas in sections 1.b.(1)(a) and (b) and section 1.b.(2), above, is the rate determined in section 1.a., Long-Term Firm PTP Transmission Service and NT Service, in $/kW/mo.

2. BILLING FACTORS

a. Point-To-Point Transmission Service

For Transmission Customers taking Point-to-Point Transmission Service (PTP, IS, and IM rates), the Billing Factor for each rate specified in sections 1.b. and 1.c.(1) and for Hourly Firm PTP Transmission Service specified in 1.c.(2) shall be the Reserved Capacity, which is the greater of:

(1) the sum of the capacity reservations at the Point(s) of Receipt, or

(2) the sum of the capacity reservations at the Point(s) of Delivery.

The Reserved Capacity for Firm PTP Transmission Service shall not be adjusted for any Short-Distance Discount or for any modifications on a non-firm basis in determining the Reactive Supply and Voltage Control from Generation Sources Service Billing Factor.

The Billing Factor for the rate specified in section 1.b.(2) for Hourly Non-Firm Service shall be the Reserved Capacity, and the following shall apply:

(1) If the need for curtailment is caused by conditions on the Federal Columbia River Transmission System, the Billing Factor will be as follows:

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

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

(2) If the need for curtailment is caused by conditions on another transmission provider’s transmission system, the Billing Factor will be the Reserved Capacity.

These Billing Factors apply to all PTP transmission service under the Open Access Transmission Tariff regardless of whether the Transmission Customer actually uses (schedules) the transmission.

b. Network Integration Transmission Service

For Transmission Customers taking Network Integration Transmission Service, the Billing Factor for the rate specified in section 1.a. shall equal the NT rate Billing Factor determined pursuant to section III.A. of the Network Integration Rate Schedule (NT-16).

c. Adjustment for Self-Supply

The Billing Factors in sections 2.a. and 2.b. above may be reduced as specified in the Transmission Customer's Service Agreement to the extent the Transmission Customer demonstrates to BPA's satisfaction that it can self-provide Reactive Supply and Voltage Control from Generation Sources Service.

d. Adjustment for Customers Subject to the Unauthorized Increase Charge (UIC)

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

C. REGULATION AND FREQUENCY RESPONSE SERVICE

The rate below for Regulation and Frequency Response (RFR) Service applies to Transmission Customers serving loads in the BPA Control Area. Regulation and Frequency Response Service provides the generation capability to follow the moment-to-moment variations of loads in the BPA Control Area and maintain the power system frequency at 60 Hz in conformance with NERC and WECC reliability standards.

1. RATE

The rate shall not exceed 0.12 mills per kilowatthour.

2. BILLING FACTOR

The Billing Factor is the customer's total load in the BPA Control Area, in kilowatthours.

D. ENERGY IMBALANCE SERVICE

The rates below apply to Transmission Customers taking Energy Imbalance Service from BPA. Energy Imbalance Service is taken when there is a difference between scheduled and actual energy delivered to a load in the BPA Control Area during a scheduling period. Accounting for hourly schedules will be on an hourly basis, and accounting for intra-hour schedules will be on the customer's shortest scheduling period in the hour.

1. RATES

a. Imbalances Within Deviation Band 1

Deviation Band 1 applies to deviations that are less than or equal to (i) ± 1.5 percent of the scheduled amount of energy, or (ii) ± 2 MW, whichever is larger in absolute value. BPA will maintain deviation accounts showing the net Energy Imbalance (the sum of positive and negative deviations from schedule for each period) for Heavy Load Hour (HLH) and Light Load Hour (LLH) periods. Return energy may be scheduled at any time during the month to bring the deviation account balances to zero at the end of each month. BPA will approve the hourly schedules of return energy. The customer shall make the arrangements and submit the schedule for the balancing transaction.

The following rates will be applied when a deviation balance remains at the end of the month:

(1) When the monthly net energy (determined for HLH and LLH periods) taken by the Transmission Customer is greater than the energy scheduled, the charge is BPA's incremental cost based on the applicable average HLH and average LLH incremental cost for the month.

(2) When the monthly net energy (determined for HLH and LLH periods) taken by the Transmission Customer is less than the energy scheduled, the credit is BPA's incremental cost based on the applicable average HLH and LLH incremental cost for the month.

b. Imbalances Within Deviation Band 2

Deviation Band 2 applies to the portion of the deviation (i) greater than ± 1.5 percent of the scheduled amount of energy or (ii) ± 2 MW, whichever is larger in absolute value, up to and including (i) ± 7.5 percent of the scheduled amount of energy or (ii) ± 10 MW, whichever is larger in absolute value.

(1) When energy taken by the Transmission Customer in a schedule period is greater than the energy scheduled, the charge is 110 percent of BPA's incremental cost.

(2) When energy taken by the Transmission Customer in a schedule period is less than the scheduled amount, the credit is 90 percent of BPA's incremental cost.

c. Imbalances Within Deviation Band 3

Deviation Band 3 applies to the portion of the deviation (i) greater than ± 7.5 percent of the scheduled amount of energy, or (ii) greater than ± 10 MW of the scheduled amount of energy, whichever is larger in absolute value.

(1) When energy taken by the Transmission Customer in a schedule period is greater than the energy scheduled, the charge is 125 percent of BPA's highest incremental cost that occurs during that day. The highest daily incremental cost shall be determined separately for HLH and LLH.

(2) When energy taken by the Transmission Customer in a schedule period is less than the scheduled amount, the credit is 75 percent of BPA's lowest incremental cost that occurs during that day. The lowest daily incremental cost shall be determined separately for HLH and LLH.

2. OTHER RATE PROVISIONS

a. BPA Incremental Cost

BPA's incremental cost will be based on an hourly energy index in the Pacific Northwest. If no adequate hourly index exists, an alternative index will be used. BPA will post the name of the index to be used on its OASIS Web site at least 30 days prior to its use. BPA will not change the index more often than once per year unless BPA determines that the existing index is no longer a reliable price index.

For any hour(s) that the energy index is negative, no credit is given for positive deviations (actual energy delivered is more than scheduled).

b. Spill Conditions

For any day that the Federal System is in a Spill Condition, no credit is given for negative deviations (actual energy delivered is less than scheduled) for any period of that day.

If the energy index is negative in any hour that the Federal System is in a Spill Condition:

(1) For negative deviations (energy taken is less than the scheduled energy) within Band 1, no credit will be given.

(2) For negative deviations (energy taken is less than the scheduled energy) within Band 2, the charge is the energy index for that hour.

(3) For negative deviations (energy taken is less than the scheduled energy) within Band 3, the charge is the energy index for that hour.

c. Persistent Deviation

The following penalty charges shall apply to each Persistent Deviation (GRSP III.42):

(1) No credit is given when energy taken is less than the scheduled energy.

(2) When energy taken exceeds the scheduled energy, the charge is the greater of (i) 125 percent of BPA's highest incremental cost that occurs during that day, or (ii) 100 mills per kilowatthour.

If the energy index is negative in any hour(s) in which there is a negative deviation (energy taken is less than the scheduled energy) that BPA determines to be a Persistent Deviation, the charge is the energy index for that hour.

If BPA assesses a persistent deviation penalty charge in any scheduled period for a positive deviation, BPA will not also assess a charge pursuant to section II.D.1. of this ACS-16 schedule.

Reduction or Waiver of Persistent Deviation Penalty

BPA, at its sole discretion, may waive all or part of the Persistent Deviation penalty charge if (i) the customer took mitigating action(s) to avoid or limit the Persistent Deviation, including but not limited to changing its schedule to mitigate the magnitude or duration of the deviation, or (ii) the Persistent Deviation was caused by extraordinary circumstances.

E. OPERATING RESERVE – SPINNING RESERVE SERVICE

The rates below apply to Transmission Customers taking Operating Reserve – Spinning Reserve Service from BPA, and to generators in the BPA Control Area for settlement of energy deliveries. Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. BPA will determine the Transmission Customer's Spinning Reserve Requirement in accordance with applicable NERC, WECC, and NWPP standards.

1. RATES

a. For customers that elect to purchase Operating Reserve –Spinning Reserve Service from BPA, the rate shall not exceed 11.40 mills per kilowatthour.

b. For customers that are required to purchase Operating Reserve – Spinning Reserve Service from BPA because they defaulted on their self-supply or third-party supply obligations, the rate shall be 13.11 mills per kilowatthour.

For energy delivered, the generator shall, as directed by BPA, either:

(1) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or

(2) Return the energy at the times specified by BPA.

2. BILLING FACTORS

a. The Billing Factor for the rates specified in sections 1.a. and 1.b. is the Transmission Customer's Spinning Reserve Requirement determined in accordance with applicable NERC, WECC and NWPP standards. BPA will post on its OASIS Web site the Spinning Reserve Requirement.

b. The Billing Factor for energy delivered when Spinning Reserve Service is called upon is the energy delivered, in kilowatthours.

F. OPERATING RESERVE – SUPPLEMENTAL RESERVE SERVICE

The rates below apply to Transmission Customers taking Operating Reserve – Supplemental Reserve Service from BPA and to generators in the BPA Control Area for settlement of energy deliveries. Supplemental Reserve Service is available within a short period of time to serve load in the event of a system contingency. BPA will determine the Transmission Customer's Supplemental Reserve Requirement in accordance with applicable NERC, WECC, and NWPP standards.

1. RATES

a. For customers that elect to purchase Operating Reserve – Supplemental Reserve Service from BPA, the rate shall not exceed 10.45 mills per kilowatthour.

b. For customers that are required to purchase Operating Reserve – Supplemental Reserve Service from BPA because they defaulted on their self-supply or third-party supply obligations, the rate shall be 12.02 mills per kilowatthour.

For energy delivered, the Transmission Customer (for interruptible imports only) or the generator shall, as directed by BPA, either:

(1) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or

(2) Return the energy at the times specified by BPA.

The Transmission Customer shall be responsible for the settlement of delivered energy associated with interruptible imports. The generator shall be responsible for the settlement of delivered energy associated with generation in the BPA Control Area.

2. BILLING FACTORS

a. The Billing Factor for the rates specified in sections 1.a. and 1.b. is the Transmission Customer's Supplemental Reserve Requirement determined in accordance with applicable NERC, WECC and NWPP standards. BPA will post on its OASIS Web site the Supplemental Reserve Requirement.

b. The Billing Factor for energy delivered when Supplemental Reserve Service is called upon is the energy delivered, in kilowatthours.

SECTION III. CONTROL AREA SERVICE RATES

A. REGULATION AND FREQUENCY RESPONSE SERVICE

The rate below applies to all loads in the BPA Control Area that are receiving Regulation and Frequency Response Service from the BPA Control Area, and such Regulation and Frequency Response Service is not provided for under a BPA transmission agreement. Regulation and Frequency Response Service provides the generation capability to follow the moment-to-moment variations of loads in the BPA Control Area and maintain the power system frequency at 60 Hz in conformance with NERC and WECC reliability standards.

1. RATE

The rate shall not exceed 0.12 mills per kilowatthour.

2. BILLING FACTOR

The Billing Factor is the customer's total load in the BPA Control Area, in kilowatthours.

B. GENERATION IMBALANCE SERVICE

The rates below apply to generation resources in the BPA Control Area if Generation Imbalance Service is provided for in an interconnection agreement or other arrangement. Generation Imbalance Service is taken when there is a difference between scheduled and actual energy delivered from generation resources in the BPA Control Area during a scheduling period. Accounting for hourly schedules will be on an hourly basis, and accounting for intra-hour schedules will be on the customer's shortest scheduling period in the hour.

1. RATES

a. Imbalances Within Deviation Band 1

Deviation Band 1 applies to deviations that are less than or equal to (i) ± 1.5 percent of the scheduled amount of energy, or (ii) ± 2 MW, whichever is larger in absolute value. BPA will maintain deviation accounts showing the net Generation Imbalance (the sum of positive and negative deviations from schedule for each period) for Heavy Load Hour (HLH) and Light Load Hour (LLH) periods. Return energy may be scheduled at any time during the month to bring the deviation account balances to zero at the end of each month. BPA will approve the hourly schedules of return energy. The customer shall make the arrangements and submit the schedule for the balancing transaction.

The following rates will be applied when a deviation balance remains at the end of the month:

(1) When the monthly net energy (determined for HLH and LLH periods) delivered from a generation resource is less than the energy scheduled, the charge is BPA's incremental cost based on the applicable average HLH and average LLH incremental cost for the month.

(2) When the monthly net energy (determined for HLH and LLH periods) delivered from a generation resource is greater than the energy scheduled, the credit is BPA's incremental cost based on the applicable average HLH and LLH incremental cost for the month.

b. Imbalances Within Deviation Band 2

Deviation Band 2 applies to the portion of the deviation (i) greater than ± 1.5 percent of the scheduled amount of energy or (ii) ± 2 MW, whichever is larger in absolute value, up to and including (i) ± 7.5 percent of the scheduled amount of energy or (ii) ± 10 MW, whichever is larger in absolute value.

(1) When energy delivered in a schedule period from the generation resource is less than the energy scheduled, the charge is 110 percent of BPA's incremental cost.

(2) When energy delivered in a schedule period from the generation resource is greater than the scheduled amount, the credit is 90 percent of BPA's incremental cost.

c. Imbalances Within Deviation Band 3

Deviation Band 3 applies to the portion of the deviation (i) greater than ± 7.5 percent of the scheduled amount of energy, or (ii) greater than ± 10 MW of the scheduled amount of energy, whichever is larger in absolute value.

(1) When energy delivered in a schedule period from the generation resource is less than the energy scheduled, the charge is 125 percent of BPA's highest incremental cost that occurs during that day. The highest daily incremental cost shall be determined separately for HLH and LLH.

(2) When energy delivered in a schedule period from the generation resource is greater than the scheduled amount, the credit is 75 percent of BPA's lowest incremental cost that occurs during that day. The lowest daily incremental cost shall be determined separately for HLH and LLH.

2. OTHER RATE PROVISIONS

a. BPA Incremental Cost

BPA's incremental cost will be based on an hourly energy index in the Pacific Northwest. If no adequate hourly index exists, an alternative index will be used. BPA will post the name of the index to be used on its OASIS Web site at least 30 days prior to its use. BPA will not change the index more often than once per year unless BPA determines that the existing index is no longer a reliable price index.

For any hour(s) that the energy index is negative, no credit is given for positive deviations (actual generation less than scheduled).

b. Spill Conditions

For any day that the Federal System is in a Spill Condition, no credit is given for negative deviations (actual generation greater than scheduled) for any period of that day.

If the energy index is negative in any hour that the Federal System is in a Spill Condition:

(1) For negative deviations (actual generation greater than scheduled) within Band 1, no credit will be given.

(2) For negative deviations (actual generation greater than scheduled) within Band 2, the charge is the energy index for that hour.

(3) For negative deviations (actual generation greater than scheduled) within Band 3, the charge is the energy index for that hour.

c. Persistent Deviation for Generation

Persistent Deviation for generation applies to (i) Dispatchable Energy Resources operating in the BPA Balancing Authority Area and (ii) Variable Energy Resources operating in the BPA Balancing Authority Area that are not subject to the Intentional Deviation Penalty Charge specified in GRSP II.H.

The following penalty charges shall apply to each Persistent Deviation (GRSP III.42):

No credit is given for negative deviations (actual generation greater than scheduled) for any hour(s) that the imbalance is a Persistent Deviation (as determined by BPA).

For positive deviations (actual generation less than scheduled) that are determined by BPA to be Persistent Deviations, the charge is the greater of (i) 125 percent of BPA's highest incremental cost that occurs during that day, or (ii) 100 mills per kilowatthour.

If the energy index is negative in any hour(s) in which there is a negative deviation (actual generation greater than scheduled) that BPA determines to be a Persistent Deviation, the charge is the energy index for that hour.

If BPA assesses a Persistent Deviation Penalty charge in any scheduled period for a positive deviation, BPA will not also assess a charge pursuant to section 1 of this ACS-16 Generation Imbalance Service rate schedule.

For Variable Energy Resources (wind and solar resources), BPA will remove specific scheduled periods for billing purposes from a Persistent Deviation event when the deviation is equal to or less than the deviation that would result from 30-minute persistence scheduling for those scheduled periods.

New generation resources undergoing testing before commercial operation are exempt from the Persistent Deviation penalty charge for up to 90 days.

Reduction or Waiver of Persistent Deviation Penalty

BPA, at its sole discretion, may waive all or part of the Persistent Deviation penalty charge if (a) the customer took mitigating action(s) to avoid or limit the Persistent Deviation, including but not limited to changing its schedule to mitigate the magnitude or duration of the deviation, or (b) the Persistent Deviation was caused by extraordinary circumstances.

d. No Credit for Negative Deviations During Curtailments

No credit is provided for negative deviations (actual generation greater than schedules) during scheduling periods when a schedule from a generator is curtailed.

e. Exemption from Deviation Band 2

The 10 percent penalty charge under section 1.b., Imbalances Within Deviation Band 2, will not apply to customers participating in a committed 15-minute scheduling program in accordance with the ACS-16 Variable Energy Resources Balancing Service rates, section III.E.2.a.(2) and (3).

f. Exemptions from Deviation Band 3

The following resources are not subject to Deviation Band 3:

(1) wind resources
(2) solar resources
(3) new generation resources undergoing testing before commercial operation for up to 90 days

Unless otherwise stated in this section 2, all deviations greater than ± 1.5 percent or ± 2 MW will be charged consistent with section 1.b., Imbalances Within Deviation Band 2.

C. OPERATING RESERVE – SPINNING RESERVE SERVICE

Operating Reserve – Spinning Reserve Service must be purchased by a party with generation in the BPA Control Area that is receiving this service from BPA and such Spinning Reserve Service is not provided for under a BPA transmission agreement. Service is being received if there are no other qualifying resources providing this required reserve service in conformance with NERC, WECC, and NWPP standards. BPA will determine the Control Area Service Customer's Spinning Reserve Requirement in accordance with applicable NERC, WECC, and NWPP standards.

1. RATES

a. For customers that elect to purchase Operating Reserve – Spinning Reserves from BPA, the rate shall not exceed 11.40 mills per kilowatthour.

b. For customers that are required to purchase Operating Reserve – Spinning Reserve Service from BPA because they defaulted on their self-supply or third-party supply obligations, the rate shall be 13.11 mills per kilowatthour.

For energy delivered, the customer shall, as directed by BPA, either:

(1) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or

(2) Return the energy at the times specified by BPA.

2. BILLING FACTORS

a. The Billing Factor for the rates specified in sections 1.a. and 1.b. is the Spinning Reserve Requirement determined in accordance with applicable NERC, WECC and NWPP standards. BPA will post on its OASIS Web site the Spinning Reserve Requirement.

b. The Billing Factor for energy delivered when Spinning Reserve Service is called upon is the energy delivered, in kilowatthours.

D. OPERATING RESERVE – SUPPLEMENTAL RESERVE SERVICE

Operating Reserve – Supplemental Reserve Service must be purchased by a party with generation in the BPA Control Area that is receiving this service from BPA, and such Supplemental Reserve Service is not provided for under a BPA transmission agreement. Service is being received if there are no other qualifying resources providing this required reserve service in conformance with NERC, WECC, and NWPP standards. BPA will determine the Control Area Service Customer's Supplemental Reserve Requirement in accordance with applicable NERC, WECC, and NWPP standards.

1. RATES

a. For customers that elect to purchase Operating Reserve – Supplemental Reserve Service from BPA, the rate shall not exceed 10.45 mills per kilowatthour.

b. For customers that are required to purchase Operating Reserve – Supplemental Reserve Service from BPA because they defaulted on their self-supply or third-party supply obligations, the rate shall be 12.02 mills per kilowatthour.

For energy delivered, the customer shall, as directed by BPA, either:

(1) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or

(2) Return the energy at the times specified by BPA.

2. BILLING FACTORS

a. The Billing Factor for the rates specified in sections 1.a. and 1.b. is the Supplemental Reserve Requirement determined in accordance with applicable NERC, WECC and NWPP standards. BPA will post on its OASIS Web site the Supplemental Reserve Requirement.

b. The Billing Factor for energy delivered when Supplemental Reserve Service is called upon is the energy delivered, in kilowatthours.

E. VARIABLE ENERGY RESOURCE BALANCING SERVICE

1. APPLICABILITY

The rates contained in this rate schedule apply to all wind and solar generating facilities of 200 kW nameplate rated capacity or greater in the BPA Control Area except as provided in section 2.c. of this rate schedule.

Variable Energy Resource Balancing Service ("VERBS" or "Balancing Service") is comprised of three components: regulating reserves (which compensate for moment-to-moment differences between generation and load), following reserves (which compensate for larger differences occurring over longer periods of time during the hour), and imbalance reserves (which compensate for differences between the generator's schedule and the actual generation during an hour). Variable Energy Resource Balancing Service is required to help maintain the power system frequency at 60 Hz and to conform to NERC and WECC reliability standards.

2. BALANCING SERVICE FOR WIND RESOURCES

The total charge for Balancing Service is the applicable rate in section 2.a., below, plus Direct Assignment Charges under section 4 and Intentional Deviation Penalty Charges under section 5.

a. BALANCING SERVICE RATES

(1) <u>Rate for 30/60 Committed Scheduling</u>

This rate is applicable to customers taking Balancing Service that commit to receive BPA's 30-minute signal for each 60-minute schedule period (30/60 committed scheduling) and submit schedules that are consistent with the signal or that result in less imbalance for the scheduling period.

(a)	Regulating Reserves	\$0.08 per kilowatt per month
(b)	Following Reserves	\$0.32 per kilowatt per month
(c)	Imbalance Reserves	\$0.80 per kilowatt per month

(2) <u>Rate for 40/15 Committed Scheduling</u>

This rate is applicable to customers taking Balancing Service that commit to receive BPA's 40-minute signal for each 15-minute schedule period (40/15 committed scheduling) and submit schedules that are consistent with the signal or that result in less imbalance for the scheduling period.

(a) Regulating Reserves $0.08 per kilowatt per month
(b) Following Reserves $0.32 per kilowatt per month
(c) Imbalance Reserves $0.54 per kilowatt per month

(3) <u>Rate for 30/15 Committed Scheduling</u>

This rate is applicable to customers taking Balancing Service that commit to receive BPA's 30-minute signal for each 15-minute schedule period (30/15 committed scheduling) and submit schedules that are consistent with the signal or that result in less imbalance for the scheduling period.

(a) Regulating Reserves $0.08 per kilowatt per month
(b) Following Reserves $0.32 per kilowatt per month
(c) Imbalance Reserves $0.33 per kilowatt per month

(4) <u>Rate for Uncommitted Scheduling</u>

This rate is applicable to customers taking Balancing Service that do not commit to 30/60, 40/15 or 30/15 scheduling ("uncommitted scheduling").

(a) Regulating Reserves $0.08 per kilowatt per month
(b) Following Reserves $0.32 per kilowatt per month
(c) Imbalance Reserves $1.08 per kilowatt per month
(d) Opt Out Fee
The fee for customers that opt out of the Intentional Deviation Penalty Charge (GRSP II.H) shall be $0.20 per kilowatt per month.

b. BILLING FACTOR

The Billing Factor for rates in section 2.a. is as follows:

(1) For each wind plant, or phase of a wind plant, that has completed installation of all units no later than the 15th of the month prior to the billing month, the billing factor in kW will be the greater of the

maximum one-hour generation or the nameplate of the plant. A unit has completed installation when it has generated and delivered power to the BPA system.

(2) For each wind plant, or phase of a wind plant, for which some but not all units have been installed by the 15th day of the month prior to the billing month, the billing factor will be the maximum measured hourly output of the plant through the 15th day of the prior month in kW.

(3) For each wind plant, or phase of a wind plant, where none of the units have been installed on or before the 15th of the month prior to the billing month, but some units have been installed before the start of the billing month, the billing factor will be zero.

c. EXCEPTIONS

(1) The rates under section 2.a. above will not apply to a Variable Energy Resource, or portion of a Variable Energy Resource, that, in BPA's determination, has put in place, tested, and successfully implemented in conformance to the criteria specified in BPA business practices, no later than the 15th day of the month prior to the billing month, the dynamic transfer of plant output out of BPA's Balancing Authority Area to another Balancing Authority Area.

(2) Individual rate components under section 2.a.(1)-(5) above will not apply to a Variable Energy Resource, or portion of a Variable Energy Resource, that, in BPA's determination, has put in place, tested, and successfully implemented in conformance to criteria specified in BPA business practices, no later than the 15th day of the month prior to the billing month, self-supply of that component of Balancing Service, including by contractual arrangements for third-party supply.

3. BALANCING SERVICE FOR SOLAR RESOURCES

The total charge for this service is the applicable rate below, plus Direct Assignment Charges under section 4 and Intentional Deviation Penalty Charges under section 5.

a. RATES

(1) Regulating Reserves $0.04 per kilowatt per month
(2) Following Reserves $0.17 per kilowatt per month

b. BILLING FACTOR

For each solar plant that has completed installation no later than the 15th of the month prior to the billing month, the billing factor in kW will be the greater of the maximum one-hour generation or the nameplate of the plant. A unit has completed installation when it has generated and delivered power to the BPA system.

c. EXCEPTIONS

See section 2.c. above.

4. DIRECT ASSIGNMENT CHARGES

BPA shall directly assign to the customer the cost of incremental balancing reserve capacity purchases that are necessary to provide Variable Energy Resource Balancing Service to the customer if:

a. the customer elected to self-supply in accordance with section 2.c. but is unable to self-supply one or more components to Variable Energy Resource Balancing Service; or

b. the customer has a projected generator interconnection date after FY 2017, but chooses to interconnect during the FY 2016–2017 rate period; or

c. the customer elected to take service under section 2.a.(1), 2.a.(2), or 2.a.(3) above, but fails to conform to the committed scheduling criteria specified in BPA business practices; or

d. the customer elected to take service under section 2.a.(1), 2.a.(2), or 2.a.(3) above, but chooses to take a Balancing Service scheduling option with a longer scheduling period in accordance with the criteria specified in BPA business practices; or

e. the customer either elected to dynamically transfer its resource out of BPA’s Balancing Authority Area or has successfully dynamically transferred its resource out of BPA’s Balancing Authority Area, but chooses to keep its resource in BPA’s Balancing Authority Area.

When determining the balancing reserve capacity requirement for a resource subject to direct assignment charges, BPA will round the incremental increase down to the nearest whole megawatt.

Customers that are subject to direct assignment charges will be billed for all costs incurred above $0.29 per kilowatt-day for any incremental balancing reserve capacity acquisitions. Customers billed for direct assignment charges will also be billed at the applicable VERBS rate in section 2.

5. INTENTIONAL DEVIATION PENALTY CHARGE

Customers taking Variable Energy Resources Balancing Service under this rate schedule are subject to the Intentional Deviation Penalty Charge specified in GRSP II.H.

F. DISPATCHABLE ENERGY RESOURCE BALANCING SERVICE

The rate below applies to all Dispatchable Energy Resources of 3 MW nameplate rated capacity or greater in the BPA Control Area except as provided in section 3 below. Dispatchable Energy Resource Balancing Service ("DERBS") is required to help maintain the power system frequency at 60 Hz and to conform to NERC and WECC reliability standards.

The total charge for service is the charge determined by applying the rates in section 1 below, plus Direct Assignment Charges in section 4 below.

1. RATES

The rates for Dispatchable Energy Resource Balancing Service shall not exceed:

a. Incremental Reserves 18.15 mills per kW maximum hourly deviation
b. Decremental Reserves 3.94 mills per kW maximum hourly deviation

2. BILLING FACTORS

a. The hourly billing factor for use of Incremental Reserves is the maximum of the absolute value of the five-minute average negative Station Control Error (under-generation), including ramp periods, that exceeds 3 MW for that hour.

b. The hourly billing factor for use of Decremental Reserves is the maximum of the five-minute average positive Station Control Error (over-generation), including ramp periods, that exceeds 3 MW for that hour.

3. EXCEPTIONS

a. This rate will not apply to a Dispatchable Energy Resource, or portion of a Dispatchable Energy Resource, that, in BPA's determination, has put in place, tested, and successfully implemented no later than the 15th day of the month prior to the billing month the dynamic transfer of plant output out of BPA's Balancing Authority Area to another Balancing Authority Area.

b. This rate will not apply to a Dispatchable Energy Resource, or portion of a Dispatchable Energy Resource, for any schedule period in which the Dispatchable Energy Resource has called on contingency reserve.

c. This rate will not apply to a Dispatchable Energy Resource, or portion of a Dispatchable Energy Resource, for any hour in which the Dispatchable Energy Resource has been ordered by BPA or a host utility within BPA's

Balancing Authority Area to generate at a level different from the schedule or generation estimate that the Dispatchable Energy Resource submitted to BPA for any schedule period during that hour.

d. Five-minute average station control periods where system frequency deviates by more than 68 mHz shall be excluded from determining the maximum positive (Decremental) or negative (Incremental) value of five-minute station control error for the hour.

4. DIRECT ASSIGNMENT CHARGES

BPA shall directly assign to the customer the cost of incremental balancing reserve capacity purchases that are necessary to provide Dispatchable Energy Resource Balancing Service to the customer if:

a. the customer elected to self-supply but is unable to self-supply the Dispatchable Energy Resource Balancing Service; or

b. a customer has a projected generator interconnection date after FY 2017 but chooses to interconnect during the FY 2016-2017 rate period;

c. a customer operating in another Balancing Authority Area chooses to dynamically transfer into the BPA Balancing Authority Area during the FY 2016-2017 rate period; or

d. the customer elected to dynamically transfer its resource out of BPA's balancing authority area, but chooses to keep its resource in the BPA balancing authority area.

When determining the balancing reserve capacity requirement for a resource subject to direct assignment charges, BPA will round the incremental increase down to the nearest whole megawatt.

Customers that are subject to direct assignment charges will be billed for all costs incurred above $0.29 per kilowatt-day for any incremental balancing reserve capacity acquisitions. Customers billed for direct assignment charges will also be billed at the DERBS rates in section 1.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. RATE ADJUSTMENT DUE TO FERC ORDER UNDER FPA § 212

Customers taking service under this rate schedule are subject to the Rate Adjustment Due to FERC Order under FPA § 212 specified in GRSP II.C.

B. RATE ADJUSTMENT DUE TO BPA POWER SERVICES ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

Customers taking Regulation and Frequency Response Service, Operating Reserve – Spinning Reserve Service, Operating Reserve – Supplemental Reserve Service, Variable Energy Resource Balancing Service, or Dispatchable Energy Resource Balancing Service under this rate schedule are subject to the Cost Recovery Adjustment Clause, Dividend Distribution Clause, and NFB Mechanisms specified in GRSP II.G.

GENERAL RATE SCHEDULE PROVISIONS

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SECTION I. GENERALLY APPLICABLE PROVISIONS

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A. Approval Of Rates

These BP-16 rate schedules and General Rate Schedule Provisions (GRSPs) for Transmission and Ancillary Service Rates shall become effective upon interim approval or upon final confirmation and approval by the Federal Energy Regulatory Commission (FERC or Commission). Bonneville Power Administration (BPA) has requested that FERC make these rates and GRSPs effective on October 1, 2015. All rate schedules shall remain in effect until they are replaced or expire on their own terms.

B. General Provisions

These BP-16 rate schedules and the GRSPs associated with these schedules supersede BPA's BP-14 rate schedules (which became effective October 1, 2013) to the extent stated in the Availability section of each rate schedule. These schedules and GRSPs shall be applicable to all BPA contracts, including contracts executed both prior to and subsequent to enactment of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). All sales under these rate schedules are subject to the following acts, as amended: the Bonneville Project Act (P.L. 75-329), 16 U.S.C.§ 832; the Pacific Northwest Consumer Power Preference Act (P.L. 88-552), 16 U.S.C.§ 837; the Federal Columbia River Transmission System Act (P.L. 93-454), 16 U.S.C.§ 838; the Northwest Power Act (P.L. 96-501), 16 U.S.C.§ 839; and the Energy Policy Act of 1992 (P.L. 102-486), 16 U.S.C.§ 824(i)–(l).

These BP-16 rate schedules do not supersede any previously established rate schedule that is required, by agreement, to remain in effect.

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

C. Notices

For the purpose of determining elapsed time from receipt of a notice applicable to rate schedule and GRSP administration, a notice shall be deemed to have been received at 0000 hours on the first calendar day following actual receipt of the notice.

D. Billing and Payment

1. BILLING PROCEDURE

Within a reasonable time after the first day of each month, BPA shall submit an invoice to the Transmission Customer for the charges for all services furnished under the Tariff and other agreements during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to BPA, or by wire transfer to a bank named by BPA.

2. INTEREST ON UNPAID BALANCES

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by BPA.

3. CUSTOMER DEFAULT

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to BPA on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after BPA notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, BPA may notify the Transmission Customer that it plans to terminate services in sixty (60) days. The Transmission Customer may use the dispute resolution procedures to contest such termination. In the event of a billing dispute between BPA and the Transmission Customer, BPA will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then BPA may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

SECTION II. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

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A. Delivery Charge

Transmission Customers shall pay a Delivery Charge for service over DSI Delivery and Utility Delivery facilities and equipment.

1. RATES

a. DSI Delivery

Use-of-Facilities (UFT-16) Rate, section III

b. Utility Delivery

$1.285 per kilowatt per month

2. BILLING FACTOR

a. Utility Delivery

The monthly Billing Factor for the Utility Delivery rate in section 1.b. shall be the total load on the hour of the Monthly Transmission Peak Load at the Points of Delivery specified as providing Utility Delivery service.

The monthly Utility Delivery Billing Factor shall be adjusted for customers that pay for Utility Delivery service under the Use-of-Facilities (UFT) rate schedule. The kilowatt credit shall equal the transmission service over the Delivery facilities and equipment used to calculate the UFT charge. This adjustment shall not reduce the Utility Delivery Charge billing factor below zero.

B. Failure To Comply Penalty Charge

If a party fails to comply with BPA's dispatch, curtailment, redispatch, or load shedding orders, the party will be assessed the Failure to Comply Penalty Charge. Parties that are unable to comply with a dispatch, curtailment, load shedding, or redispatch order due to a *force majeure* on their system will not be subject to the Failure to Comply Penalty Charge provided that they immediately notify BPA of the situation upon occurrence of the *force majeure*.

1. RATES

The Failure to Comply Penalty Charge shall be the greater of 500 mills per kilowatthour or 150 percent of an hourly energy index in the Pacific Northwest.

If no adequate hourly index exists, an alternative index will be used. At least 30 days prior to the use of such index BPA will post on its OASIS Web site the name of the index to be used. BPA will not change the index more often than once per year unless BPA determines that the existing index is no longer a reliable price index.

2. BILLING FACTOR

The Billing Factor for the Failure to Comply Penalty Charge shall be the kilowatthours that were not curtailed, redispatched, shed, changed, or limited within ten (10) minutes after issuance of the order in any of the following situations:

a. Failure to shed load when directed to do so by BPA in accordance with the Load Shedding provisions of the Open Access Transmission Tariff or any other applicable agreement between the parties. This includes failure to shed load pursuant to such orders within the time period specified by the North American Electric Reliability Council (NERC), Western Electricity Coordinating Council (WECC), or Northwest Power Pool (NWPP) criteria.

b. Failure of a generator in the BPA Control Area or which directly interconnects to the FCRTS to change or limit generation levels when directed to do so by BPA in accordance with Good Utility Practice as defined in the OATT. This includes failure to change generation levels pursuant to such orders within the time period specified by NERC, WECC, or NWPP criteria.

c. Failure to curtail or redispatch a reservation or schedule or failure to curtail or redispatch actual transmission use of the Contract or Service

Agreement when directed to do so by BPA in accordance with the curtailment or redispatch provisions of the Open Access Transmission Tariff or any other applicable agreement between the parties. This includes failure to curtail or redispatch pursuant to such scheduling protocols or orders within the time period specified by NERC, WECC, or NWPP criteria.

3. ASSESSMENT OF OTHER COSTS RESULTING FROM THE FAILURE TO COMPLY

In addition to the Failure to Comply Penalty Charge, the party will be assessed the costs of alternate measures taken by BPA in order to manage the reliability of the FCRTS due to the failure to comply.

The party will also be assessed monetary penalties imposed on BPA by a regional reliability organization, electric reliability organization, or FERC for a violation of a reliability standard authorized under section 215 of the Energy Policy Act of 2005, if the violation was caused by the party's failure to comply.

C. Rate Adjustment Due To FERC Order Under FPA § 212

If, after review by FERC, the NT, PTP, ACS, IS, or IM rate schedule, as initially submitted to FERC, is modified to satisfy the standards of section 212(i)(1)(B)(ii) of the Federal Power Act (16 U.S.C. § 824k(i)(1)(B)(ii)) for FERC-ordered transmission service, then such modifications shall automatically apply to the rate schedule for non-section 212(i)(1)(B)(ii) transmission service. The modifications for non-section 212(i)(1)(B)(ii) transmission service, as described above, shall be effective only prospectively from the date of the final FERC order granting final approval of the rate schedule for FERC-ordered transmission service pursuant to section 212(i)(1)(B)(ii). No refunds shall be made or additional costs charged as a consequence of this prospective modification for any non-section 212(i)(1)(B)(ii) transmission service that occurred under the rate schedule prior to the effective date of such prospective modification.

D. Reservation Fee

The Reservation Fee is a nonrefundable fee that shall be charged to any PTP Transmission Service customer that postpones the commencement of service by requesting an extension of the Service Commencement Date specified in the executed Service Agreement.

The Reservation Fee shall be specified in the executed agreement for transmission service.

1. FEE

The Reservation Fee shall be a nonrefundable fee equal to one month's charge for the requested Long-Term Firm Point-to-Point Transmission Service for each year or fraction of a year for which the customer chooses to extend the Service Commencement Date. The Reservation Fee shall be paid annually until transmission service begins or the reservation period ends, whichever occurs first.

2. PAYMENT

The Reservation Fee for the first extension of the Service Commencement Date shall be paid in a lump sum within 30 days of the original Service Commencement Date. For subsequent extensions, the Reservation Fee shall be paid in a lump sum within 30 days of the anniversary date of the original Service Commencement Date.

E. Transmission and Ancillary Services Rate Discounts

BPA may offer discounted rates for transmission and ancillary services available under the Open Access Transmission Tariff and to the extent provided for in the PTP, IS, IM, and ACS rate schedules.

Three principal requirements apply to discounts for transmission service and Ancillary Services provided by BPA in conjunction with its provision of transmission service, as follows:

1. any offer of a discount made by BPA must be announced to all Eligible Customers solely by posting on the OASIS;

2. any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS; and

3. once a discount is negotiated, details must be immediately posted on the OASIS.

For any discount agreed upon for transmission service on a path, from point(s) of receipt to point(s) of delivery, BPA must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that connect to the same point(s) of delivery on the transmission system.

A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on BPA's transmission system.

F. Unauthorized Increase Charge (UIC)

Transmission Customers taking Point-to-Point Transmission Service under the PTP, IS, and IM rate schedules shall be assessed the UIC when they exceed their capacity reservations at any Point of Receipt (POR) or Point of Delivery (POD). BPA will notify a Transmission Customer that is subject to a UIC once BPA has verified the UIC amount.

1. RATES

a. Point-To-Point Transmission Service (PTP, IS, and IM Rate Schedules)

The UIC rate shall be the lesser of (i) 100 mills per kilowatthour plus the price cap established by FERC for spot market sales of energy in the WECC, or (ii) 1000 mills per kilowatthour. If FERC eliminates the price cap, the rate will be 500 mills per kilowatthour.

2. BILLING FACTORS

a. Point-To-Point Transmission Service (PTP, IS, and IM Rate Schedules)

For each hour of the monthly billing period, BPA shall determine the amount by which the Transmission Customer exceeds its capacity reservation at each POD and POR, to the extent practicable. BPA shall use hourly measurements based on a 10-minute moving average to calculate actual demands at PODs associated with loads that are one-way dynamically scheduled and at PORs associated with resources that are one-way dynamically scheduled. To calculate actual demands at PODs and PORs that are associated with two-way dynamic schedules, BPA shall use instantaneous peak demands for each hour. Actual demands at all other PODs and PORs will be based on 60-minute integrated demands or transmission schedules.

For each hour, BPA will sum these amounts that exceed capacity reservations for all PODs and for all PORs. The Billing Factor for the monthly billing period shall be the greater of the total of the POD hourly amounts or the total of the POR hourly amounts.

3. UIC RELIEF

a. Criteria for Waiving or Reducing the UIC

Under appropriate circumstances, BPA may waive or reduce the UIC to a Transmission Customer on a non-discriminatory basis. A Transmission

Customer seeking a reduction or waiver must demonstrate good cause for relief, including demonstrating that the event that resulted in the UIC:

(1) was inadvertent or was the result of an equipment failure or outage that the Transmission Customer could not have reasonably foreseen;

(2) could not have been avoided by the exercise of reasonable care; and

(3) did not result in harm to BPA's transmission system or transmission services, or to any other Transmission Customer.

If a waiver or reduction is granted to a Transmission Customer, notice of such waiver or reduction will be posted on the BPA OASIS Web site.

b. Transmission Rate if BPA Waives or Reduces the UIC

If BPA waives or reduces the UIC, the Transmission Customer remains subject to the applicable rates, including Ancillary Services rates, for the Transmission Customer's transmission demand. The following rates shall apply to transmission demand that exceeds the capacity reservations of a Transmission Customer taking service under the PTP, IS, or IM rate schedules if BPA waives or reduces the UIC:

(1) If BPA waives or reduces the UIC for excess transmission demand in one or more hours in the same calendar day, the rate for one day of service under section II.B.1. of the applicable PTP, IS, or IM rate schedule shall apply.

(2) If BPA waives or reduces the UIC for excess transmission demand on multiple calendar days in the same calendar week, the rate for seven days of service under section II.B.1. of the applicable PTP, IS, or IM rate schedule shall apply.

(3) If BPA waives or reduces the UIC for excess transmission demand in one or more hours in multiple calendar weeks in the same calendar month, the rate for the number of days in the month of service under section II.B.1. of the applicable PTP, IS, or IM rate schedule shall apply.

For a Transmission Customer taking Point-to-Point Transmission Service under the PTP, IS, or IM rate schedules, the Billing Factor for rates in this section 3.b. shall be: (a) the Transmission Customer's highest excess transmission demand for which BPA waives the UIC; or (b) if BPA reduces the UIC, the Transmission Customer's highest excess transmission demand that is not subject to the UIC as a result of the reduction.

G. CRAC, DDC, and NFB Mechanisms

The Cost Recovery Adjustment Clause (CRAC), Dividend Distribution Clause (DDC), and NFB Mechanisms (the NFB Adjustment and the Emergency NFB Surcharge) are detailed in the BPA Power Rate Schedules, GRSPs II.C, II.E, and II.N.

The CRAC and the Emergency NFB Surcharge are upward adjustments to certain Power and Transmission rates. The DDC is a downward adjustment to certain Power and Transmission rates. The NFB Adjustment is an upward adjustment to the cap on the amount of incremental BPA revenue that can be generated by a CRAC during a fiscal year. Except as otherwise provided, the CRAC, DDC, and Emergency NFB Surcharge apply to the following Ancillary and Control Area Service (ACS) rate schedules:

- Regulation and Frequency Response Service
- Operating Reserve – Spinning Reserve Service
- Operating Reserve – Supplemental Reserve Service
- Variable Energy Resource Balancing Service (VERBS)

  Exception: For the VERBS rate schedule, the CRAC, DDC, and Emergency NFB Surcharge do not apply to any charge calculated under section III.E.2.a.(4), opt out fee, section III.E.4., Direct Assignment Charges and Intentional Deviation, GRSP II.H.

- Dispatchable Energy Resource Balancing Service (DERBS)

  Exception: For the DERBS rate schedule, the CRAC, DDC, and Emergency NFB Surcharge do not apply to any charge calculated under section III.F.4., Direct Assignment Charges.

1. CUSTOMER CHARGES FOR THE ACS CRAC

The ACS CRAC Amount is the share, in dollars, of the total CRAC Amount that is to be recovered from the ACS rates specified above; the balance of the CRAC Amount is to be recovered from specified Power rates. The ACS CRAC Amount is converted to an ACS CRAC Percentage by dividing the ACS CRAC Amount by the most recent forecast of revenues for the relevant fiscal year at the ACS rates subject to the CRAC.

Line items will be added to the bills for each service during the 12 months of the applicable year by multiplying the ACS CRAC Percentage times each of the applicable rates times the billing factors for each rate for each customer.

2. CUSTOMER CREDIT FOR THE ACS DDC

The ACS DDC Amount is the share, in dollars, of the total DDC Amount that is to be distributed from the ACS rates specified above; the balance of the DDC Amount is to be distributed from specified Power rates. The ACS DDC Amount is converted to an ACS DDC Percentage by dividing the ACS DDC Amount by the most recent forecast of revenues for the relevant fiscal year at the ACS rates subject to the DDC.

Line items showing a credit will be added to the bills for each service during the 12 months of the applicable year by multiplying the ACS DDC Percentage times each of the applicable rates times the billing factors for each rate for each customer.

3. CUSTOMER CHARGES FOR THE ACS EMERGENCY NFB SURCHARGE

The ACS Surcharge amount is the share, in dollars, of the total Surcharge Amount that is to be collected from the ACS rates specified above; the balance of the Surcharge Amount is to be collected from specified Power rates. The ACS Surcharge is converted to an ACS Surcharge Percentage by dividing the ACS Surcharge by the most recent forecast of revenues for the relevant fiscal year at the ACS rates subject to the Emergency NFB Surcharge.

Line items will be added to the bills for each service during the 12 months of the applicable year by multiplying the ACS Surcharge Percentage times each of the applicable rates times the billing factors for each rate.

4. CRAC, DDC, AND NFB MECHANISM RATE PROVISIONS

The CRAC, DDC, and NFB Mechanism rate provisions specified in the Power Rate Schedules, GRSPs II.C, II.E, and II.N, are incorporated by reference.

H. Intentional Deviation Penalty Charge

1. APPLICABILITY

Except as otherwise provided, the Intentional Deviation Penalty Charge applies to Variable Energy Resources taking service at the ACS-16 Variable Energy Resources Balancing Service rate.

Exceptions:

a. With 90 days' notice before the start of the applicable billing month, customers taking service at the VERBS rate for uncommitted scheduling can elect to opt out of the Intentional Deviation Penalty Charge for an additional Opt Out Fee (ACS-16 VERBS rate schedule, section III.E.2.a.(4)). The opt-out election will remain in place until the customer elects to change its opt-out election with 90 days' notice before the start of the applicable billing month. Once each fiscal year, a customer can: (1) opt out of the Intentional Deviation Penalty Charge, and (2) change its opt-out election. Customers that opt out of the Intentional Deviation Penalty Charge are subject to the Persistent Deviation for Generation penalty charge as specified in the ACS-16 Generation Imbalance Service rate schedule (section III.B.2.c).

b. New Variable Energy Resources undergoing testing before commercial operation are exempt from the Intentional Deviation Penalty Charge during testing for up to 90 days.

c. Customers participating in the Customer Supplied Generation Imbalance ("CSGI") Pilot Program are not subject to the Intentional Deviation Penalty Charge.

2. RATE

For each Intentional Deviation event, the Intentional Deviation Penalty Charge rate shall be $100 per megawatthour (MWh).

An Intentional Deviation event occurs when:

ABS(Intentional Deviation Measurement Value – Resource Schedule) > 1

(See section 3, below, for definition of terms.)

3. BILLING FACTOR

The Billing Factor in MWh shall be:

ABS(Intentional Deviation Measurement Value – Resource Schedule) – 1

Multiplied by

Minutes of schedule divided by 60 minutes

Where:

ABS = the absolute value of the term in parentheses.

Intentional Deviation Measurement Value = one of the following three values:

1) for wind generating customers taking VERBS at a committed scheduling rate (VERBS rate schedule, sections 2.a.(1)-(3)), the applicable committed schedule value provided by BPA;

2) for wind generating customers taking VERBS at the uncommitted scheduling rate (VERBS rate schedule, section 2.a.(4)), the 40-minute forecast schedule value produced by the Super Forecast Methodology; or

3) for solar generating customers taking VERBS (section 3), the matrix forecast schedule value or applicable committed schedule value provided by BPA.

Resource Schedule = for each wind or solar resource, the amount in megawatts of generation that is scheduled by the customer for the scheduling period.

Minutes of schedule = 15 if a 15-minute schedule, 30 if a 30-minute schedule, or 60 if a 60-minute schedule.

4. OTHER PROVISIONS

Exemption from Intentional Deviation Penalty Charge

A customer that schedules its resource to a value other than the Intentional Deviation Measurement Value is exempt from the Intentional Deviation Penalty Charge for a scheduling period if

ABS(Station Control Error) ≤ ABS(Intentional Deviation Measurement Value Error) + 1 MW

Where:

ABS(Intentional Deviation Measurement Value Error) = the absolute value of the Station Control Error that *would have resulted* from a schedule that was set equal to the resource's applicable Intentional Deviation Measurement Value.

I. Modified Tier 1 Cost Allocators (TOCA) for Oversupply Rate

BPA Customer ID	Customer Name	Modified TOCAs	
		FY 2016	FY 2017
10005	Alder Mutual	0.0000775	0.0000777
10015	Asotin County PUD #1	0.0000818	0.0000814
10024	Benton County PUD #1	0.0287656	0.0286115
10025	Benton REA	0.0095225	0.0094715
10027	Big Bend Elec Coop	0.0087323	0.0086855
10029	Blachly Lane Elec Coop	0.0025137	0.0025002
10044	Canby, City of	0.0028981	0.0028826
10046	Central Electric Coop	0.0116799	0.0116173
10047	Central Lincoln PUD	0.0220629	0.0220015
10055	Albion, City of	0.0000568	0.0000565
10057	Ashland, City of	0.0030064	0.0029903
10059	Bandon, City of	0.0010887	0.0010843
10061	Blaine, City of	0.0012481	0.0012414
10062	Bonners Ferry, City of	0.0007591	0.0007551
10064	Burley, City of	0.0019817	0.0019769
10065	Cascade Locks, City of	0.0003153	0.0003138
10066	Centralia, City of	0.0034778	0.0034592
10067	Cheney, City of	0.0022571	0.0022450
10068	Chewelah, City of	0.0003755	0.0003735
10070	Declo, City of	0.0000511	0.0000508
10071	Drain, City of	0.0002732	0.0002717
10072	Ellensburg, City of	0.0034222	0.0034039
10074	Forest Grove, City of	0.0038075	0.0037871
10076	Heyburn, City of	0.0006874	0.0006837
10078	McCleary, City of	0.0005080	0.0005066
10079	McMinnville, City of	0.0125829	0.0125154
10080	Milton, Town of	0.0010611	0.0010554
10081	Milton-Freewater, City of	0.0014324	0.0014310
10082	Minidoka, City of	0.0000164	0.0000166
10083	Monmouth, City of	0.0011935	0.0011871
10086	Plummer, City of	0.0005630	0.0005600
10087	Port Angeles, City of	0.0120226	0.0119759
10089	Richland, City of	0.0147767	0.0146975
10091	Rupert, City of	0.0013445	0.0013373
10094	Soda Springs, City of	0.0004238	0.0004194

BPA Customer ID	Customer Name	Modified TOCAs	
		FY 2016	FY 2017
10095	Sumas, Town of	0.0005197	0.0005170
10097	Troy, City of	0.0002908	0.0002893
10101	Clallam County PUD #1	0.0108490	0.0107909
10103	Clark County PUD #1	0.0427033	0.0426580
10105	Clatskanie PUD	0.0132478	0.0131768
10106	Clearwater Power	0.0033347	0.0033303
10109	Columbia Basin Elec Coop	0.0017292	0.0017199
10111	Columbia Power Coop	0.0004186	0.0004191
10112	Columbia River PUD	0.0080633	0.0080784
10113	Columbia REA	0.0053787	0.0053499
10116	Consolidated Irrigation District #19	0.0000286	0.0000284
10118	Consumers Power	0.0065175	0.0064826
10121	Coos Curry Elec Coop	0.0057280	0.0057119
10123	Cowlitz County PUD #1	0.0783695	0.0779496
10136	Douglas Electric Cooperative	0.0025973	0.0025906
10142	East End Mutual Electric	0.0003835	0.0003814
10144	Eatonville, City of	0.0004780	0.0004780
10156	Elmhurst Mutual P & L	0.0045851	0.0045757
10157	Emerald PUD	0.0067304	0.0067541
10158	Energy Northwest	0.0003949	0.0003925
10170	Eugene Water & Electric Board	0.0343469	0.0342560
10172	U.S. Airforce Base, Fairchild	0.0008172	0.0008211
10173	Fall River Elec Coop	0.0047277	0.0047023
10174	Farmers Elec Coop	0.0000724	0.0000720
10177	Ferry County PUD #1	0.0016645	0.0016556
10179	Flathead Elec Coop	0.0238053	0.0236778
10183	Franklin County PUD #1	0.0167458	0.0166560
10186	Glacier Elec Coop	0.0030419	0.0030256
10190	Grant County PUD #2	0.0007408	0.0007369
10191	Grays Harbor PUD #1	0.0187243	0.0186240
10197	Harney Elec Coop	0.0032468	0.0032294
10202	Hood River Elec Coop	0.0018692	0.0018592
10203	Idaho County L & P	0.0008866	0.0008819
10204	Idaho Falls Power	0.0113525	0.0112916
10209	Inland P & L	0.0153744	0.0152920
10230	Kittitas County PUD #1	0.0013846	0.0013771
10231	Klickitat County PUD #1	0.0052311	0.0052031
10234	Kootenai Electric Coop	0.0072775	0.0072385
10235	Lakeview L & P (WA)	0.0045743	0.0045726

BPA Customer ID	Customer Name	Modified TOCAs	
		FY 2016	FY 2017
10236	Lane County Elec Coop	0.0039476	0.0039280
10237	Lewis County PUD #1	0.0156264	0.0155702
10239	Lincoln Elec Coop (MT)	0.0019784	0.0019661
10242	Lost River Elec Coop	0.0013593	0.0013520
10244	Lower Valley Energy	0.0122773	0.0122116
10246	Mason County PUD #1	0.0012824	0.0012755
10247	Mason County PUD #3	0.0114057	0.0113446
10256	Midstate Elec Coop	0.0065469	0.0065413
10258	Mission Valley	0.0053227	0.0053682
10259	Missoula Elec Coop	0.0038326	0.0038301
10260	Modern Elec Coop	0.0036974	0.0037095
10273	Nespelem Valley Elec Coop	0.0008392	0.0008347
10278	Northern Lights	0.0051267	0.0050993
10279	Northern Wasco County PUD	0.0092419	0.0091924
10284	Ohop Mutual Light Company	0.0014078	0.0014084
10285	Okanogan County Elec Coop	0.0009303	0.0009266
10286	Okanogan County PUD #1	0.0065514	0.0065162
10288	Orcas P & L	0.0035296	0.0035107
10291	Oregon Trail Coop	0.0112063	0.0112385
10294	Pacific County PUD #2	0.0051838	0.0051560
10304	Parkland L & W	0.0019989	0.0019968
10306	Pend Oreille County PUD #1	0.0008002	0.0036566
10307	Peninsula Light Company	0.0102722	0.0102172
10326	U.S. Naval Base, Bremerton	0.0041294	0.0041072
10331	Raft River Elec Coop	0.0050216	0.0050338
10333	Ravalli County Elec Coop	0.0026420	0.0026279
10338	Riverside Elec Coop	0.0003385	0.0003367
10342	Salem Elec Coop	0.0053746	0.0053605
10343	Salmon River Elec Coop	0.0017627	0.0017524
10349	Seattle City Light	0.0747610	0.0743604
10352	Skamania County PUD #1	0.0022162	0.0022159
10354	Snohomish County PUD #1	0.1103304	0.1110411
10360	Southside Elec Lines	0.0009653	0.0009602
10363	Springfield Utility Board	0.0131493	0.0131054
10369	Surprise Valley Elec Coop	0.0023306	0.0023323
10370	Tacoma Public Utilities	0.0574202	0.0571126
10371	Tanner Elec Coop	0.0015743	0.0015659
10376	Tillamook PUD #1	0.0079015	0.0078817

BPA Customer ID	Customer Name	Modified TOCAs	
		FY 2016	FY 2017
10378	Coulee Dam, City of	0.0002883	0.0002868
10379	Steilacoom, Town of	0.0006861	0.0006824
10388	Umatilla Elec Coop	0.0161567	0.0160701
10391	United Electric Coop	0.0042775	0.0042546
10406	U.S. DOE Albany Research Center	0.0000654	0.0000651
10408	U.S. Naval Station, Everett (Jim Creek)	0.0002134	0.0002121
10409	U.S. Naval Submarine Base, Bangor	0.0029141	0.0028985
10426	U.S. DOE Richland Operations Office	0.0037194	0.0037315
10434	Vera Irrigation District	0.0038752	0.0038545
10436	Vigilante Elec Coop	0.0027329	0.0027182
10440	Wahkiakum County PUD #1	0.0007142	0.0007103
10442	Wasco Elec Coop	0.0018218	0.0018317
10446	Wells Rural Elec Coop	0.0136664	0.0135932
10448	West Oregon Elec Coop	0.0011932	0.0011867
10451	Whatcom County PUD #1	0.0037454	0.0037364
10482	Umpqua Indian Utility Cooperative	0.0004092	0.0004094
10502	Yakama Power	0.0016601	0.0016512
10597	Hermiston, City of	0.0018011	0.0017911
10706	Port of Seattle - SETAC In'tl. Airport	0.0023796	0.0024524
11680	Weiser, City of	0.0009031	0.0008983
12026	Jefferson County PUD #1	0.0060820	0.0061064
10007	Alcoa	0.0108078	0.0107499
10312	Port Townsend Paper	0.0023057	0.0022933
10298	PNGC Aggregate	0.0714533	0.0711460

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SECTION III. DEFINITIONS

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1. Ancillary Services

Ancillary Services are those services that are necessary to support the transmission of energy from resources to loads while maintaining reliable operation of BPA's Transmission System in accordance with Good Utility Practice. Ancillary Services include:

a. Scheduling, System Control, and Dispatch
b. Reactive Supply and Voltage Control from Generation Sources
c. Regulation and Frequency Response
d. Energy Imbalance
e. Operating Reserve – Spinning
f. Operating Reserve – Supplemental

Ancillary Services are available under the ACS rate schedule.

2. Balancing Authority Area

See definition in Control Area.

3. Billing Factor

The Billing Factor is the quantity to which the rate specified in the rate schedule is applied. When the rate schedule includes rates for several products, there may be a Billing Factor for each product.

4. Control Area

A Control Area (also known as Balancing Authority Area) is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

a. match at all times the power output of the generators within the electric power system(s) and the import of energy from entities outside the electric power system(s) with the load within the electric power system(s) and the export of energy to entities outside the electric power system(s);

b. maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

c. maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

d. provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

5. Control Area Services

Control Area Services are available to meet the Reliability Obligations of a party with resources or loads in the BPA Control Area. A party that is not satisfying all of its Reliability Obligations through the purchase or self-provision of Ancillary Services may purchase Control Area Services to meet its Reliability Obligations. Control Area Services are also available to parties with resources or loads in the BPA Control Area that have Reliability Obligations but do not have a transmission agreement with BPA. Reliability Obligations for resources or loads in the BPA Control Area are determined by applying the North American Electric Reliability Council (NERC), Western Electricity Coordinating Council (WECC), and Northwest Power Pool (NWPP) reliability criteria. Control Area Services include, without limitation:

a. Regulation and Frequency Response Service
b. Generation Imbalance Service
c. Operating Reserve – Spinning Reserve Service
d. Operating Reserve – Supplemental Reserve Service
e. Variable Energy Resource Balancing Service
f. Dispatchable Energy Resource Balancing Service

6. Daily Service

Daily Service is service that starts at 00:00 of any date and stops at 00:00 at least one (1) day later, but less than or equal to six (6) days later.

7. Direct Assignment Facilities

Direct Assignment Facilities are facilities or portions of facilities that are constructed by BPA for the sole use and benefit of a particular Transmission Customer requesting service under the Open Access Transmission Tariff, the costs of which may be directly assigned to the Transmission Customer in accordance with applicable Federal Energy Regulatory Commission policy. Direct Assignment Facilities shall be specified in the service agreement that governs service to the Transmission Customer.

8. Direct Service Industry (DSI) Delivery

The DSI Delivery segment consists of equipment necessary to deliver power to DSI customers at low voltages (i.e., 6.9 or 13.8 kV).

9. Dispatchable Energy Resource

For purposes of the ACS rate schedule, a Dispatchable Energy Resource is any non-Federal thermally based generating resource that schedules its output or is included in BPA's Automatic Generation Control system.

10. Dispatchable Energy Resource Balancing Service

Dispatchable Energy Resource Balancing Service (DERBS) is a Control Area Service that provides imbalance reserves (which compensate for differences between a thermal generator's schedule and the actual generation during an hour). DERBS is required to help maintain the power system frequency at 60 Hz and to conform to NERC and WECC reliability standards.

11. Dynamic Schedule

See definition in Dynamic Transfer Operating and Scheduling Business Practice.

12. Dynamic Transfer

See definition in Dynamic Transfer Operating and Scheduling Business Practice.

13. Eastern Intertie

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

14. Energy Imbalance Service

Energy Imbalance Service is provided when a difference occurs between the scheduled and actual delivery of energy to a load located within a Control Area. BPA must offer this service when the transmission service is used to serve load within BPA's Control Area. The Transmission Customer must either purchase this service from BPA or make alternative comparable arrangements specified in the Transmission Customer's Service Agreement to satisfy its Energy Imbalance Service obligation.

15. Federal Columbia River Transmission System

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

16. Federal System

The Federal System is the generating facilities of the Federal Columbia River Power System, including the Federal generating facilities for which BPA is designated as marketing agent; the Federal facilities under the jurisdiction of BPA; and any other facilities:

a. from which BPA receives all or a portion of the generating capability (other than station service) for use in meeting BPA's loads to the extent BPA has the right to receive such capability ("BPA's loads" do not include any of the loads of any BPA customer that are served by a non-Federal generating resource purchased or owned directly by such customer that may be scheduled by BPA);

b. that BPA may use under contract or license; or

c. to the extent of the rights acquired by BPA pursuant to the 1961 U.S.-Canada Treaty relating to the cooperative development of water resources of the Columbia River Basin.

17. Generation Imbalance

Generation Imbalance is the difference between the scheduled amount and actual delivered amount of energy from a generation resource in the BPA Control Area.

18. Generation Imbalance Service

Generation Imbalance Service is provided when there is a difference between scheduled and actual energy delivered from generation resources in the BPA Control Area during a schedule period.

19. Heavy Load Hours (HLH)

Heavy Load Hours (HLH) are all those hours in the period beginning with the hour ending 7 a.m. through hour ending 10 p.m., Monday through Saturday, Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable), except for holidays recognized by NERC.

20. Hourly Non-Firm Service

Hourly Non-firm Service is non-firm transmission service under Part II of the Open Access Transmission Tariff in hourly increments.

21. Integrated Demand

Integrated Demand is the quantity derived by mathematically "integrating" kilowatthour deliveries over a 60-minute period. For one-way dynamic schedules, demand is integrated on a rolling ten-minute basis.

22. Light Load Hours (LLH)

Light Load Hours (LLH) are all those hours in the period beginning with the hour ending 11 p.m. through hour ending 6 a.m., Monday through Saturday and all hours Sunday, Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable).

BPA considers as LLH six holidays classified according to NERC Standards as LLH. Memorial Day, Labor Day and Thanksgiving occur on the same day each year: Memorial Day is the last Monday in May; Labor Day is the first Monday in September; and Thanksgiving Day is the fourth Thursday in November. New Year's Day, Independence Day, and Christmas Day fall on predetermined dates each year. In the event that a holiday falls on a Sunday, the holiday is celebrated the Monday immediately following that Sunday, so that Monday is also LLH all day. If a holiday falls on a Saturday, the holiday remains on that Saturday, and that Saturday is classified as LLH.

23. Long-Term Firm Point-To-Point (PTP) Transmission Service

Long-Term Firm Point-to-Point Transmission Service is Firm Point-To-Point Transmission Service under Part II of the Open Access Transmission Tariff with a term of one year or more.

24. Main Grid

As used in the FPT rate schedule, the Main Grid is that portion of the Network facilities with an operating voltage of 230 kV or more.

25. Main Grid Distance

As used in the FPT rate schedules, Main Grid Distance is the distance in airline miles on the Main Grid between the Point of Integration (POI) and the Point of Delivery (POD), multiplied by 1.15.

26. Main Grid Interconnection Terminal

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

27. Main Grid Miscellaneous Facilities

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

28. Main Grid Terminal

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

29. Measured Demand

The Measured Demand is that portion of the customer's Metered or Scheduled Demand for transmission service from BPA under the applicable transmission rate schedule. If transmission service to a point of delivery or from a point of receipt is provided under more than one rate schedule, the portion of the measured quantities assigned to any rate schedule shall be as specified by contract. The portion of the total Measured Demand so assigned shall be the Measured Demand for transmission service for each transmission rate schedule.

30. Metered Demand

Except for dynamic schedules, the Metered Demand in kilowatts shall be the largest of the 60-minute clock-hour Integrated Demands at which electric energy is delivered (received) for a transmission customer:

a. at each point of delivery (receipt) for which the Metered Demand is the basis for the determination of the Measured Demand;

b. during each time period specified in the applicable rate schedule; and

c. during any billing period.

Such largest Integrated Demand shall be determined from measurements made in accord with the provisions of the applicable contract and these GRSPs. This amount shall be adjusted as provided herein and in the applicable agreement between BPA and the customer.

For one-way Dynamic Schedules, the Metered Demand in kilowatts shall be the largest ten-minute moving average of the load (generation) at the point of delivery (receipt). The ten-minute moving average shall be assigned to the hour in which the ten-minute period ends. For two-way Dynamic Schedules, the Metered Demand in kilowatts shall be the largest instantaneous value of the Dynamic Schedule during the hour.

31. Montana Intertie

The Montana Intertie is the double-circuit 500 kV transmission line and associated substation facilities from Broadview Substation to Garrison Substation.

32. Monthly Services

Monthly Service is service that starts at 00:00 on any date and stops at 00:00 at least 28 days later, but less than or equal to 364 days later.

33. Monthly Transmission Peak Load

Monthly Transmission Peak Load is the peak loading on the Federal Transmission System during any hour of the designated billing month, determined by the largest hourly integrated demand produced from the sum of Federal and non-Federal generating plants in BPA's Control Area and metered flow into BPA's Control Area.

34. Network

The Network consists of facilities that transmit power from Federal and non-Federal generation sources, from interconnections with other utilities, or from the interties, to the load centers of BPA's transmission customers in the Pacific Northwest, to interconnections with other utilities, or to other segments (*e.g.*, an intertie or delivery segment).

35. Network Integration Transmission (NT) Service

Network Integration Transmission (NT) Service is the transmission service provided under Part III of the Open Access Transmission Tariff.

36. Network Load

Network Load is the load that a Network Customer designates for Network Integration Transmission Service under Part III of the Open Access Transmission Tariff. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery.

Where an Eligible Customer has elected not to designate a particular load at discrete Points of Delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of the Tariff for any Point-to-Point Transmission Service that may be necessary for such non-designated load.

37. Network Upgrades

Network Upgrades are modifications or additions to transmission-related facilities that support the BPA Transmission System for the general benefit of all users of such Transmission System.

38. Non-Firm Point-to-Point (PTP) Transmission Service

Non-Firm Point-To-Point Transmission Service is Point-To-Point Transmission Service under the Open Access Transmission Tariff that is reserved and scheduled on an as-available basis and is subject to curtailment or interruption as set forth in section 14.7

under Part II of the Tariff. Non-Firm PTP Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

39. Operating Reserve – Spinning Reserve Service

Operating Reserve – Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output. BPA must offer this service in accordance with applicable NERC, WECC, and NWPP standards. The Transmission Customer or Control Area Service Customer must either purchase this service from BPA or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The Transmission Customer's or Control Area Service Customer's obligation is determined consistent with NERC, WECC, and NWPP criteria.

40. Operating Reserve – Supplemental Reserve Service

Operating Reserve – Supplemental Reserve Service is needed to serve load in the event of a system contingency. It is not available immediately to serve load, but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation, or by interruptible load. BPA must offer this service in accordance with applicable NERC, WECC, and NWPP standards. The Transmission Customer or Control Area Service Customer must either purchase this service from BPA or make alternative but comparable arrangements to satisfy its Supplemental Reserve Service obligation. The Transmission Customer's or Control Area Service Customer's obligation is determined consistent with NERC, WECC, and NWPP criteria.

41. Operating Reserve Requirement

Operating Reserve Requirement is a party's total operating reserve obligation (spinning and supplemental) to the BPA Control Area. A party is responsible for purchasing or otherwise providing Operating Reserves associated with its transactions that impose a reserve obligation on the BPA Control Area.

The specific amounts required are determined consistent with NERC Policies, the NWPP Operating Manual, "Contingency Reserve Sharing Procedure," and WECC Standards.

42. Persistent Deviation

A Persistent Deviation event is one or more of the following:

a. **For Generation Imbalance Service only:**

All hours or scheduled periods in which either a negative deviation (actual generation greater than scheduled) or positive deviation (generation is less than scheduled) exceeds:

(1) both 15 percent of the schedule and 20 MW in each scheduled period for three consecutive hours or more in the same direction;

(2) both 7.5 percent of the schedule and 10 MW in each scheduled period for six consecutive hours or more in the same direction;

(3) both 1.5 percent of the schedule and 5 MW in each scheduled period for twelve consecutive hours or more in the same direction; or

(4) both 1.5 percent of the schedule and 2 MW in each scheduled period for twenty-four consecutive hours or more in the same direction.

b. **For Energy Imbalance Service only:**

All hours or scheduled periods in which either a negative deviation (energy taken is less than the scheduled energy) or positive deviation (energy taken is greater than energy scheduled) exceeds:

(1) both 15 percent of the schedule and 20 MW in each scheduled period for three consecutive hours or more in the same direction;

(2) both 7.5 percent of the schedule and 10 MW in each scheduled period for six consecutive hours or more in the same direction;

(3) both 1.5 percent of the schedule and 5 MW in each scheduled period for twelve consecutive hours or more in the same direction; or

(4) both 1.5 percent of the schedule and 2 MW in each scheduled period for twenty-four consecutive hours or more in the same direction.

c. A pattern of under- or over-delivery or over- or under-use of energy occurs generally or at specific times of day.

43. Point of Delivery (POD)

A Point of Delivery is a point on the BPA Transmission System, or transfer points on other utility systems pursuant to section 36 of the Open Access Transmission Tariff, where capacity and energy transmitted by BPA will be made available to the Receiving Party under Parts II and III of the Tariff or to the Transmission Customer under other

BPA transmission service agreements. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-to-Point Service, Network Integration Transmission Service, and other BPA transmission services.

44. Point of Integration (POI)

A Point of Integration is the contractual interconnection point where power is received from the customer. Typically, a point of integration is located at a resource site, but it could be located at some other interconnection point.

45. Point of Interconnection (POI)

A Point of Interconnection is a point where the facilities of two entities are interconnected. This term is used in certain pre-Open Access Transmission Tariff service agreements and has the same meaning as "Point of Integration" and "Point of Receipt."

46. Point of Receipt (POR)

A Point of Receipt is a point of interconnection on the BPA Transmission System where capacity and energy will be made available to BPA by the Delivering Party under Parts II and III of the Open Access Transmission Tariff. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-to-Point Service, Network Integration Transmission Service, and other BPA transmission services.

47. Ratchet Demand

The Ratchet Demand in kilowatts or kilovars is the maximum demand established during a specified period of time during or prior to the current billing period. The Ratchet Demand shall be the maximum demand established during the previous 11 billing months. If a Transmission Demand has been decreased pursuant to the terms of the transmission agreement during the previous 11 billing months, such decrease will be reflected in determining the Ratchet Demand.

48. Reactive Power

Reactive Power is the out-of-phase component of the total volt-amperes in an electric circuit. Reactive Power Demand is expressed in kilovars or kVAr, and Reactive Power Energy is expressed in kilovarhours or kVArh.

49. Reactive Supply and Voltage Control from Generation Sources Service

Reactive Supply and Voltage Control from Generation Sources Service is required to maintain voltage levels on BPA's transmission facilities within acceptable limits. In order to maintain transmission voltages on BPA's transmission facilities within acceptable limits, generation facilities (in the Control Area where the BPA transmission facilities are located) are operated to produce (or absorb) reactive power. Thus, Reactive

Supply and Voltage Control from Generation Sources Service must be provided for each transaction on BPA's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by BPA. The Transmission Customer must purchase this service from BPA.

50. Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generation control equipment) as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with BPA. BPA must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from BPA or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation.

51. Reliability Obligations

Reliability Obligations are the obligations that a party with resources or loads in the BPA Control Area must provide in order to meet minimum reliability standards. Reliability Obligations shall be determined consistent with applicable NERC, WECC, and NWPP standards. BPA offers Ancillary Services and Control Area Services to allow resources or loads to meet their Reliability Obligations.

52. Reserved Capacity

Reserved Capacity is the maximum amount of capacity and energy that BPA agrees to transmit for the Transmission Customer over the BPA Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the Open Access Transmission Tariff. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60)-minute interval (commencing on the clock hour) basis. In cases where Dynamic Schedules are involved, the Reserved Capacity must be set at a level to accommodate (i) a demand equal to the largest ten-minute moving average of the load or generation expected to occur during the contract period for one-way Dynamic Schedules used to transfer generation or load from one Control Area to another Control Area; or (ii) a demand equal to the instantaneous peak demand, for each direction, of the supplemental Control Area service request expected to occur during the contract period for two-way Dynamic Transfers used to provide supplemental Control Area services. The supplemental Control Area service response shall always be the lesser of the Control Area service request or the Reserved Capacity associated with the supplemental Control Area service.

53. Scheduled Demand

Scheduled Demand is the hourly demand at which electric energy is scheduled for transmission on the FCRTS.

54. Scheduling, System Control, and Dispatch Service

Scheduling, System Control, and Dispatch Service is an Ancillary Service required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. The Transmission Customer must purchase this service from BPA.

55. Secondary System

As used in the FPT rate schedules, Secondary System is that portion of the Network facilities with an operating voltage greater than or equal to 69 kV and less than 230 kV.

56. Secondary System Distance

As used in the FPT rate schedules, Secondary System Distance is the number of circuit miles of Secondary System transmission lines between the secondary Point of Integration and either the Main Grid or the secondary Point of Delivery (POD), or between the Main Grid and the secondary POD.

57. Secondary System Interconnection Terminal

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

58. Secondary System Intermediate Terminal

As used in the FPT rate schedules, Secondary System Intermediate Terminal refers to the first and last terminal facilities in the Secondary System transmission path, exclusive of the Secondary System Interconnection terminals.

59. Secondary Transformation

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

60. Short-Term Firm Point-to-Point (PTP) Transmission Service

Short-Term Firm Point-To-Point Transmission Service is Firm Point-To-Point Transmission Service under Part II of the Open Access Transmission Tariff with a term of less than one year. Short-Term Firm Point-To-Point Transmission Service with a duration of less than one calendar day is sometimes referred to as Hourly Firm Point-To-Point Transmission Service.

61. Southern Intertie

The Southern Intertie is the segment of the FCRTS that includes, but is not limited to, the major transmission facilities consisting of two 500-kV AC lines from John Day Substation to the Oregon-California border; a portion of the 500-kV AC line from Buckley Substation to Summer Lake Substation; and the 500-kV AC Intertie facilities, which include Captain Jack Substation, the Alvey-Meridian AC line, one 1,000-kV DC line between the Celilo Substation and the Oregon-Nevada border, and associated substation facilities.

62. Spill Condition

Spill Condition, for the purpose of determining credit or payment for Deviations under the Energy Imbalance and Generation Imbalance rates, exists when spill physically occurs on the BPA system due to lack of load or market. Spill due to lack of load or market typically occurs during periods of high flows or flood control implementation, but can also occur at other times. Discretionary spill, where BPA may choose whether to spill, does not constitute a Spill Condition. Spill for fish is included in discretionary spill and is not a Spill Condition.

63. Spinning Reserve Requirement

Spinning Reserve Requirement is a portion of a party's Operating Reserve Requirement to the BPA Control Area. A party is responsible for purchasing or otherwise providing Operating Reserve – Spinning Reserve Service associated with its transactions that impose a reserve obligation on the BPA Control Area.

The specific amounts required are determined consistent with NERC Policies, the NWPP Operating Manual, "Contingency Reserve Sharing Procedure," and WECC Standards.

64. Station Control Error

Station Control Error is the difference between the amount of generation scheduled from a generator and the actual output of that generator.

65. Super Forecast Methodology

The Super Forecast Methodology is an algorithm that selects the best forecast for predicting generation from a particular project based on historical performance. The customer may submit its forecast for use by the methodology and its forecast will be used if it out-performs the BPA forecast vendors. BPA will deliver the model results to the customer each scheduling period electronically.

66. Supplemental Reserve Requirement

Supplemental Reserve Requirement is a portion of a party's Operating Reserve Requirement to the BPA Control Area. A party is responsible for purchasing or otherwise providing Operating Reserve – Supplemental Reserve Service associated with its transactions that impose a reserve obligation on the BPA Control Area.The specific amounts required are determined consistent with NERC Policies, the NWPP Operating Manual, "Contingency Reserve Sharing Procedure," and WECC Standards.

67. Total Transmission Demand

Total Transmission Demand is the sum of all the transmission demands as defined in the applicable agreement.

68. Transmission Customer

A Transmission Customer is any Eligible Customer (or its Designated Agent) under the Open Access Transmission Tariff that (i) executes a Service Agreement, or (ii) requests in writing that BPA file with the Commission a proposed unexecuted Service Agreement to receive transmission service under Part II of the Tariff. In addition, a Transmission Customer is an entity that has executed any other transmission service agreement with BPA.

69. Transmission Demand

Transmission Demand is the maximum amount of capacity BPA agrees to make available to transmit energy for the Transmission Customer over the BPA Transmission System between the Point(s) of Integration/Interconnection/Receipt and the Point(s) of Delivery.

70. Transmission Provider

A Transmission Provider, such as BPA, owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the Open Access Transmission Tariff and other agreements.

71. Utility Delivery

The Utility Delivery segment consists of facilities and equipment that transform and deliver energy to a utility's distribution system at (or close to) the utility's prevailing distribution voltage.

72. Variable Energy Resource

A Variable Energy Resource is an electric generating facility that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator. This includes, for example, wind, solar photovoltaic, and hydrokinetic generating facilities. This does not include, for example, hydroelectric, geothermal, biomass, or process steam generating facilities.

73. Variable Energy Resource Balancing Service

Variable Energy Resource Balancing Service (VERBS) is a Control Area Service comprised of three components: regulating reserves (which compensate for moment-to-moment differences between generation and load); following reserves (which compensate for larger differences occurring over longer periods of time during the hour); and imbalance reserves (which compensate for differences between the generator's schedule and the actual generation during an hour). Variable Energy Resource Balancing Service is required to help maintain the power system frequency at 60 Hz and to conform to NERC and WECC reliability standards.

74. Weekly Service

Weekly Service is service that starts at 00:00 on any date and stops at 00:00 at least seven (7) days later, but less than or equal to 27 days later.

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CASE: UE 308
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
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STAFF EXHIBIT 103

Exhibits in Support
Of Opening Testimony

June 20, 2016

Exhibit 103 is confidential and is subject to

Protective Order No. 16-137.

CASE: UE 308
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 104

Exhibits in Support Of Opening Testimony

June 20, 2016

Exhibit 104 is confidential and is subject to

Protective Order No. 16-137.

CASE: UE 308
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 105

Exhibits in Support Of Opening Testimony

June 20, 2016

Exhibit 105 is confidential and is subject to

Protective Order No. 16-137.

CASE: UE 308
WITNESS: JOHN CRIDER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

<u>REDACTED</u>
Opening Testimony

June 20, 2016

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

A. My name is John Crider. I am a Utilities Analyst for the Public Utility Commission of Oregon (Commission or OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/201.

Q. What is the purpose of your testimony?

A. I discuss three issues related to the Company's power cost projection.

Q. Other than your witness qualification, did you prepare an exhibit for this docket?

A. Yes. Staff provides Confidential Staff Exhibit 202, Coyote Springs FOR calculation.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1, WIND PRODUCTION TAX CREDIT

Q. Please explain the issue related to federal PTCs.

A. PGE includes forecasted federal PTCs in its forecasted NVPC for 2017 relying on Section 18(b) of Senate Bill 1547 signed into law on March 8, 2016, which provides:

> Each public utility that makes sales of electricity shall forecast on an annual basis the projected state and federal production tax credits received by the public utility due to variable renewable electricity production, and the Public Utility Commission shall allow those forecasts to be included in rates through any variable power cost forecasting process established by the Commission.

Q. Are changes to the AUT mechanism made in connection with the review of PGE's annual update to NVPC?

A. Under Order No. 07-015, "[m]odel changes or updates could be considered, not in the Annual Update process, but in a separate docket."[1] PGE has filed Advice No. 264 proposing changes to Schedule 125 to include annual updates to forecasted PTCs in the AUT for true up to actual PTCs in the PCAM. The Commission has not yet established a procedural schedule in that docket.

Q. Does Staff address in this docket whether Schedule 125 should be modified to incorporate forecasted PTCs in NVPC for 2017?

A. Yes. As noted above, forecasts of PTCs must be included in PGE's annual variable power cost mechanism. So the question before the Commission is not whether the forecasted PTCs should be included in PGE's AUT, but whether they should be included in the AUT for 2017 given the short time for review of

[1] Order No. 07-015 at 19.

issues arising from their inclusion. Accordingly, in addition to reviewing PGE's calculation of forecasted PTCs, Staff reviewed PGE's proposed treatment of PTCs to determine whether modifications to Schedule 125 to include forecasted PTCs should be considered in a separate docket rather than in this AUT.

Q. What issues arise related to including forecasted PTCs in NVPC for 2017?

A. Credit for PTCs is included in the fixed component of generation revenue requirement approved by the Commission in Order No. 15-356 in Docket No. UE 294. For this reason, it would have been preferable to address the proposed change to Schedule 125 in a general rate case. However, Staff concludes that PGE's proposed re-categorization of the fixed and variable components of the generation revenue requirement approved by Commission Order No. 15-536 provides sufficient clarity about what PTCs are being passed through to ratepayers, and that it is appropriate to allow PGE to change Schedule 125 at the same time the Commission is reviewing updates to PGE's forecasted NVPC for its AUT.

Q. Please describe the company's proposed treatment of wind production tax credits (PTC).

A. Senate Bill 1547 directed the utilities to include a forecast of PTC's in an annual adjustment. Previously, tax credits were accounted for through base rates in a general rate case. From this AUT forward, the Company proposes to project the annual PTC in the power cost mechanism.

Q. How much was the PTC worth to PGE in 2016?

A. The Company projected $81.5 million in PTCs for 2016. This credit was spread among customers through rates using the generation allocation factor in the Company's last general rate case (UE 294, 2015).

Q. Has the Company estimated the value of the PTCs for 2017?

A. Yes. Due to a reduction in the credit paid per MWh by the federal government from 2016, the value of the PTCs for 2017 is projected to be $76.2 million which is less than the amount forecast in 2016. The Company will include these credits towards the calculation of NPC. The Company proposes to remove the PTC's currently in rates using the generation allocation factor as shown in PGE Exhibit 502.

Q. What is the effect of the PTC treatment on NPC?

A. The effect is to lower NPC for the test year by $76.2 million.

Q. What is the overall effect of the PTC treatment on rates?

A. Although NPC is reduced, the credit currently distributed to customers will be removed from rates. The credit in rates is $81.5 million, so the net effect is an increase in rates equal to the difference in credit amount between the 2016 and 2017 test years, or a $5.3 million increase in rates.

Q. Does Staff have any objection to this method?

A. Staff has no concern about the projection of PTCs in the Company's AUT. This is a straightforward calculation utilizing standard Commission approaches such as a multiyear average of energy production for smoothing and normalization. The prices paid per MWh are clearly established by the federal government so estimate of the credits are transparent and clear. Staff maintains a concern over treatment of the PTCs in the true-up portion of power cost recovery and will analyze the treatment of PTCs carefully in the 2017 PCAM when it is filed.

ISSUE 2, ENERGY IMBALANCE MARKET

Q. When does the Company expect to join the CAISO Energy Imbalance Market (EIM)?

A. The Company currently plans to begin operating in the EIM in October 2017. (PGE/400, Niman-Peschka-Hager/17).

Q. Will the Company's MONET modeling of this AUT's test year of 2017 include this entry into the EIM in October?

A. Yes.

Q. Has the Company included costs or benefits associated with the EIM in net power cost (NPC)?

A. No.

Q. What rationale does the Company provide for not including costs and benefits of EIM?

A. The Company claims that " [due]ue to the uncertainty surrounding the level of benefits … and costs…, we propose to set benefits equal to zero in our 2017 forecast." (PGE/400, Niman-Peshka-Hagerp20). The Company proposes capturing actual costs and benefits in the 2017 PCAM, when actuals will be trued up with this year's AUT projection.

Q. Does Staff agree with this treatment?

A. No. If costs are to be incurred and benefits realized in CY 2017 then Staff believes the Company should include a projection of these costs and benefits, even if the net of the costs and benefits turn out to be zero; i.e., the costs equal the benefits.

Q. Has the Company estimated the costs to be incurred in the test year?

A. Yes. The Company estimates approximately [redacted] in year one for capital expenses and start-up O&M costs of [redacted]. The Company also estimates incurring [redacted] of "ongoing O&M" costs during the test year. The Company itemizes these costs in Confidential Exhibit 403C. Approximately [redacted] are non-labor related costs.

Q. Has the Company proposed a method to recover these costs in the filing?

A. No. In the absence of a proposed recovery method, Staff assumes that the capital expense of [redacted] and the labor O&M costs will be recovered through base rates. Staff assumes the non-labor portion of O&M costs will be recovered through the AUT and PCAM.

Q. Has the Company estimated the benefits from joining the EIM?

A. Yes. The Company engaged consultant Energy + Environmental Economics (E3) to estimate the benefits of joining the EIM. The Company has included this study as PGE Exhibit 402 in its direct testimony.

Q. Did E3 estimate the benefit in dollar terms?

A. Yes. E3's study assumed a 2020 test year and determined benefits in three categories: "sub-hourly dispatch", "flexible reserve savings", and "reliability benefits". Below Staff summarizes the estimated benefits footnote PGE/400 p 77 in a table:

EIM Category	Savings Estimate (millions)
Subhourly Dispatch	$2.7
Flexible Reserve	0.8
Reliability	No estimate
Total Savings	***$3.5***

Q. Is the 2020 test year in the E3 study representative of the test year in the 2017 AUT?

A. Yes. The Company assumes ongoing annual O&M cost at a constant real rate. Benefits estimated in the E3 study do not appear to escalate over time. E3's study assumed a begin date of 2020 for the EIM; the benefits in the AUT are also projected for the inaugural year of the EIM. For all these reasons, the E3 study results are reasonably applied to the current AUT.

Q. What is Staff's recommendation for treating EIM costs and benefits?

A. Staff proposes including the [redacted] in ongoing O&M costs estimated by the Company and one quarter of the annual $3.5 million in benefits estimated by E3 in NPC. These values represent the estimated costs and benefits of operating in the EIM for the last quarter of 2017.

Q. What is the dollar impact of this recommendation on NPC?

A. Using the Company's estimates of costs and benefits, the effect is a net benefit of [redacted], or a decrease in NPC of [redacted]. [2]

Q.

[2] ($3,500,000 annual benefits) / 4 = $875,000 quarterly benefits - $240,000 costs = $635,000 net benefits.

ISSUE 3, COYOTE SPRINGS FORCED OUTAGE RATE

Q. Please describe the circumstances related to this issue.

A. In each power cost filing the Company recalculates the forced outage rate (FOR) for all thermal generation plants. In the Company's previous power cost filing (UE 294), Staff took issue with how the FOR for Coyote Springs was calculated. In that case, parties and Staff stipulated to a NPC reduction incorporating an adjustment related to the issue of Coyote Springs FOR. The issue still remains in this filing and Staff recommends a similar adjustment in this case.

Q. Please summarize the issue.

A. The Commission has directed the Company to use a four-year rolling average of outage hours in order to determine the forced outage rates. The Company has correctly completed this calculation for Coyote Springs as submitted with the minimum filing requirements. However, in 2013 Coyote Springs experienced an extended outage lasting many weeks. Inclusion of this outage in the FOR calculation raises the FOR more than fivefold. Clearly, the extended outage makes 2013 an outlier year and is not representative of typical operations. Staff believes the FOR used in the Company's modeling should represent a typical operational year and thus outlying events should not be included.

Q. Has this issue been previously addressed by the Commission?

A. Not directly. In UM 1355 the Commission comprehensively considered the issue of outlying FOR events for baseload coal plants and issued Order 10-414 offering the Company direction on how to treat these events for ratemaking purposes. However, Coyote Springs is a natural gas (NG) fueled plant, not a coal fired plant, and the Commission has issued no directive regarding such treatment for NG baseload plants.

As mentioned previously, Staff included this issue in UE 294 in which parties reached a settlement of this issue with the Company that included a reduction in NPC for the 2016 test year. The Commission accepted the settlement and stipulated NPC adjustments for that case.

Q. What remedy to outlying FOR events does the Commission offer in Order 10-414?

A. In the case that an outlying event causes the annual FOR to exceed that of 90th percentile of comparable NERC coal units, then the outlier year is replaced with the mean annual FOR for the entire unit's history, or 20 years, whichever is shorter. No individual outage in this time period may exceed 28 days.

Q. What does Staff recommend regarding this issue?

A. Staff recommends an adjustment to the FOR calculation that removes the outlier year of 2013 and applies the Commission treatment of coal plant outlier years. In this case, the 2013 FOR would be replaced with the 20-year historical FOR and MONET rerun to calculate the effect on NPC.

Q. Does Staff have an estimate of the NPC impact of this adjustment?

A. The Company has not provided the 20-year historical FOR to complete this valuation. In order to estimate the impact, Staff instead removed the 2013 outage data and replaced it with 2011 outage data filed with a previous AUT, UE 266. Staff recalculated the FOR for Coyote Springs using data for years 2011-12 and 2014-15[3]. Staff input this value into MONET which produced an NPC reduction of approximately $1.7 million. Staff expects that the Company's adjustment using the 20-year average FOR will yield a similar value.

Q. Does this conclude your testimony?

A. Yes.

[3] See Staff Confidential Exhibit 202

CASE: UE 308
WITNESS: JOHN CRIDER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualifications Statement

June 20, 2016

WITNESS QUALIFICATIONS STATEMENT

NAME:	John Crider
EMPLOYER:	Public Utility Commission Of Oregon
TITLE:	Senior Utility Analyst Energy Resources And Planning Division
ADDRESS:	201 High Street, SE., Suite 100 Salem OR 97301-3612
EDUCATION:	Bachelor of Science, Engineering, University Of Maryland
EXPERIENCE:	I have been employed at the Oregon Public Utility Commission (Commission) since August of 2012. My current responsibilities include analysis and technical support for electric power cost recovery proceedings, with an emphasis on variable power costs and purchases from qualifying facilities. Prior to working for the OPUC I was an engineer in the Strategic Planning division for Gainesville Regional Utilities (GRU) in Gainesville, Florida. My responsibilities at GRU included analysis, design and support for generation economic dispatch modeling, wholesale power transactions, net metering, integrated resource planning, distributed solar generation and fuel (coal and natural gas) planning. Previous to working for GRU, I was a staff design engineer for Eugene Water & Electric Board (EWEB) where my responsibilities included design of control and communications system in support of water and hydro operations. I am a registered professional engineer in both Oregon and Florida.

CASE: UE 308
WITNESS: JOHN CRIDER

PUBLIC UTILITY COMMISSION
OF
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STAFF EXHIBIT 202

Exhibits in Support
Of Opening Testimony

June 20, 2016

Exhibit 202 is confidential and is subject to

Protective Order No. 16-137.

This Exhibit is an excel file and is included on the

Confidential CD filed with the

PUC.FILING CENTER.

CASE: UE 308
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

REDACTED
Opening Testimony

June 20, 2016

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

A. My name is Lance Kaufman. I am a Senior Economist for the Public Utility Commission of Oregon (Commission or OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in exhibit staff/301.

Q. What is the purpose of your testimony?

A. I discuss two issues related to the Company's power cost projection.

Q. Other than your witness statement, did you prepare an exhibit for this docket?

A. No.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1, CALIFORNIA – OREGON TRADING MARGIN

Q. Please describe the issue related to the Oregon-California Trading Margin?

A. In PGE's last AUT proceeding, the Commission ordered PGE to propose a methodology to capture, for purposes of the AUT, the value of benefits PGE obtains through transactions at the California-Oregon Border (COB) made possible by transmission rights paid for by PGE ratepayers. (Order No. 15-356.)

Q. What is PGE's proposed methodology?

A. PGE calculates an incremental benefit to power costs associated with transactions at COB. The benefit exists at times when PGE has excess transmission capacity between COB and MidC and a price differential between the two markets exists. The benefit is incremental because sales at the COB market are not explicitly modeled by MONET. Instead, PGE calculates the benefit for each month based on the forecasted COB volumes times the forecasted price difference between COB and MidC.

Q. Why is the price difference between MidC and COB an appropriate value for COB transactions?

A. The market price at each trading hub represents the marginal cost and benefit of transmitting power to and from COB. The difference between these prices is the gain that PGE realizes when it purchases energy at one hub and sells at the other.

Q. Has PGE appropriately estimated the COB transaction benefits?

A. No. I have two concerns. First, PGE is only modeling 87 percent of normal transactions at COB. Second, the method used to estimate monthly transaction volumes is not consistent with the method used to estimate the price difference between COB and MidC.

Q. Please explain why PGE is only modeling 87 percent of normal COB transactions.

A. PGE estimates normal COB transactions by calculating the three year rolling average of purchases and sales in each month, split for high load hours and low load hours. However, when calculating the monthly benefit in each month, PGE only counts sales at COB. This ignores [redacted] hours of purchases at COB and sales at MidC. PGE has apparently not recognized the marginal gain on these sales.

Q. Is it normal for PGE both buy and sell at COB in the same month?

A. Yes. PGE has made both purchases and sales at COB in every month in 2013, 2014, and 2015. This is understandable, given that while the *average* monthly margin may be always positive, the *actual* margin at a particular time can be either positive or negative within the month.

Q. Please provide an example.

A. Assume that in one month there are 15 days where the MidC price is $30 per MWh and the COB price is $20 per MWh. Assume on the other 15 days that the MidC price is $45 per MWh and the COB price is $15 per MWh. In this case, there are 15 days where the margin at COB is minus $10 and 15 days where the margin at COB is plus $30. The monthly average is (15 x (-10) + 15 x 30)/30 = $10 per month. However, even though the monthly average is positive representing an incremental margin at COB, there are half the days in the month where it is better economically to sell at COB and half where it is better to buy at COB. The important point is that the Company can realize an incremental benefit on both purchases and sales, within the same month, by arbitraging between the appropriate markets. PGE will likely have 2017 purchases at COB even though the COB forecast price is higher than the MidC forecast price. This will happen because the forecasted margin is equivalent to an average price. In actual normal operations PGE will have profitable purchases. Therefore excluding normal COB purchases from the valuation of the COB transactions is inappropriate.

Q. What is an appropriate solution to this issue?

A. PGE should include both purchases and sales in the calculation of the COB trading benefit. PGE should maintain the margin estimate as the absolute price difference between COB and MidC.

Q. Does Staff's proposal allow the power cost forecast to capture all the benefits of arbitraging between the COB and MidC markets?

A. Staff's proposal is only a partial solution. To understand why Staff's proposal is a partial solution, consider the scenario presented in the Q&A above, where there are 15 days in the month with a negative margin of ($10) per MWh, 15 days in the month with a positive margin of $30 per MWh, and the average margin is $10 per month. Suppose further that there is 1 MWh of transmission available in every day. The table below summarizes the actual operations that would minimize power cost.

Margin	**Transaction**	**MWh**	**Profit**
-10	Purchase at COB	15	$150
30	Sell at COB	15	$450
		Total Profit	**$600**

PGE's modeling approach to COB transactions for this example would result in the following estimate.

Avg. Margin	**Transaction**	**MWh**	**Profit**
10	Sell at COB	15	$150
		Total Profit	$150

Staff's modeling approach to COB transactions for this example would result in the following estimate.

Avg. Margin	**Transaction**	**MWh**	**Profit**
10	Buy/Sell at COB	30	$300
		Total Profit	$300

Q. Does Staff propose other adjustments to the methodology?

A. Staff's approach results in a cost estimate that is closer to reality than PGE's approach, but that remains conservatively small. However, Staff is not sure whether the benefit obtained by introducing more complexity into the methodology is warranted. In reality purchase and sale MWh are split closer to 90/10. In addition, the actual margin likely has a continuous distribution around the forecasted COB MidC spread.

Q. What is the dollar impact of Staff's method in this AUT?

A. Staff's proposal [redacted] hours to the benefit calculation. This results in an additional power cost reduction of [redacted].[1]

Q. What is Staff's recommendation regarding the margin calculation?

A. Staff recommends that the Commission adopt Staff's method to calculate the net benefits obtained from PGE's access to the COB market. Staff's methodology is simple and can be easily integrated into PGE's modeling and produces more accurate results than the methodology proposed by PGE. Staff plans to undertake more complete analysis of the Company's valuation method in next year's AUT in order to obtain more precise valuation of the trading margin.

[1] *See* Exhibit Staff/302 Kaufman/1.

ISSUE 2, BOARDMAN COAL MANAGEMENT

Q. Why has PGE changed the way it models coal costs at the Boardman plant?

A. The Boardman plant receives coal through transportation agreements with BNSF Railway Company (BNSF) and Union Pacific Railroad Company (UP). Both contracts require [redacted] tons of coal be shipped in 2017. If PGE does not meet minimum shipping requirements PGE will be subject to liquidated damage charges. PGE has an ability to partially manage liquidated damages through coal stockpiling and, for the BNSF contract only, by rolling shipments into future years.

The forecasted market conditions are such that PGE will likely incur liquidated damages associated with Boardman coal transportation. Previous MONET models have not had the capability of incorporating liquidated damages into dispatch logic. PGE proposes a model change that dispatches based on the marginal cost of coal, inclusive of liquidated damages.

Q. What are forecasted damages if PGE does not modify the MONET model to account for liquidated damages?

A. Boardman burns [redacted] tons when liquidated damages are not accounted for. However, PGE expects to enter 2017 with [redacted] tons of coal in inventory, and has a target of 500,000 tons of inventory (60 days of coal burn). In order to reduce the coal stockpile, PBE would ship no coal in 2017. PGE would accrue an incremental shipping shortfall of [redacted]

[redacted] tons. In addition, PGE anticipates having a shortfall liability for 2016. PGE expects to rollover of [redacted] tons of this liability into 2017 and [redacted] tons into 2018. The rollover is only available for BNSF damages, and not for UP damages. Because of the reduction in rollover, BNSF shortfall increases from of [redacted] tons.

This results in liquidated damages for [redacted] tons through the BNSF contract and [redacted] tons through the UP contract, for a total of [redacted] in damages.[2]

Q. What would the liquidated damages be if PGE did not reduce its coal inventory or roll 2016 shortfall into 2017?

A. If the stockpile and rollover were held fixed in 2017, PGE would ship [redacted] tons, shortfall would only be [redacted] tons and liquidated damages would only be [redacted]. See the table below for the detailed calculations.

[2] *See* Staff/303 Kaufman/1.

[redacted]

Q. Is it possible that PGE could minimize damages in 2017 without modifying Boardman dispatch?

A. Yes. If PGE chooses to enter 2017 with low stockpile and no rollover, PGE could take its minimum coal requirements for BNSF by increasing the stockpile by [redacted] tons, having a 2018 shortfall rollover of [redacted] tons and burning [redacted] tons. This would result in no damages for BNSF, and only [redacted] in damages for UP. See the table below for detailed calculations.

[redacted]

Q. Why is PGE modeling a reduction in the coal stockpile?

A. PGE states that the 2017 target stockpile inventory is set 27 percent below the historical Boardman average inventory level. The purpose of this is to position PGE to "more easily mitigate safety and operational risks if low power prices continue to displace the Boardman plant in 2017 and beyond."[3] This means that the purpose of the abnormally low stockpile target is to absorb the impact of the minimum coal transportation requirements. However, PGE intends to enter 2017 with a stockpile of 94 days, and will not achieve the target until the end of 2017. Thus the large reduction in the coal stockpile during 2017 is intended to mitigate risks for 2018 and beyond.

PGE's stated goal to "more easily mitigate safety and operational risks if low power prices continue" is essentially shifting uncertain transportation shortfalls of 2018 and beyond into 2017. This means that PGE is pushing costs

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[3] PGE/400, Niman-Peshka-Hager/26.

associated with the minimum transportation requirements into 2017 from both 2016 and 2018.

Q. PGE is also proposing to reduce the UP transportation shortfall rollover. Does PGE provide a reason for this in testimony?

A. No. PGE's testimony does not provide a rational for reducing the transportation shortfall rollover from [redacted].

Q. Please evaluate the risk that "low power prices continue to displace the Boardman plant in [2018] and beyond."

A. PGE is forecasting gas prices to increase five to seven percent per year between 2017 and 2020. This should put upward pressure on power prices and cause less displacement of Boardman generation. In addition, the minimum transportation requirements for Boardman are reducing from [redacted] tons per year to [redacted] tons per year in 2018 and 2019, then to [redacted] tons in 2020. These factors combined make the likelihood and magnitude of the 2017 transportation shortfall much greater than in 2018 and beyond.

Q. What are the safety risks on which PGE bases its decision to reduce the coal stockpile in 2017?

A. PGE raises a concern that high coal inventory could lead to spontaneous combustion. Staff has requested additional information on the operational limits and safety limits of the coal inventory. In 2015 PGE maintained coal inventory above [redacted] days for six months.[4] PGE takes measures to reduce inventory before it reaches unsafe levels.[5] Based on these two facts, an inventory of above [redacted] days must be an acceptably save inventory. The safe inventory is well above PGE's January 1, 2017 inventory target. Therefore PGE should be able to maintain the January 1, 2017 level without compromising safety.

Q. Do you propose any alternative modeling method related to coal stockpile and shortfall rollover?

A. For the current AUT, I agree with PGE's method of modeling liquidated damages. However, PGE should not model liquidated damages attributable to 2016 or 2018. To accomplish this, I propose that inventory stockpile be modeled without change from January 1, 2017 to December 31, 2017. I also propose that zero rollover be modeled entering and leaving 2017. The purpose of this change is that it will correctly attribute liquidated damage liabilities to the year in which they are accrued. This prevents actual 2016 operations from inflating cost estimates for 2017.

Q. Does your proposal shift any shortfall liability from 2017 into 2018?

A. No. My proposal contains all 2017 transportation liability in 2017. Given the reduced likelihood of a shortfall in 2018, it may be reasonable to shift the liability from 2017 into 2018 (i.e., roll over a portion of any 2017 shortfall into

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[4] *See* Staff 304 Kaufman/3 response to OPUC DR 13.
[5] *See* Staff 305 Kaufman/2 response to OPUC DR 12 part d.

2018). Shifting liability into 2018 may be the least cost least risk approach. However, for consistency across time I have decided not to propose this.

Q. Do you have an estimated impact of your proposed change to liquidated damages?

A. Yes, my proposed change will reduce 2017 coal use by [redacted] tons and reduce annual net power costs by approximately [redacted] Staff has submitted a data request to the Company to establish a more precise figure.[6]

Q. Does this conclude your testimony?

A. Yes.

[6] *See* Staff/ 306 Kaufman/1.

CASE: UE 308
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualifications Statement

June 20, 2016

WITNESS QUALIFICATIONS STATEMENT

NAME:	Lance Kaufman
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Economist Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 9730
EDUCATION:	In 2013 I received a Doctorate degree in economics from the University of Oregon. In 2008 I received a Master of Science degree in Economics from the University of Oregon. In 2004 I received a Bachelor of Business Administration in Economics from the University of Alaska Anchorage.
EXPERIENCE:	From March of 2013 to September of 2014 and from September of 2015 to the present I have been employed by the Oregon Public Utility Commission (OPCU). My current responsibilities include analysis of power costs, cost allocations, decoupling mechanisms, and sales forecasts. I have worked on power costs in the following OPUC dockets: IPC UE 301, IPC UE 305, PAC UE 307, and PGE UE 308. From September 2014 to September 2015 I was employed by Regulatory Affairs Public Advocacy group of the Alaska Department of Law. From 2008 to 2012 I was employed by the University of Oregon as an instructor. I taught undergraduate level courses in Microeconomics, Urban Economics, and Public Economics.

CASE: UE 308
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 302

Exhibits in Support
Of Opening Testimony

June 20, 2016

Exhibit 302 is confidential and is subject to

Protective Order No. 16-137.

CASE: UE 308
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
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STAFF EXHIBIT 303

Exhibits in Support
Of Opening Testimony

June 20, 2016

Exhibit 303 is confidential and is subject to

Protective Order No. 16-137.

CASE: UE 308
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
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STAFF EXHIBIT 304

Exhibits in Support
Of Opening Testimony

June 20, 2016

Exhibit 304 is confidential and is subject to

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CASE: UE 308
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 305

Exhibits in Support
Of Opening Testimony

June 20, 2016

June 14, 2016

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 308
PGE Response to OPUC Data Request No. 012
Dated June 2, 2016

Request:

Niman – Peschka – Hager/24, line 6 through 8, discusses the average days of coal carried as inventory at Boardman.

a. **Please define "days of coal burn". Is this number equating to the number of days Boardman could dispatch at 100% given current inventory? Or does this number take into account the projected dispatch levels of Boardman.**
b. **How is this unit of measurement affected by decreasing dispatch?**
c. **If Boardman is dispatching less frequently, does the average of 82 days mean that the coal is sitting longer than if it were dispatched more frequently, and does that lead to higher safety concerns as mentioned in lines 1 through 5 of the same page?**
d. **Please describe the process PGE takes when the coal reaches unsafe levels.**
e. **Please define assumed days of coal burn as the number of days of coal in inventory under the projected dispatch levels for Boardman. For example, if Boardman had 60 days of coal and was projected to dispatch at 60% capacity over the next four months then the assumed days of coal would be 100 (60/.6). Please provide the average assumed days of coal burn by month from 2013-2015.**

Response:

a. The fuel inventory ("days of coal burn") is in terms of days of full power dispatch (100% capacity factor). It assumes Boardman running at base load, with an assumed plant heat rate and coal heat content. For Boardman, this is approximately 8,100 tons of coal per day. This is an approximate measure of the fuel inventory and does not account for the potential effects of unit starts (burning more fuel) or partial dispatch (burning less fuel).

b. Decreasing dispatch levels would increase the number of "days of burn," while also producing fewer MWh of generation (and fewer total MWhs over the period as partial loading has higher heat rates).

c. If Boardman is dispatching less frequently, and we continue to take the planned or forecasted coal nominations under the coal and rail contracts, then there would be more coal sitting on the ground. If coal deliveries exceed coal burn at any time, the coal inventory will increase. Moisture build up and degradation dust are safety concerns for very long-term coal inventory stagnation. To reduce this risk, PGE monitors the size of Boardman's coal pile closely to ensure it does not get too large.

d. Before the pile reaches a level that PGE deems to be unsafe, PGE will consider taking fewer coal deliveries. However, the decision to reduce deliveries must be balanced against the contractual obligations PGE has under our coal and rail agreements. Typically, PGE contracts for most of Boardman's projected needs in the prior year. If we make fewer deliveries than contracted, we are potentially exposed to paying a shortfall tonnage rate.

   In order to balance the size of the coal pile against contractual obligations, PGE may also employ a strategy of incorporating the cost of paying a shortfall tonnage rate into Boardman's dispatch decisions. This strategy would allow Boardman to run at times when, ignoring the cost of paying a shortfall tonnage rate, it is marginally uneconomic to do so, or slightly "out-of-the money," helping to reduce the size of the coal pile while mitigating overall costs.

e. PGE objects to part (e) of this request on the grounds that it is overly broad. Without waiving its objection, PGE responds as follows:

   PGE's definition for assumed "days of coal burn" is provided in part (a) above. In reporting on "days of coal burn", PGE does not adjust capacity factors or deviate from the definition provided in part (a) above. See PGE's response to OPUC Data Response No. 013, Attachment A, for PGE's coal inventory levels at Boardman covering the period of 2013-2015.

CASE: UE 308
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
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STAFF EXHIBIT 306

Exhibits in Support
Of Opening Testimony

June 20, 2016

Exhibit 306 is confidential and is subject to

Protective Order No. 16-137.

CERTIFICATE OF SERVICE

UE 308

I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 20th day of June, 2016 at Salem, Oregon

Kay Barnes

Kay Barnes
Public Utility Commission
201 High Street SE Suite 100
Salem, Oregon 97301-3612
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UE 308 – SERVICE LIST

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