

**2012 Wholesale Power and Transmission Rate
Adjustment Proceeding (BP-12)**

**ADMINISTRATOR'S FINAL
RECORD OF DECISION**

July 2011

BP-12-A-02



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APPENDICES

- Appendix A – Partial Transmission Settlement Agreement
- Appendix B – Power Rate Schedules
- Appendix C – Transmission Rate Schedules

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COMMONLY USED ACRONYMS

12CP	Twelve Coincidental Peak (Monthly peak method)
1P	One Coincidental Peak (Annual peak method)
ACS	Ancillary Services and Control Area Services (Rate)
AGC	Automatic Generation Control
ALF	Agency Load Forecast (computer model)
AMNR	Accumulated Modified Net Revenues
aMW	Average Megawatt
ANR	Accumulated Net Revenues
ASC	Average System Cost
BiOp	Biological Opinion
BOR	U.S. Bureau of Reclamation
BPA	Bonneville Power Administration
Btu	British thermal unit
CA	Control Area
CDD	cooling degree day(s)
CDQ	Contract Demand Quantity
CGS	Columbia Generating Station
CHWM	Contract High Water Mark
COI	California-Oregon Intertie
Commission or FERC	Federal Energy Regulatory Commission
Corps or USACE	U.S. Army Corps of Engineers
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council	Northwest Power and Conservation Council
CRAC	Cost Recovery Adjustment Clause
CSL	Customer-Served Load
CSP	Customer System Peak
CT	combustion turbine
CY	calendar year (January through December)
DDC	Dividend Distribution Clause
<i>dec</i>	decrease, decrement, or decremental
DERBS	Dispatchable Energy Resource Balancing Service
DFS	Diurnal Flattening Service
DOE	U.S. Department of Energy
DSI	Direct-Service Industrial Customer or Direct-Service Industry
DSO	Dispatcher Standing Order
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.
EPP	Environmentally Preferred Power
ESA	Endangered Species Act
e-Tag	electronic interchange transaction information
FBS	Federal base system
FCRPS	Federal Columbia River Power System

FCRTS	Federal Columbia River Transmission System
FELCC	firm energy load carrying capability
FERC or Commission	Federal Energy Regulatory Commission
FORS	Forced Outage Reserve Service
FPS	Firm Power Products and Services (rate)
FPT	Formula Power Transmission Rate
FY	Fiscal Year (October through September)
GARD	Generation and Reserves Dispatch (computer model)
GEP	Green Energy Premium
GI	Generation Integration, or Generation Imbalance
GRSPs	General Rate Schedule Provisions
GTA	General Transfer Agreement
GWh	Gigawatthour
HDD	heating degree day(s)
HLH	Heavy Load Hour(s)
HNF	Hourly Non-Firm
HOSS	Hourly Operating and Scheduling Simulator (computer model)
HYDSIM	Hydro Simulation (computer model)
ICE	Intercontinental Exchange
IE	Eastern Intertie (Rate)
IM	Montana Intertie (Rate)
<i>inc</i>	increase, increment, or incremental
IOU	investor-owned utility
IP	Industrial Firm Power (rate)
IPR	Integrated Program Review
IR	Integration of Resources (Rate)
IRD	Irrigation Rate Discount
IS	Southern Intertie (Rate)
JOE	Joint Operating Entity
kV	Kilovolt (1000 volts)
kvar	Kilovoltampere Reactive
kW	Kilowatt (1000 watts)
kWh	Kilowatthour
LDD	Low Density Discount
LGIA	Large Generator Interconnection Agreement
LLH	Light Load Hour(s)
LRA	Load Reduction Agreement
m/kWh	Mills per kilowatthour
Maf	million acre-feet
Mid-C	Mid-Columbia
MMBtu	million British thermal units
MNR	Modified Net Revenues
MRNR	Minimum Required Net Revenue
MW	Megawatt (1 million watts)
MWh	Megawatthour
NEPA	National Environmental Policy Act

NERC	North American Electric Reliability Corporation
Network	Integrated Network
NFB	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NORM	Non-Operating Risk Model (computer model)
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPV	net present value
NR	New Resource Firm Power (rate)
NT	Network Integration Transmission (Service and Rate)
NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation
NWPP	Northwest Power Pool
O&M	Operation and Maintenance
OATT	Open Access Transmission Tariff
OMB	Office of Management and Budget
OY	operating year (August through July)
PDCI	Pacific Direct Current Intertie
PF	Priority Firm Power (rate)
PNCA	Pacific Northwest Coordination Agreement
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration or Point of Interconnection
POM	Point of Metering
POR	Point of Receipt
Project Act	Bonneville Project Act
PRS	Power Rates Study
PS	BPA Power Services
PSW	Pacific Southwest
PTP	Point to Point (service and rate)
PUD	public or people's utility district
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
RD	Regional Dialogue
REC	Renewable Energy Certificate
Reclamation or USBR	U.S. Bureau of Reclamation
REP	Residential Exchange Program
RevSim	Revenue Simulation Model (component of RiskMod)
RFA	Revenue Forecast Application (database)
RHWM	Rate Period High Water Mark
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model (component of RiskMod)

ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RR	Resource Replacement (rate)
RSS	Resource Support Services
RT1SC	RHWM Tier 1 System Capability
RTO	Regional Transmission Operator
SCADA	Supervisory Control and Data Acquisition
SCD	Scheduling, System Control and Dispatch (Ancillary Service)
SCS	Secondary Crediting Service
SDD	Short Distance Discount
SGIA	Small Generator Interconnection Agreement
Slice	Slice of the System (product)
T1SFCO	Tier 1 System Firm Critical Output
TCMS	Transmission Curtailment Management Service
TGT	Townsend-Garrison Transmission (Rate)
TOCA	Tier 1 Cost Allocator
TPP	Treasury Payment Probability
TRAM	Transmission Risk Analysis Model
Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load
TRM	Tiered Rate Methodology
TS	BPA Transmission Services
TSS	Transmission Scheduling Service
TTSL	Total Transmission System Load
UAI	Unauthorized Increase
UD	Utility Delivery
UFT	Use of Facilities (Rate)
UIC	Unauthorized Increase Charge
ULS	Unanticipated Load Service
USACE or Corps	U.S. Army Corps of Engineers
USBR or Reclamation	U.S. Bureau of Reclamation
USFWS	U.S. Fish and Wildlife Service
VERBS	Variable Energy Resources Balancing Service (rate)
VOR	Value of Reserves
WECC	Western Electricity Coordinating Council (formerly WSCC)
WIT	Wind Integration Team
WSPP	Western Systems Power Pool

**PARTY ABBREVIATIONS
AND JOINT PARTY DESIGNATION CODES**

Alcoa	Alcoa, Inc.
APAC	Association of Public Agency Customers
Avista	Avista Corporation
Benton	Benton County Public Utility District No. 1
CP	Calpine Corporation
Canby	Canby Utility Board
Clatskanie	Clatskanie People’s Utility District
Cowlitz	Cowlitz County Public Utility District No. 1
EWEB	Eugene Water & Electric Board
Franklin	Franklin County Public Utility District No. 1
Grant	Grant County Public Utility District No. 1
GH	Grays Harbor Energy, LLC
Iberdrola	Iberdrola Renewables, Inc.
Idaho Falls	Idaho Falls Power
IPC	Idaho Power Company
Idaho PUC or IPUC	Idaho Public Utilities Commission
ICNU	Industrial Customers of Northwest Utilities
MSR	M-S-R Public Power Agency
NorthWestern	NorthWestern Corporation
NRU	Northwest Requirements Utilities
NWG	Northwest Wind Group
Okanogan	Okanogan County Public Utility District No. 1
PNGC	Pacific Northwest Generating Cooperative
PacifiCorp	PacifiCorp
Pend Oreille	Pend Oreille County Public Utility District No. 1
Port Townsend	Port Townsend Paper Corporation
PGE	Portland General Electric
Powerex	Powerex Corp.
PGP	Public Generating Pool
PPC	Public Power Council
OPUC	Public Utility Commission of Oregon
PSE	Puget Sound Energy
SCE	Southern California Edison Company
Seattle	City of Seattle – Seattle City Light
Snohomish	Snohomish County Public Utility District No. 1
Tacoma	City of Tacoma/Tacoma Power
TransAlta	TransAlta Energy Marketing
WUTC	Washington Utilities and Transportation Commission
WMG&T	Western Montana Electric Generating and Transmission Cooperative
WPAG	Western Public Agencies Group

Joint Party 1 (JP01) comprises:

Cowlitz PUD
Eugene Water & Electric Board

Joint Party 2 (JP02) comprises:

Northwest Requirements Utilities
Pacific Northwest Generating Cooperative
Western Montana Generating and Transmission Cooperative

Joint Party 3 (JP03) comprises:

Northwest Requirements Utilities
Pacific Northwest Generating Cooperative

Joint Party 4 (JP04) comprises:

Public Power Council
Industrial Customers of Northwest Utilities
Northwest Requirements Utilities
Pacific Northwest Generating Cooperative

Joint Party 5 (JP05) comprises:

Public Power Council
Industrial Customers of Northwest Utilities

Joint Party 6 (JP06) comprises:

Avista Corporation
Idaho Power Company
PacifiCorp
Portland General Electric Company
Puget Sound Energy, Inc.

Joint Party 7 (JP07) comprises:

Snohomish PUD
Cowlitz PUD
Clark PUD
Okanogan PUD
Pend Oreille PUD
City of Seattle
City of Tacoma/Tacoma Power
Idaho Falls Power
Clatskanie People's Utility District
Eugene Water & Electric Board

Joint Party 8 (JP08) comprises:

Snohomish PUD
Cowlitz PUD
Clark PUD
Okanogan PUD
Pend Oreille PUD
Benton PUD
Franklin PUD
Pacific County PUD No. 2
City of Seattle
City of Tacoma/Tacoma Power
Idaho Falls Power
Clatskanie People's Utility District
Eugene Water & Electric Board

Joint Party 9 (JP09) comprises:

Northwest Requirements Utilities
Pacific Northwest Generating Cooperative
Public Power Council
Western Montana Generating and Transmission Cooperative

Joint Party 10 (JP10) comprises:

Northwest Requirements Utilities
Public Power Council
Western Montana Generating and Transmission Cooperative

Joint Party 11 (JP11) comprises:

Industrial Customers of Northwest Utilities
Northwest Requirements Utilities
Public Power Council
Western Montana Generating and Transmission Cooperative

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1.0 GENERAL TOPICS

1.1 Introduction

This Final Record of Decision (ROD) contains the decisions of the Bonneville Power Administration (BPA), based on the record compiled in this rate proceeding, with respect to the adoption of power, transmission and ancillary services rates for the two-year rate period October 1, 2011, through September 30, 2013 (Fiscal Years (FY) 2012–2013). This Final ROD follows an evidentiary hearing, briefing, and oral argument before the BPA Administrator.

The 2012 Wholesale Power and Transmission Rate Adjustment Proceeding (BP-12) establishes power and transmission rate schedules and General Rate Schedule Provisions (GRSPs) that replace existing rate schedules and GRSPs, which expire on September 30, 2011.

This ROD presents the issues raised by parties in this proceeding, as stated in their briefs. The ROD thoroughly describes the parties' positions, and BPA Staff's positions on the issues. It then provides an evaluation of the positions and the Administrator's decisions. This ROD also tallies, summarizes, and responds to participant comments (section 5.1 for power and section 5.2 for transmission). Participant comments were submitted during the public comment period, which ended February 18, 2011, for power-related comments and March 15, 2011, for transmission-related comments.

Parties filed briefs on exceptions to the Draft ROD, which was issued on June 14, 2011. This Final ROD and BPA's Final Proposal will be submitted with the rate case record to the Federal Energy Regulatory Commission (FERC or the Commission) no later than 60 days prior to October 1, 2011.

1.1.1 Procedural History of this Rate Proceeding

1.1.1.1 Issue Workshops

For several months prior to the release of Staff's Initial Proposal, BPA sponsored a series of workshops and technical conference calls on a variety of topics related to its power and transmission ratemaking. These workshops and conference calls were held so BPA Staff and interested parties could develop a common understanding of the issues, generate ideas, and make rate proposals. The workshops placed significant emphasis on Priority Firm Power (PF) rate design under the Tiered Rate Methodology (TRM) and generation inputs issues, including level of service for wind generators and new Ancillary and Control Area Services (ACS) for thermal generators. The workshops also included discussion of all transmission issues and led to a partial settlement of transmission rates.

Conducting the issue workshops prior to the development of the Initial Proposal enabled BPA Staff and interested parties to freely exchange ideas and comments relevant to rate issues without the constraints of the prohibition on *ex parte* communication that go into effect upon publication of the rate proposal in the Federal Register. The *ex parte* prohibition for this rate proceeding went into effect on November 18, 2010, for power rate issues and the proposed ACS rate

schedule with the exception of the two required ancillary service rates, and December 16, 2010, for transmission rate issues, including the two required ancillary service rates. The *ex parte* prohibition ends when BPA issues this Final ROD. The Initial Proposal incorporated many of the ideas and proposals that were discussed in the workshops. The workshops also culminated in a Partial Transmission Settlement Agreement (*see* ROD sections 1.1.1.3 and 4.1, and Appendix A).

1.1.1.2 BP-12 Rate Proceeding

Section 7(i) of the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. § 839e(i) (Northwest Power Act), requires that BPA's rates be established according to specific procedures. These procedures include, among other things, issuance of a notice in the Federal Register announcing the proposed rates; the opportunity for interested parties to submit written views, supporting information, questions, and arguments; and a decision by the Administrator based on the record. This proceeding is governed by BPA's rules for general rate proceedings contained in the *Procedures Governing Bonneville Power Administration Rate Hearings*, 51 Fed. Reg. 7611 (1986) (hereinafter, *Procedures*). The *Procedures* implement the section 7(i) requirements.

BPA functionally separated its power and transmission business lines in 1997. From the time of the separation through the BPA-10 rate proceeding, BPA conducted separate power and transmission rate proceedings. The BP-12 rate proceeding is a consolidated case that includes both power and transmission rates in a single docket.

On November 18, 2010, BPA published in the Federal Register a Notice of "Fiscal Year (FY) 2012–2013 Proposed Power Rate Adjustments Public Hearing and Opportunities for Public Review and Comment," 75 Fed. Reg. 70744 (2010). On December 16, 2010, BPA published in the Federal Register a Notice of "Fiscal Year (FY) 2012–2013 Proposed Transmission Rate Adjustments Public Hearing and Opportunities for Public Review and Comment," 75 Fed. Reg. 78690 (2010). The delay in filing the notice of the transmission rate adjustment was to allow additional time for parties to negotiate a partial settlement of the transmission rates (discussed in sections 1.1.1.3 and 4.1 and included in Appendix A). Because of the large number of issues with respect to power rates, BPA could not delay the start of the proceeding and provide sufficient time to allow for a full discussion and analysis of the issues. The power rate-related notice included the proposed ACS rate schedule with the exception of the two required ancillary services. These two ancillary services are included in the Partial Transmission Settlement Agreement.

On November 9, 2010, BPA held a scheduling conference to discuss a procedural schedule for the power rates portion of the case and draft procedural orders. On December 14, 2011, BPA held a second scheduling conference to discuss the same topics for the transmission rates portion of the case. BPA's BP-12 rate proceeding began with a prehearing conference on November 19, 2010, for power and December 17, 2010, for transmission. Soon after the prehearing conferences, the Hearing Officer issued orders establishing the schedules for this rate

proceeding, special rules of practice, data request procedures, and general acronyms, and granted petitions to intervene.

BPA Staff's Initial Proposals, filed on November 19, 2010, for power and December 17, 2010, for transmission, is supported by Staff's initial studies and written testimony. Clarification of the Initial Proposals took place on December 6–8 and 10, 2010, for power and on January 4–7, 2011, for transmission. The parties filed their direct testimony and statements of counsel on January 21, 2011, for power and February 15, 2011, for transmission. Clarification of parties' testimony took place February 1, 2011, for power and February 23, 2011, for transmission. BPA and parties filed rebuttal testimony on March 8, 2011, for power and March 15, 2011, for transmission. Clarification of the rebuttal testimony took place March 10 and 11, 2011, for power and March 21, 2011, for transmission. Parties filed surrebuttal testimony on March 23, 2011. Cross-examination for power occurred on March 28, 2011. BPA and the parties waived cross-examination for transmission.

The parties filed their initial briefs on May 2, 2011. Oral argument before the Administrator took place on May 12. The Draft Record of Decision was issued June 14, 2011. Briefs on exceptions were filed June 24.

At times, certain parties to this proceeding chose to consolidate for the purpose of filing testimony or submitting a brief on one or more issues. *See* BP-12-HOO-02. The rate case clerks assigned each consolidated group of parties (joint party) an alphanumeric designation (*e.g.*, JP01, JP02, JP03). For convenience, a list of the joint parties appears in the list of Party Abbreviations and Joint Party Designation Codes that is included at the beginning of this ROD.

BPA received nine written comments submitted during the participant¹ comment periods, which began with the publication of the notices in the Federal Register on November 18, 2010, for power and December 16, 2010, for transmission. Close of participant comments was February 18, 2011, for power and March 15, 2011, for transmission. The participant comments are part of the record upon which the Administrator bases his decisions. Comments relevant to power and transmission rates are summarized and addressed separately in ROD Chapter 5. Participant comments may be viewed at BPA's Web site under "Public Involvement."

The power rates portion of this rate proceeding addresses all power rates issues, including the calculation and pricing of capacity reserves for ancillary and control area services (regulating reserves, operating reserves, and balancing reserves). The power rates portion also includes other generation inputs and inter-business line topics, including synchronous condensing, generation dropping, redispatch expense, energy and generation imbalance revenue, segmentation of U.S. Army Corps of Engineers and U.S. Bureau of Reclamation transmission facilities, and station service. Also included is the rate design and ACS rate schedule and

¹ For interested persons who are not eligible or do not wish to become parties to the formal evidentiary hearings, BPA's *Procedures* provide opportunities to participate in the ratemaking process through submission of comments as a "participant." *See* section 1010.5 of BPA's *Procedures*. No party may submit comments as a participant, and comments so submitted will not be included in the record. BP-12-HOO-02.

relevant GRSPs for all ancillary and control area services with the exception of the two required ancillary services.

Except for the generation inputs issues and subset of ACS rates listed above that are included in the power rates portion of this rate proceeding, the transmission rates portion includes all transmission rates issues.

1.1.1.3 Partial Transmission Settlement Agreement

As noted above, prior to the start of the BP-12 rate proceeding BPA held technical workshops and conference calls to discuss potential rate issues with interested parties. On March 3, 2010, BPA held the first workshop for the joint rate proceeding. BPA held its first workshop on transmission issues on April 14, 2010. During several of the workshops, BPA Transmission Services and the parties discussed the possibility of settlement of most transmission rates issues.

At the September 15, 2010, workshop BPA discussed proposed rate levels for the FY 2012–2013 rate period as part of a proposed settlement of the transmission portion of the rate case. BPA held several more workshops to discuss settlement and circulated several draft settlement agreements. Bermejo *et al.*, BP-12-E-BPA-35, at 2. BPA posted the final Partial Transmission Settlement Agreement on December 7, 2010, and asked parties to respond by December 8, 2010, as to whether they intended to sign the settlement agreement or otherwise agree not to contest it.

The partial settlement included all transmission rates except for the Montana Intertie (IM), Eastern Intertie (IE), and Townsend-Garrison Transmission (TGT) rates. The settlement also included rates for two ancillary services: (1) Scheduling, System Control, and Dispatch Service and (2) Reactive Supply and Voltage Control from Generation Sources Service. It did not include the rates for the remaining ancillary services or for control area services.

All parties except one agreed to either sign the Partial Transmission Settlement Agreement or not contest it. The Hearing Officer set a date of January 4, 2011, for parties that had not signed the Partial Transmission Settlement Agreement to object to the settlement or waive their rights to do so. Only one party preserved its right to object to the partial settlement. Therefore, BPA signed the Partial Transmission Settlement Agreement, which formed the basis of its Initial Proposal for transmission rates. The Partial Transmission Settlement Agreement is attached as Appendix A. A list of parties that signed the agreement is attached to the agreement.

The party that preserved its right to object to the settlement did not file testimony challenging any aspect of the rates included in the settlement agreement. Under the settlement agreement, the IM, IE, and TGT rates were established in a contested process in this rate case. Therefore, interested parties filed testimony on these issues.

1.1.1.4 Waiver of Issues by Failure to Raise in Briefs

Pursuant to section 1010.13(b) of the *Procedures*, arguments not raised in parties' briefs are deemed to be waived. Under this provision, a party's brief must specifically address the legal or

factual dispute at issue. Blanket statements that seek to preserve every issue raised in testimony will not preserve the matter at issue.

However, a party need only raise an issue in either its initial brief or its brief on exceptions. While a party may wish to reassert an issue for other reasons, the party need not reassert an issue in its brief on exceptions in order to avoid waiving the issue. All arguments raised by a party in its initial brief shall be deemed to have been raised in the party's brief on exceptions.
BP-12-HOO-02.

1.1.2 Legal Guidelines Governing Establishment of Rates

1.1.2.1 Statutory Guidelines

Section 7(a)(1) of the Northwest Power Act directs the Administrator to establish, and periodically review and revise, rates for the sale and disposition of electric energy and capacity and for the transmission of non-Federal power. 16 U.S.C. § 839e(a)(1). Rates are to be set to recover, in accordance with sound business principles, the costs associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the Federal Columbia River Power System (FCRPS) (including irrigation costs required to be paid by power revenues) over a reasonable period of years. *Id.* Section 7 of the Northwest Power Act also contains rate directives describing how rates for individual customer groups are to be derived.

Section 7(a)(1) of the Northwest Power Act reaffirms the applicability of section 5 of the Flood Control Act of 1944 (Flood Control Act), which directs that rate schedules should encourage the most widespread use of power at the lowest possible rates to consumers consistent with sound business principles. 16 U.S.C. § 825s. Section 5 of the Flood Control Act provides that rate schedules should be drawn having regard to the recovery of the cost of producing and transmitting electric energy, including the amortization of the Federal investment over a reasonable number of years. *Id.*

Section 7(a)(1) of the Northwest Power Act also reaffirms the applicability of sections 9 and 10 of the Federal Columbia River Transmission System Act of 1974, 16 U.S.C. § 838 (Transmission System Act), which contains requirements similar to those of the Flood Control Act. Section 9 of the Transmission System Act, 16 U.S.C. § 838g, provides that rates shall be established (1) with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles; (2) with regard to the recovery of the cost of producing and transmitting electric power, including amortization of the capital investment allocated to power over a reasonable period of years; and (3) at levels that produce such additional revenues as may be required to pay, when due, the principal, premiums, discounts, expenses, and interest in connection with bonds issued under the Transmission System Act. Section 10 of the Transmission System Act, 16 U.S.C. § 838h, allows for uniform rates and specifies that the costs of the Federal transmission system be equitably allocated between Federal and non-Federal power utilizing the system.

1.1.2.2 The Broad Ratemaking Discretion Vested In the Administrator

The Administrator has broad discretion to interpret and implement statutory directives applicable to ratemaking. These directives focus on cost recovery and do not restrict the Administrator to any particular rate design methodology or theory. See *Pacific Power & Light v. Duncan*, 499 F. Supp. 672 (D.C. Or. 1980); accord *City of Santa Clara v. Andrus*, 572 F.2d 660, 668 (9th Cir. 1978) (“widest possible use” standard is so broad as to permit “the exercise of the widest administrative discretion”); *ElectriCities of North Carolina v. Southeastern Power Admin.*, 774 F.2d 1262, 1266 (4th Cir. 1985).

The United States Court of Appeals for the Ninth Circuit (Ninth Circuit or Court) has recognized the Administrator’s ratemaking discretion. *Central Lincoln Peoples’ Utility District v. Johnson*, 735 F.2d 1101, 1120-29 (9th Cir. 1984) (“Because BPA helped draft and must administer the Northwest Power Act, we give substantial deference to BPA’s statutory interpretation”); *PacificCorp v. FERC*, 795 F.2d 816, 821 (9th Cir. 1986) (“BPA’s interpretation is entitled to great deference and must be upheld unless it is unreasonable”); *Atlantic Richfield Co. v. Bonneville Power Admin.*, 818 F.2d 701, 705 (9th Cir. 1987) (BPA’s rate determination upheld as a “reasonable decision in light of economic realities”); *Department of Water and Power of the City of Los Angeles v. Bonneville Power Admin.*, 759 F.2d 684, 690 (9th Cir. 1985) (“Insofar as agency action is the result of its interpretation of its organic statutes, the agency’s interpretation is to be given great weight”); *Public Power Council v. Bonneville Power Admin.* 442 F.3d 1204, 1211 (9th Cir. 2006) (“[The GRSPs] are entirely bound up with BPA’s rate making responsibilities, and we owe deference to the BPA in that area”). The Supreme Court of the United States has also recognized the Administrator’s ratemaking discretion. *Aluminum Company of America v. Central Lincoln Peoples’ Utility District*, 467 U.S. 380, 389 (1984) (“The Administrator’s interpretation of the Regional Act is to be given great weight.”).

1.1.3 Federal Energy Regulatory Commission Confirmation and Approval of Rates

BPA’s rates become effective upon confirmation and approval by the Commission. 16 U.S.C. §839e(a)(2) and (k). The Commission’s review is appellate in nature, based on the record developed by the Administrator. *United States Department of Energy—Bonneville Power Admin.*, 13 FERC ¶ 61,157, 61,339 (1980). The Commission may not modify rates proposed by the Administrator but may only confirm, reject, or remand them. *United States Department of Energy—Bonneville Power Admin.*, 23 FERC ¶ 61,378, 61,801 (1983). Pursuant to section 7(i)(6) of the Northwest Power Act, 16 U.S.C. §839e(i)(6), the Commission has promulgated rules establishing procedures for the approval of BPA rates. 18 C.F.R. Part 300 (1997).

1.1.3.1 Standard of Commission Review

The Commission reviews BPA rates under the Northwest Power Act to determine whether they (1) are sufficient to ensure repayment of the Federal investment in the FCRPS over a reasonable number of years after first meeting BPA’s other costs; and (2) are based on BPA’s total system costs. With respect to transmission rates, Commission review includes an additional requirement: to ensure that the rates equitably allocate the cost of the Federal transmission

system between Federal and non-Federal power using the system. 16 U.S.C. § 839e(a)(2). See *United States Department of Energy—Bonneville Power Admin*, 39 FERC ¶ 61,078, 61,206 (1987). The limited Commission review of rates permits the Administrator substantial discretion in the design of rates and the allocation of power costs, neither of which is subject to Commission jurisdiction. *Central Lincoln Peoples' Utility District v. Johnson*, 735 F.2d 1101, 1115 (9th Cir. 1984).

1.2 Related Processes

This section includes discussion of processes separate and distinct from this rate proceeding that provide information and policy context to the BP-12 rate proceeding, including the Integrated Program Review, the Tiered Rate Methodology and the TRM Change Process, the Average System Cost Methodology (ASCM) process, and the 2012 Residential Exchange Program (REP-12) 7(i) proceeding. Issues related to those processes are outside the scope of the BP-12 7(i) proceeding. 75 Fed. Reg. 70744, 70745 (2010); 75 Fed. Reg. 78690, 78692 (2010).

1.2.1 Integrated Program Review

Since 1986, BPA has conducted a public review of planned spending levels used in the development of rates in a process separate from the rate proceeding. The IPR process provides persons interested in BPA's program levels an opportunity to review and provide comment on all of BPA's expense and capital spending level estimates prior to the use of those estimates in setting rates. BPA began the most recent IPR public process in May 2010 as a consolidated program-level review of the planned expenses that would be included in setting power and transmission rates in the BP-12 rate proceeding. Between May and September 2010, BPA held 19 technical workshops and two meetings with utility general managers. The workshops and meetings provided opportunities to review and discuss power, transmission, and agency services programs and included detailed review of asset strategies and associated program spending levels.

BPA reviewed and considered the comments on FY 2012–2013 program spending levels that BPA received during this public process when making spending level decisions leading up to the BP-12 Initial Proposal. On October 27, 2010, BPA issued the Final Close-Out Letter and 2010 IPR Final Close-Out Report, which summarized the comments and stated BPA's responses to comments. These documents are available on BPA's Web site. In the Letter and Report BPA presented the program-level cost estimates that would be used in the BP-12 Initial Proposal. The IPR resulted in cost reductions from the spending levels proposed at the start of the IPR. For the 2012 rate period, the cost reductions amounted to \$142 million annually for each of the two fiscal years, FY 2012 and FY 2013. For further information on the IPR, see the BPA Web site at <http://www.bpa.gov/corporate/finance/IBR/IPR/>.

As noted in the Federal Register notices that BPA published for the BP-12 rate proceeding, the IPR process is separate from the rate proceeding. 75 Fed. Reg. 70744, 70745 (2010); 75 Fed. Reg. 78690, 78692 (2010). Cost levels were developed and finalized in the IPR process and thus are not at issue in the rate proceeding. Homenick *et al.*, BP-12-E-BPA-13, at 2.

1.2.2 Tiered Rate Methodology

The TRM, adopted in November 2008 and revised in September 2009, is a 17-year methodology that is intended to ensure a long-term PF Public rate design structure that coincides with new power sales contracts under which service begins October 2011. See TRM ROD, TRM-12-A-01 (November 2008); TRM Supplemental ROD, TRM-12S-A-02 (September 2009); and TRM, BP-12-A-03 (July 2011). Two key features of the TRM are (1) customers that choose to have BPA serve their load growth will pay the incremental costs of serving that load growth; and (2) the PF Public rate design. Bliven *et al.*, BP-12-E-BPA-11, at 2-4. The TRM remains in effect through FY 2028 and applies to rates established pursuant to section 7 of the Northwest Power Act. The BP-12 rate proceeding is the first rate case in which the TRM is being implemented.

The TRM sets forth a process to make changes to the TRM, including corrections for unintended consequences. Prior to the BP-12 rate proceeding, BPA and customers identified five unintended consequences and followed the TRM process to allow those changes to be proposed in the BP-12 rate proceeding. The process and proposed changes are discussed in section 2.2. The Administrator has decided to adopt the technical corrections to the TRM that have been proposed and evaluated in the BP-12 proceeding. The TRM as revised in the BP-12 proceeding is incorporated in the BP-12 Final Proposal as BP-12-A-03.

1.2.2.1 Contract High Water Mark (CHWM) Process

The CHWM establishes the initial basis for each PF Public rate customer to purchase at Tier 1 rates. Each customer's CHWM was calculated in the FY 2011 CHWM Process, as described in the TRM. BPA-12-A-03, section 4.1. CHWMs are based on the Tier 1 System Firm Critical Output (T1SFCO) and the customer's FY 2010 measured load, which may be adjusted to account for load temporarily lost and for conservation achievements. The CHWM Process was conducted in the spring of 2011, with final CHWMs issued May 19, 2011.

1.2.2.2 Rate Period High Water Marks (RHWMs)

Analogous to CHWMs, Rate Period High Water Marks define a customer's eligibility to purchase at PF Public Tier 1 rates for the applicable rate period. Each customer's RHW is based on the customer's CHWM scaled to periodic determinations of the RHW Tier 1 System Capability. RHWs are established outside of the rate case in the RHW Process prior to each rate case beginning with the BP-14 rate case. TRM, BPA-12-A-03, section 4.2. For the FY 2012–2013 rate period, each customer's CHWM is used as its RHW. *Id.* The CHWM for Jefferson County Public Utility District (PUD), a new public customer, will not be finalized in time to be included in the BP-12 Final Proposal. Therefore, the best available forecast of Jefferson County PUD's CHWM is being used as its FY 2012–2013 RHW for purposes of setting the BP-12 rates. Booth *et al.*, BP-12-E-BPA-12, at 14. See section 2.6 for further discussion. Once it is developed, if Jefferson County PUD's CHWM is different from the one used to set BP-12 rates, Jefferson County PUD's Tier 1 Cost Allocator (TOCA) will be updated based on Jefferson County PUD's RHW for the FY 2012–2013 rate period divided by the sum

of RHWMs used to set BP-12 rates; its Contract Demand Quantity (CDQ) will be appropriately updated as well.

1.2.3 The REP-12 Proceeding

The Residential Exchange Program (REP) is a statutory power exchange established by section 5(c) of the Northwest Power Act. Currently, litigation is pending in the U.S. Court of Appeals for the Ninth Circuit on issues related to BPA's establishment of its power rates and BPA's implementation of the Residential Exchange Program from FY 2002 to the present. This litigation creates significant uncertainty for BPA and its customers regarding both retrospective and prospective wholesale power rate levels and REP benefits.

BPA conducted the 2012 Residential Exchange Program Settlement Agreement Proceeding (REP-12) to review the terms and conditions of a proposed 27-year settlement of issues regarding the implementation of the Residential Exchange Program. 75 Fed. Reg. 78694 (2010). The REP-12 proceeding reviewed and evaluated the 2012 REP Settlement Agreement (Settlement). The Settlement has been adopted by the Administrator, and thus BPA calculates relevant elements of power rates for FY 2012–2013 pursuant to the terms of the Settlement.

Matters within the scope of the REP-12 proceeding include the following:

1. Proposed 2012 REP Settlement
2. Section 7(b)(2) Rate Test Implementation
3. Section 7(b)(3) Surcharge Implementation
4. Lookback Assumptions
5. ASC forecasts for FY 2014–2032, except for challenges to the Final ASCs, which are reserved to the Final ASC Reports for FY 2012–2013

75 Fed. Reg. 78694, 78696 (2010). The above-listed items thus are outside the scope of the BP-12 rate proceeding.

1.2.4 Average System Cost Methodology and Review Process

The ASC is the unit cost of a utility's allowable generation and transmission system as determined pursuant to the 2008 Average System Cost Methodology, an administrative rule developed by BPA in consultation with its customers and other stakeholders. *See* 16 U.S.C. § 839c(c)(7); *see also* 18 C.F.R. § 301.1–301.9. On September 4, 2009, the Commission granted final approval of BPA's 2008 ASC Methodology. The 2008 ASCM is not subject to challenge or review in a section 7(i) proceeding.

BPA reviews utility ASCs in a separate administrative process conducted under the procedural terms and conditions prescribed by the 2008 ASC Methodology. Once the ASC Review Processes are complete, BPA publishes an ASC Report for each utility, which establishes each utility's final ASC. The final ASCs are used to calculate the utilities' REP benefits for the term of the ASC Exchange Period, which coincides with BPA's FY 2012–2013 rate period. Utilities'

ASCs are used as an input to estimate REP costs for purposes of setting rates. The final ASCs have been incorporated into the determination of the BP-12 rates.

1.2.5 Wind Topics

The integration of Variable Energy Resources (VERs) into BPA's balancing authority area is an important initiative and is leading to significant changes in operations and business practices. BPA is working with customers to solve the issues arising from the integration of a significant amount of VERs in several ongoing processes related to the Ancillary and Control Area Services (ACS) rates. BPA is addressing these non-rate operational and business practice issues so they may be discussed and resolved. In addition, BPA is engaged in other processes with its customers, such as the discussion on BPA's reciprocity status, that are not specifically about the integration of VERs but relate to the process and issues that are being addressed in the rate proceeding. All these processes are described below.

1.2.5.1 Wind Integration Team Initiatives

As part of the WI-09 Settlement, BPA assembled an internal cross-agency Wind Integration Team (WIT) to explore technical solutions to address the challenge of balancing loads and resources to preserve system reliability while accommodating the rapid development of wind energy in the BPA balancing authority. The mission of the WIT is to clearly define and execute a plan for integrating wind generation in a manner that allows for the continued highly reliable operation of the Federal power and transmission system at the lowest cost consistent with sound business and operations practices.

One of the first accomplishments of the WIT was the development of operational and reliability protocols designed to maintain system reliability when wind variability exhausts the incremental (*inc*) and decremental (*dec*) balancing reserve capacity established on a planning basis. BPA codified the protocols in Dispatcher Standing Order 216 (DSO 216) in October 2009.

In addition, the BPA Wind Integration Team has worked on a set of specific initiatives designed to address the broader operational challenges associated with wind integration. These initiatives are designed to make better use of the existing system through improved wind forecasting and more flexible scheduling arrangements, to use dynamic scheduling to transfer some of the wind variability off the BPA system, and to bring new resources (especially the region's thermal generators and demand-side resources) into the marketplace for balancing services. Over time, these initiatives are intended to reduce dependence on the Federal hydro system for balancing services and dampen the increase in the wind integration cost curve. These initiatives are:

1. **Dynamic transfer capability (DTC):** Development of a methodology for determining dynamic transfer limits and application of that methodology to nine transmission paths was completed by February 2009. BPA and customers collaboratively developed and implemented a process to allocate and award the DTC to requesting utilities. That process resulted in new DTC offers, awards and Dynamic Transfer Operating Agreements that are now in effect.

2. **Forecasting, state awareness tools:** BPA installed 14 anemometers by September 2009 and made the data available to the public, and BPA has developed and deployed an in-house wind forecasting system. BPA also has applied for patents for its new wind displays now available to BPA and wind project operators on BPA's Integrated Curtailment and Redispatch System or iCRS (pronounced Icarus).
3. **Intra-hour scheduling:** In the fall of 2009 BPA developed a business practice and tools to allow half-hour scheduling of wind generation in excess of the associated schedule. Intra-hour scheduling began December 1, 2009. The pilot was evaluated and deemed a success in March 2010 and has been extended indefinitely. The scope of the pilot was expanded in June 2011.
4. **California Independent System Operator (CISO) Intra-hour Scheduling Pilot:** The purpose of the CISO Intra-Hour Scheduling Pilot is to expand the reach of intra-hour scheduling into California and to leverage its balancing resources to aid in Northwest wind integration. Participating wind plant operators within the BPA balancing authority area will, on an intra-hour basis, schedule the output of the wind plants to the CISO. The CISO pilot is scheduled to begin in October 2011.
5. **Customer-supplied generation imbalance:** BPA invited participation in this pilot in 2009 and developed a generation imbalance business practice in June 2010. The pilot launched ahead of schedule on September 1, 2010, and continues into the BP-12 rate period.
6. **Third-party supply purchased:** BPA purchased 75 MW of generation imbalance reserves for September through November 2010 from a Calpine Corporation natural-gas fired generator located in BPA's balancing authority area.
7. **Intra-Hour Transaction Accelerator Project (ITAP):** The purpose of the ITAP is to develop systems and processes to enable the BPA Power Services purchasing/selling entity to buy and sell power within the operating hour and hourly through the Open Access Transmission Tariff (OATT) WebExchange system.

1.2.5.2 **Reciprocity**

As a Federal power marketing administration, BPA is not subject to Federal Energy Regulatory Commission jurisdiction or to the standards that apply to "public utilities" under the Federal Power Act. Non-jurisdictional entities, including BPA, can voluntarily file an OATT with the Commission to confirm that the tariff's terms and conditions substantially conform or are superior to the Commission's national model. This is called seeking "reciprocity" status.

BPA last filed its OATT with the Commission seeking reciprocity status in October 2008. In July 2009, the Commission denied BPA reciprocity subject to the agency making certain additions to and clarifications of its tariff. BPA filed a request for rehearing, stating that the agency might ask the Commission to convene a conference to discuss the rehearing and other issues regarding reciprocity. In January 2011, BPA filed a request that the Commission rule on its request for rehearing without convening a conference. In April 2011, the Commission issued

an order denying rehearing and reiterating that to satisfy reciprocity requirements, BPA must revise its OATT as specified in the Commission's July 2009 order.

BPA has examined the issues the Commission raised in its ruling, as well as broader issues related to BPA's OATT. In February 2011, BPA initiated a series of workshops with customers and stakeholders to discuss these tariff issues. The workshops are expected to continue over the next several months, after which BPA will determine whether to continue to seek reciprocity status and how it wishes to amend its OATT.

1.2.5.3 Northwest Power Pool Definition of Contingency Reserve Qualifying Event

The Northwest Power Pool (NWPP) includes all the balancing authorities in the Northwest. One of the primary purposes of the NWPP is to maintain the contingency reserve sharing agreement between the members, which allows the members to call on the shared contingency reserves when one of the members has a qualifying event and has exhausted its own contingency reserves. The reserve sharing program allows all members to hold fewer contingency reserves than if they were not members of the NWPP.

Since late 2009 there have been ongoing discussions between the NWPP members regarding expansion of the definition of qualifying contingency events. These are the specified events under which a member can deploy its own contingency reserves and then call on the other members to provide additional contingency reserves if the member has exhausted its contingency reserves. One of the events that has been under discussion is significant drops in wind generation or wind tail events. Under the current contingency reserve sharing agreement, generation loss due to lack of fuel is not a qualifying event for which contingency reserves can be deployed. In early 2010 some NWPP members proposed a pilot project that would have recognized some amount of loss of wind generation as a qualifying contingency event. This proposal was not adopted, but the NWPP membership agreed to continue working on this issue. This issue is still being debated among the NWPP members. The eventual outcome of this debate is related to several rate issues that are addressed in Chapter 3.

1.2.5.4 BPA E-Tagging Requirements for VERs in BPA's Balancing Authority Area

When the amount of balancing reserve capacity BPA has deployed reaches 90 percent of the amount BPA has forecast in its rate proceeding that it will maintain, BPA issues a DSO 216 order, which either directs the wind generators to limit their output in a *dec* event or cuts a portion of the wind generators' schedule to a set amount above the actual level of generation in an *inc* event. The result of a DSO 216 *inc* curtailment is that a schedule is cut back during the hour and the load serving entity receiving that schedule must make some adjustment to make up for the schedule cut.

Most of the transmission schedules' e-Tags for the wind generation have classified the energy as firm energy. Some entities have questioned whether wind generation that is occasionally subject to DSO 216 should be classified as firm energy. BPA has had an ongoing public process attempting to resolve this debate and to decide whether BPA will impose special e-Tagging rules for wind generation that is subject to DSO 216 curtailments. BPA held meetings and took public

comment on this issue in the spring and summer of 2010, but did not indicate a decision until the public meeting held on June 10, 2011. BPA informed participants in the June 10 meeting that BPA will continue to use DSO 216 to limit the amount of balancing reserve capacity BPA deploys, but BPA will not be implementing specific rules regarding the appropriate energy product code used on e-Tags for wind located in the BPA balancing authority area. Rather, the determination of the appropriate energy product code used on an e-Tag will be left to the buyer, seller, and receiving balancing authority. BPA stated that the effective date for this policy will be October 1, 2011.

1.2.5.5 Transmission Business Practices

BPA will develop several new business practices to implement new or revised Ancillary and Control Area Services. New business practices will include Variable Energy Resource Balancing Service (VERBS) Supplemental Service and Dispatchable Energy Resource Balancing Service (DERBS). The specific content of these new business practices will be developed in consultation with customers, and the service parameters for the referenced services will be defined in the business practices.

BPA will also modify several existing business practices. The Scheduling Business Practice or the Intra-hour Scheduling Pilot Business Practices will be modified to include requirements for Committed Intra-Hour Scheduling. Generator Imbalance Service and Energy Imbalance Service Business Practices will be modified to reflect changes to Persistent Deviation metrics in the FY 2012–2013 rate schedules.

1.2.5.6 Commission VER Integration Notice of Proposed Rule Making

The Commission issued a VER Integration Notice of Inquiry on January 21, 2010, which posed several questions regarding many aspects of VER integration and the interrelationship of VERs to the existing tariff and market mechanisms. BPA and several other parties to this rate proceeding provided responsive comments to the Commission. The Commission issued the VER Integration Notice of Proposed Rulemaking (VER NOPR) on November 18, 2010. In the VER NOPR the Commission proposed that all jurisdictional utilities provide 15-minute scheduling, use VER power production forecasts, and establish a new rate schedule for regulation provided to generators. BPA and several parties to this rate proceeding filed additional comments on the VER NOPR on March 2, 2011, expressing a wide range of opinions regarding the proposed reforms. The Commission has not yet taken further action on the proposed rule.

1.2.5.7 Environmental Redispatch

In June 2010, BPA experienced an extreme high water/high generation event that made it very difficult to maintain load-generation balance and manage river flows without violating certain Clean Water Act requirements. Such requirements limit the amount of voluntary spill at FCRPS resources to protect fish listed under the Endangered Species Act from gas bubble trauma due to nitrogen gas saturation. Following the June 2010 event BPA began an evaluation process to determine how to manage such events in the future. During the June 2010 event, BPA offered to

offset other generation in the region with zero-cost power from the FCRPS, because, compared to spilling water, water run through turbines results in reduced nitrogen gas supersaturation. During past high water events, most generators in the region had accepted this displacement when BPA offered low-cost or free FCRPS power. This did not occur during the June 2010 event, because some wind generators receive production tax credits and renewable energy credit for every megawatthour they generate, and thus they had no economic incentive to limit their generation output when BPA faced an extreme high water event.

BPA's evaluation led to a public process that investigated several possible solutions to evaluate the excess generation problems caused by high water events. As a result of this public process and BPA's internal assessment of the hydro operations during high water events and the requirements of the Clean Water Act and other laws, BPA issued a Draft ROD on February 18, 2011, detailing its proposed Environmental Redispatch and Negative Pricing policies and requested public comment on the Draft ROD. BPA received 41 comments on the Draft ROD both in support of and against BPA's proposals. On May 13, 2011, BPA responded to comments and issued the Interim Environmental Redispatch and Negative Pricing Policies Final Record of Decision. BPA's Environmental Redispatch and Negative Pricing policies for handling high water events call for taking all measures, short of paying negative prices, to find load and reduce spill at FCRPS projects, followed by redispatching all thermal generators down to their minimum generation levels necessary to maintain reliable operations. Once these measures are taken, BPA will redispatch wind generators by ordering the wind generator to decrease generation while BPA supplies replacement power from the FCRPS at zero cost for the wind schedules.

1.3 Procedural Issues

This section of the ROD presents BPA's responses to the procedural issues raised by parties in their briefs. Procedural issues are matters raised by parties that involve BPA's adherence to the procedural requirements of a section 7(i) proceeding and other due process directives.

1.3.1 Development of the Dispatchable Energy Resource Balancing Service Rate

Several parties argue that BPA should not adopt a DERBS rate in this rate proceeding because they had insufficient time and opportunities to comment on the BPA Staff's revised DERBS rate proposal. BPA addresses these procedural arguments in section 3.4.1.1 below.

1.3.2 Prior Notice of Rate Proposal

JP02 expressed a concern that Staff should have provided parties with an opportunity to review and discuss the inclusion of Balancing Augmentation, Transmission Losses, and Unused RHW as line items in the Non-Slice Cost Pool before including them in BPA's Initial Proposal. JP02 Br., BP-12-B-JP02-01, at 16. Because these matters were not discovered until late in the process of developing the Initial Proposal, there was not sufficient time to discuss these matters with interested parties as is the typical practice. While BPA Staff view the pre-rate case workshops as a valuable tool to help shape the Initial Proposal, there is no legal obligation to engage in these pre-rate case discussions. JP02 and all the other parties to the proceeding had the opportunity to discuss the proposed additions to the Non-Slice Cost Pool during the rate

proceeding. JP02 did not find the additions contrary to the TRM and did not raise any objection to the proposal itself, only the process.

1.3.3 Planned Net Revenues for Risk (PNRR) and Cost Recovery Adjustment Clause (CRAC) Thresholds for Final Proposal

Issue 1.3.3.1

Whether, as part of the development of final power rates, BPA is prohibited from updating any of the financial assumptions regarding the current fiscal year made in the Initial Proposal and therefore cannot adjust the CRAC threshold or add PNRR to the revenue requirement in order to maintain a 95 percent Treasury Payment Probability (TPP) in the Final Proposal.

Parties' Positions

JP05 notes that in the Initial Proposal, Staff explains that, as part of the updates for studies for the Final Proposal, if BPA's finances for FY 2011 were especially bad, BPA might add PNRR to the revenue requirement or adjust the CRAC threshold in order to maintain a 95 percent TPP. JP05 Br., BP-12-B-JP05-01, at 8. JP05 states "even after proposing a 'Day 1 CRAC' with a substantial chance of triggering, BPA seeks to give itself discretion to impose an additional rate increase over and above the CRAC through increased PNRR and a high threshold for the CRAC." *Id.* JP05 concludes "BPA's discretion to 'update the numbers' should not be completely devoid of any substantive or procedural limitations. The process by which BPA has proposed a 99% TPP in this rate period already incorporates the possibility that BPA may have a bad year financially in FY 2011." *Id.* JP05 contends that this ability to update the CRAC threshold or add PNRR without meaningful oversight and review is inconsistent with the provisions of section 7(i) of the Northwest Power Act. *Id.* JP05 suggests that Staff withdraw its proposal to add PNRR or adjust the CRAC threshold absent complying with the provisions of section 7(i). *Id.* at 8-9.

JP05 contends, "we are not suggesting that BPA conduct an additional Section 7(i) proceeding to make an adjustment to the CRAC threshold or add PNRR to the revenue requirement in order to maintain a 95 percent TPP. Rather, we are suggesting that it is inappropriate for BPA to make *any* change to the parameters of the CRAC and PNRR solely based upon how BPA performs financially during the year leading up to the rate period (while BPA conducts the rate proceeding)." JP05 Br. Ex., BP-12-R-JP05-01, at 3 (emphasis in original).

JP05 and NRU assert that they have standing to address all issues in the rate proceeding based upon the doctrine of associational standing. JP05 Br. Ex., BP-12-R-JP05-01, at 6; NRU Br. Ex., BP-12-NR-01, at 6-7.

BPA Staff's Position

This issue is raised for the first time in brief and was not addressed by Staff in testimony. Staff indicates that "the most important update" for calculating TPP in the Final Proposal would be the forecast of FY 2011 net secondary revenue. Lovell *et al.*, BP-12-E-BPA-15, at 84.

Evaluation of Positions

JP05 recognizes BPA's need to account for significant deterioration in BPA's financial condition between the filing of the Initial Proposal and the Final Proposal.² JP05 Br., BP-12-B-JP05-01, at 7. JP05 contends, however, there are both *procedural* and *substantive* due process limits to BPA's ability to use the updated financial information in the Final Proposal. *Id.* at 8. According to JP05, these due process limitations prohibit BPA from modifying the amount of PNRR in rates or adjusting the CRAC thresholds to maintain the 95 percent TPP standard absent providing parties some section 7(i) protections. *Id.*

JP05 does not explain how adjusting the PNRR in rates or the CRAC threshold rises to the level of a substantive due process claim. The doctrine of substantive due process has two primary features: to protect fundamental rights and liberties that are deeply rooted in history and to provide a careful description of some asserted fundamental liberty interest.

Washington v. Glucksberg, 521 U.S. 702, 117 S. Ct. 2258, 138 L. Ed.2d 772 (1997). Substantive due process prevents government power from being used for purposes of oppression or an action that is legally irrational in that it is not sufficiently keyed to any legitimate state interest.

Tri County Industries, Inc. v. District of Columbia, 104 F.3d 455 (D.C. Cir. 1997). Adding PNRR to rates or adjusting the CRAC threshold does not rise to the level of a fundamental right protected under substantive due process. The stated purpose for making either of these changes to the rate proposal is to ensure that BPA maintains a 95 percent TPP; this is clearly a legitimate government interest. *Lovell et al.*, BP-12-E-BPA-15, at 86.

The Draft ROD questioned whether the addition of PNRR or adjusting the CRAC threshold, without the procedural protections of a section 7(i) hearing, violates JP05's procedural due process rights. Draft ROD, BP-12-A-01, at 16. As noted in the Draft ROD, the essential elements of procedural due process are notice and the opportunity to be heard prior to depriving one of a protected property interest. *Wolf v. Fauquier County Bd. of Supervisors*, 555 F.3d 311 (4th Cir. 2009). The Draft ROD also questioned whether ICNU and the PPC have a protected property interest sufficient to assert a procedural due process claim. Draft ROD, BP-12-A-01, at 17.

JP05 and NRU assert that they have standing to address all issues in the rate proceeding based upon the doctrine of associational standing. JP05 Br. Ex., BP-12-R-JP05-01 at 6; NRU Br. Ex., BP-12-NR-01 at 6-7.

The Draft ROD could be read as intimating, erroneously, that neither ICNU or PPC (the entities that comprise JP05) nor NRU has standing to raise issues in BPA rate proceedings. The issue raised in the Draft ROD is now moot. The final rates maintain at least a 95 percent TPP without including any PNRR or adjusting the CRAC thresholds. In addition, review of section 7(i) of the

² Although not stated by JP05, improvements in BPA's financial condition would also be reflected in the updates for the Final Proposal. These improvements in BPA's financial condition could result in lowering the amount of PNRR or the CRAC threshold. However, it does not appear that JP05 is concerned that updates that reduce the cost of risk mitigation raise the same substantive and procedural due process issues.

Northwest Power Act and BPA's *Procedures Governing Bonneville Power Administration Rate Hearings*, especially its definition of "person," which includes associations, make it clear that associations have the right to participate and, among other things, raise issues concerning BPA's proposed rates. 16 U.S.C. § 839e(i); *Procedures Governing Bonneville Power Administration Rate Hearings*, § 1010.2(i). Associations such as ICNU, PPC and NRU have played an important and valuable role in BPA's section 7(i) hearings, efficiently and effectively representing their members so that the Administrator has the benefit of a full record and the best arguments possible.

It should be noted that JP05 does not question the 95 percent TPP goal. This goal has been examined in two separate financial plans, one in 1993 and the other in 2008. This goal has been employed in setting rates since the 1993 rate case. In each rate adjustment, BPA has sought to meet this goal, sometimes with success, sometimes consciously lowering the goal for specific reasons. JP05 expresses no reason why the goal should be relaxed this time.

Additionally, JP05's argument for BPA providing some procedural protections prior to adding PNRR or adjusting the CRAC thresholds leads to either (1) the potential for a never-ending cycle of adjustment and review; (2) abandoning any adjustments to the risk package in the Final Proposal; or (3) structuring rates based on a worst-case outcome that would eliminate any need for increasing the amount of risk mitigation. As to the first possibility, at some point the opportunity to review the actual numbers must come to an end so BPA can finalize the rates. JP05's contention that it is entitled to additional procedural protection before updates are incorporated into the risk analysis would result in recurring rounds of updates and procedure or freezing the current year assumptions in the Initial Proposal. Either one of those possibilities is untenable. As to the second possibility, the thought of ignoring actual financial positions when setting rates is not good business practice; nor would such practice be countenanced by the Commission or the courts. *See, e.g., Golden Northwest Aluminum v. Bonneville Power Admin.*, 501 F.3d 1037, 1052-1053 (9th Cir. 2007). As to the third possibility, the rational response to such a requirement that JP05 would place on BPA would be to so inflate the Initial Proposal so that it would cover the worst-case situation, and then reduce the risk mitigation in the Final Proposal, a procedural outcome which JP05 does not address. However, this would result in an Initial Proposal that is so over-inflated that it gives rate case parties no good idea of how the Final Proposal would most likely turn out. None of these alternatives is tenable.

Even though the alleged procedural error is moot, the argument that BPA cannot make any changes to the CRAC threshold or add PNRR, and must freeze Initial Proposal assumptions regarding the current fiscal year, raises some new substantive issues that will be addressed here.

JP05 states, "we are not suggesting that BPA conduct an additional Section 7(i) proceeding to make an adjustment to the CRAC threshold or add PNRR to the revenue requirement in order to maintain a 95 percent TPP. Rather we are suggesting that it is inappropriate for BPA to make *any* change to the parameters of the CRAC and PNRR solely based upon how BPA performs financially during the year leading up to the rate period (while BPA conducts the rate proceeding)." *Id.* at 3 (emphasis in original).

It is difficult to reconcile JP05’s statement that it is not insisting on the procedural protections of a 7(i) hearing before adding PNRR or adjusting the CRAC threshold with statements in its initial brief. JP05’s initial brief included the following heading: “BPA MAY ONLY IMPOSE A PNRR OR RAISE THE CRAC THRESHOLDS BY CONDUCTING A 7(i) RATE PROCEEDING.” JP05 Br., BP-12-B-JP05-01, at 7 (capitalization in original). JP05 appears to be revising its argument to contend that BPA should be prohibited from making *any* changes to the CRAC threshold or adding PNRR based upon changes to BPA’s financial condition in FY 2011. JP05 Br. Ex., BP-12-R-JP05-01, at 4. According to JP05, the Initial Proposal “*explicitly incorporates into that analysis the chance that the year prior to the rate period will be financially poor for BPA.*” *Id.* (italics in original). JP05 claims that there is a significant process issue because these updates are “based upon new data that parties have no ability to examine and using new analysis that parties have no ability to check, since the new data and new analysis will only be released with BPA’s final Record of Decision.” *Id.* at 7-8.

JP05 acknowledges, however, that it is necessary for BPA to “update the numbers” when BPA develops final rates. JP05 Br., BP-12-B-JP05-01, at 7. It further acknowledges that these updates can include assumptions about market prices and water conditions. *Id.* Given these statements, it is difficult to understand how JP05 can still contend that BPA should be prohibited from updating the assumptions for FY 2011. JP05 contends that in the Final Proposal, BPA can update the *forecasts* of market prices and hydro conditions for FY 2012 and FY 2013, and make changes to the PF rates on the basis thereof, but that BPA cannot update market prices and hydro conditions for the first part of FY 2011 by replacing the *forecasts* in the Initial Proposal with the *facts* that have become available by the time of the Final Proposal and make corresponding changes to rates or risk mitigation. *Id.* It would appear that accepting the due process argument of JP05 would lead to the conclusion that no numbers for the current fiscal year—risk-related or not—could be updated in the Final Proposal in ways that would affect rates because parties would not have a subsequent opportunity to challenge those numbers.

At the time the Initial Proposal is filed, one of the biggest financial unknowns is the amount of net secondary revenue BPA will realize, for both the current fiscal year and the years in the upcoming rate period. Net secondary revenue is one of the most significant variables affecting BPA’s financial performance during any particular year. Net secondary revenue uncertainty is driven largely by uncertainty in hydro volume and market prices. In the rate case, BPA creates distributions of net secondary revenue for the two years of the rate period and for the year prior to the rate period. At the time of the Initial Proposal, all three distributions include a huge range of hydro conditions and market prices, as little to nothing is yet known with certainty about any of those three years. By the time of the Final Proposal, much has been learned about the net secondary revenue results from the first part of the year prior to the rate period; nothing is yet known about the hydro conditions for the two years in the rate period, but BPA has received more-recent information from the electricity market that is used to update the forecasts of market prices for those two years. In general, it is impossible to predict how the probability distributions for net secondary revenue for the two years in the rate period will change from the Initial Proposal to the Final. The average hydro volume is not expected to change; nor is the variability of hydro volume. Average market prices and price volatility may well change, but they are about

as likely to increase as to decrease. Thus, the average net secondary revenue average volatility may change but may be higher or lower than in the Initial Proposal.

This is not the case for net secondary revenue for the year prior to the rate period. Much of what is unknown at the time of the Initial Proposal is known at the time of the Final Proposal. BPA can predict confidently that the volatility (*e.g.*, as measured by the standard deviation) of net secondary revenue for the year prior to the rate period will be much smaller by the time of the Final Proposal. However, BPA cannot predict at the time of the Initial Proposal whether the average net secondary revenue will be higher or lower. Stronger rate case risk mitigation measures are required when prior-year net secondary revenue is lower, and when it is more volatile. Since BPA can be sure that the results will be less volatile by the Final Proposal, and there is an equal chance of the average increasing or decreasing, updating the prior-year net secondary revenue distribution usually results in a reduced need for risk mitigation. Only if the Final Proposal average net secondary revenue is so much lower than the average in the Initial Proposal that the reduction in the average outweighs the predictable reduction in the variability will the need for risk mitigation increase from Initial to Final.

What JP05 essentially argues for is a freezing of the financial assumptions in the Initial Proposal, ignoring any subsequent information on BPA's actual financial performance in the current fiscal year. It would be irresponsible for BPA to ignore seven to eight months of actual financial performance, especially if actual performance was negative, for FY 2011 when developing final rates for FY 2012-2013. JP05's claim that BPA has already incorporated the chance of poor financial performance also ignores the fact that BPA has actual financial results for the first part of FY 2011 as well as updated probability information for the later part of the year that better reflects the overall prospects for that year.

It is true that the Initial Proposal incorporates the *possibility* of a great many outcomes for FY 2011. *See generally* Power Risk and Market Price Study, BP-12-FS-BPA-04. The Initial Proposal does so by associating a *probability* distribution with the set of possible outcomes. By the time of the Final Proposal, many of the outcomes that were possible at the time of the Initial Proposal have become impossible due to the actual events in early FY 2011, and other possible outcomes have become more likely than they were at the time of the Initial Proposal. At the time the Final Proposal is prepared, BPA has much more recent information about the probabilities of the possible outcomes for FY 2011. This matters because the financial outcome for FY 2011 determines the level of reserves available for risk at the start of the FY 2012-2013 rate period. The probability distribution of starting FY 2012 reserves is one of the primary variables that determine TPP for the rate period, and thus, that determine the amount of risk mitigation that is needed.

As established in BPA's Ten-Year Financial Plan, BPA's TPP standard requires BPA to "establish rates to maintain a level of financial reserves sufficient to achieve a 95 percent probability of making its U.S. Treasury payments." WP-93 ROD, WP-93-A-02, at 59. Rates are proposed in the Initial Proposal but established in the Final Proposal. Therefore, BPA must have the ability to adjust its risk mitigation tools in the Final Proposal if necessary to meet the TPP standard, or the standard would be impossible to implement.

Decision

Section 7(i) of the Northwest Power Act and BPA's Procedures Governing Bonneville Power Administration Rate Hearings make it clear that associations have the right to participate in BPA rate hearings and, among other things, raise issues concerning BPA's proposed rates. Procedural issues associated with updating PNRR or the CRAC threshold in order to maintain a 95 percent TPP are moot due to the fact that final rates will not include either additional PNRR or a modified CRAC threshold. BPA will continue to update financial assumptions used in the Initial Proposal for the current fiscal year when developing final rates.

Issue 1.3.3.2

Whether the CRAC comports with the procedural requirements of section 7(i) of the Northwest Power Act.

Parties' Positions

WPAG contends that a CRAC that triggers after the close of the rate proceeding but before the start of the rate period may not comply with the procedural requirements of section 7(i) of the Northwest Power Act. WPAG Br., BP-12-B-WG-01, at 42. WPAG states that "there is a serious question whether a change to a rate based on information not in the §7(i) record, and not subject to the §7(i) procedures, is a lawful rate change." *Id.*

WPAG claims there is serious legal question whether the proposed CRAC is a "rate" established in this proceeding and whether any CRAC complies with section 7(i). WPAG Br. Ex., BP-12-R-WG-01, at 10. WPAG questions whether the CRAC is a lawful rate change because it does not comply with procedural requirements of section 7(i). *Id.* WPAG states that there is no Federal Register notice, hearing, testimony or decision by the Administrator before triggering a CRAC. *Id.* at 10-11.

BPA Staff's Position

This issue is raised for the first time in brief and was not addressed by Staff in testimony.

Evaluation of Positions

WPAG argues that the imposition of a CRAC on the first day of the rate period raises serious concerns regarding whether parties have been given an adequate opportunity to offer "refutation or rebuttal of any material" as provided under the Northwest Power Act. *Id.* However, WPAG does not explain how or why the triggering or imposition of a CRAC in the first year is procedurally inconsistent with section 7(i) or why the triggering and imposition of a CRAC in the first year of a rate period requires a section 7(i) hearing.

The CRAC is a one-year adjustment to rates if Accumulated Net Revenue (ANR) falls below a specific threshold. Lovell *et al.*, BP-12-E-BPA-15, at 51. The CRAC triggers at the ANR

equivalent of \$0 in reserves for risk attributed to BPA's Power Services. *Id.* at 52. There are only minor timing differences between triggering and imposing a CRAC adjustment in FY 2012 as compared to FY 2013. For rates starting in FY 2012, BPA proposed to forecast end-of-year ANR in July 2011, while for FY 2013, the end-of-year forecast of ANR would be in September 2012. In both years, BPA will forecast the ANR for the end of the fiscal year, and if the ANR is \$5 million below the ANR that calibrates to \$0 in reserves attributed to Power Services, the CRAC will trigger. Power Rate Schedules, BP-12-A-02B, GSRP II.C.3.

WPAG argues that triggering a CRAC in July 2011, after the close of the BP-12 rate proceeding record, and applying it to rates at the start of the BP-12 rate period is inconsistent with section 7(i) of the Northwest Power Act. WPAG Br., BP-12-B-WG-01, at 42; WPAG Br. Ex., BP-12-R-WG-01, at 10-12. WPAG does not take issue with triggering the CRAC in September 2012 and applying it in October 2012, despite the fact that that situation also occurs after the close of the BP-12 record. Nor does WPAG take issue with the application of the Dividend Distribution Clause (DDC) in FY 2012, even though it also triggers after the close of the BP-12 record and is determined before the start of the BP-12 rate period. WPAG explains that the procedural distinction between imposing a CRAC during the first and second years of the rate period is its reliance on information that is outside of the rate period after the record is closed. Mundorf, Oral Tr. at 162. WPAG does not explain the distinction between a first-year DDC (which would entail a downward adjustment to certain rates) and a first-year CRAC (which would entail an upward adjustment to certain rates). In each of these instances the CRAC or DDC is triggered after the close of the rate proceeding and can be applied in the first year of the rate period. Despite these similarities, only the application of the CRAC in the first year is somehow procedurally defective, according to WPAG.

There is no procedural distinction between the triggering and application of a CRAC in the first year of the rate period versus the second. In both cases, there is a public notice and workshop to discuss the information used in deriving a CRAC. Power Rate Schedules, BP-12-A-02B, GRSP II.C. Similarly, there is no procedural distinction between imposition of a CRAC or imposition of a DDC in the first year of the rate period. The requirements for triggering both a CRAC and a DDC are spelled out in great detail in the GRSPs and are virtually identical to the requirements adopted in the WP-10 rate proceeding. *Id.*; Final ROD, WP-10-A-02, Appendix B, GRSP II.D. BPA included so-called "Day 1 CRACs" in its WP-02, WP-07, and WP-10 rates. WP-02 ROD, WP-02-A-09, Appendix, GRSP II.F; WP-07 ROD, WP-07-A-02, Appendix A, GRSP II.C; WP-10 ROD, WP-10-A-02, Appendix B, GRSP II.D. In the WP-10 and BP-12 rate proposals the triggers are almost the same, and each provides for the application of the CRAC in the first year.

To the extent that WPAG's procedural concern is premised upon its inability to comment on the CRAC before it is imposed in the first year of the rate period, there are two factors WPAG ignores. First, the GRSPs provide an opportunity to comment on the CRAC before it is imposed:

Associated with any notification as described above of CRAC calculations, BPA staff shall conduct a workshop(s) to explain the ANR calculations, describe the calculation of the CRAC Amount and allocations to various rates, and

demonstrate that the CRAC has been implemented in accordance with these GRSPs. The workshop(s) will provide an opportunity for public comment.

Power Rate Schedules, BP-12-A-02B, GRSP II.C.3.

Second, during the BP-12 rate proceeding WPAG has had a significant opportunity to comment on the design of the CRAC and the procedures associated with its application. Due process provides parties only notice and the opportunity to comment. *National Private Truck Council, Inc. v. Oklahoma Tax Comm.*, 515 U.S. 582, 115 S. Ct. 2351, 132 L. Ed.2d 509 (1995). The combination of the 7(i) proceeding and workshops afforded WPAG the opportunity to comment on the design and application of CRAC. These proceedings provided WPAG with a significant and adequate amount of process to evaluate and discuss the issues.

WPAG states that it proposes removing the Day 1 CRAC to “lessen the impact of the proposed rate increase on the economically hard-hit communities” WPAG Br., BP-12-B-WG-01, at 2-3. What WPAG misses is that removal of the “Day 1 CRAC” leaves PNRR as the only tool to meet the 95 percent TPP goal. This, and WPAG’s other concerns, are discussed more fully in section 2.5.1.

In WPAG’s brief on exceptions, WPAG slightly revises its procedural argument. WPAG acknowledges that BPA triggered a CRAC on the first day of the WP-02 rate period. WPAG Br. Ex., BP-12-R-WG-01, at 10. However, it expands its prior argument and contends that no CRAC can be imposed, Day 1 or even later, absent going through all of the procedural steps associated with a 7(i) hearing. WPAG’s proposal effectively eliminates the use of a CRAC as a risk mitigation tool. The primary purpose of a CRAC is to allow BPA to avoid adding PNRR to the base rates but still allow BPA the ability to quickly recover additional dollars through rates in the event BPA experiences poor financial circumstances. Requiring BPA to go through a 7(i) process prior to triggering a CRAC greatly diminishes the value of a CRAC as a risk mitigation tool. A large part of the value of a CRAC as a risk mitigation tool is its ability to raise rates for one year at a time to address actual financial issues. If BPA is forced to comply with the all the procedural requirements of a 7(i) process before imposing a CRAC, it means that CRACs and other similar risk tools are no longer effective tools and BPA would likely need to use PNRR where it would have used a CRAC. This would result in higher rates for all years of the rate period—not just one year at a time. Limiting the risk mitigation toolbox to only PNRR is the most expensive option to all BPA ratepayers.

WPAG’s argument has far-reaching impacts on BPA’s rate design beyond imposition of a CRAC. To the extent the imposition of a CRAC is inconsistent with the procedural requirements of section 7(i), all formula rates, the DDC, and even the Slice True-up would be subject to the same procedural requirements. The CRAC and DDC are nothing more than formula rate adjustments. The circumstances and parameters for triggering are spelled out in great detail in the GRSPs. The CRAC or DDC trigger is dictated by the specific thresholds and the amounts of money BPA can collect or refund annually, which are also specified in the GRSPs. Likewise, the Slice True-up and other formula rates adjust the rates paid by customers for the power they purchase. Each of these rate tools is spelled out in great detail in the GRSPs and has strict limits on how the rate is modified to collect or refund additional dollars during the course of a rate

period. BPA also notes that WPAG fully supports the VERBS formula rates that will recover the cost of non-Federal reserve acquisitions that may be required at any time during the rate period. WPAG Br., BP-12-B-WG-01 at 9-11. Consequently, if WPAG is correct and BPA cannot adjust rates mid-rate period absent complying with the procedural requirements of 7(i), then product design and offerings as well as the overall rate design will need to be reexamined.

BPA does not believe that WPAG’s procedural position has any merit; nor is it good business practice. Formula rates are rate design mechanisms that have been employed by BPA and many other utilities over the years. Under formula rates, basic parameters are spelled out in advance regarding how the rate will be set or adjusted. In the case of the CRAC, the GRSPs spell out in detail the specific circumstances for triggering a CRAC and how the amount to be collected under the CRAC will be determined. Power Rate Schedules, BP-12-A-02B, GRSP II.C. By providing these specific instructions, and in the case of the CRAC, basing the trigger on objective standards that are subject to section 7(i) review by rate case parties during the rate proceeding, BPA has satisfied its obligations under section 7(i). That is, BPA has complied with all requirements of section 7(i) in proposing and adopting formula rates, including the CRAC and DDC. The fact that these formula rates may trigger during the rate period does not require BPA to comply with the procedural steps of section 7(i) a second time.

Decision

The CRAC comports with the procedural rights under section 7(i) of the Northwest Power Act.

1.3.4 No Opportunity to Testify Regarding Operational Issues

Issue 1.3.4.1

Whether BPA acted in an unfair and discriminatory manner by prohibiting parties from offering testimony on operational issues.

Parties’ Positions

MSR states that Staff “provided pages and pages” of testimony on issues that influence how ancillary and control area services can be valued in the context of operational constraints, but prohibited testimony to rebut or support the Staff position. MSR states that these actions raise issues of “discrimination and fundamental fairness.” MSR Br., BP-12-B-MS-01, at 3.

MSR argues that the testimony that was struck in the transmission portion of the case responded to positions advanced in BPA’s Initial Proposal, and that BPA moved to strike the testimony from the transmission case based on the Federal Register notice for the power case. MSR notes that its testimony raised three issues: use of transmission financial reserves by Power Services; determination of the amount of reserves needed for wind balancing; and the need for longer-term solutions for integration of variable resources within BPA’s system. MSR asserts that these are all transmission issues. MSR Br. Ex., BP-12-R-MS-01, at 2.

BPA Staff's Position

Staff has not specifically addressed MSR's allegations, which were raised in MSR's brief and in its answer to a motion to strike. However, Staff filed two motions to strike portions of MSR's testimony because the testimony raised operational issues that were outside the scope of the rate case. BP-12-M-BPA-10; BP-12-M-BPA-14. The Hearing Officer granted both motions. BP-12-HOO-41; BP-12-HOO-51.

Evaluation of Positions

The Federal Register notice announcing the power segment of the rate proceeding provides that the forecast amount of generation inputs, cost allocations to determine generation input costs, and associated Ancillary and Control Area Service rates are all matters within the scope of the rate proceeding, but that the Hearing Officer should strike all argument, testimony, and other evidence "that seeks in any way to revisit the appropriateness or reasonableness of any other issues related to the generation inputs or Ancillary and Control Area Services." The notice adds that this exclusion included but was not limited to issues regarding reliability, dispatcher standing orders, "e-Tag requirements, and business practices." 75 Fed. Reg. 780744, 70746.

MSR's brief does not specify which Staff testimony concerns operational issues that the parties are prohibited from rebutting or supporting. (MSR's citation for the relevant BPA testimony reads "BP-12-E-BPA-," with no actual testimony number or page numbers. MSR Br., BP-12-B-MS-01, at 3 n.2.) MSR may be referring to Staff's generation inputs policy testimony, BP-12-E-BPA-23, which sets out the underlying principles governing ancillary and control area services and provided background for the testimony on cost determination and cost allocation.

Staff does not offer any of this policy testimony to support particular rate case outcomes. None of it addressed "the appropriateness or reasonableness" of the issues excluded by the Federal Register notice. Instead, because these issues have been addressed in other forums, the testimony takes their resolutions as a given and provides background necessary to understand the issues that Staff does address in the rate case.

For example, Staff explains how BPA "uses generation inputs ... to maintain reliability of the system" and describes the various types of balancing reserves. Mainzer *et al.*, BP-12-E-BPA-23, at 10-14. Another example is MSR's reference to "testimony on issues that influence how [Ancillary and Control Area] services can be valued in context of operational constraints." MSR may be referring to Staff's testimony regarding the tradeoff that is necessary between quality of service and price. Staff testifies that there is a limit to the amount of balancing capacity the FCRPS can provide and discusses the resulting quality of service and the possibility of providing a higher quality of service. *Id.* at 22-30, 36-42.

If this is the testimony to which MSR refers, it also provides necessary background information so parties can understand Staff's rate proposals. The testimony explains the nature of the services the customer purchases when it buys ancillary or control area services, *id.* at 23-25, and the actions BPA proposes to take in a situation in which BPA has insufficient balancing reserves, *id.* at 25-27. None of this testimony addresses particular rate issues or is intended to support one

rate case outcome over another. Rather, the testimony accepts that BPA has made its operational decisions outside of the rate proceeding and conveys those decisions as background for Staff's rate proposals.

This testimony contrasts starkly with MSR's testimony. For example, with respect to e-Tags (the subject of one of BPA's motions to strike), Staff testified that "the decision whether or not to require firm contingent e-Tag[s] ... is not a rate issue." *Id.* at 43. However, because Staff has to make assumptions about the use of e-Tags to calculate the operating reserve forecast, Staff simply assumes that e-Tags would be required of all wind generation in the BPA Balancing Authority Area except for generators that self-supply. *Id.*

MSR, on the other hand, contests the use of e-Tags, stating that "durability" is compromised by "proposed discrimination with respect to tagging." Arthur and Mayson, BP-12-E-MS-01, at 3. This testimony challenges the appropriateness of a decision made outside of the rate proceeding, and the Hearing Officer properly struck it. As the Hearing Officer states, "The testimony must be stricken because it goes beyond the scope of this proceeding by 'revisit[ing] the appropriateness or reasonableness' of e-Tag requirements." BP-12-HOO-41, at 3.

BPA filed a second motion to strike, which the Hearing Officer also granted. MSR's brief may be referring to that motion, which is directed at testimony that MSR filed in the transmission segment of the case (Arthur and Mayson, BP-12-E-MS-02). The primary basis of the motion is that this piece of MSR's testimony concerned power issues and therefore could not be filed in the transmission segment.

A portion of the motion, however, moved to strike parts of MSR's testimony because MSR raises operational issues that are outside the scope of the rate proceeding. A review of this testimony again shows the distinction between Staff's testimony, which provides background, and MSR's, which challenges decisions or policies BPA adopted outside of the rate proceeding.

For example, MSR challenges BPA's curtailment protocol—a non-rates issue—by arguing that it "does not seem consistent with the direction taken at the national level to treat [variable energy resources] similar to dispatchable resources." *Id.* at 14. MSR encourages BPA "to find ways to both address the operational challenges and conform to the national priorities." *Id.* This testimony explicitly advocates a particular result in the rate proceeding for an issue that is not a rate proceeding issue.

A second and particularly pointed example in this testimony is MSR's statement that BPA must address certain "emerging issues," including "determining available transfer capability ... and how best to use the transmission system so that the greatest number of uses can be accommodated." *Id.* at 16. MSR even proposes that BPA alter its interconnection policies: "BPA must consider the potential limitations of the FCRPS prior to entering into [Large Generator Interconnection Agreement] discussions. There is no statute or regulation of which M-S-R is aware that requires BPA to continue to interconnect [variable energy resources] without regard to system operational flexibility." *Id.* at 17.

Staff appropriately makes no proposals concerning BPA's curtailment policies, operational protocols, interconnection policies, or any other non-rates issues. MSR, however, clearly proposes that BPA alter these protocols and policies and therefore raises non-rates issues. The two parties' testimony is not comparable, and there is no discrimination or unfairness in prohibiting the MSR testimony at issue.

MSR asserts that the testimony that was struck responded to positions advanced in BPA's Initial Proposal and that BPA moved to strike the testimony based on the Federal Register notice for the power case. MSR Br. Ex., BP-12-R-MS-01, at 2. However, the testimony that was struck responded to positions advanced in the Initial Proposal in the power segment of the case and therefore was untimely. *See* BP-12-M-BPA-14, at 3-9; BP-12-HOO-51, at 3. As to BPA's alleged reliance on the Federal Register notice in the power case, even if BPA had relied only on that notice, its reliance would be appropriate. There is one docket in this case with two segments, power and transmission, and the Federal Register notice in the power segment of the case put all parties on notice of the issues that would be addressed in that segment. In any case, BPA did not rely only on that notice. BPA's motion also cited the Federal Register notice issued in the transmission segment of the case, and quoted that notice's statement of the issues that would be addressed in the transmission segment. BP-12-M-BPA-14, at 3.

MSR also notes that its testimony raised three transmission issues. MSR Br. Ex., BP-12-R-MS-01, at 2. The first issue is Power Services' use of transmission financial reserves. BPA did not move to strike this portion of MSR's testimony, and the Hearing Officer did not strike it. *See* BP-12-HOO-51, Attachment A at 3-4, 18. The other two issues were the determination of the amount of reserves needed to balance wind generation and longer-term solutions for integrating wind generation into BPA's system. As to the amount of reserves for wind balancing, the Federal Register notice issued in the power segment of the case made clear that issues related to wind balancing would be addressed in that segment. *Fiscal Year (FY) Proposed Power Rate Adjustments Public Hearing and Opportunities for Public Review and Comment*, 75 Fed. Reg. 70744, 70751 (2010); BP-12-HOO-51, at 3. In fact, MSR filed testimony on these issues in the power segment. *See* BP-12-M-BPA-14, at 4-9.

As to the issue of longer-term solutions for the integration of wind generation, that testimony raised operational rather than rate issues and is therefore outside the scope of the rate case. *See id.* at 7-9; BP-12-HOO-51, at 4. Indeed, MSR makes this clear: MSR argues that BPA "must lead by first understanding and then addressing the fundamental operating challenges posed by non-dispatchable resources ... [T]he actual operating capabilities of the FBS [must] be understood and then deployed in a manner that addresses the legal, political, and economic mandates imposed upon BPA." MSR Br. Ex., BP-12-R-MS-01, at 3.

The Hearing Officer properly struck portions of both pieces of MSR's testimony.

Decision

There is no unfairness or discrimination in allowing Staff's background testimony on operational issues but prohibiting MSR testimony that sought to challenge and revisit policy and operational

issues that were decided outside of the rate proceeding. MSR's testimony is outside of the scope of the rate proceeding, and the Hearing Officer properly struck it.

1.3.5 Development of Implementation Details of Certain Ancillary Services After the Rate Case

Issue 1.3.5.1

Whether it is appropriate for BPA to develop the implementation details for certain variable resources products in a business practices forum after the rate proceeding.

Parties' Positions

MSR argues that BPA must not keep the terms and conditions associated with variable resources "unknown" until developed in a business practices forum held after the rate proceeding. MSR states that instead BPA should develop the terms and conditions first and set the rates afterward. MSR Br., BP-12-B-MS-01, at 8.

BPA Staff's Position

Because this issue is raised for the first time in MSR's brief, Staff has not taken a position on it. However, MSR appears to be referring to two new services Staff is proposing, VERBS Supplemental Service and the committed intra-hour scheduling pilot. Staff has proposed rates for these services and testifies that implementation issues will be addressed in a business practices process after the rate proceeding. Kitchen *et al.*, BP-12-E-BPA-45, at 3; Simpson *et al.*, BP-12-E-BPA-46, at 6.

Evaluation of Positions

MSR does not state which variable resource services it is referring to. However, it appears to be referring to the two services listed above, as those are new services, and Staff testifies that BPA would adopt implementation details for these services in a business practices process after the rate proceeding. Nevertheless, MSR overstates both the extent and the significance of this process.

First, BPA could not offer the services unless it had developed terms and conditions sufficient to define them for purposes of costing, sale, and purchase. The basics of both services are straightforward and are adequately described in the testimony. Kitchen *et al.*, BP-12-E-BPA-45, at 1-7; Simpson *et al.*, BP-12-E-BPA-46, at 1-2.

Second, BPA's development of the details of service outside the rate proceeding is not new. BPA's business practices are continually evolving and indeed must do so if BPA is to function effectively. Many of BPA's business practices have been revised multiple times as BPA and its customers gain experience in a particular service or business practice. Refining the details of BPA's products over time is both necessary and normal.

Third, the purpose of a rate proceeding is to determine the costs of services and establish rates for the services. Business decisions are traditionally and appropriately made outside of the rate proceeding. As Staff testifies with respect to the committed intra-hour scheduling pilot,

We are proposing that the rate case address the rate treatment associated with the pilot and the forecast of the balancing reserve capacity requirements of participants in the pilot. Implementation details that are unrelated to the rate treatment or the reserve requirement [which determines the cost of the service] would be resolved through discussions with individual participants in the context of developing business practice and participant agreements.

Simpson *et al.*, BP-12-E-BPA-46, at 6. Staff offers similar testimony with respect to VERBS Supplemental Service. Kitchen *et al.*, BP-12-E-BPA-45, at 3.

Fourth, Staff introduces sufficient evidence to determine the costs of the services and to establish rates, thus meeting its rate case burden. The costs of VERBS Supplemental Service are administrative costs and the costs of reserves needed to supply the service. *Id.* at 11. Staff proposes a formula rate to recover the costs of the reserves BPA will purchase to supply the service; thus, the rate will track actual costs. *Id.*; *see also* Jackson *et al.*, BP-12-E-BPA-47, at 42-44. Staff also presents detailed evidence to support the rate treatment of the committed intra-hour scheduling pilot. Simpson *et al.*, BP-12-E-BPA-46, at 7-10.

Fifth, both services are voluntary, and any customer dissatisfied with the price (or the terms and conditions) need not purchase them. Kitchen *et al.*, BP-12-E-BPA-45, at 2; Simpson *et al.*, BP-12-E-BPA-46, at 1. Moreover, customers will have the opportunity to be involved in the establishment of the terms and conditions through the business practice process and, with respect to the intra-hour pilot, through the negotiation of participant agreements. Kitchen *et al.*, BP-12-E-BPA-45, at 3; Simpson *et al.*, BP-12-E-BPA-46, at 6. Therefore, customers will have full opportunity to influence the terms and conditions and to evaluate the services before purchasing them.

Decision

The record includes sufficient evidence to establish the rates for all ancillary services, including the committed intra-hour scheduling pilot and VERBS Supplemental Service. It is appropriate for BPA to establish rates for these services in the rate proceeding and establish implementation details after the rate proceeding. BPA will engage customers to help them understand implementation details so they can make a well-informed decision on whether or not to purchase these services.

Issue 1.3.5.2

Whether rate proceeding parties that are not a TRM-defined Customer or Customer Group should be allowed to propose changes to the TRM without complying with the TRM change process in Section 13 of the TRM.

Parties' Positions

ICNU states that it is “in an impossible Catch-22 situation” in that it does not have a forum to request that the TRM be revised. ICNU Br., BP-12-B-IN-01, at 21-22. ICNU notes that the Hearing Officer struck portions of ICNU’s testimony regarding changes to the TRM because the Federal Register notice required ICNU to follow certain procedures, including TRM Section 13, if it wished to propose changes to the TRM. *Id.* at 22. ICNU notes that the generic rule for TRM revisions is that the TRM will not be revised without the introduction, consideration, and adoption of such revision in a 7(i) process. *Id.* Thus, ICNU concludes, changes to the TRM must be made in rate proceedings such as this case. *Id.*

ICNU requests “that the Administrator reverse the Hearing [Officer’s] conclusion, and instead make it clear that ICNU is not required to utilize procedures in TRM Section 13, as they are not available for use by ICNU, nor do they limit ICNU’s ability to propose changes in this rate proceeding.” *Id.* This is because, ICNU states, the requirement to use Section 13 applies only to BPA utility “Customers” and “Customer Groups” and does not include groups such as ICNU that represent end-use consumers. *Id.* at 23. ICNU therefore proposes the Administrator “should provide ICNU with a fair forum to propose revisions to the TRM, and should consider revising the TRM in this proceeding to ensure that the rates for Future CF/CT Loads are based on BPA’s low cost Federal base system resources.” *Id.*

BPA Staff’s Position

ICNU raised this issue for the first time in its brief; therefore, Staff has not taken a position on the issue.

Evaluation of Positions

ICNU argues that it should be allowed to propose modifications to the TRM without utilizing the procedures in TRM Section 13. ICNU Br., BP-12-B-IN-01, at 22. ICNU notes that it is not a Customer Group, as that term is defined in the TRM, and thus ICNU is deprived of a fair forum to propose TRM changes. *Id.* at 23.

ICNU is correct that it is not a “Customer” or “Customer Group” as defined in TRM Section 13. ICNU represents consumers of Customers. The Section 13 procedures were included in the TRM to prevent BPA from (1) making unilateral changes to the TRM; or (2) agreeing to a TRM change proposed by a minority of public customers. The purpose for allowing rate case parties the opportunity to propose TRM changes in a 7(i) Process without following the Section 13 procedures is to recognize that other rate case parties (*e.g.*, IOUs and DSIs) have interests that may be affected adversely by TRM implementation; the TRM is a rate design methodology for PF rates for Customers. The ability to propose TRM changes by non-Customers preserves their procedural rights. It is expected that TRM change proposals by these parties will be limited to items directly affecting their interests. If a non-Customer were to propose a TRM change that was not directly linked to its interests and had not solicited the broad support described in the Section 13 procedures, the proposal would be viewed with a greater eye toward the input of Customers. Even if a proposal is directly linked to its interests, the proposed modification is to

be enacted in a manner that cures the non-Customer's adverse impact while making as little change as possible in the overall effect of the TRM on Customers.

In the instant proceeding, ICNU seeks a change to the TRM that would ensure that the rates for future CF/CT Loads are based on BPA's low-cost Federal base system resources. ICNU Br., BP-12-B-IN-01, at 23; see also Wolverton, BP-12-E-IN-01, at 19-22 (non-conformed copy). JP02 moved to have pages 19-22 of ICNU's testimony proposing a TRM change stricken as outside the scope of this proceeding because the proposal did not follow Section 13 of the TRM. BP-12-M-JP02-01. The Hearing Officer granted this portion of the Motion. BP-12-HOO-44.

The Hearing Officer found that the ICNU testimony was outside the scope of this proceeding as defined in the Federal Register notice. *Fiscal Year (FY) 2012–2013 Proposed Power Rate Adjustments Public Hearing and Opportunities for Public Review and Comment*, 75 Fed. Reg. 70744 (2010). Specifically, the Hearing Officer found that the testimony violated the portion of the notice that states:

Pursuant to § 1010.3(f) of BPA's Procedures, the Administrator hereby directs the Hearing Officer to exclude from the record all argument, testimony, or other evidence that seeks in any way to propose other proposed revisions to the TRM made by BPA, customers with a CHWM contract, their representatives, or *representatives of their consumers*, unless it can be established that the TRM procedures for proposing a change to the TRM have been concluded. This restriction does not extend to a party or customer that does not have a CHWM contract.

Id. at 70746 (emphasis added).

ICNU argues that this restriction does not comport with the TRM. ICNU Br., BP-12-B-IN-01, at 22. ICNU is correct. While the Hearing Officer appropriately found that the testimony should be stricken on the basis of the guidance he was given in the Federal Register, the notice in the Federal Register misapplied the direction in the TRM and the TRM ROD by inappropriately including consumer representatives with Customer and Customer Groups. The TRM states that: "Nothing in section 12 or this section 13 either 1) precludes any party to a BPA 7(i) Process, other than a Customer, from making any proposal or offering any testimony of other evidence on any matter that may otherwise be raised in a BPA 7(i) Process" BP-12-A-03, section 13.1. Because ICNU is not a Customer, it is clearly a "party to a BPA 7(i) Process, other than a Customer"

This is BPA's mistake. BPA now corrects its mistake by reversing the Hearing Officer's Order. Pages 19-22 of ICNU's testimony, BP-12-E-IN-01, are reinstated.

While non-Customers are not defined as "Customers" or "Customer Groups" within Section 13, BPA would look to see whether a TRM change proposed by a non-Customer that is directly tied to its particular interests should observe the Section 13 process. The modification sought by ICNU is offered to correct what it believes is an adverse impact of the TRM, but it does so in a manner that materially affects all public customers. If ICNU's proposed modification could be

enacted in a manner that cures ICNU's adverse impact but makes as little change as possible in the overall effect of the TRM on Customers, it would be considered. However, ICNU has proposed a modification that significantly affects Customers. In this situation, the Customers should have the right to be consulted and express their support or lack thereof to such a change.

Even though ICNU does not have an avenue to place its modification before Customers pursuant to Section 13, BPA has such an avenue. BPA is willing to work with ICNU and any other party to construct TRM changes and present them to voting customers. This allows all parties, including ICNU, to work together to achieve language that is clear, concise, and implementable, thereby limiting later disputes over implementation of new language.

Decision

BPA reverses the Hearing Officer's decision and reinstates the cited portion of ICNU's testimony. BPA declines to adopt ICNU's modification to the TRM without first placing this matter before Customers pursuant to Section 13.

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2.0 POWER TOPICS

2.1 Power Policy Issues

2.1.1 Contracted For/Committed To (CF/CT) Loads

Issue 2.1.1.1

Whether BPA's discussion of CF/CT issues in the Draft ROD is procedurally misplaced.

Parties' Positions

Clatskanie filed a brief on exceptions raising certain CF/CT issues. Prior to its brief on exceptions, Clatskanie offered no testimony, legal argument, or any other filings in the BP-12 case related to these issues. Clatskanie now argues that BPA's discussion in the Draft ROD of CF/CT issues is "procedurally misplaced." Clatskanie Br. Ex., BP-12-R-CK-01, at 2. That is, Clatskanie contends that "BPA is not deciding any matter that is before it in this proceeding. BPA is simply advancing legal arguments in support of a decision that it had previously made in the TRM ROD." *Id.* In other words, "the CF/CT dispute only concerns BPA's rate-setting methodology, not the actual rates." *Id.* Therefore, Clatskanie concludes, "discussion of the CF/CT issue in the Draft ROD is merely dicta and should therefore not be included in the final BP-12 ROD" *Id.*

Clatskanie continues its argument by suggesting that, even if BPA intended to resolve CF/CT issues in this BP-12 proceeding, it would be precluded from doing so for three reasons. *Id.* Specifically, Clatskanie contends that (1) the record in this proceeding is not sufficient to support BPA's discussion of CF/CT loads; (2) BPA has "resisted" parties' efforts to put in the record information concerning CF/CT loads; and (3) the TRM precludes BPA from unilaterally amending any of its terms unless it is through a formal BPA administrative proceeding. *Id.* at 2-3.

Finally, Clatskanie suggests that "BPA has included its legal arguments concerning CF/CT in the Draft ROD for the sole purpose of obfuscating the Ninth Circuit's jurisdiction over a pending appeal of the TRM ROD." *Id.* at 3. Clatskanie's theory is that BPA has intentionally failed to mention Case No. 10-72838 (a pending petition for review which Clatskanie filed against BPA in the Ninth Circuit Court of Appeals) in order to perform an end-run around a Court order by "belatedly attempt[ing] to make CF/CT a rate case issue ..." in this proceeding. *Id.*

No other parties have raised this procedural issue, and no party addressing CF/CT issues has argued Clatskanie's theories.

BPA Staff's Position

This is a legal issue, which Clatskanie raised for the first time in its brief on exceptions; therefore, BPA Staff has not taken a position on the issue.

Evaluation of Positions

BPA plainly stated at the beginning of its analysis of the first CF/CT issue in the Draft ROD and will repeat here:

At the outset, it is important to note that, in *Industrial Customers of Northwest Utilities, et al., v. Bonneville Power Administration*, 388 Fed. Appx. 586 (9th Cir. 2010) (unpublished memorandum opinion), GP and ICNU filed petitions for review challenging the TRM and BPA's treatment of CFCT load under the TRM as allegedly violating, among other things, the ratemaking provisions of the Northwest Power Act. The Court held that the majority of claims raised by these petitioners were not ripe for review. *Id.* In the context of that case, BPA fully addressed its legal authority to establish tiered rates and explained why BPA's treatment of CFCT load under the TRM was consistent with and supported by BPA's statutory authorities. *See id.*, Answering Brief of Respondent Bonneville Power Administration, filed Sept. 29, 2009, at 36-52. Because GP and ICNU raise many of the same or similar statutory arguments that they raised in that litigation, BPA hereby incorporates by reference its answering brief filed in that case.

BP-12 Draft ROD, BP-12-A-01, at 30.

From that paragraph it is apparent that BPA clearly understands the procedural state of play regarding the CF/CT issues that have been (repeatedly) raised by Clatskanie, GP, and ICNU. A plain reading of the *Industrial Customers* memorandum opinion shows which CF/CT issues have been decided and which were unripe until such time as rates were set. Specifically, the Court found that “[b]ecause the BPA has not yet completed a rate-making proceeding, and the petitioners’ [Clatskanie, GP, and ICNU] challenge under section 7(b)(4) [of the Northwest Power Act] is based on future rate-making and cost allocation decisions, this challenge is not ripe for review.” *Industrial Customers*, 388 Fed. Appx. 586, at 588. Thus, the Court dismissed those aspects of Clatskanie and the other petitioners’ claims, concluding that “[b]ecause the BPA has not yet completed a rate-making proceeding, and the petitioners are not challenging an actual rate made in violation of a controlling statute, these particular challenges are not ripe for decision.” *Id.* at 589.

The Court then gave clear direction to Clatskanie, GP, and ICNU about how and when to bring their claims. It stated: “Once the BPA sets the new rates and FERC approves such rates, the petitioners may be able to file new petitions for review with this court ... [because] a challenge to the method of calculating rates, dismissed as unripe at this stage, could become reviewable at a later date ...” once BPA has calculated and FERC has approved such rates. *Id.* (internal citation omitted).

Accordingly, that is exactly what GP and ICNU have opted to do. They have renewed their CF/CT-related challenges to BPA's calculation of rates under the TRM, which is the calculation BPA has performed in this BP-12 rate proceeding. For its part, BPA readily acknowledges and agrees with the court's direction and therefore believes it is procedurally proper for GP and

ICNU to bring their claims in this proceeding (assuming they have standing to do so, and noting that all their claims are fatally flawed for a host of other reasons as explained throughout this section 2.1.1). See *Industrial Customers*, 388 Fed. Appx. 586, at 588-89. Thus, Clatskanie stands alone in its erroneous interpretation of the procedural state of play.

Moreover, because GP and ICNU have raised issues in this proceeding regarding CF/CT, it is entirely appropriate and necessary for BPA to have addressed those issues in its Draft ROD and to decide those issues in this Final ROD. Clatskanie's suggestion, that BPA's CF/CT discussion is "dicta" that does not belong in this case, is patently wrong. BPA did not raise the CF/CT issue in this proceeding; that was done by GP and ICNU.

Clatskanie tries to spin the CF/CT dispute into something it is not. Clatskanie contends: "What is at issue in this proceeding is the level of rates to be charged by BPA. The dispute over CF/CT loads does not relate to the level of the Tier 1 or Tier 2 rates, but rather which rate tier should be applied." Clatskanie Br. Ex., BP-12-R-CK-01, at 2. To the contrary, the CF/CT dispute amounts to GP's, ICNU's, and Clatskanie's disagreement with BPA over how its ratemaking decisions should implement the TRM and the CF/CT exception to the statutory definition of "New Large Single Load." There can be no doubt these are challenges to BPA's calculation of rates. There is no longer an opportunity for these parties to re-litigate the TRM itself. That opportunity occurred in *Industrial Customers*, wherein the court stated, "[i]t is undisputed that the Tiered Rate Methodology Record of Decision is a 'final action' ..." and addressed the only merit-based challenge that was ripe, namely, ICNU's discrimination claim.³ *Industrial Customers*, 388 Fed. Appx. 586, at 589 ("Because this claim challenges the BPA's authority to provide such differential treatment, and neither challenges a rate established under the Tiered Rate Methodology nor requires analysis of hypothetical characteristics of future rates, we conclude that it is ripe.... This claim fails on the merits, however, because the BPA did not act arbitrarily and capriciously.").

Thus, the court reviewed the TRM once it became a final action and upheld the TRM on all merit-based claims that were timely brought at that point. All that remains is for BPA to set rates under the TRM (as it is doing in this proceeding). Then, following Commission review, parties may, if they choose, challenge those ratemaking decisions pursuant to the statutory judicial review provisions at the appropriate time. See 16 U.S.C. § 839f(e)(5); *Industrial Customers*, 388 Fed. Appx. 586, at 589 ("Once the BPA sets the new rates and FERC approves such rates, the petitioners may be able to file new petitions for review with this court ... [because] a challenge to the method of calculating rates, dismissed as unripe at this stage, could become reviewable at a later date ..." (citation omitted)).

Turning to Clatskanie's three reasons why BPA is allegedly precluded from resolving the CF/CT dispute in this proceeding, this line of argument warrants little response. As the *Industrial Customers* decision makes clear, and as BPA has long maintained, and as all other parties concerned with the CF/CT issue acknowledge by choosing to make their arguments in this

³ The Court referred to the claim as having been brought by ICNU, however Clatskanie raised and argued it as well. See *Industrial Customers*, 388 Fed. Appx. 586, Opening Brief of Petitioner Clatskanie, filed June 30, 2009, at 22-24.

proceeding, this BP-12 rate case is unquestionably the forum for BPA to resolve CF/CT issues that were contingent on ratemaking decisions and were unripe in *Industrial Customers*.

First, contrary to Clatskanie's assertion, there is copious material in the record that supports BPA's discussion of CF/CT loads in the Draft ROD. This ROD and the Draft ROD cite to testimony and evidence in this case and, to the extent necessary to respond to parties' renewed issues that were already litigated in the proceeding that established the TRM itself, BPA has properly cited to materials from that proceeding as well.

Second, Clatskanie mischaracterizes the facts when it asserts that BPA has "vigorously resisted" parties' efforts to put information into the record concerning CF/CT loads. BPA argued, just as it has explained on these very pages, that

[N]othing in *Industrial Customers* supports the proposition that the TRM itself is subject to re-litigation in this rate proceeding. This is evidenced by the Court's finding that the TRM was a "final action" that was ripe for review. Consistent with that determination, the Court decided on the merits a single properly raised challenge to the TRM. On the other hand, the Court declined to address the remaining challenges raised by petitioners because they involved rates not yet established by BPA and approved by FERC.

Hearing Officer Order, BP-12-HOO-13, filed Dec. 15, 2010 at 3-4 (summarizing BPA's argument from its response to APAC's motion). In this order, the Hearing Officer was responding to a motion by APAC that the notice of hearing published in the Federal Register improperly restricted parties from raising TRM issues in this proceeding, in contravention of *Industrial Customers*. The restriction pertained to the foreclosure of certain parties proposing changes to the TRM, not to raising issues in this proceeding. 75 Fed. Reg. at 70746. The Hearing Officer did not, as Clatskanie now contends, "expressly exclude[e] from BP-12 any issues challenging BPA's treatment of CF/CT loads in the TRM" Clatskanie Br. Ex., BP-12-R-CK-01, at 2. Instead the Hearing Officer explained simply that the TRM was a final action that had been reviewed by the Ninth Circuit in *Industrial Customers* and therefore was not subject to being re-litigated in this BP-12 proceeding. Hearing Officer Order, BP-12-HOO-13, filed Dec. 15, 2010 at 4-5. Then, the Hearing Officer clearly pointed out (as BPA had stressed in its argument against APAC's motion) that "certain challenges raised by the petitioners [in *Industrial Customers*] were not yet ripe for review because rates had not been established by BPA and approved by FERC." *Id.* Thus, those challenges could be (and have been) raised in this BP-12 proceeding. BPA has not "vigorously resisted" the introduction of any of these issues in this proceeding.

If anything, this proceeding has demonstrated BPA's attempts to receive *further information* and concrete evidence to support the CF/CT arguments GP and ICNU made in testimony. Specifically, BPA sent a myriad of data requests to both of these parties on this topic. Across the board, BPA's data requests were met with vague responses, objections based on lack of knowledge, and a complete dearth of evidence in general.

Third, Clatskanie misinterprets the language of the TRM as precluding BPA from amending the TRM's terms. Clatskanie Br. Ex., BP-12-R-CK-01, at 2-3. This issue has already been raised and properly addressed by the Hearing Officer. Hearing Officer Order, BP-12-HOO-13, filed Dec. 15, 2010 at 4. The same reasoning still stands. From the very beginning of this proceeding, the FRN clearly stated that "modifications to the TRM are within the scope of this proceeding." 75 Fed. Reg. at 70746. The only limitation is that the procedures specified in Chapters 12 and 13 of the TRM must be followed and concluded before a proposed modification to the TRM may be placed into evidence. Accordingly, changes to the TRM can be proposed in this proceeding—indeed, five changes have been proposed and adopted herein. In addition, ICNU suggested that BPA modify the TRM to accommodate future CF/CT loads. *See* Issue 1.3.5.2.

Turning to Clatskanie's last argument, it attempts to support its theory that "the CF/CT issue is not properly before BPA" by bringing up the fact that it has filed another Ninth Circuit petition, Case No. 10-72838. That case purports to re-litigate the legitimacy of the TRM. However, the case does nothing to alter the procedural analysis discussed above. As BPA pointed out to the Court in its Motion To Dismiss that case, which BPA hereby fully incorporates by reference, Clatskanie's new petition is meritless and seeks only to re-argue the exact same issues raised and either decided, or found to be unripe, in *Industrial Customers*, 388 Fed. Appx. 586. *See Clatskanie People's Utility Dist. v. Bonneville Power Admin.*, Case No. 10-72838, Respondent Bonneville Power Administration's Motion To Dismiss For Lack Of Subject Matter Jurisdiction, filed Mar. 3, 2011, at 3-14. In ruling on BPA's motion, the Court did not "specifically reject[]" BPA's argument, as Clatskanie claims. Clatskanie Br. Ex., BP-12-R-CK-01, at 3. Rather, the Court's Appellate Commissioner merely issued a routine denial of BPA's Motion but pointed out that BPA could renew the jurisdictional argument at a later stage of the case (*i.e.*, in BPA's answering brief) and that the actual merits panel would decide the issue at that time. *See Clatskanie People's Utility Dist. v. Bonneville Power Admin.*, Case No. 10-72838, Order of April 29, 2011.

Even Clatskanie's own customer, GP, whose CF/CT interests are entirely aligned with Clatskanie's, appears to believe that Clatskanie's petition in Case No. 10-72838 may be procedurally improper and, instead, that the instant proceeding is the forum for CF/CT issues. GP did not attempt to intervene in Clatskanie's new case until months after the deadline for doing so. GP's explanation for its delayed decision to intervene was because GP had been proceeding under the same procedural understanding as BPA had argued in its Motion to Dismiss. Namely, that GP was "bound by the prior mandate of the Court" in *Industrial Customers*, 388 Fed. Appx. 586 which, in GP's words, found that GP's claims "lack[ed] ripeness until BPA had approved rates." *Clatskanie People's Utility Dist. v. Bonneville Power Admin.*, Case No. 10-72838, Motion To Intervene Of Georgia Pacific, filed May 17, 2011, at 4-5.

Accordingly, GP purposely awaited the outcome of BPA's Motion To Dismiss (which directly raised the jurisdictional problems with Clatskanie's petition) before deciding to intervene in Clatskanie's case. Moreover, even when GP filed its motion to intervene, GP was careful to point out that "some issues to be raised by GP may not be properly raised in this case, *but must be reserved for a subsequent petition for review after BPA adopts rates.*" *Id.* at 4 n.6 (emphasis

added). Thus GP acknowledges that CF/CT issues are proper in this proceeding (and appeals thereof), rather than in Clatskanie’s lawsuit in Case No. 10-72838.

As for BPA, the agency’s position on these procedural matters has been the same in all forums, and has not changed over time. The Court’s direction is clear and BPA has been equally clear in its interpretation: (1) the TRM was “indisputably” a final action when BPA adopted it on November 10, 2008, (*Industrial Customers*, 388 Fed. Appx. at 588); (2) the majority of claims raised by Petitioners in *Industrial Customers*, including Clatskanie, were based on alleged impacts of future rates which had not yet been established (*id.* at 588-89); and (3) those claims would not be ripe for judicial review until rates were established by BPA and confirmed and approved by FERC. *Id.* at 589. BPA is now concluding the second stage of that process. That is, in this BP-12 proceeding BPA is establishing rates and making decisions related thereto. Accordingly, parties such as GP and ICNU have raised their CF/CT arguments based on those decisions. BPA has considered those arguments and decided them as discussed in the sections below. If any parties ultimately choose to seek judicial review of those decisions, the time to do so will be after BPA concludes this rate proceeding and within 90 days after FERC grants final confirmation and approval of these rates. 16 U.S.C. § 839f(e)(5).

In sum, because Clatskanie’s petition is not germane to this proceeding, it was not discussed in the Draft ROD. As discussed in BPA’s motion to dismiss, that petition lacks merit and is a misguided attempt to perform a procedural slight of hand by re-litigating issues that the Court already decided or declined to review until they could be resolved in this proceeding (then appealed if necessary). Thus it is Clatskanie that is “obfuscating the Ninth Circuit’s jurisdiction over a pending appeal” Clatskanie Br. Ex., BP-12-R-CK-01, at 3.

Decision

BPA’s discussion of CF/CT issues in the Draft ROD and this Final ROD is procedurally appropriate in light of the Ninth Circuit’s rulings, and necessary given the arguments raised by the parties in this proceeding.

Issue 2.1.1.2

Whether BPA’s treatment of CF/CT load is contrary to the Northwest Power Act, and whether CF/CT load must be served at BPA’s “lowest” preference rate.

Parties’ Positions

Georgia-Pacific (GP) argues that unrealized CF/CT load—if and when it comes online—would “not share the advantageous costs of Federal hydroelectric resources in the Tier 1 cost pool which was promised by BPA to the entities incurring that load at the ti[m]e of passage of the [Northwest Power Act].” GP Br., BP-12-B-GP-01, at 2. GP states that the “proper treatment of CF/CT under the [Northwest Power Act] requires that, as the remaining CF/CT amount is utilized by the consumer, such loads must receive service at the lowest Preference rate.” *Id.* Similarly, ICNU argues that “[t]he TRM violates the Northwest Power Act because it eliminates

the rate protections for Future CF/CT Loads” and that Congress “required BPA to provide cost-based power at its lowest rate to utilities for service to [CF/CT loads]....” ICNU Br., BP-12-B-IN-01, at 13.

GP asserts that the “concept of CF/CT load was developed to preserve [the] opportunity for melded rates that blended the costs of the Federal hydro system and the other resources in the Federal base system.” GP Br., BP-12-B-GP-01, at 3. GP states that because BPA required, in order to designate CF/CT load, that a utility must have made a request from BPA for assurances of a supply to serve the load, this must therefore mean that BPA has preserved a portion of its existing resource base to serve the future requirements of the CF/CT load. *Id.* From that logic GP infers that “[t]he requirement of both a commitment from the utility to serve and a request from the utility to BPA to reserve resources is consistent with the notion embedded in the [Northwest Power Act] of preservation of an existing cost structure to benefit those prior commitments.” *Id.* at 3-4.

GP states that the law “ensures that CF/CT Load has access to power at the embedded cost of the Federal hydro system, and is not required to be served at the incremental cost of the new resources that BPA might be required to procure in the future.” *Id.* at 4. GP continues that the Northwest Power Act legislative history requires that “Preference Customer load be served at the lowest rate, to distinguish it from the additional load to be served at the marginal rate of new procurements,” and GP suggests that “if CF/CT were served at a rate higher than other Preference load, it would render the original concept of CF/CT utterly moot.” *Id.*

GP notes that a “Section By Section Analysis” of the Northwest Power Act states that general requirements of preference customers must be served at a section 7(b) rate, which would likely be BPA’s lowest rate. *Id.* GP and ICNU also point to a similar passage in legislative history. *Id.* at 5; ICNU Br., BP-12-B-IN-01, at 16-17.

GP states that it is not true that the only purpose of the CF/CT designation is to distinguish it from a New Large Single Load. GP Br., BP-12-B-GP-01, at 5. According to GP, if that were the only purpose there would be no need to designate commitments of less than 10 MW as CF/CT, but GP notes that BPA has created three designations of less than 10 MW. *Id.*

Clatskanie adopts GP and ICNU’s arguments on this issue. Clatskanie Br. Ex., BP-12-R-CK-01, at 5. Clatskanie’s take on the issue is that BPA must serve CF/CT loads “on the same basis” as BPA serves preference customers’ general requirements. *Id.* at 4-5. In support, Clatskanie refers to the Northwest Power Act section 7(b)(4) definition of the term “general requirements” and cites to one sentence of legislative history (the same sentence GP and ICNU have cited). *Id.* at 5. Based on this one sentence, Clatskanie concludes: “Putting it all together, Congress directed BPA to serve all CF/CT loads, regardless of when they come on-line, loads at the lowest-cost rate otherwise available to serve the preference customers’ general requirements.” *Id.* Clatskanie believes the CF/CT-related problem with BPA’s tiered rate approach “is that BPA has inserted into the Act the word ‘future.’ The end result is that BPA’s treatment of a [p]reference [c]ustomer’s CF/CT loads may, in the future, bear absolutely no relationship to BPA’s treatment of the same [p]reference [c]ustomer’s general requirements.” *Id.*

BPA Staff's Position

Staff testified that it was unaware of any assurance that BPA has given that CF/CT load will be served at “the lowest rate.” Bliven and Cherry, BP-12- E-BPA-36, at 10. Staff noted that ICNU cites page 14 of BPA’s New Large Single Load Policy Issue Review ROD (NLSL ROD) as support for its statement. *Id.* However, the actual words on that page state that “[o]nce the determination is made the utility customer and its load are given assurance that BPA service within the CF/CT load amount will be subject to the then effective priority firm (PF) power rate.” *Id.*, citing NLSL ROD (March 2002) at 14. Thus, the NLSL ROD does not support ICNU’s claim that CF/CT determinations preserve the lowest rate for the load. Rather, it supports the application of the then-effective PF rate, which may or may not be BPA’s “lowest rate.” *Id.*

Consistent with the TRM, BPA will apply the then-effective PF Tier 2 rate should any future CF/CT load be placed on BPA to the extent such load causes a utility’s load to exceed its Rate Period High Water Mark (RHWM), and if the utility elects to place that load on BPA. *Id.*

Evaluation of Positions

At the outset, it is important to note that, in *Industrial Customers of Northwest Utilities, et al., v. Bonneville Power Administration*, 388 Fed. Appx. 586 (9th Cir. 2010) (unpublished memorandum opinion), GP and ICNU filed petitions for review challenging the TRM and BPA’s treatment of CF/CT load under the TRM as allegedly violating, among other things, the ratemaking provisions of the Northwest Power Act. The Court held that the majority of claims raised by these petitioners were not ripe for review. *Id.* In the context of that case, BPA fully addressed its legal authority to establish tiered rates and explained why BPA’s treatment of CF/CT load under the TRM was consistent with and supported by BPA’s statutory authorities. *See id.*, Answering Brief of Respondent Bonneville Power Administration, filed Sept. 29, 2009, at 36-52. Because GP and ICNU raise many of the same or similar statutory arguments that they raised in that litigation, BPA hereby incorporates by reference its answering brief filed in that case.

First and foremost, BPA’s rates are wholesale power rates and not retail service rates. BPA does not directly serve the retail load of its utility customers, including any CF/CT load or NLSL load.⁴ Retail ratesetting is the province of the local utility. Congress recognized in the context of large retail loads that BPA’s utility customers have the authority to set their retail rates so that whatever the cost of power sold by BPA, “[i]t will remain possible, ... for a public utility to subsidize industry with lower-cost residential power. This would, of course, need the consent of the utility’s governing body.” H.R. Rep. No. 96-976, Part I, 96th Cong. 2d Sess., 44 (1980). Accordingly, any special price treatment is up to the local utility, not BPA.

⁴ GP is a retail load, and ICNU is a trade organization representing various retail loads. These loads are not wholesale power customers of BPA and therefore are not the object of the government action being decided in this proceeding, *i.e.*, BPA’s setting of rates pursuant to the TRM. Though GP and ICNU have been granted party status in this administrative proceeding, that should not be construed as an indication that this proceeding affects any legally protected interest of GP or ICNU.

The designation of a CF/CT creates an obligation on BPA only *to serve* such load as part of a preference utility customer's general requirements. A CF/CT designation does not guarantee price. The first sentence of section 5(a) of the Northwest Power Act states that all power sales shall be subject to preference. 16 U.S.C. § 839c(a). The second sentence of section 5(a) states that such sales of power shall be at rates established pursuant to section 7. *Id.* This expressly de-links the preference rights of the purchase of power from the rates for the power sold to preference customers. Section 7 governs the setting of rates for CF/CT loads. Section 7(b)(4) specifically points out that the term "general requirements" does not include NLSLs. 16 U.S.C. § 839e(b)(4). Section 3(13) specifically exempts CF/CT from being an NLSL. 16 U.S.C. § 839a(13). The Northwest Power Act defines no other class of service for CF/CT to fall into but "general requirements." Thus, section 7(b) governs the setting of rates for CF/CT loads. 16 U.S.C. § 839e(b). BPA has designated the PF rate as the rate developed pursuant to section 7(b) and applicable to the general requirements of public body, cooperative, and Federal agency customers. 16 U.S.C. § 839e(b)(1).

It is not true, as GP, ICNU, and Clatskanie contend, that a CF/CT determination creates a right to receive power only at the lowest PF rate, generally asserted by these parties to be the PF Tier 1 rates. To the contrary, once a large load is determined to be CF/CT and the ceiling amount of load is set, the actual amount of CF/CT load that consumes power is treated as part of the utility customer's general requirements load.

However, unrealized nonexistent CF/CT load is not served.⁵ In contrast, the actual load is served with requirements power sold by BPA at the applicable PF rates, and the CF/CT load gains no greater rights to service than the rest of its serving utility's general requirements load; all general requirements load is to be charged the PF rate and not the NR rate. When BPA includes the CF/CT-determined actual load as part of a utility's general requirements load, it simply means the actual amount of load is not treated as an NLSL and thus is not served at BPA's NR rate. *See* 16 U.S.C. § 8393(b)(4); H.R. Rep. No. 96-976, Part II, 96th Cong. 2d Sess., 52 (1980).

Whenever requested, BPA will sell power to GP's retail utility (Clatskanie People's Utility District), which will then resell it to serve GP's load. BPA's sale of power to Clatskanie will be made subject to the applicable PF rate, the form of which is based on the two-tiered PF rate design established in the TRM.

The TRM follows closely the language set forth in section 7(b)(1) of the Northwest Power Act. Section 7(b)(1) states that the Administrator shall establish "a rate or rates" that are to apply to meet the *general requirements* of BPA's public body, cooperative, and Federal agency customers. Since it uses the plural form "rates," this rate directive clearly permits BPA to establish more than one section 7(b) (PF) rate, 16 U.S.C. § 839e(b)(1), and clearly demonstrates

⁵ For this reason, Clatskanie's contention that BPA has improperly inserted the word "future" into the Northwest Power Act is groundless. The simple fact is that load which does not exist cannot be served. Moreover, Congress did not preserve a superior price treatment for any CF/CT load whether it presently exists and is being served or it comes into existence at a later date. Clatskanie's arguments on this point are also addressed in greater detail in Issue 2.1.1.3.

that Congress expressly allowed BPA to determine the number of 7(b) rates that would be applicable to 5(b) sales. BPA enjoys substantial discretion as to how it designs rates to recover costs appropriately allocated to a rate pool, in this case the PF rate pool. 16 U.S.C. § 839e(e); *City of Seattle v. Johnson*, 813 F.2d 1364, 1367 (9th Cir. 1987); *Central Lincoln People's Utility District v. Johnson*, 735 F.2d 1101, 1121-1122 (9th Cir. 1984) (*Central Lincoln II*).

Section 3(10) permits BPA to add replacement resources to the Federal base system. Section 7(b) permits BPA to recover (in such rate or rates) the cost of additional power needed to supply sales of power to meet the general requirements of BPA's public body, cooperative, and Federal agency customers that exceed the Federal Base System resources. As such, unrealized, nonexistent CF/CT load that comes on line after FY 2010 will be viewed the same as the other general requirements load growth of any public utility customer. There is no pricing treatment of load that has been determined to be CF/CT that would be contrary to section 7(b)(1), because the TRM is establishing only the method of calculating 7(b) PF rates that will be of general application to sales of general requirements power made under contracts offered by BPA pursuant to section 5(b).

Second, the price signals that will result from the TRM are intended to inform the local utility of the wholesale power costs incurred by BPA in supplying power needed by the utility to serve its load so the utility may make informed decisions to structure its resource acquisitions over the next 20 years. These wholesale rates will not impose any limitation on the utility to set its retail rates in a manner that either subsidizes a consumer's future CF/CT load or equitably allocates costs among all retail consumers that are served by the utility with power bought at the wholesale level as general requirements load. *See* H.R. Rep. No. 96-976, Part I, 96th Cong. 2d Sess., 44 (1980) ("[i]t will remain possible . . . for a public utility to subsidize industry with lower-cost residential power.") Under the TRM, the Tier 2 rates are rates of general application, and any Federal power that is supplied to serve a customer's general requirements load, irrespective of it being CF/CT load or non-CF/CT load, that is above the customer's RHWL will be sold at a Tier 2 rate.

The cost signals BPA provides its utility customers through BPA's wholesale power rates may or may not, in turn, be mirrored in the retail rates the local utility applies to retail power sold to any CF/CT load it serves. BPA's utility customers establish their own retail rates and may choose to meld, flatten, or reduce the rates applicable to any segment of their retail loads in any manner they deem reasonable. As such, the retail utility's actions may dampen the effects of the wholesale rate level and design at which they buy from BPA or any other wholesale power supplier.

ICNU argues that tiered rates violate the Northwest Power Act because they eliminate the rate protections for future CF/CT loads. ICNU Br., BP-12-B-IN-01, at 13. An examination of the Northwest Power Act reveals several rate protections for general requirements, but no special rate protections for CF/CT loads. General requirements get rate protections in the form of a specific allocation of costs pursuant to section 7(b)(1), first Federal base system resource costs, then section 5(c) resource costs, then new resource costs. 16 U.S.C. § 839e(b)(1). Section 7(b)(2) provides a rate protection to general requirements in the form of a rate ceiling.

16 U.S.C. § 839e(b)(2). Section 7(b)(3) specifies that the costs not recoverable from public agency customers shall be recovered from power sales other than general requirements.

16 U.S.C. § 839e(b)(3). Section 7(b)(4) assures that the costs of serving NLSLs will not be included in the 7(b) rates. 16 U.S.C. § 839e(b)(4).

Tiered rates are consistent with all of these rate protections. The PF rate, including Tier 1 and Tier 2 rates, is determined based on allocations of Federal base system resource and section 5(c) resource costs. The PF rate is reduced to the rate ceiling pursuant to section 7(b)(2). No surcharge pursuant to section 7(b)(3) is included in the PF rate. The PF rate is applicable solely to general requirements; NLSLs are not eligible to purchase at the PF rate, nor is any cost of serving an NLSL included in the PF rate.

Next, GP states, without citation, that there is a “notion embedded in the [Northwest Power Act] of preservation of an existing cost structure . . .” GP Br., BP-12-B-GP-01, at 4. GP attempts to shore up this argument by reiterating that this “notion” is “represented by the prerequisites for CF/CT [l]oad,” namely, that the utility has “committed to serve the load, and that the utility has requested BPA to reserve capacity to serve the load.” GP Br. Ex., BP-12-R-GP-01, at 2. This commitment and request merely assures the CF/CT load of service as part of a preference customer’s “general requirements” that the preference customer may place upon BPA. BPA has never claimed otherwise. However, the commitment and request do not address price and certainly do not provide any assurance or right to the “lowest” possible rate. GP also errs by asserting “some historical right to the [F]ederal hydro system.” This assertion is misplaced. Nowhere in sections 3(13) or 7 of the Northwest Power Act is there mention of the Federal hydro system. Section 7(b)(1) directs that the basis for the rates applicable to general requirements and, hence, CF/CT loads is the Federal base system. As directed by section 7(b)(1), BPA has structured the entire PF rate, including the Tier 2 rate, using all of the available Federal base system prior to including any section 5(c) resources. 16 U.S.C. § 839e(b)(1).

The implication of GP’s argument is that the word “melded” has the same meaning as the word “uniform.”⁶ See GP Br., BP-12-B-GP-01, at 3-5, 20. It does not, and BPA will not read into the Northwest Power Act words that are not there. For one thing, “uniform” is a vestige of when BPA’s power and transmission rates were combined, and Congress was directing that customers whose loads were distant from the source of Federal generation would pay the same or “uniform” cost for the transmission of Federal power as those that were closer to the generation. See Bonneville Project Act, section 6, 16 U.S.C. § 832e. However, as applied to rates for the sale of power, the language in section 7(b)(1) contains the words “rate or rates of general application.” 16 U.S.C. § 839e(b)(1). Section 7(b)(1) does not contain the word “uniform,”

⁶ In its brief on exceptions, GP appears to retreat from this argument by contending there is a “misunderstanding” on BPA’s part as to what GP argues. GP Br. Ex., BP-12-R-GP-01, at 2. There is no misunderstanding. GP argues in its initial brief: “[t]he concept of CF/CT [l]oad was developed to preserve that opportunity for melded rates that blended the costs of the Federal hydro system and the other resources in the Federal base system.” GP Br., BP-12-B-GP-01, at 3. GP continues: “[t]his ensures that CF/CT [l]oad has access to power at the embedded cost of the Federal hydrosystem, and is not required to be served at the incremental cost of the new resources that BPA might be required to procure in the future.” *Id.* at 4. GP has not withdrawn this argument. Accordingly, BPA’s above response addresses and disposes of it.

although that does not preclude each of the “rates” established pursuant to section 7(b)(1) from being uniform. In section 7(e), Congress stated that nothing in section 7 prohibits the Administrator from establishing, in rate schedules of general application, “a uniform rate or rates ... or other rate forms.” 16 U.S.C. § 839e(e). Uniform in this context means that rate designs or rate forms for peaking capacity should be applied to those customers that purchase power from BPA under rate schedules of general application. It further uses the word “or” in a manner which the list should be read as a non-exclusive listing of “other rate forms.” *Id.* Tiered rates, as in the BP-12 rates, are consistent with this direction.

While BPA has historically used a melded rate design, section 7(e) is clear that BPA is not precluded from adopting a different rate design. Tiered rates provide BPA with a rate design that will further the long-term interest of the region as a whole. In the Regional Dialogue Policy, BPA set forth the policy goals and objectives furthered by a tiered rate structure:

Promotion of Regional Electric Infrastructure: Adequate infrastructure development is essential to ensuring a reliable future power supply and to avoiding excessive market price volatility such as occurred during the West Coast energy crisis of 2000–2001. Although the region is not currently short of generation resources, new resource development requires long lead times. While public utilities and resource developers are motivated and able to develop new power resources, they need certainty about how much low-cost power each utility can purchase from BPA in the long term and how BPA will price its power. Defining the amount of power each customer is eligible to purchase from BPA at the lowest-cost Tier 1 rate (the HWM) will allow utilities to move forward with plans to meet their additional or new load by developing their own resources or purchasing additional power from BPA at a potentially higher Tier 2 rate.

* * * *

Low and Stable BPA Tier 1 Power Rates: Low power rates are one of BPA’s most important contributions to the regional economy. The Policy will help to keep BPA’s Tier 1 rate low and stable by greatly reducing the amount of augmentation cost included as part of a Tier 1 rate. Historically, these augmentation costs have been one of the largest drivers of BPA rate increases.

* * * *

Enhanced BPA Financial Stability and Assurance of Treasury Payments: A low and stable Tier 1 rate created by a major reduction in BPA’s past practice of acquiring new power and melding its costs with those of the existing system will greatly reduce the financial uncertainty that occurred when BPA rates rose above wholesale market prices. This rate stability should significantly reduce future risks to BPA’s ability to make its Treasury payments. Long-term take-or-pay commitments from customers will add further assurance that BPA will make those payments in full and on time, as will largely relieving BPA of the obligation to acquire power to replace reductions in existing system output at melded rates.

Regional Dialogue Policy at 5-6. GP’s argument that BPA is constrained from altering its historical practice of melding the costs of resources when setting rates ignores the fact that a tiered rate structure is not only consistent with BPA’s statutory authority but is in the long-term interest of the region. Fostering resource development, ensuring BPA rates are low and stable, and enhancing BPA’s financial stability are all furthered through the transition to tiered rates. Effective and efficient price signals also further the positive economic goal of ensuring that customers better understand the true cost of their actions. This, in turn, induces customers to conserve power. The intent of Congress that BPA’s customers understand the true cost of serving load growth is evident in section 7(j): “All rate schedules adopted ... by the Administrator pursuant to this section shall indicate ... (2) *the cost of resources acquired to meet load growth* within the region and the relation of such cost to the average cost of resources available to the Administrator.” 16 U.S.C. § 839e(j) (emphasis added). BPA is not limited from establishing a rate design that promotes the purposes of the Northwest Power Act and serves the important public policy interests identified above.

On the contrary, this conclusion is reinforced by and consistent with section 7(e) of the Northwest Power Act, 16 U.S.C. § 839e(e). Section 7(e) is a savings clause which clarifies that the rate provisions of the Act should not be construed to prohibit BPA from establishing various rate forms or designs: “[n]othing in this chapter prohibits the Administrator from establishing, in rate schedules of general application, a uniform rate or rates for sale of peaking capacity or from establishing time-of-day, seasonal rates, or *other rate forms*.” 16 U.S.C. § 839e(e) (emphasis added). The legislative history of section 7(e) expresses Congress’s recognition that the rate directives expressed in section 7(b)(1) and other sections of the Northwest Power Act:

only govern the amount of money BPA is to collect from each class of customer *and not the form of the rate used to collect that sum of money*. For example, time-of-day rates, seasonal rates, *rate structures designed to give BPA customers particular price signals*, and other rate forms *would be permissible*.

H.R. Rep. No. 96-976, Part I, 96th Cong., 2d Sess., 69 (1980) (emphasis added).

It is true that while the Northwest Power Act was being considered by Congress, discussion occurred about whether BPA should be mandated to implement a two-tier rate structure. At the same time, Congress chose not to include express language in the Northwest Power Act that would have required a particular rate design. The Ninth Circuit explained that, instead, the legislative history “shows only that Congress rejected a ‘multi-tier pricing’ amendment that would have *mandated* direct assignment of the cost of new energy sources to certain customer classes.” *Central Lincoln II*, 735 F.2d at 1122 (emphasis added), *citing* 126 Cong. Rec. H10, 526-527 (daily ed. Nov. 12, 1980), reprinted in BPA Legislative History at 171-172. Significantly, the Court went on to note that:

.... *the Act specifically allows the Administrator latitude in choosing rate forms*. See 16 U.S.C. § 839e(e). Because a main purpose of the Act is to encourage conservation and efficiency, 16 U.S.C. § 839(1), the Administrator is given discretion to achieve these purposes through rate design. That the Act specifies certain methods of conservation cannot reasonably be read to prohibit other conservation measures. Indeed, the House Interior Committee comments on 16

U.S.C. § 839e(e) specifically state that *the statute permits rate forms “designed to give BPA customers price signals,”* such as the LRIC. House Report, Part II, *supra*, at 53.

Id. (emphasis added).

In rejecting a mandatory tiered rates structure, Congress did not prohibit such a structure. Lacking clear direction from Congress as to the structure of BPA’s rates, it must be concluded that Congress left such determination to the discretion of the Administrator. *See also Central Electric Power Cooperative, Inc., et al., v. Southeastern Power Administration, et al.*, 338 F.3d 333, 337 (4th Cir. 2003), *quoting Town of Norwood v. FERC*, 962 F.2d 20, 22 (D.C. Cir. 1992) (“since ‘issues of rate design are fairly technical and, insofar as they are not technical, involve policy judgments that lie at the core of the regulatory mission,’ [Southeastern Power Administration] enjoys considerable discretion in determining how to structure the recovery of such costs.”). Southeastern Power Administration is a power marketing agency in the Department of Energy, as is BPA.

Moreover, the legislative history GP cites does little to advance its argument. The Ninth Circuit has held that it will not read into the Northwest Power Act statutory prohibitions that constrain the Administrator’s discretion based merely on inference. For instance, with respect to BPA’s Intertie Access Policy, the Court found that “Congress has never disapproved a policy allocating Intertie access on a pro rata basis despite being aware that BPA contemplated such a policy even before the Intertie was constructed. . . . In outlining this history we do not mean to suggest that Congress has approved the Formula Allocation. This history does indicate, however, that Congress has not prohibited such a policy and that it is within BPA’s discretion to adopt a pro rata allocation scheme.” *California Energy Comm’n v. Bonneville Power Administration*, 909 F.2d 1298, 1311, n.12 (9th Cir. 1990) (*CEC*). This ruling contradicts GP’s notion that BPA is required to have melded cost 7(b) rates that apply to sales under section 5(b) of the Northwest Power Act.

BPA also notes that in BPA’s first rate case record of decision following enactment of the Northwest Power Act, BPA considered adopting the rate design alternative of tiered rates. *See* 1981 Wholesale Power Rate ROD (June 1981), at III-5 to III-7. BPA did not adopt tiered rates due to uncertainty as to whether tiered rates could promote conservation or provide rate relief to low-income groups. There is no hint in the June 1981 ROD that there was any uncertainty that BPA would have been precluded by the newly enacted Northwest Power Act from adopting such rates.

GP argues that by designating load as CF/CT load, this ensures that BPA has preserved a portion of its existing resource base to serve the future requirements of the CF/CT load. GP Br., BP-12-B-GP-01, at 3. This is a complete misstatement of the intent of CF/CT designation. There are currently almost 1,000 aMW of unused CF/CT load in the region. Wolverton, BP-12-E-IN-03, at 19 (1,013.16 aMW) and 25 (970.01 aMW with corrections applied). The idea that BPA has stored almost 1,000 aMW of Federal base system resources awaiting the day for a future CF/CT load to appear is without merit (and likely illegal) due to the economic waste that would be involved.

Section 7(b)(1) requires that BPA “recover the costs of that portion of the Federal base system resources needed to supply such loads *until such sales exceed* the Federal base system resources.” 16 U.S.C. § 839e(b)(1) (emphasis added). Then, and only then, may BPA “recover the cost of additional electric power as needed to supply such loads.” *Id.* BPA allocates the costs of about 7,500 aMW of Federal base system costs and about 5,000 aMW of section 5(c) resource costs to the 7(b)(1) loads. PRS Documentation, BP-12-FS-BPA-01A, at 29, lines 30 and 35. If BPA were required to set aside almost 1,000 aMW of Federal base system resources for future CF/CT loads, this would require BPA to reduce the Federal base system costs from 7,500 aMW to 6,500 aMW, increase the 5(c) costs from 5,000 aMW to 5,300 aMW, and add new resource costs of 700 aMW. Doing so would mean that BPA would be allocating an extra 1,000 aMW of section 5(c) resource costs when the 7(b)(1) loads exceeded the Federal base system by only 5,000 aMW, in direct contravention of section 7(b)(1).

Rather than preserving Federal base system resources, the CF/CT determination only grants future loads access to the 7(b)(1) rate pool. By gaining access to the 7(b)(1) rate pool, the future CF/CT load is assured of access to BPA’s PF rate. Given the circumstances stated above, if 1,000 aMW of new CF/CT load appeared in FY 2012, the Federal base system might expand to 8,500 aMW with the 5(c) resource contribution remaining at 5,000 aMW. Or the Federal base system resource might stay at 7,500 aMW, with the 5(c) resources rising to the full 5,300 aMW, and then 700 aMW of new resources would be assigned to the 7(b)(1) rate pool. In neither case is 1,000 aMW of Federal base system resources “preserved” (as GP argues) to serve the potential that CF/CT might become actual load at some point in the future.

GP goes on to argue that the law “ensures CF/CT Load has access to power at the embedded cost of the Federal hydro system.” GP Br., BP-12-B-GP-01, at 4. However, that is not what the statute says. By allowing the CF/CT load to be treated as general requirements, section 7(b)(1) allows the inclusion of CF/CT load access to the 7(b)(1) rate pool, whereby its rates are to be first based on “the costs of that portion of the Federal base system resources needed to supply such loads until such sales exceed the Federal base system resources,” and then “the cost of additional electric power as needed to supply such loads.” 16 U.S.C. § 839e(b)(1). Thus, the notion that CF/CT load has any sort of priority access to the generation of the Federal system is simply not the law.

GP suggests that “if CF/CT were served at a rate higher than other Preference load, it would render the original concept of CF/CT utterly moot.” GP Br., BP-12-B-GP-01, at 4. However, GP’s suggestion, that CF/CT is being treated differently from other general requirements, is simply not the case under tiered rates. First, existing CF/CT load is considered in the general requirements that are granted the right to purchase at Tier 1 rates. Second, future CF/CT load, should it ever occur, would be considered in the general requirements; that is, granted the right to purchase at either Tier 1 or Tier 2 rates, depending upon the utility’s circumstances, which are section 7(b)(1) rates. There is no distinction between future CF/CT loads and other future general requirements. They are both treated in the same manner. This treatment is consistent with section 7(b), granting all existing and future load access to section 7(b)(1) rates. The fact

that such rates are tiered is a matter of rate design, not one of resource cost allocation in violation of section 7(b)(1).

Next, GP appeals to the Section-by-Section Analysis of the Northwest Power Act. Legislative History of the Pacific Northwest Power Planning and Conservation Act, at 34-65. Specifically, GP refers to this analysis, which says “[u]nder Section 7(b), BPA is obligated to sell power at its lowest rate—the “regional rate”—to preference customers to meet their general requirements, i.e., their net requirements exclusive of power to serve new single large loads.” *Id.* at 77. GP and ICNU both point to different portions of the House Interior Committee Report on the Northwest Power Act as more evidence that Congress established the right of CF/CT to the “lowest rate.” GP Br., BP-12-B-GP-01, at 5, *citing* H.R. Rep. No. 96-976, Pt. II, 96th Cong., 2nd Sess. 36 (1980); ICNU Br., BP-12-B-IN-01, at 16, *citing* H.R. Rep. No. 96-976, Pt. II, 96th Cong., 2nd Sess. 36, 52 (1980). Nevertheless, these cites do not support the claims of GP and ICNU.

First, the Section Analysis clearly states that “[t]his analysis paraphrases the Act and incorporates material from the accompanying reports. It is not a definitive statement of law.” Legislative History at 1, n.1. In addition, the Section Analysis elsewhere states that “[s]ection 7(e) clarifies that BPA may establish a uniform rate for the sale of peaking capacity, and that the Act’s rate directives govern the amount of revenue BPA must collect from each customer class, not the rate form (e.g., time-differentiated rates remain valid).” *Id.* at 92. The House Interior report clarifies that its discussion of “lowest rate” in section 7(b)(1) “govern[s] the amount of money BPA is to collect from each class of customer and not the form of the rate used to collect that sum of money.” H.R. Rep. No. 96-976, Pt. II, 96th Cong., 2nd Sess. 36, 53 (1980). Thus, Congress allowed BPA to continue to set the rates under section 7(b)(1) in a manner that allowed “time-of-day rates, seasonal rates, *rate structures designed to give BPA customers particular price signals*, and other rate forms...” *Id.* (emphasis added). Tiered rates have been designed in a way that does not violate section 7(b)(1) but sends appropriate price signals to BPA’s public body customers.

Taken to its logical conclusion, the GP, ICNU, and Clatskanie position would allow only one PF rate structure, “the lowest rate.” Any PF rate that was greater than “the lowest rate” would not be allowed. Under such thinking, BPA’s longstanding use of seasonal or monthly rates, time-differentiated rates, product-specific rates (such as Slice and Load Following rates) would not be allowable because some of the specific rates exceeded “the lowest rate.” Thus, these arguments strike at the very heart of BPA’s rate design discretion, the ability to set rates appropriate to the type of product being purchased, the time the power is purchased, or the amount of power being purchased. Such rate design restrictions were clearly not the intent of Congress when it considered the Northwest Power Act.

Clatskanie disagrees with this portion of BPA’s Draft ROD, and takes a very different interpretation of congressional intent. Clatskanie Br. Ex., BP-12-R-CK-01, at 7-8. However, this two-page portion of Clatskanie’s argument contains not a single citation to support its assertions (save for one cite to a general, hornbook principle regarding the purpose of statutory construction). *Id.* Despite Clatskanie’s misplaced argument, Congress’s purpose is as BPA has

thoroughly described above, and throughout this section 2.1.1 of the ROD. Namely, Congress did not provide the “lowest rate” and price protection that Clatskanie seeks.

GP takes exception with Staff’s position that the only purpose of the CF/CT designation is to distinguish it from an NLSL. GP Br., BP-12-B-GP-01, at 5. If there were another purpose, one would expect to find other references in the Northwest Power Act to CF/CT other than in the definition of “New Large Single Load.” 16 U.S.C. § 839a(13). However, this is the *only* mention in the statute. Thus, the purpose of the designation is to assure the utility that should such load occur, it would not be considered an NLSL but would be a part of the utility’s general requirements load. Once established as a general requirements load, it would be charged the 7(b)(1) PF rate. The fact that the PF rate is now tiered does not alter the fact that CF/CT load has to be charged the PF rate. BPA is not proposing to treat the CF/CT load, should it ever occur, as an NLSL and charge it the NR rate.

GP further questions why BPA would create CF/CT designations in an amount less than 10 aMW if the sole purpose of CF/CT is to distinguish such load from NLSL. GP Br., BP-12-B-GP-01, at 5. GP states that if the Staff contention were true, then there would be no need for CF/CT designations less than 10 aMW. *Id.* But GP misses an important aspect in making this connection. CF/CT designations less than 10 aMW still retain value to the utility. For example, suppose that a utility has a consumer industrial operation with a CF/CT designation of 6 aMW and the consumer decides to expand its facility and increase its load by 13 aMW. If the utility does not have any CF/CT designation, the entire expansion would be exposed to a potential NLSL determination. However, because the utility has a 6 aMW CF/CT attributable to this consumer, the first 6 aMW of expansion is shielded from an NLSL determination, thereby subjecting only the remaining 7 aMW to a potential NLSL determination. Thus, CF/CT designations of less than 10 aMW are potentially important to the utility. This provides no rationale for GP to attempt to expand the rights granted pursuant to a CF/CT determination.

Finally, ICNU maintains that “the right to service as a CF/CT load is guaranteed to *both* the industrial load and the preference utility customer.” ICNU Br., BP-12-B-IN-01, at 16 (emphasis in original). ICNU bases this on a BPA statement that, once a CF/CT determination is made, the utility and its load are given assurance that BPA service within the CF/CT amount will be subject to the then-effective PF rate. *Id.* ICNU appears to misunderstand the definition of New Large Single Load.

The definition of New Large Single Load in section 3(13) of the Northwest Power serves to differentiate between large load that is served by a BPA customer (*i.e.*, CF/CT compared to NLSL). This differentiation is made for purposes of applying either the PF rate or the NR rate to power BPA sells to its wholesale power customers that serve either a CF/CT load or an NLSL. End-use consumers, whether or not industries, do not hold CF/CT determinations. Indeed, ICNU acknowledges that the “CF/CT determination is requested by and *provided to* the preference utility” *Id.* (emphasis added). The determination is used merely for billing purposes under BPA’s power sales contracts with those utility customers that serve CF/CT load. By knowing the amount of a customer’s load that is CF/CT load, BPA can then apply the applicable rate and bill accordingly.

BPA does not dispute the fact that the determination may be important to the industry. However, BPA does not know how or in what manner utility customers will subsequently recover their power costs from their retail ratepayers, including a CF/CT load. The ability to avoid the NR rate for industrial load growth should be of particular value. However, there is no merit to ICNU's contention that the value is linked solely to the PF Tier 1 rate. ICNU Br., BP-12-B-IN-01, at 19-20. To the contrary, the determination of load as CF/CT brings with it the benefit of the PF rate. There remains considerable value even if the load would be charged a PF Tier 2 rate. As explained in Issue 2.1.1.3 below, Tier 2 rates and NR rates are not the same.

Tier 2 rates are a part of the 7(b)(1) PF rate, just as Tier 1 rates are. The PF rate is allocated the costs of first the FBS, then section 5(c) resources, and then, as needed, new resources. Further, the PF rate, in its entirety, is eligible for section 7(b)(2) rate protection. In contrast, additional large load being served by a public utility without CF/CT status would likely be determined to be an NLSL and subject to the NR rate. The NR rate is allocated FBS or section 5(c) resource costs only if such resources are surplus to the needs of the section 7(b) rate pool. If there are no surplus Federal base system resources, then the NR rate will be allocated the costs of section 5(c) and new resources. (Currently, 7(b)(1) loads are greater than 12,000 aMW and the Federal base system is about 7,000 aMW; the likelihood of surplus Federal base system being allocated to the NR rate at any point in the future is non-existent. *See* Power Rates Study, BP-12-FS-BPA-01A, at 29). Further, section 7(b)(3) exposes the NR rate to paying for a portion of the rate protection afforded preference customers through the application of section 7(b)(2). For example, the section 7(b)(3) rate surcharge for the NR-12 rate is \$7.73 per megawatt-hour. Thus, even if the resource costs incurred by BPA to serve an Above-RHWM Load and an NLSL were identical (in this case, the Tier 2 rate is considerably below the cost of new resources), the rates for the two loads would still be distinctly different.

Decision

BPA's treatment of CF/CT load complies with all applicable laws, and there is no requirement that CF/CT load must be served at BPA's "lowest" preference rate.

Issue 2.1.1.3

Whether BPA is charging CF/CT loads a Tier 2 rate based only on the marginal, market cost of power and thereby impermissibly treating CF/CT loads the same as NLSLs.

Parties' Positions

ICNU argues that "BPA essentially treats Future CF/CT Loads no better than NLSLs ..." and that "BPA does not have the legal authority to charge preference customers with CF/CT loads at rates primarily based on the costs of new resources as Tier 2 rates are under BPA's TRM." ICNU Br., BP-12-B-IN-01, at 14. ICNU contends that service at Tier 2 rates does not give CF/CT loads access to BPA's lowest-cost resources but, rather, "is similar to the NR rate

because the resource component of the NR and Tier 2 rates are based on the same market sources.” ICNU Br., BP-12-B-IN-01, at 15.

ICNU states that “[c]harging Future CF/CT Loads a rate that does not include any of BPA’s lowest cost resources and is instead based on the costs of only market resources defeats the reason for establishing a distinction between CF/CT and NLSL loads.” ICNU Br., BP-12-B-IN-01, at 17. ICNU states that the Tier 2 rate “will be based on the same underlying resources costs as the NR rate ...” and “[t]his impermissibly treats most CF/CT loads essentially the same as NLSLs prior to Section 7(b)(3) surcharges, and practically eliminates the statutory rate protections CF/CT loads were provided in the Northwest Power Act.” *Id.*

ICNU contends Tier 2 rates “do not benefit from the existing low-cost resources in the Federal Base System because Tier 2 loads are served with market priced resources.” *Id.* at 19. ICNU states that “[w]hile it is correct that Tier 2 rates are based on specific resources costs, these are priced at the market. Thus, the Tier 2 rates are essentially market rates” *Id.* ICNU bases its conclusions “on the fact that there are no Tier 1 Generation surplus resources to serve any Tier 2 or NR loads” and “[a]ny excess Tier 1 system firm resources are priced at market levels for crediting back to Tier 1 costs, and are not used to lower the NR or Tier 2 rates.” *Id.* at 20. Therefore, ICNU concludes, “because there is no cost based generation in BPA’s own resources to serve Tier 2 and NR loads, then it follows that any substantial additional loads must be served with market purchases.” *Id.*

Similarly, GP states that a CF/CT load that comes on-line in the future will suffer financial harm from being served at Tier 2 rates because the costs of such rates “would be driven by current market conditions and generally would be higher than the embedded costs of the Federal hydro system.” GP Br., BP-12-B-GP-01, at 6. GP estimates this harm to be “\$3.5 million more a year in additional electric costs to serve a 35 MW expansion at Tier 2 as opposed to Tier 1 rates.” *Id.* GP notes that BPA’s rebuttal testimony points out that Clatskanie PUD has elected to serve any load growth during the FY 2012 rate period from other resources, rather than from BPA under Tier 2 rates. *Id.* at 7. Regardless of that fact, GP states it is still harmed “because any additional load will not be served at Tier 1 rates, but at the significantly increased rates of either Tier 2 or market-based procurement.” *Id.*

ICNU proposes that BPA should revise its rates to ensure that future CF/CT loads are not charged a rate that excludes all BPA’s low-cost Federal Base System resources and is not based on the same costs as the NR rate. *Id.* ICNU argues that “[c]harging Future CF/CT Loads a Tier 2 rate based on only the marginal, market cost of power is directly contradictory to the Northwest Power Act because these loads were specifically protected, and eliminates any practical benefits for any CF/CT that increases service in the future.” *Id.* at 20-21.

Clatskanie adopts GP and ICNU’s arguments on this issue. Clatskanie Br. Ex., BP-12-R-CK-01, at 5, 6-7. Clatskanie believes the CF/CT-related problem with BPA’s tiered rate approach “is that BPA has inserted into the Act the word ‘future.’ The end result is that BPA’s treatment of a [p]reference [c]ustomer’s CF/CT loads may, in the future, bear absolutely no relationship to BPA’s treatment of the same [p]reference [c]ustomer’s general requirements.” *Id.* at 5. In a

related theory, Clatskanie states that “BPA is treating new CF/CT loads like NLSL by subjecting them to market risk.” *Id.* at 6 (paragraph heading). Clatskanie argues this is improper because “Congress could have allowed BPA to serve such CF/CT loads at the incremental cost of the additional power [that Clatskanie assumes would be needed to serve CF/CT as it comes into existence and online], just as BPA does for NLSLs. This would have imposed the market-risk for such power squarely on the consumer. Alternatively, Congress could have taken steps to protect CF/CT loads from such market risks by directing BPA to serve them, when they arise, at a melded rate on the same basis that BPA serves each Preference Customer’s general requirements.” *Id.* at 7. Clatskanie believes Congress chose the latter.

BPA Staff’s Position

BPA Staff explains that a CF/CT determination “allows certain consumer loads that meet specific statutory requirements to avoid being designated as an NLSL.” Bliven and Cherry, BP-12-E-BPA-36, at 10. If the consumer load is determined by BPA to be CF/CT load, it would be included in the utility’s general requirement and would be eligible for service at a 7(b)(1) rate. *Id.* at 11. Thus, the CF/CT determination allows any increase in the consumer load to be treated exactly as any other non-NLSL load growth of the utility—that is, not subject to NLSL treatment. *Id.* Staff contends that both GP and ICNU make the same mistake: equating the resources defining the amount of power available at Tier 1 rates to the Federal base system. *Id.* at 13. Staff shows that Tier 2 rates are based on allocations of Federal base system resources and that the NR rate for NLSLs is based on new resources. *Id.* at 15.

Evaluation of Positions

ICNU and GP (and therefore Clatskanie too, since it adopts their arguments) are incorrect on a number of key factual points. In addition to these errors, their underlying arguments lack merit. This discussion will correct the misconceptions first, and then address the arguments.

First, GP and ICNU misstate BPA’s rate proposal. Both GP and ICNU mistakenly equate the resources defining the amount of power available at Tier 1 rates to the Federal base system. Bliven and Cherry, BP-12-E-BPA-36, at 13. The two concepts are not the same, and the distinctions are important. *Id.*

The Federal base system is defined in section 3(10) of the Northwest Power Act:

“Federal base system resources” means—

- (A) the Federal Columbia River Power System hydroelectric projects;
- (B) resources acquired by the Administrator under long-term contracts in force on December 5, 1980; and
- (C) resources acquired by the Administrator in an amount necessary to replace reductions in capability of the resources referred to in subparagraphs (A) and (B) of this paragraph.

16 U.S.C. § 839a(10). In contrast, Tier 1 System Resources are defined in the TRM as “the Federal System Hydro Generation Resources listed in Table 3.1; the Designated Non-Federally

Owned Resources listed in Table 3.2; and the Designated BPA Contract Purchases listed in Table 3.3.” BP-12-A-03, at xxii.

The resources listed in the TRM tables include some, but not all, of the Federal base system resources as they are identified in the BP-12 Power Rates Study. Bliven and Cherry, BP-12-E-BPA-36, at 14. In addition, the resources included in the TRM tables include resources that have been identified in the PRS as new resources. *Id.*

These distinctions are important because, pursuant to the TRM, the resources that are included in Tier 1 System Resources are used to establish the maximum amount of load that will be served at Tier 1 rates for each rate period. *Id.* Unrelated to the amount of load served at these rates are the cost allocations directed by section 7 of the Northwest Power Act, in particular, section 7(b)(1). *Id.* Section 7(b)(1) states that:

The Administrator shall establish a rate or rates of general application for electric power sold to meet the general requirements of public body, cooperative, and Federal agency customers within the Pacific Northwest, and loads of electric utilities under section [5(c)]. Such rate or rates shall recover the costs of that portion of the Federal base system resources needed to supply such loads until such sales exceed the Federal base system resources. Thereafter, such rate or rates shall recover the cost of additional electric power as needed to supply such loads, first from the electric power acquired by the Administrator under section [5(c)] of this title and then from other resources.

BPA has designated the rates set pursuant to section 7(b)(1) as the Priority Firm Power rates. Bliven and Cherry, BP-12-E-BPA-36, at 15. The resource costs allocated to the PF rates, including both Tier 1 and Tier 2 rates, are a mix of Federal base system resources and section 5(c) exchange resources. *Id.* The Power Rates Study allocates no new resource costs to the PF rates. Power Rate Schedules, BP-12-A-02B, GRSP II.B. New resource costs are allocated to the IP, NR, and FPS rate classes, as are the remainder of the 5(c) exchange resource costs that are not allocated to the PF rates. *Id.*

Next, ICNU tries to link the FBS resources used to serve loads priced at the Tier 2 rate to resources used to serve loads priced at the NR rate. In doing so, ICNU confuses the distinction between resources in the FBS pool and resources in the new resources pool. Specifically, ICNU states “BPA is setting rates so that utility purchases for Future CF/CT Loads will be charged a rate based on the cost of market resources. This rate will be based on the same underlying resources costs as the NR rate that BPA would charge if it actually served any NLSLs.” ICNU Br., BP-12-B-IN-01, at 17.

ICNU’s statement is wrong. It confuses the resources used to establish the Tier 2 rates with resources assigned to the new resources pool. The costs of resources used to establish Tier 2 rates are Federal base system resources, not new resources. PRS Documentation, BP-12-FS-BPA-01A, Table 2.3.2, line 22. The resources used to establish the NR rate are a mix of 5(c) exchange resources and new resources. *Id.*, Table 2.5.8.4, line 21. As shown in the GRSPs, the NR rate is comprised of 67.58 percent exchange resources and 32.42 percent new resources.

Power Rate Schedules, BP-12-A-02B, GRSP II.B. The PF rates are comprised of 46.19 percent Federal base system resources and 53.81 percent exchange resources. *Id.* Underlying these resource cost contributions is a 100 percent assignment of Federal base system resource costs to the PF rate pool. *Id.* Exchange resource pool costs are assigned 94.14 percent to the PF rate pool, 4.6 percent to the IP rate pool, 1.25 percent to the FPS rate pool, and a minuscule amount to the NR rate. *Id.* New resource costs are assigned 78.60 percent to the IP rate pool, 21.40 percent to the FPS rate pool, and a minuscule amount to the NR rate pool. *Id.*

Although BPA's proposed Tier 2 rates are based on the cost of newer FBS resources, that does not mean that such rates will be the same as the NR rate, that the utility itself may not meld its costs in its retail rates, or that BPA's tiering of rates is an inappropriate pricing signal for load growth. BPA is not proposing to establish a different NR rate nor establish an NR rate that would apply to general requirements service. To the contrary, as defined in the TRM, the Tier 2 rates will be cost-based rates based on FBS resource costs.

ICNU and GP are also incorrect that the resources used to establish the NR rate are market resources.⁷ ICNU Br., BP-12-B-IN-01, at 18; Wolverton, BP-12-E-IN-01, at 19; GP Br., BP-12-B-GP-01, at 2, 6. There are no market purchases in either the exchange resource pool or the new resources resource pool. PRS Documentation, BP-12-FS-BPA-01A, Table 2.2.2.2, lines 63-82. Thus, there are no market purchase costs in the NR rate.

While BPA does not expect to supply power to customers serving loads subject to the NR rate, the presence or lack of NR rate loads does not have anything to do with the resource cost assignments. ICNU appears to believe that because there are no NR rate loads, there are likewise no resources in the new resources pool. Although the rate pool and the resource pool have similar names, the two are distinct concepts, and the size of the rate pool does not determine the size of the resources or vice versa.

ICNU and GP further presuppose that, if an NR rate load would be placed on BPA, the resource costs for that purchase would be based on market purchases. ICNU Br., BP-12-B-IN-01, at 19-20; GP Br., BP-12-B-GP-01, at 2, 6. It is impossible to draw such a conclusion at this time. Such a conclusion can be made only when and if NR load materializes by examining the full range of resource pool costs that BPA would establish when rates are set for such NR load.

In addition, as noted above, the Tier 2 rates are based on specific resource costs included in the Federal base system. PRS Documentation, BP-12-FS-BPA-01A, Table 2.2.2.1, at line 47. The NR rate is based on a mix of exchange resource costs and new resources costs. Power Rate Schedules, BP-12-A-02B, GRSP II.B. Staff included Table 1 in its rebuttal testimony to show the differences in treatment between how each resource (or grouping of resources) is used in constructing the power available to sell at Tier 1 and Tier 2 rates and how the costs of those resources are allocated pursuant to section 7(b)(1) of the Northwest Power Act. Bliven and

⁷ GP contends its initial brief did not specifically make an argument that likened the Tier 2 rate to the NR rate. GP Br. Ex., BP-12-R-GP-01, at 3. However, the argument in GP's initial brief relies directly on the testimony of ICNU's witness and upon the same logic that ICNU presents in its own initial brief. Thus, by now trying to distance itself from that argument, GP is merely splitting hairs.

Cherry, BP-12-E-BPA-36, at 34. As can be seen on this table, there is no necessary correlation between the treatment of any specific resource in constructing the rate tiers and in allocating the costs of the resource to the section 7 rate pools. *Id.*

Beyond the factual errors in ICNU, GP, and Clatskanie’s positions, the merits of their arguments suffer from several fatal flaws.

First, BPA does not serve or apply rates to unrealized, nonexistent load. BPA does not sell power to its utility customer to supply load that cannot consume power. It is therefore incorrect, as ICNU, GP, and Clatskanie contend, that a CF/CT determination made by BPA creates a present right to power or to receive only the lowest-cost PF rate for such unrealized, nonexistent load.⁸ As previously discussed, the CF/CT determination is used for billing purposes under BPA’s power sales contracts with those utility customers that serve CF/CT load. By knowing the amount of a customer’s load that is CF/CT load, BPA can then apply the applicable rate and bill accordingly. In addition, the CF/CT load amount also serves as a floor for measurement of increase in the consumer load. Should the power consumed by a CF/CT load exceed its CF/CT amount, then BPA would be able to determine whether such amount has triggered the application of NLSL.

In any case, CF/CT is not a promise of service, and any actual CF/CT load is simply treated as part of the utility customer’s general requirements load. Such actual load is served with BPA power sold at the applicable PF rates, and the CF/CT load gains no greater rights to service than the rest of the utility customer’s general requirements load. By treating the CF/CT load as part of a utility’s general requirements load, BPA will not be treating that load as an NLSL. As such, the CF/CT load will not constitute an amount of load of the utility that is served at the NR rate. *See* 16 U.S.C. § 839e(b)(4); H.R. Rep. No. 96-976, Part II, 96th Cong. 2d Sess., 52 (1980) (“Subsection 7(b)(4) defines ‘general requirements’ as power used by the relevant customers under section 5(b), exclusive of power used by the customer to serve any new large single loads.... This provision thus affects power rates only, not the amount of power supplied to the customer under section 5(b).”).

The TRM’s design is grounded on, and is consistent with, the Northwest Power Act, including its treatment of load of a utility that has been determined as “contracted for, or committed to” as still being part of the general requirements load met by the Administrator. 16 U.S.C. § 839a(13)(A). The amount of load that BPA determines is CF/CT and that is able to consume electricity is included in the amounts of customer load that BPA serves with general requirements power. *See* 16 U.S.C. § 839e(b)(4). For example, when establishing PF rates, BPA includes in its load forecast CF/CT load that is consuming electricity, along with all other general requirements loads of a customer, except for an NLSL. CF/CT load, whether currently operating or when realized in the future, will be included in the load that is served as the utility’s general requirements, and there is no difference between and among the load that is used for determining the amount of general requirements power BPA sells to its customers under section 5(b) and is

⁸ Clatskanie raises this contention through both its argument about the word “future” and its argument about market risk. Clatskanie Br. Ex., BP-12-R-CK-01, at 5, 6-7.

priced according to section 7(b) of the Northwest Power Act. Therefore, it will not be the case that CF/CT load, compared to other load served under general requirements, will be treated like an NLSL.

Second, as evaluated above in Issue 2.1.1.1, BPA has the authority to establish, pursuant to sections 7(b)(1) and 7(e) of the Northwest Power Act, more than one PF rate. Accordingly, BPA has the authority to tier the PF rate in accordance with section 7(b)(1), which results in more than one PF rate. The section 7(e) rate directive is clear that BPA is not required to establish a particular rate design, although the rates must recover BPA's total costs.

Third, nothing prohibits BPA from allocating, within the PF rate pool, the cost of additional power BPA is obligated to acquire to serve the general requirements of BPA's public body, cooperative, and Federal agency customers in order to better reflect cost causation and to send effective marginal cost price signals. Thus, the TRM provides for the establishment of tiered PF rates of general application, consistent with the express language of the statute. 16 U.S.C. § 839e(b)(1). In the original TRM proceeding Staff testified that if CF/CT load amounts actually increase after the utility customer begins taking power deliveries under the new contract, the PF tiered rate design proposed in the TRM would ensure that the proper PF rate is determined and applied. *Stene et al.*, TRM-12-E-BPA-18, at 4. In this BP-12 proceeding, BPA has determined the proper PF rate and applied it. That is, based on BPA's load forecast and the customer elections under the Regional Dialogue power sales contract, there are no power sales expected during the term of the BP-12 rate period for which a Tier 2 rate will apply to service to CF/CT load.

Finally, the rate treatment ICNU, GP, and Clatskanie are advocating boils down to an inequitable windfall. As BPA Staff noted in the original TRM proceeding, what ICNU, GP, and Clatskanie advocate would provide a superior rate treatment to the serving utility for CF/CT load than exists under current melded rates, since the costs of serving load growth will not be included in the Tier 1 rates. *Stene et al.*, TRM-12-E-BPA-18, at 6.

GP maintains the supposed rate protection to which it is entitled is not a superior rate treatment. GP Br. Ex., BP 12-R-GP-01, at 4. GP believes that "CF/CT [l]oad, having received a commitment to be served prior to September 1979, is entitled to be treated as all that other historical growth" that occurred prior to October 2010. *Id.* What GP refuses to acknowledge is the simple fact that load growth that occurred prior to October 2010 is *actual load that exists*. In contrast, CF/CT that does not exist is not entitled to an eternal placeholder right that somehow gives it access to BPA's "lowest" rate when no other BPA customer has such a right (let alone a customer's end-use consumer such as GP).

Decision

BPA will properly calculate, pursuant to sections 7(b)(1), 7(e), and 7(g) of the Northwest Power Act, the Tier 2 rate for general requirements service including CF/CT loads (where applicable), and BPA is not impermissibly treating CF/CT loads the same as NLSLs.

Issue 2.1.1.4

Whether BPA has placed an illegal time bar on CF/CT status.

Parties' Positions

GP suggests that the TRM required a CF/CT load to take service before October 2010, or else “lose rights it has under the CF/CT designation to receive power at the *lowest* Preference rate.” GP Br., BP-12-B-GP-01, at 7 (emphasis in original). GP states that the use of a deadline to set the Contract High Water Mark used in determining which loads can be served under Tier 1 is contrary to the Northwest Power Act and BPA policies because it eliminates the benefit created by Congress to preserve access for CF/CT load to rates based on the melded costs of the FBS. *Id.* at 8. Similarly, ICNU argues, the TRM will arbitrarily close out the class of customers eligible to place CF/CT loads on BPA by imposing a time bar on CF/CT status requiring all CF/CT loads “to obtain service by 2010 or be treated essentially the same as NLSLs.” ICNU Br., BP-12-B-IN-01, at 21. Clatskanie adopts GP and ICNU’s arguments on this issue and adds nothing new. Clatskanie Br. Ex., BP-12-R-CK-01, at 3-4.

BPA Staff's Position

This is a legal issue, which GP and ICNU raised for the first time in their briefs; therefore, BPA Staff has not taken a position on the issue.

Evaluation of Positions

ICNU correctly notes that BPA previously queried parties whether to administratively close out the CF/CT class by imposing a cut-off date. *See* New Large Single Load Policy Issue Review Administrator’s Record of Decision (March 2002) (NLSL Policy ROD). BPA concluded that section 3(13) of the Northwest Power Act does not grant BPA the discretion to take such administrative action and noted that the provision does not place a time bar on the CF/CT class. *Id.* at 14. However, it is not true that the TRM will result in any time limitation on a utility’s request of BPA to determine a load’s CF/CT status.

The application of section 3(13) of the Northwest Power Act will continue to be given effect during the term of the TRM and beyond, subject only to an act of Congress. As stated in the NLSL Policy ROD, once a load has been determined as CF/CT there is an assurance that BPA *will provide service* up to the CF/CT load amount at the then-effective PF rates. NLSL Policy ROD at 14. The TRM proposes no time limit on BPA’s determination of CF/CT loads under section 3(13). The Administrator’s determination of whether a load is a CF/CT load under that section of the Act remains as it has been. ICNU, GP, and Clatskanie are simply seeking a lower price.

ICNU, GP, and Clatskanie’s arguments on the so-called time bar are unfounded. CF/CT load is part of the utility customer’s general requirements load that is served with requirements power. The TRM does not preclude BPA’s utility customers from requesting a CF/CT load determination by BPA or preclude them from taking service at the PF rates applicable to such service. They are also not forced to make such requests by FY 2010. Whenever CF/CT load is

determined by BPA and served, it will be general requirements load that is served with power sold at the applicable PF rate, including its particular rate form or rate design.

Therefore, the TRM and the rates established thereunder do not establish any time bar. As GP acknowledges in its brief on exceptions, the parties' real issue is simply "*the rate* that will be utilized in making that service." GP Br. Ex., BP-12-R-GP-01, at 4 (emphasis added). As BPA has explained extensively in this ROD, CF/CT loads are not entitled to superior rate treatment at BPA's "lowest" rate. To do so would be superior to the rate treatment afforded to other future Above-RHWM loads.

Decision

The TRM and the rates set pursuant to it will not foreclose utilities from adding CF/CT load in the future.

Issue 2.1.1.5

Whether the TRM and the rates set pursuant to it result in a regulatory taking of GP's property rights for which GP must receive compensation.

Parties' Positions

GP alleges that the TRM "disregards the designation of certain loads as CF/CT Loads in determining Preference Customers' eligibility to purchase power at Tier 1 versus Tier 2 rates." GP Br., BP-12-B-GP-01, at 8. GP states that this is "an improper interference in GP's property rights for which BPA must compensate GP pursuant to the Takings Clause of the Fifth Amendment of the US Constitution."⁹ *Id.*

GP's claimed property right is its contract for electric service with Clatskanie PUD, under which it "is entitled to obtain service for its Wauna Mill up to its CF/CT Load level at rates derived from BPA's lowest Preference rate." *Id.* at 9. GP contends this property right has been devalued by BPA's proposed rates in this case because they result in higher energy costs that would reduce the incentive of GP to expand its operations at the Wauna Mill and undermine the value of the mill itself. *Id.*

BPA Staff's Position

Because this is a purely legal argument set forth in briefing, BPA Staff has not taken a position. BPA's legal position is set forth below.

⁹ GP makes this argument under the broader heading of "CF/CT CONSUMERS HAVE A LEGAL INTEREST WHICH IS HARMED BY THIS PROPOSED RATE." GP Br., BP-12-B-GP-01, at 8 (emphasis added). However, nowhere in the argument does GP address CF/CT "consumers" as a general group. Instead GP's argument is limited exclusively to GP's specific situation. *Id.* at 8–20. Moreover, GP is the only CF/CT consumer to advance this novel theory, and no other CF/CT consumers have joined or supported this section of GP's brief. Accordingly, this ROD addresses the argument solely with respect to the facts surrounding GP's situation.

Evaluation of Positions

The Takings Clause of the Fifth Amendment provides that “private property [shall not] be taken for public use, without just compensation.” U.S. Const. amend. V, cl. 4. It is “designed not to limit the governmental interference with property rights *per se*, but rather to secure *compensation* in the event of otherwise proper interference amounting to a taking.” *First English Evangelical Lutheran Church of Glendale v. County of Los Angeles*, 482 U.S. 304, 315 (1987) (emphasis in original). “The purpose of the takings clause is to prevent ‘Government from forcing some people alone to bear public burdens which, in all fairness and justice, should be borne by the public as a whole.’” *Air Pegasus of D.C., Inc. v. United States*, 424 F.3d 1206, 1212 (Fed. Cir. 2005) (quoting *Penn Cent. Transp. Co. v. City of New York*, 438 U.S. 104, 123 (1978)).

The Supreme Court has recognized two kinds of compensable takings: (1) actual takings, through the Government’s physical invasion or appropriation of private property, and (2) regulatory takings, through government regulations that unduly burden private property interests. See *Huntleigh USA Corp. v. United States*, 525 F.3d 1370, 1378 (Fed. Cir. 2008). GP alleges a regulatory taking. GP Br., BP-12-B-GP-01, at 8 (section heading).

To analyze GP’s regulatory taking claim, the law applies “a two-part test for determining whether ‘fairness and justice’ require compensation for burdens imposed by a particular governmental action.” *Huntleigh*, 525 F.3d at 1377. As the first step, the court must determine whether the claimant has established a legally cognizable property interest for purposes of the Fifth Amendment. *Id.*; *Vandevere v. Lloyd*, --F.3d--, 2001 WL 2675917, *4 (9th Cir. July 11, 2011). Second, after the court has identified a valid property interest, it must determine whether the government action at issue amounted to a compensable taking of that property interest. *Huntleigh*, 525 F.3d at 1378; *Am. Pelagic Fishing*, 379 F.3d at 1372; *Engquist v. Or. Dep’t of Ag.*, 478 F.3d 985, 1002 (9th Cir. 2007) (“We use a two-step analysis to determine whether a “taking” has occurred: first, we determine whether the subject matter is “property” within the meaning of the Fifth Amendment and, second, we establish whether there has been a taking of that property, for which compensation is due.”). However, if the claimant fails to demonstrate the existence of a legally cognizable property interest, the court does not proceed with this second step. *Air Pegasus*, 424 F.3d at 1213; *Vandevere*, 2001 WL 2675917, *4.

A. GP does not have a legally cognizable property interest that has suffered a taking as a result of the TRM or the rates promulgated thereunder.

Although contracts, leases, and other agreements may be considered property within the meaning of the Fifth Amendment, the Government’s appropriation of which may trigger the resulting obligation to pay just compensation, “not every exercise of governmental power that interferes with, or frustrates, performance of a contract constitutes a compensable taking.” *Kearney & Trecker Corp. v. United States*, 688 F.2d 780, 783 (Cl. Ct. 1982) (citing *Lynch v. United States*, 292 U.S. 571, 579 (1934) and *Omnia Commercial Co. v. United States*, 261 U.S. 502, 510-11 (1923)). To explain what constitutes a cognizable Fifth Amendment property interest, courts have distinguished between a plaintiff’s actual property and its “collateral interest.” See, e.g.,

Air Pegasus, 424 F.3d at 1215; *Mitchell Arms, Inc. v. United States*, 7 F.3d 212, 217 (Fed. Cir. 1993). “The Fifth Amendment concerns itself solely with the ‘property,’ *i.e.*, with the owner’s relation as such to the physical thing and not with the other collateral interests which may be incident to his ownership.” *Mitchell Arms*, 7 F.3d at 217 (*quoting United States v. General Motors Corp.*, 323 U.S. 373, 378 (1945)).

Here, GP alleges it has a “property right” in its contract for electric service with Clatskanie PUD. GP Br., BP-12-B-GP-01, at 10-11. First, GP contends the contract gives GP “a right to purchase power from Clatskanie PUD *based on* BPA’s lowest rate (*i.e.*, the 7(b) rate for Preference customers) up to the level of its CF/CT Load” GP Br., BP-12-B-GP-01, at 11 (emphasis added). But then GP goes further. Instead of arguing that its rates from Clatskanie must be “based on” BPA’s rates, GP flatly contends that its contract with Clatskanie “affords [GP] the contractual right to receive service *at BPA’s lowest possible rates....*” *Id.* at 12 (emphasis added). Without explanation, GP contends this right is derived from a letter BPA sent to Clatskanie designating the Wauna Mill as a CF/CT load. *Id.* In GP’s view, its Wauna Mill is therefore “entitled to receive service at Preference Customer rates pursuant to the CF/CT designation made by BPA itself.” *Id.* Thus, GP appears to believe that its power supply contract with Clatskanie, coupled with the letter from BPA to Clatskanie, somehow confers upon GP “a present property interest in its source of supply ... at BPA’s lowest possible rates....” *Id.* There are numerous reasons why this is not a legally cognizable property interest.

First and foremost, GP’s argument is completely unsupported by the plain language of GP’s contract with Clatskanie. The contract contains no language affording GP a right to receive service at BPA’s lowest possible rates. BPA-12-E-BPA-100. Instead, under the heading “Payment For Power Sold” the contract sets forth the various charges *Clatskanie* will assess to GP and makes clear those charges are to be “computed by application of *Clatskanie’s* ... Industrial Contract Rate Schedule....” *Id.* at 5 (emphasis added). Nowhere does the contract even mention BPA rates, much less the BPA rate for Preference Customers, much less the “lowest” possible BPA rate.¹⁰ It is clear from the plain language of the contract that GP is paying Clatskanie based solely on charges computed by Clatskanie pursuant to Clatskanie’s own rate schedule.¹¹

In fact, the contract even goes so far as to make clear that the price of power that Clatskanie acquires from BPA is “subject to change” and that Clatskanie’s obligations under the contract are “subject to” the conditions in its contracts with BPA. *Id.* at 9. Hence, the contract explicitly acknowledges that there is no way an agreement between GP and Clatskanie could lock in a particular price or dictate any terms of the relationship between Clatskanie and BPA.

¹⁰ The only mention of BPA in the payment section is to note that, if BPA charges Clatskanie a certain penalty as a result of the GP load, then that penalty will be included in the total monthly charges that Clatskanie assesses GP.

¹¹ Indeed, Clatskanie’s latest publicly available Annual Report directly confirms that Clatskanie has sole responsibility for determining GP’s rates. It states that Clatskanie “has the exclusive right and responsibility to determine rates and charges for services provided.” Clatskanie 2009 Annual Report, at 3, *available at* <http://www.clatskaniepud.com/Clatskanie%20Final%20audit2009.pdf>.

GP's response to BPA's examination of its contract is tellingly short. GP merely notes that there is a recital in the contract which indicates "the parties intend for Clatskanie to charge GP its actual costs of providing service" which, GP argues, would include the costs of power from BPA. GP Br. Ex., BP-12-R-GP-01, at 5. For one, this is a recital and not a binding substantive provision of the contract. More importantly though, the recital does not say what GP suggests. The recital speaks only to Clatskanie charging GP "actual costs," it says nothing about what such actual costs are, where they come from, or how Clatskanie might calculate them. And it makes no mention of BPA.

Shifting focus away from the contract, GP complains that BPA's Draft ROD ignored the testimony of GP's witness, Michael Tompkins, which stated that GP's bills from Clatskanie contain a pass-through of BPA's charges. GP Br. Ex., BP-12-R-GP-01, at 5-6. Regardless of Mr. Tompkins' personal interpretation or opinion of GP's contractual relationship with Clatskanie, he was not testifying on the legal matter of contract interpretation. Moreover, there is nothing in the contract to substantiate his claim of a "pass-through." Accordingly, BPA can only conclude that such testimony is made in GP's own self interest and is not convincing.

Essentially GP is now attempting to assert that GP and Clatskanie, through their own contract, could dictate terms (price in particular) of the relationship between Clatskanie and BPA. GP contends its contract with Clatskanie "affords [GP] the contractual right to receive service *at BPA's lowest possible rates....*" GP Br., BP-12-B-GP-01, at 12 (emphasis added). This is plainly incorrect and unsupported by the language of the GP/Clatskanie contract. GP's claimed property right simply does not exist.

Second, for a variety of reasons, Clatskanie cannot convey rights to GP on BPA's behalf. For one thing, BPA itself has no statutory authority to contract with a retail consumer such as GP. GP ignores this fact and suggests that some kind of statutory relationship exists between GP and BPA as a result of the fact that BPA wrote a letter designating GP's load as CF/CT. GP Br. Ex., BP-12-R-GP-01, at 5. A letter hardly amounts to an Act of Congress, and certainly does not create a statutory relationship between BPA and GP.

Even if Clatskanie could somehow convey rights on BPA's behalf (which it has no authority to do), BPA itself could not convey anything to a retail consumer such as GP. Thus, Clatskanie could never convey or "afford [GP] the contractual right to receive service at BPA's lowest possible rates...." GP Br., BP-12-B-GP-01, at 12.

Third, turning to GP's other contention (*i.e.*, that the contract gives GP "a right to purchase power from Clatskanie PUD *based on BPA's lowest rate....*" GP Br., BP-12-B-GP-01, at 11 (emphasis added)), there is even less argument that a valid property right has been taken. This is because GP alleges that a change in the rate applicable to power sold to Clatskanie constitutes the taking. However, neither Clatskanie nor any other BPA preference customers have property rights in a fixed price for power sold by BPA, because BPA by law must review and revise its rates at least once every five years. 16 U.S.C. § 832d(a). Further, the Northwest Power Act does not provide Clatskanie an alleged right to the "lowest preference rate" for its CF/CT customers such as GP. The Northwest Power Act simply affords preference customers a PF rate or rates,

and, as extensively explained in issues 2.1.1.2 and 2.1.1.3 above, that is what BPA is providing Clatskanie under the TRM.

GP devotes nearly two pages to arguing that BPA's logic (about reviewing and revising rates) is flawed. GP Br. Ex., BP-12-R-GP-01, at 7-8. First, GP tries to re-word its argument in an effort to dodge BPA's point. GP states that it "is not claiming that it has the right to receive service at a specific rate amount ... or rate design, *per se*." *Id.* at 7. Yet in the very same paragraph GP returns to its usual stance that it is entitled to "the lowest BPA rate" *Id.* BPA's point stands: in light of the fact that BPA must periodically review and revise rates, GP could not possibly have an eternal entitlement to the lowest rate. Next, GP states BPA has made "a fundamental change in its rate structure" which encompasses more than raising its rates. *Id.* That may be true, but it does not change the fact (as explained elsewhere in this ROD) that BPA has long had the authority to tier rates and could always have done so at any time it "revised" its rates within the rate review cycles. Thus, again, GP could never have had (and does not have) a perpetual right to a particular "lowest rate" structure. Lastly, GP brings up the *Cienega Gardens* decision and concludes that "the fact that BPA may have the statutory authority to make this change in its regulations should not in and of itself invalidate GP's takings claim." *Id.* at 8 (*citing Cienega Gardens v. United States*, 331 F.3d 1319 (Fed. Cir. 2003)). BPA has not suggested that its authority to revise rates "in and of itself" is the only thing that invalidates GP's takings claim. Rather, BPA has provided a lengthy list of reasons, all of which independently invalidate GP's claim. This "authority to revise rates" reason is just one of many.

Fourth, GP's supposed "economic injury is not the result of the government taking [its] property, but is the more attenuated result of the government's purported taking of other people's property." *Air Pegasus*, 424 F.3d at 1215. GP says that its contract rates are "based on" Clatskanie's rates and that BPA's TRM proposal would have a "consequence" for GP in the loss in value GP will suffer to its contractual right to receive the lowest preference rate. GP Br., BP-12-B-GP-01, at 11, 13. Even if this right existed and if it were being harmed in the manner GP alleges, it would be a classic consequential harm—a "derivative injury" that does "not form the basis for a viable takings claim." *Air Pegasus*, 424 F.3d at 1215; *see also Yuba Natural Res., Inc. v. United States*, 904 F.2d 1577, 1581 (Fed. Cir. 1990) ("It is a well settled principle of Fifth Amendment Taking law, however, that the measure of just compensation is the fair value of what was taken, and not the consequential damages the owner suffers as a result of the taking.").

A similar claim arose where the PVM Redwood Company operated a sawmill and alleged that the passage of the Redwood Park Expansion Act, 16 U.S.C. § 79b *et seq.*, caused a taking of its property by the United States. *PVM Redwood Co. Inc. v. United States*, 686 F.2d 1327, 1328 (9th Cir. 1982). PVM Redwood's "alleged property right" was the fact that the "Secretary of the Interior had acquired ... timber lands owned by [individuals] who had in the past supplied 98% of PVM's [raw material] requirements" and this acquisition "made it impossible for them to continue to meet PVM's needs." *Id.* As a consequence, PVM alleged that it had "suffered an increase in production costs...." *Id.* The problem with PVM's claim was that it had "no ownership interest in its source of supply." *PVM*, 686 F.2d at 1329.

GP's claim suffers from the same flaw. The TRM and rates set pursuant to it will not cause GP to be "denied use of its property; it can still run its ... mill." *PVM*, 686 F.2d at 1329. Specifically, GP does not allege that it would be denied use of its contract with Clatskanie; it can still purchase power under that contract. Instead, GP's claim is purely derivative in nature: that the *value* of its contract may decrease. GP Br., BP-12-B-GP-01, at 14 ("BPA has devalued GP's contract with Clatskanie PUD..."). This derivative injury, even if it existed, could not form the basis for a takings claim. *Air Pegasus*, 424 F.3d at 1215.

GP attempts to distinguish *PVM Redwood* by arguing that, in contrast to the claim dismissed by the Ninth Circuit in *PVM*, GP's asserted loss is not a frustration of an expectation of future benefits. GP Br., BP-12-B-GP-01, at 12. Instead, GP claims it has "a present property interest in its source of supply via its existing contract with Clatskanie PUD, which affords it the contractual right to receive service at BPA's lowest possible rates for Preference Customers." *Id.*; GP Br. Ex., BP-12-R-GP-01, at 6. The fundamental error in this logic is that GP has no such right. As discussed above, the plain language of GP's contract belies this contention altogether. In addition, GP's supposed distinction from *PVM* is irrelevant because the TRM and rates set pursuant to it will not deny GP the ability to use its property; it can still run the Wauna Mill, just like the government regulation in *PVM* did not deny the plaintiff the use of its mill. *See PVM*, 686 F.2d at 1329. GP, like the *PVM* plaintiff, simply claims it will suffer an injury to its source of supply (here a supply of power, as opposed to timber). The problem is the same, GP has no ownership interest in that source of supply – and certainly no rights to particular pricing. Accordingly, *PVM Redwood* provides a useful comparison for illustrating how GP's claim is purely derivative and therefore cannot form the basis of a takings claim.

GP also cites *Armstrong v. United States*, 364 U.S. 40 (1960), but it is beside the point. Like all takings cases, *Armstrong* required the plaintiffs to demonstrate that a valid property interest had been taken. The plaintiffs in that case did so. That was entirely different from the present situation where, as discussed above, GP has no valid property interest that has been taken.

B. Even if GP had a property interest, its alleged loss is merely consequential and not one for which takings law affords a remedy.

Assuming *arguendo* that GP has a property interest, the line of precedent starting with *Omnia Commercial Co., Inc. v. United States*, 261 U.S. 502 (1923), also precludes GP's takings claim. Beginning with *Omnia*, the Supreme Court has consistently held that a compensable taking can never occur in cases where government actions caused a commercial loss from one private party to another, but did not actually take the contract in question.

In *Omnia*, the plaintiff possessed a contractual right to purchase a large quantity of steel from the seller at a low fixed price. *Omnia*, 261 U.S. at 507. However, before the seller could deliver any steel to the plaintiff, the Government requisitioned the seller's entire production of steel plate for the year 1918, because of the war effort, and directed the seller not to fulfill its contract with the plaintiff. *Id.* While acknowledging the plaintiff's property interest in its contract, the Court nonetheless held that the plaintiff's loss was merely "consequential" and one for which takings law afforded no remedy. *Id.* at 510-511.

Although the plaintiff had suffered an undeniable loss, the Court declared that “destruction of, or injury to, property is frequently accomplished without a ‘taking’ in the constitutional sense.” *Id.* at 508. The Court added that there are many laws and governmental regulations that injuriously affect the value of private property but for which no remedy is afforded. *Id.* at 508. In rejecting *Omnia*’s takings claim, the Court noted that “[f]rustration and appropriation are essentially different things.” *Id.* at 513.

This principle remains unchanged and has been affirmed in a wide variety of takings claims where the Government has caused the loss of the benefits of a contract or frustrated business expectations. In each of these cases, the plaintiff’s economic interest was frustrated in that it failed to receive its expected compensation from private agreements as a result of the Government’s actions. *See Air Pegasus*, 424 F.3d at 1209-1210; *NL Indus. v. United States*, 839 F.2d 1578, 1579 (Fed. Cir. 1988). In *Air Pegasus*, the Federal Circuit aptly characterized the *Omnia* court’s view on takings as finding a “significant difference between an *injury* to one’s property interest and a *taking* of one’s property interest.” *Air Pegasus*, 424 F.3d at 1216 (emphasis in original).

Here, the most GP suggests is that rates calculated under the TRM may frustrate its business expectation (*i.e.*, the full economic advantage it is expecting from its private agreement with Clatskanie). This does not amount to a compensable taking under the *Omnia* line of cases. Indeed, GP’s takings claim is even less compelling than those of the plaintiffs in *Omnia* and *Air Pegasus*, because those plaintiffs at least had existing contracts that were directly and immediately impacted by the government’s actions. At best, GP only has a contract “based on” the BPA-Clatskanie contract, which is the actual contract that will be affected by the rates being set in this proceeding. GP Br., BP-12-B-GP-01, at 11.

Moreover, GP does not allege any present, immediate effects on its contract, only the possibility of future consequential increases in energy costs that could remove “the incentive of GP to expand its operations at the Wauna Mill” and may “undermine the value of the mill itself.” *Id.* at 9. Again, this so-called devaluation is dependent on GP’s non-existent entitlement “to obtain service for its Wauna Mill up to its CF/CT Load level at rates derived from BPA’s lowest Preference rate.” *Id.* Moreover, GP has made only vague assertions that a devaluation will happen, without offering anything to demonstrate that the devaluation has occurred. Under the same reasoning as *Omnia* and *Air Pegasus*, GP’s claim fails because the TRM and the rates set thereunder do not effectuate an immediate taking of the assets in question. *Omnia*, 261 U.S. at 513.

GP goes to great lengths in attempting to distinguish *Omnia*. GP Br. Ex., BP-12-R-GP-01, at 9-11. Essentially, GP is troubled by BPA’s decision to not allow preference customers to receive Tier 1 rates for CF/CT load that comes into existence after 2010. *Id.* at 10. GP believes that decision “render[s] specious BPA’s argument that the diminishment in value of GP’s contractual right to receive the lowest preference rate for its CF/CT loads is somehow merely ‘consequential’ to its TRM decision” *Id.* But, in the next sentence, GP admits “BPA has not directly ‘appropriated’ GP’s contract with Clatskanie” *Id.* Nevertheless, GP contends, the loss of value associated with that contract is a direct and “for all intents and purposes” intentional

result of BPA's decision. *Id.* at 10-11. The problem is, intent does not play a part in the *Omnia* analysis. The question is simply whether there has been a present, immediate effect to GP's contract—an appropriation, not a mere frustration. *Omnia*, 261 U.S. at 513. GP has not alleged such an effect, much less demonstrated one. Thus, at best, its situation can only amount to an *injury* to its alleged property interest, not a *taking* of that interest. *See Air Pegasus*, 424 F.3d at 1216.

In a related effort to distinguish *Omnia*, GP cites to *Armstrong v. United States*, 364 U.S. 40 (1960). GP uses *Armstrong* to argue that BPA has devalued GP's contract for its own advantage and that “BPA is the direct, positive beneficiary of GP's loss, and therefore, is obligated to pay just compensation to GP” GP Br. Ex., BP-12-R-GP 01, at 11. GP misses the point of the case law. The key issue is not whether BPA “benefits” (which it does not), the question is whether BPA has devalued GP's contract. As just discussed, GP has not demonstrated or even alleged a devaluation of its contract resulting from an appropriation.

Seemingly anticipating this fatal flaw in its claim, GP argues that “there is no requirement that the contract at issue be one to which the party asserting the [takings] claim and the government are both parties” and cites as an example the case of *Cienega Gardens v. United States*, 331 F.3d 1319 (Fed. Cir. 2003). GP Br., BP-12-B-GP-01, at 10. *Cienega* is distinguishable from GP's situation for a variety of reasons. Therefore its holding, that a takings claim may be possible even without privity of contract, does not apply here.

First, in *Cienega* the government's position was very different than what BPA argues herein. Specifically, the government was arguing that contract rights created between two private parties would be illusory if the rights concerned an activity subject to pervasive Government control. *Cienega Gardens*, 331 F.3d at 1330. Essentially, the government was asking the court to hold that nothing in the plaintiffs' private agreements had any force and effect. *Id.* at 1330-31. That is a far cry from BPA's position. Unlike *Cienega* where the plaintiffs had “unequivocal contractual rights,” and thus they had “a property interest in those rights,” *id.* at 1330, in the present case GP does not have a legally cognizable property interest for Fifth Amendment purposes. BPA thoroughly demonstrated this point above. Thus, BPA's argument is not that GP's rights are illusory; instead, BPA argues GP has no such rights on the face of its contract. Additionally, BPA has pointed out that GP could never contract for such “rights” with Clatskanie because Clatskanie has no power to convey a right to a particular price level or rate treatment. Indeed, BPA itself has no such power. In short, BPA's position is not analogous to the government's case in *Cienega*.

Second, in *Cienega* the government action (the passage of two pieces of legislation) had an “immediate effect,” namely, “to nullify the [plaintiffs' contractual] option to prepay their mortgage.” *Id.* at 1327. As noted above, GP has not alleged any present, immediate effects on its contract, only the possibility of future, consequential increases in energy costs that could remove “the incentive of GP to expand its operations at the Wauna Mill” and may “undermine the value of the mill” GP Br., BP-12-B-GP-01, at 9. GP attempts to fill this gap by arguing that it simply “has not yet exercised the option to use the entire amount of load designated as CF/CT ...” and thus its situation is akin to the plaintiffs in *Cienega*. GP Br. Ex.,

BP-12-R-GP-01, at 9. But there are two fundamental distinctions: the plaintiffs in *Cienega* had an unequivocal contract right and a valid property interest in it. As explained above, GP has neither.

Third, although the government was not a party to the contracts in *Cienega*, it was inextricably involved in setting their terms. *Cienega Gardens*, 331 F.3d at 1325. Specifically, the Department of Housing and Urban Development (HUD) “reviewed, endorsed, and approved [the contracts] and their terms mirrored HUD regulations.” *Id.* Here, there is no such entanglement between BPA and the contract between Clatskanie and GP. Nor has GP offered any evidence of such. In fact, just the opposite is true: Clatskanie’s publicly available Annual Report plainly states that Clatskanie “has the exclusive right and responsibility to determine rates and charges for services provided.” Clatskanie 2009 Annual Report, at 3. Thus, GP’s contract with Clatskanie is governed by rate terms set exclusively by Clatskanie, not BPA.

Finally, in a key distinction from the present situation, in *Cienega* the government action (enactment of two statutes) was “aimed at the contract rights themselves in order to nullify them.” *Id.* at 1335. Because “[t]he enactment of [the statutes] directly and intentionally abrogated the contracts,” the “effect on the contracts [was], therefore, not merely consequential.” *Id.* As discussed above, this is entirely different from GP’s present situation. BPA has not taken any direct and intentional action toward GP’s contract with Clatskanie. Rather, just like the *Omnia* line of cases, the effect on GP’s contract is merely consequential (and even that effect is speculative).

C. Even if GP had a property interest, and if its loss was not merely consequential, it still fails the *Penn Central* standards for establishing a regulatory taking.

Regulatory takings challenges are governed by the standards set forth in *Penn Central Transp. Co. v. New York City*, 438 U.S. 104 (1978); see also *Lingle v. Chevron U.S.A., Inc.*, 544 U.S. 528, 538 (2005). “The Court in *Penn Central* acknowledged that it had hitherto been unable to develop any “set formula” for evaluating regulatory takings claims, but identified “several factors that have particular significance.” *Lingle*, 544 U.S. at 538 (quoting *Penn Central*, 438 U.S. at 124). Those factors are: (1) “[t]he economic impact of the regulation on the claimant;” (2) “the extent to which the regulation has interfered with distinct investment-backed expectations;” and (3) the “character of the governmental action....” *Penn Central*, 438 U.S. at 124.¹²

¹² Along with regulatory takings based on the three *Penn Central* factors, there are two “relatively narrow” categories of “regulatory action that generally will be deemed *per se* takings for Fifth Amendment purposes.” *Lingle*, 544 U.S. at 538. In a footnote, GP faintly suggested that under certain circumstances the TRM, and/or rates set pursuant to it, could result in the second category of *per se* taking, “because it would deprive Georgia-Pacific of all of the economically beneficial use of its CF/CT designation.” GP Br., BP-12-B-GP-01, at 15 n.43. This notion is untenable because, just like the rest of GP’s takings theory, it is premised entirely on the “property right” that GP has in its contract with Clatskanie. As discussed above, this is not a legally cognizable property interest that has suffered a taking as a result of the TRM or BPA’s rates. In addition, this category of *per se* taking is not available because GP is not claiming a complete loss of “all” of the economically beneficial use of its contract, only that the contract would be *less* economically beneficial. *Id.* at 9, 14 (“BPA has devalued GP’s contract with Clatskanie”).

1. Economic impact

GP suggests that it may incur approximately \$3.5 million per year in additional energy costs to serve a hypothetical 35 MW expansion at Tier 2 rates as opposed to Tier 1 rates.¹³ GP Br., BP-12-B-GP-01, at 16. GP states that such increased costs would have “detrimental consequences” on the value of GP’s Wauna mill and the incentive to expand that facility.¹⁴ *Id.* at 17. The suggestion that GP has suffered an economic impact from the TRM is highly speculative.

First, GP has not demonstrated and cannot demonstrate with any certainty that it will use any more of its CF/CT designation than it is currently using. This load uncertainty means that application of a Tier 2 rate may never come into play. GP’s witness testified: “I can state *generally* that GP’s strategic plan *may* include additional future expansion, *if* it remains economically justified.” Tompkins, BP-12-E-GP-01, at 4 (emphasis added). These vague, equivocal statements are far from the concrete, present economic impact that is required by the first factor of *Penn Central*.

In the evidentiary portion of this proceeding GP presented no evidence of concrete, present plans to use more of its CF/CT designation than it is currently using. Indeed, GP openly admitted that documentation of such plans would be speculative. If anything, GP’s evidence demonstrates that GP is *not* likely to grow beyond its current level of CF/CT load.

History also supports this conclusion. Since 1982, when Wauna’s CF/CT and ceiling load amount were determined, Wauna’s energy consumption has never increased to the full ceiling amount, which leaves over 40 aMW of potential unrealized load nonexistent and unserved. Tompkins, BP-12-E-GP-01, at 5 (“The original CF/CT amount for CPUD agreed to by BPA is 126.9 MW.... The Wauna facility currently has an average load of 85 MW in summer months.”). This 40 aMW of CF/CT load is not consuming electricity because it was never developed, and its nonexistence is certainly not due to BPA’s TRM or the rates proposed thereunder. GP has offered no colorable evidence on the record for BPA to address, refute, or rebut regarding the reasons why the multiple owners of Wauna did not expand the facility or why such consumption has not occurred during more than 29 years of operation. The bottom line is that BPA serves only actual load and does not serve yet-to-be-realized load. This failure to grow into the unrealized amount was not caused by the TRM or the rates proposed thereunder.

¹³ BPA notes that this estimated expense is significantly lower than the \$12 million for 41.9 MW that GP had posited it would lose when BPA originally promulgated the TRM and GP raised a takings claim at that time. *See* GP Br., TRM-12-B-GP-01, at 16. This is a further indication that GP’s estimates are entirely speculative.

For some reason GP asserts that no party, including BPA, has challenged its \$3.5 million estimate. GP Br. Ex., BP-12-R-GP-01, at 12. The foregoing portion of this footnote (which was also in the Draft ROD) makes clear that BPA is challenging this estimate and has found it to be entirely speculative. *See also* subsection D below.

¹⁴ GP contends that BPA’s Draft ROD “fails to address GP’s actual argument ...” on this point. GP Br. Ex., BP-12-R-GP 01, at 13. GP alters reality. As BPA stated and supported with citation to GP’s initial brief, GP’s position was that BPA’s actions would harm “the value of GP’s Wauna Mill” Draft ROD, BP-12-A-01, at 52. GP now states its “actual” argument is that BPA’s actions will harm “the value of [GP’s] Wauna Mill” GP Br. Ex., BP-12-R-GP-01, at 13. These quotes make clear that GP’s argument is the same now as it was in its initial brief.

Second, for the duration of the rates being set in this proceeding (two years), GP will be unaffected by the issue it has raised. This is because Clatskanie elected to sign a Slice/Block contract with BPA for the FY 2012–2028 contract term. Bliven and Cherry, BP-12-E-BPA-36, at 12. The amount of power Clatskanie is entitled to purchase under this contract is limited. *Id.* Clatskanie has the right to elect to purchase additional firm power from BPA, but *only* when giving notice under the contract. *Id.* For the FY 2012–2014 period, Clatskanie elected not to purchase additional firm power from BPA. *Id.*

Thus, if GP were to expand its load at the Wauna mill during this time period, Clatskanie is contractually barred from placing that load on BPA, irrespective of any CF/CT determination that Clatskanie holds for such load. *Id.* at 13. So, even if GP’s economic impact was concrete, it would not be immediate and it certainly is not guaranteed; the impact would depend entirely on Clatskanie’s actions in obtaining power (from a source other than BPA) to meet GP’s expanded load.¹⁵

Third, the connection between BPA’s TRM and the price GP may ultimately pay for power from Clatskanie is too attenuated to establish an economic impact. BPA will sell power to Clatskanie at wholesale rates; Clatskanie in turn sets its own retail rates for selling power to its customers such as GP. Clatskanie 2009 Annual Report, at 3. BPA is not involved in Clatskanie’s process of setting retail rates and has no control over the rate Clatskanie may ultimately charge to GP. *Id.*

Finally, the original TRM record showed that, if anything, Clatskanie’s rates are exceedingly low. Stene *et al.*, TRM-12-E-BPA-18, at 8, and Attachment A (“Clatskanie has the lowest rates in the state of Oregon and second or third lowest in the nation.”). Because Clatskanie PUD has such low rates, GP’s suggestion of economic impact is rendered even more suspect.

2. Interference with investment-backed expectations

This factor “incorporates an objective test—to support a claim for a regulatory taking, an investment-backed expectation must be ‘reasonable.’” *Cienega Gardens*, 331 F.3d at 1346 (quoting *Ruckelshaus v. Monsanto Co.*, 467 U.S. 986, 1005 (1984)). This factor most directly demonstrates the failings of GP’s takings argument: GP’s investment-backed expectation is not reasonable.

GP contends the relevant inquiry is, instead, whatever GP itself “reasonably anticipated” at the time it entered into its contract with Clatskanie. GP Br. Ex., BP-12-R-GP-01, at 13. This is wrong on its face. By definition, the inquiry is a more general, objective look at whether the investment-backed expectation is “reasonable.” *Cienega Gardens*, 331 F.3d at 1346; *Ruckelshaus*, 467 U.S. at 1005 (“A reasonable investment-backed expectation must be more than

¹⁵ GP appears to believe this portion of BPA’s analysis somehow creates a “suggestion that GP might be able to mitigate the economic harm suffered as a result of BPA’s decision by procuring power elsewhere” GP Br. Ex., BP-12-R-GP-01, at 13. That is not what this paragraph says. BPA is not suggesting that GP might be able to mitigate economic harm; rather, BPA is demonstrating that GP cannot show concrete, present economic harm in the first place.

a unilateral expectation or an abstract need.” (internal quotations and citation omitted)); *Guggenheim v. City of Goleta*, 638 F.3d 1111, 1120 (9th Cir. 2010) (“‘Distinct investment-backed expectations’ implies reasonable probability, like expecting rent to be paid, not starry eyed hope of winning the jackpot if the law changes.”). It is not whatever GP believed to be reasonable in its own subjective view.

GP states that it “has invested more than \$450 million in two new machines at the Wauna facility ...” and this investment was made “in reliance on the continued availability of low electricity rates for CF/CT loads.”¹⁶ GP Br., BP-12-B-GP-01, at 18. GP has an incorrect understanding of CF/CT status.

First, GP has no direct right under section 3(13) (or any other section) of the Northwest Power Act to buy power at the PF rate. 16 U.S.C. § 839a(13). BPA sells power only to the local serving utility, in this case Clatskanie. In turn, Clatskanie will determine its retail rate design and set the price for GP’s service. This has always been the relationship between BPA and Clatskanie and between Clatskanie and GP. Accordingly, it is not reasonable for GP to expect that it is entitled to dictate under which PF rate BPA serves Clatskanie.

Second, as discussed in Issue 2.1.1.2 above, CF/CT does not encompass a right to the “lowest preference rate,” as GP claims. GP Br., BP-12-B-GP-01, at 18. The CF/CT designation merely allows the BPA customer that serves CF/CT loads to include such load as part of its load that is served with general requirements power sold at the applicable PF rate established under section 7(b) of the Northwest Power Act. CF/CT status certainly does not bestow a right to the “lowest” PF rate.

No such right exists for *any* customer of BPA’s, much less for a retail consumer such as GP, to whom BPA owes no statutory or contractual duties. *See Central Lincoln II*, 735 F.2d at 1125 (stating that the Northwest Power Act “couches the preference in terms of ‘power sales,’ not price.”); *Trinity County Pub. Util. Dist. v. Harrington*, 781 F.2d 163, 166 (9th Cir. 1986) (allocation does not result in “a preferential rate in addition to a preferential power allocation”); *Kaiser Aluminum & Chem. Corp. v. Bonneville Power Admin.*, 261 F.3d 843, 851 (9th Cir. 2001) (regional power preference does not provide price preference). BPA’s TRM and the rates set thereunder do not extinguish any right of a serving utility (such as Clatskanie) to have BPA serve its CF/CT load at PF rates. Bliven and Cherry, BP-12-E-BPA-36, at 12. However, that is the extent of the rights that CF/CT status confers—it does not further convey any sort of right to the “lowest” rate.

Third, GP avers that it had “no indication that the CF/CT load would not continue to be entitled to all of the historical rights of CF/CT Loads to receive service at the lowest Preference rate.” GP Br., BP-12-B-GP-01, at 18. Beyond the fact that GP never had any right to the “lowest” preference rate to begin with, the suggestion that GP was not aware of the possibility that BPA could tier rates is without merit. BPA has asserted its authority to tier rates for many years.

¹⁶ It is not clear that GP made these investments in anticipation of future expansion, as opposed to other changes to the Wauna mill such as replacement of existing machinery.

See, e.g., pp. III-5-7 of 1981 Wholesale Power Rate ROD (June 1981) (considering whether BPA should adopt the rate design alternative of tiered rates); Notice of Proposed Wholesale Power Rate Adjustment, 60 Fed. Reg. 8496 (1995), at 8497-8498, 8503-8504.¹⁷ BPA has had the authority to tier rates since at least the passage of the Northwest Power Act. *See* Issues 2.1.1.2 and 2.1.1.3 *supra* for further discussion. Thus, to the extent GP relied on the absence of a tiered rates structure in making its investments at Wauna, such reliance was not reasonable or well founded.

Finally, GP attempts to show that BPA acknowledged that GP has relied on its CF/CT designation in planning future operations. GP Br., BP-12-B-GP-01, at 20. The BPA statement that GP points to merely demonstrates that during the original TRM proceeding BPA was mindful of GP's concerns about Clatskanie's CF/CT designation and BPA was therefore careful not to "extinguish any right of a serving utility to have BPA serve its CF/CT load at PF rates...." *Stene et al.*, TRM-12-E-BPA-18, at 7. BPA has taken precautions not to disturb utilities' CF/CT designations, but BPA will not and cannot create rights (*e.g.*, to the "lowest" preference rate) that do not exist.

3. Character of the government action

In analyzing this factor, a court would consider whether the government action "amounts to a physical invasion or instead merely affects property interests through 'some public program adjusting the benefits and burdens of economic life to promote the common good.'" *Lingle*, 544 U.S. at 539 (*quoting Penn Central*, 438 U.S. at 124). Where the "interference with the property rights ... arises from a public program that adjusts the benefits and burdens of economic life to promote the common good" then the action "does not constitute a taking requiring Government compensation." *Connolly v. Pension Benefit Guaranty Corp.*, 475 U.S. 211, 225 (1986) (collecting cases).

GP contends that BPA has "not shown that any public interest is served by its decision to exclude CF/CT Loads from eligibility to receive the lowest Preference rate...." GP Br., BP-12-B-GP-01, at 19. First, as discussed at length, CF/CT loads have never been entitled to the "lowest" preference rate. BPA could not exclude GP or any other CF/CT from something it was not entitled to in the first place.

In reality GP is taking issue with a much broader decision: BPA's overall decision to institute a tiered rate structure. GP contends "the *rate structure* that BPA is proposing to adopt in this case will have an enormously detrimental economic effect on GP...." *Id.* (emphasis added). Contrary to GP's suggestion, BPA's decision to tier rates embodies the quintessential non-taking public purpose; namely, it is about "adjusting the benefits and burdens of economic life to promote the common good...." *Connolly*, 475 U.S. at 225. BPA has explained repeatedly the public

¹⁷ Similarly, in BPA's applicable wholesale firm power rates for the period FY 2001 through FY 2006, and current effective rates, BPA established a Targeted Adjustment Charge (TAC) that applies to customer load that had not been forecast to be served within the rate period. The TAC was designed to recover any incremental costs BPA incurs to acquire power that is needed to sell power to its customers to supply such unexpected load. 2002 Wholesale Power Rate Schedules at 136 (September 2001); 2007 Wholesale Power Rate Schedules at 118 (November 2006); and 2007 Supplemental Wholesale Power Schedules (FY 2009).

purposes behind tiering rates in general and how the TRM advances these goals. *See* RD Policy, at 5-7, 21-23; Cherry *et al.*, TRM-12-E-BPA-02, at 2-4; 73 Fed. Reg. 24961-24964 (2008). With specific regard to treatment of CF/CT load under a tiered rates construct, GP is incorrect that BPA has not explained its rationale. The RD Policy ROD, which Staff summarized in the TRM testimony, evaluated this issue and thoroughly explained BPA’s actions. *See* Stene *et al.*, TRM-12-E-BPA-18, at 2-3; RD Policy, at 21-23.

Not satisfied, GP narrows its argument even further by contending BPA has not shown “that excluding CF/CT [l]oads serves” a public purpose. BPA is not required to make such a specific showing. Even if it was, this showing could easily be met because BPA’s actions continue to supply, as part of the general requirements of its customers, CF/CT loads consistent with BPA’s public purposes.

D. The remedy GP is seeking is not available under the law of takings.

GP’s basic argument is that “BPA’s implementation of the TRM will constitute a regulatory taking of GP’s property interests under its contract with Clatskanie, for which GP must be compensated.” GP Br., BP-12-B-GP-01, at 16. Yet, in each instance that GP alleges it “is entitled to just compensation” it fails to state what that compensation would be. *Id.* at 2, 8, 9, 14, 16, 19.

GP responds that “[t]here are a variety of means by which BPA could provide ‘just compensation’ adequate to cure GP’s injury.” GP Br. Ex., BP-12-R-GP-01, at 15. This statement evades the problem: the issue is not about the “means” to provide compensation, it is about whether GP has stated an *amount* of compensation to which it is supposedly entitled. GP has utterly failed to do so, despite numerous opportunities. Thus, it is missing a critical element for its takings claim because it cannot show what amount, if any, the TRM will “take” from it.

In a poor example of a “means” by which BPA could allegedly provide compensation, GP points to the testimony of Lincoln Wolverton. *Id.* This example only serves to illustrate how incomplete GP’s takings claim is. Mr. Wolverton proposed certain actions that BPA should take “to preserve CF/CT rights,” but the sole remedy available for a takings claim is *monetary compensation*. *Lingle*, 544 U.S. at 544. Requests for the government to take or not take a particular action have no home in takings law. *Id.*

The critical point is, nowhere in GP’s testimony or briefing does it present an amount of compensation to which it believes it is entitled. GP speculates that it “would suffer at least \$3.5 million more a year in additional electric costs to serve a 35 MW expansion at Tier 2 as opposed to Tier 1 rates.” GP Br., BP-12-B-GP-01, at 6. However, no such 35 MW expansion has occurred, and nothing indicates that GP has incurred any additional electric costs.

The obvious reason for the absence of this critical element is that GP cannot show with any certainty what amount, if any, the TRM will “take” from it. This is because, as discussed above, any attempt at showing GP’s potential “derivative” losses would be purely speculative.

In reality, GP is attempting to stop BPA from tiering rates altogether; much of GP’s brief is devoted to arguing that BPA’s implementation of tiered rates “is contrary to law and BPA’s statutory authority.” GP Br., BP-12-B-GP-01, at 2, 3-8. Thus, what GP is seeking amounts to an injunction against BPA’s implementation of tiered rates.

The Supreme Court has held that such a claim “does not sound under the Takings Clause.” *Lingle*, 544 U.S. at 544. This is because the party “plainly does not seek compensation for a taking of its property for a legitimate public use, but rather an injunction against the enforcement of a regulation” *Id.* Accordingly, the relief GP seeks is fundamentally at odds with the “just compensation” available under the Takings Clause. Therefore, GP’s takings argument is invalid.

E. Conclusion

GP’s takings argument is invalid for several independent reasons. GP does not have a legally cognizable property interest that has suffered a taking as a result of the TRM, its alleged loss is merely consequential and not one for which takings law affords a remedy, it fails the *Penn Central* standards for establishing a regulatory taking, and the remedy it is seeking is not available under the law of takings.

Decision

The TRM and the rates set pursuant to it do not result in an unconstitutional taking of property from Georgia-Pacific.

Issue 2.1.1.6

Whether BPA has acted arbitrarily and capriciously with regard to its treatment of DOE Richland, New Public and New Tribal loads vis-a-vis nonexistent CF/CT loads.

Parties’ Positions

Clatskanie purports to “adopt and incorporate[] the arguments advanced by GP and ICNU on this issue in this proceeding.” Clatskanie Br. Ex., BP-12-R-CK-01, at 6. However, GP and ICNU have not made any arguments on this issue, nor referred to it in testimony, or any other filing in this proceeding.

BPA Staff’s Position

This is a legal issue, which Clatskanie raised for the first time in its brief on exceptions; therefore Staff has not taken a position on the issue.

Evaluation of Positions

The Ninth Circuit has already directly addressed this issue and decided it against Clatskanie and the other petitioners in *Industrial Customers of Northwest Utilities, et al., v. Bonneville Power Administration*, 388 Fed. Appx. 586 (9th Cir. 2010) (unpublished memorandum opinion). The

Court held in no uncertain terms that the discrimination claim “fails on the merits ... because the BPA did not act arbitrarily and capriciously.”¹⁸ 388 Fed. Appx. 586, at 590.

That decision is binding precedent which disposes of this issue. Considering the facts that (1) this was the only claim that the Court found ripe for review in *Industrial Customers*, (2) Clatskanie was one of the parties that raised and lost the claim in that case, and (3) Clatskanie was represented by the same counsel in that case as in this BP-12 proceeding, it is more than passing strange that Clatskanie continues to re-litigate this dead issue. See *Puget Sound Energy, Inc. v. United States*, 47 Fed. Cl. 506, 511 (Claims Ct. 2000) (finding it strange that the plaintiff would continue to litigate an issue that had been conclusively decided against it in prior cases).

Clatskanie also attempts to build on its discrimination argument by suggesting BPA has violated some sort of non-discrimination and arbitrary/capricious standard in section 7(b)(1) of the Northwest Power Act. Specifically, Clatskanie argues BPA’s actions are “discriminatory, arbitrary and capricious, and violate[] BPA’s basic statutory mandate under [s]ection 7(b)(1) to provide preference rates of ‘general application.’” Clatskanie Br. Ex., BP-12-R-CK-01, at 6 (quoting 16 U.S.C. § 839e(b)(1)). However, Clatskanie made (and lost) the identical argument, word for word, before the Ninth Circuit. See *Industrial Customers*, 388 Fed. Appx. 586, Reply Brief of Petitioner Clatskanie, filed Dec. 7, 2009, at 6 (arguing BPA’s actions are “discriminatory, arbitrary and capricious, and violate[] BPA’s basic statutory mandate under [s]ection 7(b)(1) to provide preference rates of ‘general application.’”). ICNU also raised (and lost) this argument before the Court. See *Industrial Customers*, 388 Fed. Appx. 586, Opening Brief of Petitioner Clatskanie, filed June 30, 2009, at 22-23.

Thus, it is apparent the discrimination issue was before the Court, regardless of whether it was couched in terms of an APA argument or an interpretation of section 7(b)(1) of the Northwest Power Act. And it is clear the Ninth Circuit conclusively decided the issue against Clatskanie.

Decision

As the Ninth Circuit has already held, BPA has not acted arbitrarily and capriciously with regard to its treatment of DOE Richland, New Public and New Tribal loads with regard to nonexistent CF/CT loads.

2.2 TRM Change Process

2.2.1 TRM Change Process Prior to BP-12

The BP-12 rate proceeding is the first time the Priority Firm Public rate is being developed following the specifications of the TRM. In the process of implementing the TRM for the BP-12 Initial Proposal, five unanticipated issues arose. Bliven *et al.*, BP-12-E-BPA-11, at 26. BPA, customers, customer groups, and interested parties met during June through August 2010, prior to the BP-12 Initial Proposal, to accurately express the changes needed in the TRM to correct

¹⁸ The Court referred to the claim as having been brought by ICNU; however, Clatskanie raised and argued it as well. See *Industrial Customers*, 388 Fed. Appx. 586, Opening Brief of Petitioner Clatskanie, filed June 30, 2009, at 22-24.

these five “unintended consequences,” as defined in the TRM. *Id.* at 31. Each proposed revision reflected a consensus among participants that the revision proposed was a satisfactory response to the unintended consequences that were identified. Four of the five proposed revisions were sponsored by customer groups, and the fifth was sponsored by BPA with concurrence from customer representatives regarding the proposed revisions.

Following those discussions, BPA conducted a TRM change process as defined in TRM sections 12 and 13. *Id.* This was the first time such a process had been conducted. The TRM spells out the following requirements (from sections 12 and 13):

1. The proposed revision affects only customers with CHWM contracts and has no more than *de minimis* effects on BPA customers without CHWM contracts.
2. The proposed revision does not address or rectify unintended consequences that affect BPA programs or policies of general application (*e.g.*, BPA’s programmatic responsibilities).
3. The proposed revision will rectify the unintended consequences that put at risk the policy goals of the Regional Dialogue.
4. The value of the proposed revision outweighs any detriment.

In August 2010 BPA sent the notice of BPA’s Unintended Consequences Proposal, pursuant to TRM section 13.2.1, and an accompanying Explanation of Proposed Revisions to all customers with CHWM contracts. *Id.* The latter described (1) why each unintended consequence proposal would address or rectify the unintended consequence that would put at risk the policy goals underlying the TRM as set forth in the Regional Dialogue policy, and (2) how the value of each unintended consequence proposal would outweigh any detriment created by it. *Id.* at 31 and Attachment 1. The notice also described the voting window during which all customers had the opportunity to object to the unintended consequence proposals.

Voting on TRM revisions has two aspects: utility count and CHWM. A proposed revision in response to unintended consequences may be introduced in a 7(i) process unless 70 percent of customers, by utility count, and 50 percent of CHWMs, object. Each customer votes once on each issue; BPA counts that vote as one utility for the count; and counts the customer’s associated CHWM amount for the CHWM tally. Because CHWMs were not available in time for the revisions proposed in the BP-12 proceeding, BPA used customers’ Transition Period High Water Marks (THWMs) in place of CHWMs when tallying votes.

Between August 25 and September 17, 2010, 61 percent (by utility count) of CHWM customers submitted votes, which represents 68 percent of a proxy for the CHWM amount. Bliven *et al.*, BP-12-E-BPA-11, at 31. The TRM specifies that customers not voting on unintended consequence proposals shall be counted as non-objections to the proposal. The combination of customers voting as not objecting and non-voters resulted in 132 non-objections to the proposed changes, or 99 percent of CHWM customers, which represents over 99 percent of the customers’

proxy CHWMs. *Id.* at 31-32. One customer objected, representing less than 1 percent of CHWMs. *Id.* at 32.

The votes were below the objection thresholds, so BPA Staff was able to propose the five changes in this rate proceeding.

2.2.2 Implementation of TRM Changes in BP-12

The TRM Change Process described above resulted in five changes to the TRM being proposed in the BP-12 Initial Proposal, as summarized in Staff’s policy testimony:

We propose these five changes:

- (1) Correction of Low Density Discount Calculation (TRM section 10.2);
- (2) Clarification of Irrigation Rate Discount Basis (TRM section 10.3);
- (3) Clarification of Contract Demand Quantity Language (TRM section 5.3.5);
- (4) Clarification of Slice True-Up Adjustments (TRM section 2.7.1); and
- (5) Change to Annual Costs in Slice True-Up Calculation (TRM section 2.7.1). ...

Changes 1 and 2 are minor technical corrections to the language of the TRM that do not accurately reflect the intent of the parties drafting the TRM. They are reflected in General Rate Schedule Provisions (GRSPs) II.J [LDD] and II.H [IRD].... Change 3 is also a minor clarification and will be reflected in the revised TRM if the BP-12 [Final] ROD adopts this change. ... Changes 4 [and] 5 modify the Slice True-Up process to make it operate more in concert with the intent of the TRM. These last two changes ... are reflected in GRSP [II.R Slice True-Up Adjustment].

Bliven *et al.*, BP-12-E-BPA-11, at 32. The BP-12 Initial Proposal was prepared assuming that the five proposed TRM revisions would be adopted by BPA. *Id.* No parties challenged in their briefs either this assumption or the substance of the five proposed changes.

1. Low Density Discount

The TRM specifies that a customer’s applicable LDD percentage will be calculated to discount its Tier 1 purchases by revising its eligible LDD percentage reflective of its total load eligible for requirements service regardless of its Above-HWM service election. Bliven *et al.*, BP-12-E-BPA-11, Attachment 1, at 2. The way section 10.2 of the TRM was written, however, would result in unintended consequences. If a customer’s adjusted total retail load was less than its RHWM, and therefore all of the customer’s purchases were at Tier 1 rates, the calculation of the applicable LDD percentage would reduce the customer’s applicable LDD percentage below its eligible LDD percentage. *Id.* In addition, the definition of adjusted TRL (“*adjTRL*”) was misstated in the TRM. The TRM incorrectly used the defined term “Existing Resources for CHWMs” rather than the defined term “Existing Resources.” This TRM misstatement could result in an incorrect calculation of a customer’s applicable LDD percentage. *Id.*

By adopting this change, TRM section 10.2.2 would be changed as follows:

10.2.2 Adapting the LDD to Tiered Rates

Under tiered rates, the Tier 1 LDD for customers ~~experiencing load growth~~ will be adjusted in order to provide an applicable LDD benefit equivalent to what it would have been under melded rates, and the cost of that benefit will be allocated to the Composite Cost Pool. The LDD will be based on a customer's TRL, minus Existing Resources ~~for CHWM and NLSLs~~. When a customer's adjusted TRL is less than its RHWM, such customer's applicable LDD will not be less than that customer's eligible LDD. The base discount will be determined using the adjusted TRL and the LDD Percentage Discount Table, as published in the applicable GRSPs. To reflect an increase or decrease in a customer's adjusted TRL, the percentage discount will be adjusted for application to the customer's bill. ...

$$applicableLDD = eligibleLDD \times \max \left(\frac{adjTRL}{RHWM}, 1.0 \right)$$

where:

applicableLDD = LDD percentage to be applied to a customer's bill

eligibleLDD = LDD percentage indicated by the customer's eligibility factors

adjTRL = customer's Total Retail Load less output of Existing Resources ~~for CHWMs and NLSLs~~

RHWM = customer's Rate Period High Water Mark

Bliven *et al.*, BP-12-E-BPA-11, Attachment 1, at 2-3. These changes were incorporated in GRSP II.J. in the BP-12 Initial Proposal. Bliven *et al.*, BP-12-E-BPA-11, at 32. This change is incorporated in the 2012 Power Rate Schedules, BP-12-A-02B, and power rate studies.

2. Irrigation Rate Discount

The TRM specifies that a fixed historical percentage be applied to rates that are calculated in each rate case to determine the level of rate discount granted to contract-specified irrigation loads. Bliven *et al.*, BP-12-E-BPA-11, Attachment 1, at 5. TRM section 10.3 specifies that a Customer's IRD will be calculated to discount its Tier 1 irrigation purchases by applying a historical percentage to "...the sum of the Slice and Non-Slice customer charges...." TRM section 10.3 was written before all of the details of the Tier 1 rate design in TRM section 5 were finalized. The inexact language could give rise to varying interpretations and calculations of the level of the discount.

By adopting this change, TRM section 10.3 is changed as follows:

10.3 Irrigation Rate Mitigation [middle of third paragraph]

... This percentage will be multiplied by the sum of the ~~Slice and Non-Slice customer charges~~ divided by the Tier 1 System Capability forecast revenue that irrigation loads will pay through the Composite Customer Charge, the Non-Slice Customer Charge, and the Load Shaping Charge, adjusted for any applicable Low

Density Discount, divided by the sum of the irrigation loads (expressed in MWh) to derive a dollars per MWh discount.

Forecast revenue for irrigation loads will be calculated using an Irrigation Rate Discount (IRD) TOCA derived by dividing the sum of the irrigation loads (expressed in aMW) by the sum of all RHWMs. This IRD TOCA will be applied consistent with Section 5 of the TRM for calculation of forecast irrigation revenues from the Composite Customer Charge, the Non-Slice Customer Charge, and, the Load Shaping Charge. This discount will be seasonally available to qualifying loads during May, June, July, August, and September. ...

Bliven *et al.*, BP-12-E-BPA-11, Attachment 1, at 5. This change is incorporated in the 2012 Power Rate Schedules, BP-12-A-02B, and power rate studies.

3. Contract Demand Quantity

The Supplemental TRM added provisions for Provisional CHWM to account for loss of load during FY 2010 resulting from the economic recession or other causes. TRM section 4.1.9 specifies adjustments to a customer's CDQ amount if and when Provisional CHWM is removed after FY 2013. The TRM states that "The actual CDQs determined in accordance with section 5.3.5.2 or 5.3.5.3 will be used for billing during FYs 2012–2013 and in all subsequent Rate Periods." BP-12-A-03, section 5.3.5. Section 5.3.5 does not reference the potential modifications pursuant to section 4.1.9, however. In the drafting of the modifications to Section 4 to incorporate Provisional CHWMs, it was overlooked that Section 5 contained a definitive statement that was now in conflict with the new provisions in Section 4. The language proposed to be added to Section 5 resolves this potential conflict. Bliven *et al.*, BP-12-E-BPA-11, Attachment 1, at 7.

By adopting this change, TRM section 5.3.5 is changed to recognize the section 4.1.9 adjustments to CDQ amounts:

5.3.5 Contract Demand Quantity

... The actual CDQs determined in accordance with section 5.3.5.2 or 5.3.5.3 will be used for billing during FYs 2012–2013 and in all subsequent Rate Periods unless the CDQs are modified pursuant to section 4.1.9. If the CDQs are so modified pursuant to section 4.1.9, the modified CDQs will be effective beginning with FY 2014 and be used for billing and any necessary billing adjustments as described in section 4.1.10.

Bliven *et al.*, BP-12-E-BPA-11, Attachment 1, at 7. This change does not need to be reflected in the 2012 Power Rate Schedules.

4. Clarification of Slice True-Up Adjustments

The TRM specifies that the Slice True-Up Adjustment is each customer's Slice percentage multiplied by the difference between forecast costs and credits and actual annual costs and credits. BP-12-A-03, section 2.7.2. If all customers' Tier 1 purchases are equal to their RHWMs, then each customer's cost responsibility is equal to its proportionate share of the total

RHWMs. If some customers are not purchasing their full RHWM, then the value of the power they are not purchasing is shared with all customers. Because all customers, not just Slice customers, are paying based on percentages of their load-weighted shares of all loads, however, a Slice customer's cost responsibility is no longer necessarily equal to its Slice percentage. In return for receiving a share of the value of Unused RHWM, the cost responsibility of each customer is increased to its proportionate share of all Tier 1 loads expected to be served. If the Slice True-Up does not apportion cost and credit differences based on the established cost responsibility, then Slice customers will either under-pay or under-receive true-up amounts in the True-Up calculation. Bliven *et al.*, BP-12-E-BPA-11, Attachment 1, at 9.

By adopting this change, TRM sections 2.7.1, 2.7.2, and Attachment A section 1(b) are changed to recognize cost responsibility rather than solely the Slice percentage:

2.7.1 Composite Cost Pool True-Up

For each Slice customer, the annual Slice True-Up Adjustment Charge for the Composite Cost Pool will be calculated by 1) subtracting (i) the ~~average of the~~ forecast annual expenses and revenue credits allocated to the Composite Cost Pool for the applicable Fiscal Years of the applicable Rate Period from (ii) the actual expenses and revenue credits in the applicable Fiscal Year of the Rate Period that are allocable to the Composite Cost Pool, and 2) ~~multiplying~~ dividing the difference determined in 1) above by the sum of the Composite Cost Pool TOCAs for that Fiscal Year adjusted in accordance with section 5.1.1, based on the Annual Net Requirement for Slice customers and the Load Shaping True-Up methodology set forth in section 5.2.4.1 for Load Following customers, and 3) multiplying by each Slice customer's Slice Percentage for the applicable Fiscal Year. As part of the Composite Cost Pool True-Up, the Firm Surplus and Secondary Credit (from Unused RHWM) will be revised to reflect the adjusted TOCAs for each Fiscal Year as described above and the resulting revenue difference between a sale at the posted Composite Customer Rate and at the rate case-determined value of Unused RHWM. The dollar amount calculated, which may be positive or negative, constitutes the Slice True-Up Adjustment Charge for the Composite Cost Pool.

The effective change the Load Shaping True-Up has on Load Following customer TOCAs will be calculated as the 1) aggregate sum of the Load Shaping True-up billing determinants expressed in MWh, 2) divided by the RHWM Tier 1 System Capability expressed in MWh, and 3) multiplied by 100. A negative result means the TOCAs for Load Following customers are effectively increased by the result and is offset by an equivalent decrease in the TOCA attributed to Unused RHWM. A positive result means the TOCAs for Load Following customers are effectively decreased by the result and is offset by an equivalent increase in the TOCA attributed to Unused RHWM.

2.7.2 Slice Cost Pool True-Up

The annual Slice True-Up Adjustment Charge for the Slice Cost Pool will be calculated by 1) subtracting (i) the ~~average of the~~ forecast annual expenses and

revenue credits allocated to the Slice Cost Pool for the applicable Fiscal Years of the ~~applicable~~ Rate Period from (ii) the actual expenses and revenue credits that are allocable to the Slice Cost Pool in the applicable Fiscal Year of the Rate Period and 2) multiplying the difference from 1) above by each customer's Slice Percentage pursuant to Exhibit K of the Slice/Block Contract divided by the sum of all Slice Percentages for that Fiscal Year pursuant to Exhibit K of the Slice/Block Contract. The dollar amount calculated, which may be positive or negative, constitutes the Slice True-Up Adjustment Charge for the Slice Cost Pool.

Attachment A – Cost Verification Process for the Slice True-Up Adjustment Charge

1. Slice True-Up Adjustment Charge and Agreed-Upon Procedures

b) After such notification, BPA will post for review by customers the TRM Cost Allocation Tables (i.e., Composite, Non-Slice, and Slice Cost Pools) reflecting the actual expenses and revenue credits from the Fiscal Year just concluded. The Slice True-Up Adjustment Charge applicable to each Slice customer will not be posted, but each Slice customer will be provided: the Slice True-Up Adjustment Charge applicable to it, including its Composite Cost Pool TOCA adjusted pursuant to TRM section 5.1.1; the sum of the adjusted TOCAs; the calculation of the actual Unused RHWL credit; and the Slice Percentages used to calculate such Slice True-Up Adjustment Charge. Following the posting of the Cost Allocation Tables, BPA will allow 15 Business Days for the identification by any customer of any Slice True-Up Adjustment issue for consideration by BPA for inclusion in the Agreed-Upon Procedures (AUPs), including the following calculations: the sum of adjusted TOCAs; the actual Unused RHWL credit; and the Slice Percentages used in the Slice True-Up Adjustment Charge for the Composite Cost Pool and Slice Cost Pool calculation. AUPs are defined as services that fall under the category of miscellaneous financial services provided to BPA by an external auditor that are covered contractually between BPA and an external auditor.

The correction results in a Slice True-Up Adjustment being calculated on the same basis as the rates paid by Slice customers. Rates are computed recognizing that the sum of TOCAs may be less than 100 percent. This adjustment states the Slice True-Up on the same basis. This clarification is incorporated in the Power Rate Schedules, BP-12-A-02B.

5. Change to Annual Costs in Slice True-Up Calculation

The TRM specifies that, in determining the annual Slice True-Up Adjustment, actual annual costs and credits are compared to the average of the two-year costs and credits used to establish rates. The resulting Adjustment may be a credit to or payment by Slice customers after each fiscal year. The use of average two-year costs and credits in the determination of the Slice True-Up Adjustment could result in higher rates for non-Slice customers, however.

By adopting this change, TRM sections 2.7.1 and 2.7.2 are changed to use the annual costs and credits for each year rather than the two-year average:

2.7.1 Composite Cost Pool True-Up

For each Slice customer, the annual Slice True-Up Adjustment Charge for the Composite Cost Pool will be calculated by 1) subtracting (i) the ~~average of the~~ forecast annual expenses and revenue credits allocated to the Composite Cost Pool for the applicable Fiscal Years of the ~~applicable~~-Rate Period....

2.7.2 Slice Cost Pool True-Up

The annual Slice True-Up Adjustment Charge for the Slice Cost Pool will be calculated by 1) subtracting (i) the ~~average of the~~ forecast annual expenses and revenue credits allocated to the Slice Cost Pool for the applicable Fiscal Years of the ~~applicable~~-Rate Period....

This change corrects for a potential problem by removing the predictability that there will be a Slice True-Up for the second year where Slice customers would be paying BPA after the Rate Period ends. While there might actually be such a Slice True-Up payment, the predictability of such a payment occurring is reduced to the point where the determination of PNRR does not need to account for such a potentiality. This clarification is incorporated in the Power Rate Schedules, BP-12-A-02B.

Decision

The proposed revisions to the TRM do not change the policies agreed to during the Regional Dialogue negotiations. Rather, they are technical corrections to enable the TRM to function as intended. Therefore, they are adopted for the TRM and are incorporated in the BP-12 Final Proposal. The revised TRM is incorporated in the official record of the rate proceeding as BP-12-A-03.

2.3 Power Loads and Resources

The Power Loads and Resources Study, BP-12-FS-BPA-03, contains the load and resource data used to develop BPA's wholesale power rates for FY 2012–2013. Documentation supporting the results of the Power Loads and Resources Study is presented in the Power Loads and Resources Study Documentation, BP-12-FS-BPA-03A.

The Power Loads and Resources Study and supporting documentation have two primary purposes: (1) to determine BPA's load and resource balance (load-resource balance), and (2) to calculate various inputs that are used in other studies and calculations within the rate case. The purpose of BPA's load-resource balance analysis is to determine whether BPA's resources meet, are less than, or are greater than BPA's load and obligations for the rate period, FY 2012–2013. If BPA's resources are less than the amount of load forecast for the rate period, some amount of system augmentation is required to achieve load-resource balance.

The Power Loads and Resources Study includes three main components: (1) load data, including a forecast of the Federal system load and contract obligations; (2) resource data, including Federal system resource and contract purchase estimates, total Pacific Northwest regional hydro

resource estimates, and the estimated amount of power purchases that are eligible for section 4(h)(10)(C) credits; and (3) the Federal system load-resource balance, which compares Federal system sales, loads, and contract obligations to the Federal system generating resources and contract purchases.

The Power Loads and Resources Study provides inputs into various other studies and calculations in the ratemaking process. The results of this Study provide data to: (1) the Power Revenue Requirement Study, BP-12-FS-BPA-02; (2) the Power Rate Study (PRS), BP-12-FS-BPA-01; (3) the Power Risk and Market Price Study, BP-12-FS-BPA-04; and (4) the Generation Inputs Study, BP-12-FS-BPA-05.

No party raised issues related to the Power Loads and Resources Study.

2.4 Power Revenue Requirement

2.4.1 Introduction

BPA's power rates are designed to recover the costs of the generation function only. The Revenue Requirement Study, BP-12-FS-BPA-02, determines the level of revenue required to recover all costs of producing, acquiring, marketing, and conserving electric power, including the repayment of the Federal investment in hydro generation, fish and wildlife recovery, and conservation; Federal agencies' operations and maintenance expenses allocated to power; capitalized contract expenses associated with such non-Federal power suppliers as Energy Northwest; other purchase power expenses, such as system augmentation and balancing power purchases; power marketing expenses; cost to Power Services, if necessary, of purchasing transmission services; and all other generation-related costs incurred by BPA pursuant to law.

2.4.2 Revenue Requirement Development

BPA develops the revenue requirement in conformance with the financial, accounting, and ratemaking requirements of DOE's Order No. RA 6120.2. BPA determines the revenue requirement separately for generation and transmission. *United States Department of Energy—Bonneville Power Admin.*, 26 FERC ¶ 61,096 (1984).

The revenue requirement is developed using a cost accounting analysis comprised of the following three components.

1. Repayment studies to determine the schedule of amortization payments and to project annual interest expense for bonds and appropriations that fund the Federal investment in hydro, fish and wildlife recovery, conservation, and associated assets. Repayment studies are conducted for each year of the four-year rate test period and include a 50-year repayment period.
2. Operating expenses and minimum required net revenues for each year of the rate test period.

3. Annual Planned Net Revenues for Risk (PNRR), if any, based on the risks identified and quantified, the Treasury Payment Probability (TPP) standard, and other risk mitigation tools.

With these three parts, the revenue requirement is set at the lowest revenue level necessary to fulfill cost recovery requirements and objectives.

Order No. RA 6120.2 requires that BPA demonstrate the adequacy of proposed rates. The revised revenue test determines whether projected revenues from proposed rates will meet cost recovery requirements and objectives for the rate test period and repayment period. The revised revenue test demonstrates that revenues from proposed power rates will recover generation costs in the rate test period and over the ensuing 50-year repayment period. *Id.* In the final studies, the risks are quantified and analyzed and risk mitigation measures designed to achieve a 95-percent probability that planned payments to Treasury are recovered on time and in full over the two-year rate period.

No party raised issues related to the Power Revenue Requirement Study.

2.5 Power Risk and Market Price

BPA's business environment is filled with numerous uncertainties, also known as risks. Thus the ratesetting process must identify, analyze, and take into account a wide spectrum of risks. The Power Risk and Market Price Study encompasses three distinct portions: (1) modeling of power market price uncertainty, resulting in the market price forecast; (2) analysis and modeling of key financial risks to BPA; and (3) establishment of risk mitigation tools and modeling to test these tools against BPA's risk standards. These analyses are described in the Power Risk and Market Price Study, BP-12-FS-BPA-04, and the Power Risk and Market Price Study Documentation, BP-12-FS-BPA-04A.

This section briefly introduces the primary components of the Power Risk and Market Price Study and discusses the issues raised in relation to risk analysis and mitigation, including (1) the timing, thresholds, and procedures related to the Cost Recovery Adjustment Clause; (2) the calculation of Net Secondary Revenue (NSR) for use in calculating the Non-Slice Customer Charge; and (3) reliance by Power Services (PS) on reserves attributed to Transmission Services (TS) in order to meet BPA's Treasury Payment Probability standard. Parties raised no issues regarding the market price forecast or distribution.

2.5.1 Risk Analysis and Mitigation

The objective of the risk analysis is to identify, model, and analyze the impacts that key risks and risk mitigation tools have on PS net revenue (total revenue less total expenses) and cash flow. The risk analysis and mitigation tools are designed to ensure that power rates are set high enough that the probability that BPA can meet its cash obligations is at least as high as required by BPA's TPP standard. This evaluation is carried out in two distinct steps: a risk analysis step, in which the distributions, or profiles, of operating and non-operating risks are defined, and a risk

mitigation step, in which risk mitigation tools are defined and tested to confirm their adequacy to meet BPA's TPP standard in the face of these uncertainties.

2.5.1.1 The Cost Recovery Adjustment Clause

Issue 2.5.1.1.1

Whether the CRAC should be able to trigger for FY 2012, the first year of the rate period.

Parties' Positions

WPAG argues that the CRAC should not apply to the first year of the rate period. WPAG Br., BP-12-B-WG-01, at 40; WPAG Br. Ex., BP-12-R-WG-01, at 9-13. WPAG states, "[i]n this proceeding BPA has proposed for the first time a CRAC that could trigger on the first day of the rate period, and which would result in an additional increase over and above the one embedded in the PF Tier 1 rate adopted in this proceeding." WPAG Br., BP-12-B-WG-01, at 40. WPAG states that, while it recognizes the proposed CRAC methodology stems from a desire to avoid an unnecessary rate increase, it causes administrative and financial difficulties due to utilities not knowing the size of the wholesale rate increase they may face until just before the rate period starts. *Id.* at 41. WPAG argues that BPA's financial outlook has improved since the Initial Proposal, and, given that, BPA should re-evaluate the need for a "day one" CRAC. *Id.* at 44-45.

JP02 recommends "that BPA ... not implement a CRAC until at least the beginning of FY 2013." JP02 Br., BP-12-B-JP02-01, at 17; *see also* WPAG Br. Ex., BP-12-R-WG-01, at 13.

BPA Staff's Position

This is not the first rate proceeding in which a CRAC could trigger for the first year of the rate period. Lovell and Mandell, BP-12-E-BPA-37, at 28. BPA used a CRAC that could increase rates in the first year of the rate period (*i.e.*, a "day one" CRAC) in every rate proceeding since the WP-02 rate proceeding. In the current WP-10 rates, BPA adopted a CRAC applicable to the first year of the rate period, with the threshold set at the equivalent of \$0 in reserves available for risk attributed to PS, and a maximum recovery amount of \$300 million. Risk Analysis and Mitigation Study, WP-10-FS-BPA-04, at 54-56. The terms of the CRAC established in this rate proceeding are nearly the same as those established in the WP-10 proceeding.

Staff clarifies in its rebuttal testimony that the proposal is to calculate and announce any CRAC applicable to FY 2012 rates in July 2011, at the same time as the release of the Final ROD announcing BP-12 rates. Lovell and Mandell, BP-12-E-BPA-37, at 29.

Evaluation of Positions

WPAG's assertion, WPAG Br., BP-12-B-WG-01, at 40, that this is the first time BPA has had a "day one" CRAC in rates is wrong, and WPAG acknowledges this, admitting after research that the WP-02 CRAC triggered on the first day of the rate period. WPAG Br. Ex., BP-12-R-WG-01, at 10. WPAG does not acknowledge, however, that the WP-07 and WP-10 rates both included a "day one" CRAC that did not trigger. While only the CRAC established in the WP-02 rate

proceeding was actually deployed on the first day of the rate period, the CRACs established in the WP-07 and WP-10 rate proceedings certainly could have been. Lovell and Mandell, BP-12-E-BPA-37, at 28.

WPAG contends the first-year CRAC causes administrative and financial difficulties due to utilities not knowing the size of the wholesale rate increase they may face until just before the rate period starts. WPAG Br., BP-12-B-WG-01, at 41. While this may have been a valid concern under past implementations of a first-year CRAC, it is not so now. Customers will know their power rates for FY 2012 in July 2011. As proposed, the CRAC, if triggered, will be calculated and announced at the same time as the Final ROD and proposed rate schedules are released. Removing the CRAC applicable to FY 2012 would have no effect on the timing of utilities' knowledge of the size of the wholesale power rate increase for FY 2012. Therefore, WPAG's assertion that the CRAC creates additional administrative difficulties for BPA's customers due to their not knowing their FY 2012 rates, or knowing the rates at a later date than they otherwise would have, is false. In fact, the proposal for the FY 2012 CRAC notification in July is nearly 2 months earlier than the previous CRAC notification schedules. In the current and previous rate periods, customers were to be notified in "early September prior to each fiscal year in the rate period" if a CRAC was necessary for the next fiscal year, considerably later than the July timing established in this proceeding. 2010 Wholesale Power Rate Schedules and General Rate Schedule Provisions (FY 2010–2011), at 83; *see also* 2007 Supplemental GRSPs (FY 2009), at 79.

WPAG proposes that the FY 2012 CRAC should be removed from the Final Proposal due to improving financial conditions. WPAG Br., BP-12-B-WG-01, at 44-45. This proposal makes little sense. If the FY 2012 CRAC is unlikely to be needed, it is equally unlikely to trigger. The CRAC will trigger only if needed—only if FY 2011 financial results are poor. If PS financial conditions are good, then the CRAC will not trigger—just as if it were not there; if PS financial conditions are poor enough that the CRAC would trigger, then it should trigger. Thus, a forecast of "good" FY 2011 financial results does not justify eliminating the CRAC applicable to FY 2012 rates. Additionally, removing it would have no impact on FY 2012 rates if FY 2011 turns out well, as WPAG may believe. However, WPAG also states that "... BPA's inclusion of a 'day one' CRAC with a high probability of triggering ... is an entirely different animal" so it is unclear whether WPAG believes FY 2011 conditions are improving. WPAG Br. Ex., BP-12-R-WG-01, at 12.

Decision

BPA's risk mitigation for power rates will include a CRAC that is calculated in July 2011 that could increase rates for FY 2012.

Issue 2.5.1.1.2

Whether the CRAC methodology should be modified to replenish liquidity at a faster or slower rate than currently proposed.

Parties' Positions

WPAG states that the CRAC should not apply to FY 2012, given the availability of other liquidity in the form of the Treasury Facility and reserves attributed to TS. WPAG Br., BP-12-B-WG-01, at 42-43; WPAG Br. Ex., BP-12-R-WG-01, at 12-13. WPAG argues that the liquidity sources do not require repayment of borrowed funds as rapidly as BPA has proposed. WPAG Br., BP-12-B-WG-01, at 43; WPAG Br. Ex., BP-12-R-WG-01, at 12-13. WPAG states that the Treasury facility effectively has a two-year repayment obligation and that TS reserves do not require repayment within a specific timeframe. WPAG Br., BP-12-B-WG-01, at 43-44; WPAG Br. Ex., BP-12-R-WG-01, at 12-13. WPAG argues that therefore the CRAC should be pushed back one year, with the earliest possible date of a CRAC rate increase being the first day of FY 2013. WPAG Br., BP-12-B-WG-01, at 45; WPAG Br. Ex., BP-12-R-WG-01, at 13. WPAG argues that “relaxing the term for repayment of Transmission reserves would not jeopardize timely repayment.” WPAG Br. Ex., BP-12-R-WG-01 at 13. Further, WPAG argues that using the flexibility afforded by the two-year cycle of ratesetting under the CHWM contracts “will adequately address the repayment concerns of Transmission customers.” *Id.*

Powerex recommends that BPA “align the CRAC mechanism with the level of Transmission reserves made available to mitigate risk for Power Services....” Powerex Br., BP-12-B-PX-01, at 18. Under Powerex’s proposal, if PS were to rely upon \$150 million of reserves attributed to TS, then the CRAC should recover 100 percent of the first \$150 million shortfall and 50 percent after that up to the CRAC maximum. Opatrny, BP-12-E-PX-01, at 13. Powerex argues that a CRAC, which, in some circumstances, would be expected to recover less than the amount of reserves consumed by PS leaves a significant potential that full replenishment will be pushed to subsequent rate periods. *Id.* at 21.

JP05 argues that BPA should relax the CRAC terms. JP05 Br., BP-12-B-JP05-01, at 2. JP05 states that “BPA’s arbitrary repayment terms are unnecessarily draconian and result in both an increased probability of the CRAC triggering and an increased amount when it does.” *Id.* JP05 states that the threshold should be reduced from \$0 in Power reserves for risk to negative \$150 million for the CRAC applicable to FY 2012 rates, and reduced from \$0 to negative \$75 million for the CRAC applicable to FY 2013 rates. *Id.* at 3. This would allow PS to tap up to \$150 million of additional liquidity in FY 2011 without beginning replenishment during FY 2012, and up to \$75 million of additional liquidity in FY 2012 without beginning replenishment during FY 2013. *Id.* JP05 also suggests removing the first of the two phases of the CRAC that Staff proposed, so that the CRAC would recoup only 50 percent of the amount by which reserves fall short of the CRAC threshold. *Id.*

BPA Staff’s Position

Staff contends the CRAC proposal represents a reasonable balance between the desires of PS customers, TS customers, and BPA’s needs. Lovell *et al*, BP-12-E-BPA-15, at 53-54; Lovell and Mandell, BP-12-E-BPA-37, at 24. Staff would set the CRAC thresholds based on what it believes to be prudent management of BPA’s liquidity tools. Lovell and Mandell, BP-12-E-BPA-37, at 25. Staff argues that the CRAC terms do roughly match the two-year payback period of the Treasury Facility. *Id.* at 26. Delaying the CRAC until the second year would decrease the

probability of being able to repay the Treasury facility within the required timeframe. *Id.* at 28. Staff does not believe that the size of the CRAC should be a function of the amount of reserves attributed to TS that are relied upon by PS. *Id.* at 10-11.

Evaluation of Positions

WPAG and JP05 both argue for delaying repayment in order to minimize possible rate increases due to a CRAC. WPAG Br., BP-12-B-WG-01, at 42-43; WPAG Br. Ex., BP-12-R-WG-01, at 13; JP05 Br., BP-12-B-JP05-01, at 2. These parties argue that reserves attributed to TS do not need to be repaid quickly and that the Treasury facility would not need to be repaid in the first year. WPAG Br., BP-12-B-WG-01, at 42-43; WPAG Br. Ex., BP-12-R-WG-01, at 12; JP05 Br., BP-12-B-JP05-01, at 2. An unstated assumption underlying the WPAG and JP05 argument is that if a CRAC is triggered for FY 2013, it will generate sufficient revenue for all needed replenishment of liquidity exercised in FY 2011 plus any exercised in FY 2012. WPAG disputes this inference from the Draft ROD, BP-12-A-01, at 68, clarifying that its point is that neither the terms of the Treasury Facility nor the replenishment pace WPAG deems to be sufficient for replenishment of any usage of reserves attributed to TS justifies a day one CRAC. WPAG Br. Ex., BP-12-R-WG-01, at 12. However, WPAG misunderstands BPA's point: the implicit assumption BPA was identifying does not relate to the terms of replenishment of either source of liquidity but to the fact that until any used liquidity is replenished, it is not available to BPA. WPAG's argument assumes that an FY 2013 CRAC (without an FY 2012 CRAC) will generate sufficient revenue in FY 2013 that BPA will have sufficient liquidity in FY 2013 after restoring all liquidity used in FY 2011 and FY 2012. There can be no assurance that one year of incremental revenue from a CRAC will be sufficient to restore liquidity used over two years. Even with the additional revenue from an FY 2012 CRAC, BPA's financial circumstances in FY 2013 may not be good enough to allow the assumed replenishment to occur. Given the uncertainty in PS net revenue, BPA cannot guarantee that any specific amount of liquidity replenishment will actually occur even if a CRAC is implemented; thus, the delayed repayment methodologies proposed by WPAG and JP05 are not prudent and should not be adopted. Although WPAG argues that holding rate proceedings every two years should adequately address the concerns of Transmission customers, as noted above, the arguments of Powerex, an actual Transmission customer, cited in the following paragraph indicate otherwise.

Powerex, in contrast to WPAG, argues for more stringent repayment terms due to this uncertainty in the actual rate of replenishment of reserves. Powerex Br., BP-12-B-PX-01, at 17-22. While setting a faster pace for replenishment may help, it will not guarantee repayment in a specific timeframe, again due to uncertainty in PS net revenue; it would make little difference in the probability of full replenishment in the following year. If PS needs to tap \$150 million in additional liquidity, under Staff's proposal a \$125 million CRAC for the next year would trigger, while under Powerex's proposal a \$150 million CRAC would trigger. Under Staff's proposal, the liquidity would be fully replenished if PS cashflow is at least \$25 million above zero, and under Powerex's proposal, it would be fully replenished if PS cashflow is at least zero. The difference between the likelihoods of those two circumstances is small. One of the input files for the ToolKit from BPA's Initial Proposal, the RiskMod Output file ("RiskMod-Output_BP-12_InitProp_19-Nov-10.xls"), available at BPA's Web site at Finances & Rates—Upcoming/Current Rate Cases—BP-12 Rate Proceeding More Information—BPA Models,

Datasets, contains data that illuminate this. Tab “NetRev_Stats” shows percentiles for Power net revenue for FY 2013. There is a 55 percent chance of PS net revenue being at least negative \$14.2 million; a 50 percent chance of PS net revenue being at least \$22.6 million, and a 45 percent chance of PS net revenue being at least \$61.3 million. Interpolating, it is about 53.1 percent likely that PS net revenue will be at least \$0, and about 49.7 percent likely that PS net revenue will be at least \$25 million. This is a difference of 3.4 percentage points. This is not a significant difference in the rate of replenishment or the likelihood of full replenishment in the next year.

Underlying Powerex’s argument may be the assumption that the first \$150 million of replenishment would be used to reduce the use of TS reserves. This also is not guaranteed. If a CRAC is triggered, and if replenishment is achieved, BPA will decide which uses of liquidity are most appropriate in light of its cash management duties and obligations. Increasing the first phase of the CRAC to \$150 million will not necessarily create substantially greater assurance of timely replenishment of TS reserves.

Additionally, BPA is aware that the imposition of a CRAC could have significant impacts on the struggling economy of the Pacific Northwest. WPAG noted the need to minimize any PF rate increase due to the economic recession. WPAG Br., BP-12-B-WG-01, at 4. More stringent repayment terms could result in rate increases that are not tenable for BPA’s preference customers. The repayment terms proposed are a reasonable balance between the need for timely repayment and the impact on the Pacific Northwest (PNW) economy. None of the arguments provides a compelling reason to modify the CRAC terms.

Decision

BPA’s proposed CRAC methodology adequately matches its liquidity replenishment needs. Staff’s proposed CRAC terms are sufficient to replenish liquidity over an adequate time period.

Issue 2.5.1.1.3

Whether a public review process or additional cost-cutting should be required prior to triggering a CRAC.

Parties’ Positions

JP02 recommends “that BPA engage in additional cost cutting before implementing any CRAC ... and should hold an adequate public process prior to implementing a CRAC.” JP02 Br., BP-12-B-JP02-01, at 17. JP02 states that a public process is critical to ensuring that a CRAC and the associated rate increase are necessary. *Id.* at 18.

BPA Staff’s Position

Staff proposes that if the CRAC is triggered BPA would hold a public workshop to explain the CRAC results and provide opportunity for public comment. Power Rate Schedules, BP-12-A-02B, GRSP I.I.C. BPA costs are already subject to scrutiny through other public processes.

Lovell and Mandell, BP-12-E-BPA-37, at 22. A public discussion would delay the announcement of a CRAC rate adjustment so that it would not align with the release of Final ROD. *Id.* at 23. Financial rating agencies determine BPA's bond rating, which in turn influences the cost of debt. Rating agencies prefer adjustment clauses that trigger automatically, based on specific rules. Delays in implementation and uncertainty in triggering of the CRAC would weaken its value as a tool for enhancing BPA's financial outlook and would likely be detrimental to BPA's credit rating. *Id.* at 31.

Evaluation of Positions

JP02's request to have cost cutting as a precondition of triggering the CRAC is redundant. BPA reviews costs through several processes before, during, and after each rate proceeding. Lovell and Mandell, BP-12-E-BPA-37, at 22. Before the rate proceeding, BPA performs in-depth reviews of its costs through the Integrated Program Review (IPR). *See* ROD section 1.2.1. Between rate proceedings, BPA reviews costs and other financial information with customers quarterly in the Quarterly Business Review (QBR). This process provides customers the opportunity to understand and provide feedback on BPA's financial situation.

Additionally, the GRSPs include a provision that requires BPA to hold a public workshop in the event that a CRAC is expected to trigger. Power Rate Schedules, BP-12-A-02B, GRSP I.I.C. In this workshop, Staff would explain the net revenue calculations, describe the calculation of the CRAC Amount and allocations to various rates, and demonstrate that the CRAC has been implemented in accordance with the GRSPs. The workshop would provide an opportunity for public questions and comments. *Id.* JP02's suggestion to perform additional cost review prior to implementing a CRAC would not provide interested parties any meaningfully greater opportunity to review BPA's expense forecasts than is already provided. The GRSP provisions already fulfill JP02's request that BPA have a public process in the event of a CRAC triggering.

A public discussion or additional cost cutting as a precondition for triggering the CRAC would unnecessarily delay the announcement of a CRAC rate adjustment, such that the rates would not be known until just before the implementation of rates. In addition, BPA conducts the Integrated Program Review (IPR) process, the rate proceeding itself, the Quarterly Business Review (QBR), and the CRAC workshop, which provide customers the opportunity to review and comment on the status of BPA's finances. These processes serve the underlying purpose of the proposed public discussion requested and adding additional process does not seem warranted or needed. Furthermore, a delay in announcement of a FY 2012 CRAC would make it more difficult for BPA's customers to make any adjustments they need to implement before the start of the rate period. A delay in the CRAC timing also contradicts BPA's goal of announcing any FY 2012 CRAC and releasing the FY 2012 rates at the same time. Bliven *et al.*, BP-12-E-BPA-11, at 21.

Finally, financial rating agencies would not look favorably on any delay or uncertainty in triggering or implementing a CRAC. Lovell and Mandell, BP-12-E-BPA-37, at 31.

Decision

BPA will prescribe neither additional cost-cutting to be performed prior to triggering a CRAC nor a public process beyond the public workshop described in the GRSPs of the Power Rate Schedules. The IPR process, the rate proceeding itself, the regular QBRs, and the CRAC workshop provide sufficient and timely information and opportunity to comment on BPA's cost levels and cost recovery.

2.5.1.2 Net Secondary Revenue Crediting

Issue 2.5.1.2.1

Whether BPA should calculate the NSR credit included in power rates using the mean or median from the NSR distribution.

Parties' Positions

JP01 argues that Staff's recommendation to base the NSR credit on the median is not supported by evidence and that it artificially increases TPP, which is already above the 95 percent standard. JP01 Br., BP-12-B-JP01-01, at 21. JP01 states that, by basing the decision to use median NSR on management's tolerance for risk, BPA is indirectly increasing the TPP standard above 95 percent, inconsistent with the 10-Year Financial Plan of 1993 that was updated in July 2008. *Id.* at 19-22. JP01 further asserts that adopting changes to the standard for the NSR credit based on management's tolerance for risk would subvert the TPP standard. *Id.* at 22.

WPAG argues that BPA should not shift from mean to median water in calculating secondary revenues. WPAG Br., BP-12-B-WG-01, at 45. WPAG states that "[G]iven the economic circumstances ... this is an especially ill-timed change to the determination of net secondary revenues." *Id.* WPAG further asserts that "[T]he Proposal to shift from mean to median water, based on a management inclination that is not supported by analysis in the record, is a troubling departure from the historical approach taken in this area." *Id.* at 46.

WPAG further argues that "... BPA has abandoned its historic and proven 70 game risk model for distribution of non-firm revenues in favor of the new RAM2012 which simulates 3,500 games 'with all the uncertainties turned on.'" WPAG Br. Ex., BP-12-R-WG-01, at 8. WPAG states that "BPA should not disrupt this delicate balance [between optimism and pessimism when anticipating NSR] by overreacting to the probabilities dispensed by the new, untested 3,500 game RAM2012." *Id.* at 9.

BPA Staff's Position

Using the mean would entail a 54 percent probability that actual net secondary revenue would be below the amount assumed in setting FY 2012–2013 rates. Lovell *et al.*, BP-12-E-BPA-15, at 78. Staff proposes using median NSR for the net secondary revenue credit as a way to reflect management's tolerance for the risk that actual NSR could be below the amount forecast. Lovell *et al.*, BP-12-E-BPA-15, at 79. Management indicated to Staff that "the harmful consequences

of having actual net secondary revenue below the amount assumed in setting rates are more significant than the beneficial consequences of experiencing higher-than-assumed net revenue.” Bliven *et al.*, BP-12-E-BPA-11, at 25.

Rates and risk mitigation standards are set for multiple criteria, not only for TPP purposes. Lovell and Mandell, BP-12-E-BPA-37, at 19. The use of the median was suggested based on management’s tolerance for the risk of lower-than-assumed NSR, not to increase TPP. *Id.* In the Initial Proposal, TPP would have been above 95 percent regardless of the decision to use median or mean NSR. *Id.*

Evaluation of Positions

JP01’s statement that “Staff recommended to base the NSR credit in this case—contrary to long-standing practice—on the median value of NSR rather than the expected value,” JP01 Br., BP-12-B-JP01-01, at 21, and WPAG’s statement that the “shift from mean to median water ... is a troubling departure from the historical approach taken in this area,” WPAG Br., BP-12-B-WG-01, at 46, both contain the implicit assumption that this is the only difference in the NSR credit methodology between the WP-10 and the BP-12 rate proceedings. To the contrary, the underlying methodology has changed significantly. In prior rate proceedings, BPA has used the mean of what was termed a “70-water-year run” of RiskMod to estimate NSR for the rate credit. *See, e.g.*, Risk Analysis and Mitigation Study, WP-10-FS-BPA-04, at 32. In such a run, the only uncertainty that is modeled is the amount of hydro generation available, and so only 70 games are simulated, one for each of the 70 historical water years. In earlier rate proceedings, 50-game runs were used when only a 50-year record of regulated hydro was available. The practice of using one kind of run for calculating the NSR credit and another kind of run for the risk analysis dates back to 1989, when BPA’s early risk modeling methodology had not yet made practical the use of a single run to serve both purposes. Contrary to WPAG’s assertion that BPA is now shifting to the use of “the new, untested 3,500 game RAM2012,” WPAG Br. Ex., BP-12-R-WG-01, at 9, BPA is still using RiskMod for the NSR credit calculation, just in a different mode. RAM 2012 is not used to calculate the NSR credit or for the risk analysis. RiskMod has been significantly refined and enhanced for every rate case since its introduction in the WP-02 rate case. What is different in the BP-12 proceeding is that the cumulative refinements in BPA’s risk modeling have now made it feasible to use the same 3,500 game run of RiskMod both for calculation of the NSR credit and for the risk analysis.

BPA’s practice has been to attempt to include more and more of the relevant uncertainties in its risk analyses as BPA develops the capability to do so, in the belief that reflecting more of the various causal factors results in a higher-quality risk analysis. Once the capability to use a full risk-analysis type run for calculating the NSR credit was developed, Staff proposed its use, and BPA decided to employ it. Thus, in the BP-12 case, BPA uses a 3,500-game “risk run” of RiskMod with all of the uncertainties turned on to calculate the NSR credit. Lovell *et al.*, BP-12-E-BPA-15, at 24. As Staff examined the results from the 3,500-game run, it noticed that the mean NSR is higher than the median NSR, and as a result there is a significantly higher probability that actual NSR would be below the mean than above it (54 percent compared to 46 percent). *Id.* at 78. If the rate credit were based on mean NSR, there would be a 54 percent probability that the total cost recovery from non-Slice PF rates plus actual net secondary revenue

would be lower than that assumed in rates. Lovell *et al.*, BP-12-E-BPA-15, at 78. This sizable difference between the mean and the median of NSR data is a recent phenomenon, reflecting that inclusion of all the uncertainties, not only water uncertainty, creates an asymmetrical distribution. The simpler 70-water-year run was virtually symmetrical.

Basing the NSR credit on the mean would exacerbate the concern management has discussed with Staff over the consequences of actual NSR turning out to be lower than the amount assumed in rates. Bliven *et al.*, BP-12-E-BPA-11, at 25. Basing the NSR credit on the median instead of the mean, in this case, prevents a bias that had not been anticipated, which is probably an artifact of changing from a 70-water-year run to a 3,500-game risk run for estimating NSR. Management has also expressed two concerns over potential risks that Staff's risk modeling is not currently capturing (*i.e.*, the possibility that 10 of the last 12 water years have been below average may be signaling a change in hydro regime in the Columbia River basin and the possibility that market prices in the Pacific Northwest could be unusually low by historical standards or even negative for significant periods of time). Bliven *et al.*, BP-12-E-BPA-11, at 24. Given these concerns, this is a particularly inappropriate time to allow an optimistic bias to unwittingly creep into BPA's risk modeling of NSR.

Applying median NSR in the determination of the net secondary revenue credit in rates does result in a higher TPP compared to applying mean NSR when using the BP-12 data. *Id.* However, Staff's proposal to use the median was not motivated by TPP considerations, which deal with management's tolerance for the risk of missing Treasury payments, but by management's tolerance for a different risk—the risk of actual NSR turning out to be below the forecast amount assumed in setting rates. Lovell *et al.*, BP-12-E-BPA-15, at 79. The fact that using the median increases TPP does not indicate that the choice is made in order to increase TPP—the fact that a choice has a particular consequence does not demonstrate that the choice was made in order to produce the consequence. The choice of median does not represent a change in BPA's longstanding TPP standard. However, a 54 percent probability of NSR being lower than assumed in rates is not acceptable for this rate period. Bliven *et al.*, BP-12-E-BPA-11, at 23. Determining risk tolerance in this way does not undermine BPA's longstanding TPP standard or the credibility of the risk analysis, as is asserted by JP01. JP01 Br., BP-12-B-JP01-01, at 20.

Using median NSR for the net secondary revenue credit is not inconsistent with BPA's Financial Plan. BPA's tolerance for the risk of NSR being below the forecast is separate from BPA's tolerance of Treasury payment risk. “The objective of the Financial Risk Metrics section [of the Financial Plan] is to discuss BPA's tolerance for the risk of not making its scheduled Treasury payments, its current and contemplated tools for addressing this risk, and its plans for extending its analysis of payment certainty to within-year payments to both the Treasury and other creditors.” Bonneville Power Administration, Financial Plan, 2008, at 14. A determination of BPA's tolerance for the risk of NSR being below the forecast is not a modification of the TPP standard. As such, there is no requirement to include it in BPA's Financial Plan. In the future it is possible that BPA could face a situation where due to a different distribution of the 3,500 games, the mean NSR calculation is less than the median. Absent an overriding reason,

under such a circumstance it would seem appropriate to continue to use the median in order to maintain the 50 percent probability of achieving the NSR forecast.

Decision

BPA will use the median of the NSR distribution to determine the NSR credit for the FY 2012–2013 power rates.

Issue 2.5.1.2.2

Whether BPA should use “hydro re-weighting.”

Parties’ Positions

JP05 asserts that “BPA’s risk analysis already accurately captures the risk of good and bad water years, and no further adjustments are necessary.” JP05 Br., BP-12-B-JP05-01, at 6. JP05 further states that hydro re-weighting was improperly introduced to the record and should not be adopted. *Id.*

BPA Staff’s Position

Staff did not implement any hydro re-weighting in the Initial Proposal. Staff discussed hydro re-weighting in the context of a possible way to deal with management’s tolerance for “bad” water years or for a change in the hydro regime. Lovell *et al.*, BP-12-E-BPA-15, at 77-83.

Evaluation of Positions

The topic was discussed because of management’s risk tolerance, specifically “executive management’s willingness to tolerate the risk of actual net secondary revenue being below the amount assumed in rates.” Bliven *et al.*, BP-12-E-BPA-37, at 24. Hydro re-weighting may have merit in future rate periods for mitigating risk or dealing with a change in risk tolerance. However, not enough investigation of the idea has occurred to warrant its adoption at this time.

Decision

BPA will not use hydro re-weighting in setting the FY 2012–2013 rates.

Issue 2.5.1.2.3

Whether BPA should use a “secondary revenue rebate” methodology instead of crediting the power rates directly for anticipated net secondary revenues.

Parties’ Positions

WPAG recommends that BPA move gradually away from crediting Tier 1 rates for an expected amount of secondary revenues, toward a secondary revenue rebate approach, in which customers

are credited after the fact for actual secondary revenues received by BPA. WPAG Br., BP-12-B-WG-01, at 50-51.

JP01 argues that a secondary revenue rebate approach would transfer revenue volatility to BPA's customers while offering no net benefits and substantial costs. JP01 Br., BP-12-B-JP01-01, at 23. JP01 requests that WPAG's proposal be rejected. *Id.*

MSR states that WPAG's proposal for a secondary revenue rebate merits further study. MSR Br. Ex., BP-12-R-MS-01, at 5. MSR suggests BPA could implement a "negative CRAC" methodology for risk mitigation, which reduces reliance on the CRAC. *Id.*

BPA Staff's Position

Staff does not believe the WPAG proposal is complete enough to implement as proposed. Lovell and Mandell, BP-12-E-BPA-37, at 30. There is not enough time in this proceeding to fully and publicly consider and discuss the proposal. *Id.*

Evaluation of Positions

A "secondary revenue rebate" approach to secondary revenue crediting is an idea that should be explored for future rate periods. Many details would need to be filled in before this idea can be evaluated, including the following:

- How frequently would actual secondary revenues be calculated, and would it include balancing purchase costs?
- How often would rebates be made?
- How would rebates actually be effected?
- What provision would be made for the possibility that the secondary revenue credit in the first calculation period would be negative? Would power customers pay BPA? Or would BPA need to maintain some level of financial reserves as a buffer in case this occurs?
- Would provisions need to be made for distinguishing between balancing purchases and purchases made for augmentation?
- As evidenced by the difference in the views of WPAG and JP01, customers are likely to have a variety of attitudes on this issue, and BPA would need to understand the views of as many customers as possible. Could a proposal be crafted that satisfies all, or nearly all, of BPA's power customers? Or would we want to consider the much more complicated route of offering customers a choice between a rate package with a secondary revenue credit and one more similar to the current non-Slice power rates with a secondary revenue credit, PNRR, CRAC, and DDC?

However promising it may be, this proposal needs much more discussion with all parties before BPA could implement it.

MSR raises a new secondary revenue crediting methodology for the first time in its brief on exceptions. MSR Br. Ex, BP-12-R-MS-01, at 5. There is no evidence on the record to support

MSR's proposal. Therefore, BPA cannot adopt this methodology at this time. MSR's proposal, including reducing the secondary revenue credit to the 25th percentile, may be discussed along with other "secondary revenue rebate" topics in preparation for a future rate proceeding. MSR's recommendation that BPA include a "negative CRAC" in conjunction with the reduction in the secondary revenue credit, which appears to be similar to the Dividend Distribution Clause (DDC) in BP-12 rates, Power Risk and Market Price Study, BP-12-FS-BPA-04, section 3.2.5, has also been proposed too late to be adopted for FY 2012–2013 rates.

Decision

BPA will not use a "secondary revenue rebate" approach in calculating power rates for FY 2012–2013. BPA will discuss this and related ideas with customers and other parties during the preparation for a future rate proceeding.

2.5.1.3 PS Reliance on Reserves Attributed to TS for TPP

Issue 2.5.1.3.1

Whether BPA's proposal for PS to rely on \$150 million of reserves available for risk attributed to TS in the TPP analysis of Power rates ("BPA's reserves proposal") creates a risk to Transmission customers.

Parties' Positions

Powerex argues that "BPA's proposed reliance on reserves attributed to Transmission for risk mitigation and possible consumption by Power Services creates significant uncertainty for BPA's Transmission customers." Powerex Br., BP-12-BP-PX-01, at 3. Powerex states that BPA has failed to ensure that replenishment of any reserves consumed will be completed in a sufficiently timely manner. *Id.* Powerex argues that BPA's reserves proposal could result in significant harm to Transmission customers if PS does not replenish the reserves before TS needs them. *Id.* at 4. Powerex describes various sources of PS financial uncertainty. *Id.* at 6-8. Powerex states that "[a]ll of these factors create legitimate questions about whether BPA will, in fact, be able to keep Transmission customers 'whole'.... These questions arising from BPA's cross-subsidization proposal create significant uncertainty for Transmission customers." *Id.* at 8. Powerex contends that BPA disagrees with the need to adopt a mechanism to ensure replenishment of reserves attributed to TS. Powerex Br. Ex., BP-12-R-PX-01, at 3. Powerex argues that BPA "has not imposed a concrete methodology for ensuring recoupment" of any reserves consumed. *Id.* at 7.

BPA Staff's Position

The decision to make TS reserves available to mitigate risk is *reliance on* TS reserves by PS. Lovell and Mandell, BP-12-E-BPA-37, at 16 (emphasis in original). PS's reliance on reserves attributed to Transmission will not cause cost increases for TS. *Id.* In contrast, Powerex's concern involved the possibility that adverse circumstances for PS during the rate period could cause the *consumption* of some of the reserves attributed to TS. *Id.* It is not the reliance on TS

reserves for purposes of risk mitigation that might cause the consumption of TS reserves, but rather the unitary nature of BPA and its finances—this potential for consumption is not preventable. *Id.* BPA cannot provide a guarantee that TS stakeholders will not be harmed by PS events regardless of whether PS relies on a portion of reserves attributed to TS in ratesetting. *Id.* at 13. BPA has created a very specific rate mechanism for replenishing any borrowing under the Treasury Facility or any usage of reserves attributed to TS. Lovell *et al.*, BP-12-E-BPA-15, at 52.

Evaluation of Positions

To evaluate Powerex’s concern it is important to understand the distinction between reliance upon reserves attributed to TS for purposes of risk mitigation and the possible consumption of these reserves during the rate period. Powerex’s argument blurs the distinction between the two. The proposal for PS to *rely* upon some portion of the reserves attributed to TS is separate and distinct from the possible *consumption* of these reserves, and the consequences of reliance and consumption are very different.

There are two potential impacts of the proposal to rely on some portion of the TS reserves for risk mitigation. The first potential impact is that TS will not be able to rely upon these same reserves for purposes of setting its rates during the FY 2012–2013 rate period. Lovell *et al.*, BP-12-E-BPA-15, at 49. Powerex does not describe any harm that could result from PS’s reliance upon some portion of the reserves attributed to TS. The reliance by PS for rate mitigation purposes does not change the reserve balances. *Id.* In addition, the TS risk analysis demonstrated that TS’s TPP would be at least 95 percent even with PS reliance on \$150 million of reserves attributed to TS. Transmission Revenue Requirement Study, BP-12-E-BPA-07, at 18. Consequently, PS’s reliance upon a portion of the reserves attributed to TS does not create any new or additional risk for transmission rates or customers.

The second potential impact involves the possibility that the TS reserves could actually be consumed in paying a PS financial obligation. Whether or not BPA allows PS to rely for risk mitigation purposes on reserves attributed to TS, there is a chance that PS will experience events that completely exhaust BPA reserves. “This risk to TS from PS events cannot be eliminated...” Lovell and Mandell, BP-12-E-BPA-37, at 14.

Powerex errs in implying that BPA’s reserves proposal creates this risk. The risk that reserves attributed to Transmission could be consumed in paying financial obligations associated with PS exists whether or not BPA decides to rely upon any reserves attributed to Transmission for PS’s TPP calculations. Due to the unitary nature of BPA and its finances, the consumption of reserves attributed to TS due to PS actions could occur, even in the absence of any ratesetting reliance for risk mitigation purposes. Lovell and Mandell, BP-12-E-BPA-37, at 16. BPA has one bank account. BPA will pay its financial obligations with funds available, regardless of reserve allocations between PS and TS. Hence, if reserves attributed to PS are exhausted but obligations created by PS need to be paid, reserves attributed to TS may be consumed to cover those obligations. If PS were not to rely on reserves attributed to TS for ratesetting, this risk would still exist. Staff is proposing that the threshold for the CRAC be set no lower than \$0 in reserves for risk attributed to Power in order to begin replenishing any liquidity that has been tapped,

including reserves attributed to Transmission. Thus, the risk of the consumption of reserves attributed to Transmission, which has always existed, is now better mitigated than ever before. Lovell *et al.*, BP-12-E-BPA-15, at 52-55.

Powerex repeatedly demands that BPA provide a concrete methodology for ensuring replenishment of any consumed reserves attributed to TS. *See, e.g.*, Powerex Br. Ex., BP-12-R-PX-01, at 5 and 7. Powerex does not, however, describe any methodology that could provide such an assurance. The unitary nature of BPA and its finances causes such a guarantee to be impossible. While power rates can be raised through a CRAC or similar mechanism in order to increase the probability of replenishment, BPA's net revenue uncertainty means that restoration of BPA reserves may or may not occur within the time period expected. Due to these dynamics, no time-certain guarantee of repayment can be made. BPA has created a concrete mechanism for replenishment if any liquidity, including reserves attributed to TS, is used: the threshold for the CRAC has been set at the equivalent of \$0 in reserves for risk attributed to PS. This means that if any liquidity has had to be used (because reserves attributed to PS were exhausted), the CRAC will increase rates for the subsequent year to begin replenishing the liquidity. Lovell *et al.*, BP-12-E-BPA-15, at 52.

Decision

BPA's reserves proposal does not create a new risk to Transmission customers. The risk of reserves attributed to TS being consumed to pay financial obligations associated with PS exists with or without this proposal.

Issue 2.5.1.3.2

Whether BPA Staff's reserves proposal creates a potential cost shift that is inconsistent with the ratemaking principle of cost causation.

Parties' Positions

Powerex argues that under BPA's reserves proposal, reserves attributed to Transmission might not actually be available for Transmission needs after the FY 2012–2013 rate period if they are consumed in payment of financial obligations associated with Power. Powerex Br., BP-12-B-PX-01, at 4-5. Powerex further argues that the measures BPA has proposed for replenishing any reserves attributed to Transmission that are consumed in paying financial obligations associated with Power “do not go far enough to ensure that future [Transmission] rates are not negatively impacted.” *Id.* at 6. Powerex argues that delayed replenishment could result in rates in FY 2014 or later being higher than they would have been without BPA's reserves proposal, and that this would be inconsistent with the ratemaking principle of cost causation. *Id.* at 11; Powerex Br. Ex., BP-12-R-PX-01, at 6.

Northwest Wind Group also argues that “Staff's proposal [] violates cost causation principles, in part because as currently proposed, loaning transmission financial reserves to power customers could result in increased transmission rates.” NWG Br., BP-12-B-NG-01, at 92.

JP05 argues that BPA's reserves proposal does not violate the principle of cost causation. JP05 Br., BP-12-B-JP05-01, at 3.

BPA Staff's Position

The *reliance on* TS reserves by PS does not cause cost increases for TS. Lovell and Mandell, BP-12-E-BPA-37, at 16. TS rates are not any higher due to the proposed reliance. *Id.* In the event of consumption of TS reserves, BPA will continue to attribute to TS all of the reserves that would have been attributed had the consumption not occurred. *Id.* The reliance does not cause any costs; nor does it cause TS rates to be any higher than they would be without the reliance. PS will remain responsible for generating revenue sufficient to replenish any consumed reserves. *Id.* at 14. Therefore, the reserves proposal does not violate cost causation. *Id.* at 17.

Evaluation of Positions

Powerex and NWG state concerns about a scenario in which PS financial circumstances result in the consumption of some portion of the reserves attributed to TS during the rate period, and PS fails to fully replenish these amounts prior to the end of the rate period, resulting in TS rates in the next rate period being higher than they would have otherwise been. This, they contend, will result in a cost shift and thus violates the principles of cost causation. Powerex Br., BP-12-B-PX-01, at 11; NWG Br., BP-12-B-NG-01, at 92. Powerex states that the measures BPA has proposed to replenish TS reserves do not go far enough to ensure that future TS rates are not negatively impacted. *Id.* at 6.

The scenario posited by Powerex and NWG, while theoretically possible, is nonetheless speculative. In setting power rates, BPA is not planning to consume any reserves attributed to TS to pay PS's financial obligations. Rather, PS is considering relying upon a portion of these reserves as part of PS's risk mitigation. Lovell *et al.*, BP-12-E-BPA-15, at 48. Consequently, for this postulated scenario to occur, PS must face significant financial problems during the rate period, requiring that BPA use some portion of the reserves attributed to TS to pay financial obligations associated with PS; *and* PS's replenishment efforts must be incomplete; *and* the unreplenished amounts keep TS from achieving a 95 percent TPP; *and* BPA then fails to implement any other actions to meet the TS TPP requirement; *and* PNRR must be added to the TS revenue requirement, thereby raising TS rates.

While the scenario posited by Powerex and NWG could occur, it cannot be described as a likely event. BPA's Final Proposal evaluates a significant number of financial risks that PS faces and proposes risk mitigation measures that are designed to protect BPA from the consequences of negative outcomes. As part of this evaluation, BPA determines whether, in light of the risks it faces, BPA can achieve a 95 percent chance that it will meet all of its financial obligations during the rate period. The Final Proposal meets this standard. However, using the 95 percent standard also means there is a five percent chance that PS will not be able to meet its financial obligations. BPA has determined in the 10-Year Financial Plan that this is an acceptable risk, and neither Powerex nor NWG takes issue with BPA's reliance upon the 95 percent standard.

As noted in response to Issue 2.5.1.3.1, due to the unitary nature of BPA and its finances, the consumption of reserves attributed to TS due to PS’s circumstances could occur even without BPA Staff’s reserves proposal. Lovell and Mandell, BP-12-E-BPA-37, at 16. Rather than creating a risk of TS’s future rates being higher, the current proposal actually provides additional protection against the possibility of Powerex’s and NWG’s scenario occurring. Prior to this proposal there were no formal provisions for addressing the manner in which PS must replenish any source of liquidity, such as reserves attributed to TS, that is actually drawn upon. The proposal contains a new basis for setting the threshold for the CRAC to ensure that Power rates quickly begin to replenish any reserves attributed to TS consumed in the payment of PS obligations. It also contains a clear statement that replenishment by PS will continue until full replenishment has been accomplished. Lovell and Mandell, BP-12-E-BPA-37, at 4.

Decision

BPA Staff’s reserves proposal does not create a potential cost shift that is inconsistent with the ratemaking principle of cost causation.

Issue 2.5.1.3.3

Whether BPA Staff’s reserves proposal entails a subsidy—a use of reserves acquired by one “service” to fund the other—and is thus impermissible.

Parties’ Positions

Northwest Wind Group states that BPA’s reserves proposal violates FERC’s “policy, which forbids jurisdictional utilities from using proceeds from transmission rates to subsidize the rates of their native load customers or their wholesale energy sales.” NWG Br., BP-12-B-NWG-01, at 92.

Powerex argues that “BPA’s rates cannot permissibly be structured to use reserves accumulated by one service to fund the other service without full and timely replenishment.” Powerex Br., BP-12-B-PX-01, at 21. Powerex further argues that BPA is violating “basic ratemaking requirements such as cost causation and cost-based ratemaking principles.” Powerex Br. Ex., BP-12-R-PX-01, at 4. Powerex states that “[u]nder BPA staff’s Initial Proposal, reserves generated by Transmission rates could clearly be accessed to cross-subsidize Power rates, and costs and revenues are not being properly allocated between Federal and non-Federal users.” *Id.* at 4-5. Powerex argues that reliance on \$150 million of reserves attributed to TS by PS could cause TS’s rates to be higher because TS could have instead consumed those reserves to reduce transmission rates. *Id.* at 5.

JP05 argues that BPA’s reserves proposal does not constitute a subsidy of Power Services customers by Transmission Services customers. JP05 Br., BP-12-B-JP05-01, at 4.

BPA Staff's Position

Staff argues that “[a]n actual cross subsidy would mean that TS customers are paying a greater amount than they otherwise would in order to reduce PS rates. This is not the case in this proceeding. TS customers’ rates are no higher due to the PS reliance on TS reserves for risk mitigation than they otherwise would be.... [I]f reserves attributed to TS are actually used by PS during the rate period, there are several mechanisms, rules, and commitments ... in place designed to preclude effects on TS rates.” Lovell and Mandell, BP-12-E-BPA-37, at 2.

Evaluation of Positions

NWG contends that the reserves proposal violates a FERC policy that prohibits the use of transmission revenues to subsidize power rates. NWG Br., BP-12-B-NWG-01, at 92. Powerex makes the same basic cross-subsidy argument as NWG. Powerex Br., BP-12-B-PX-01, at 21; Powerex Br. Ex., BP-12-R-PX-01, at 4-5. FERC Order 888 established the policy that prohibits *jurisdictional* utilities from using revenues from their transmission sales to subsidize power sales. 61 Fed Reg. 21540 (1996). As NWG notes, FERC’s cross-subsidization policy is applicable to only FERC jurisdictional utilities. NWG Br., BP-12-B-NWG-01, at 92. BPA and other governmental utilities are specifically exempt from FERC jurisdiction under section 201(f) of the Federal Power Act. 16 U.S.C. § 824(f). Instead, as has been demonstrated, BPA’s reliance on Transmission reserves for risk mitigation purposes has been previously sanctioned by the Commission and also comports with BPA’s statutory directives.

Even if one agreed that BPA has a legal obligation to comply with FERC policy on these matters, the reserves proposal does not violate the FERC policy. The policy was designed to prohibit utilities from consuming transmission revenues to lower power rates. The reserves proposal does not entail any such action. NWG and Powerex repeatedly conflate the reliance upon TS reserves for purposes of risk mitigation and the actual consumption of those reserves. As previously noted, the reserves proposal does not entail the consumption or use of TS reserves to lower power rates. Rather, the proposal contemplates only reliance for purposes of PS risk mitigation during the FY 2012–2013 rate period upon a portion of TS reserves that is not needed for TS purposes during the FY 2012–2013 rate period. Lovell *et al.*, BP-12-E-BPA-15, at 49. BPA’s reserves proposal does not entail funding of PS expenses from TS revenues. *Id.* Any reserves attributed to TS that are consumed for Power purposes will be restored from PS revenues. *Id.*

Powerex contends that reliance by PS on \$150 million in reserves attributed to TS would be a cross subsidy because BPA could have instead chosen to consume some or all of those reserves in order to decrease transmission rates. Powerex Br. Ex., BP-12-R-PX-01, at 5. This contention is speculative and ignores the process BPA used in the BP-12 rate proceeding (and would likely use in future rate proceedings) to determine the quantity of reserves that PS may rely upon. Transmission Revenue Requirement Study BP-12-FS-BPA-07, Section 2.2. Transmission rates, including any consumption of reserves, were determined without setting aside any reserves for PS to rely upon for risk mitigation. The quantity of TS reserves expected to be consumed for TS purposes is determined first, with the full complement of reserves attributed to TS available. *Only after determining TS reserves needs* is the quantity of reserves PS might rely upon tested.

For example, in setting transmission rates for FY 2012-2013, it was determined that reserves would be consumed to hold TS rates constant. *Id.* This consumption was determined prior to measuring any quantity of reserves attributable to TS that PS could rely upon. It was determined in the Initial Proposal that TS TPP was still above 95 percent if \$150 million in reserves attributed to TS was set aside for PS risk mitigation and that, therefore, it would be acceptable for PS to rely upon that quantity of those reserves. *Id.* Since transmission rates are set assuming that TS had its full complement of reserves to deploy, had PS relied upon some reserves attributed to TS, TS rates would not have been impacted. Therefore, a cross subsidy would not occur.

Decision

BPA Staff's reserves proposal does not entail a subsidy and is not impermissible on that account.

Issue 2.5.1.3.4

Whether BPA's reserves proposal violates the Transmission System Act and Northwest Power Act's requirement of "equitable allocation" and the corollary requirement for separate accounting.

Parties' Positions

Powerex argues that "§ 10 of the Transmission System Act and § 7(a)(2)(C) of the Northwest Power Act provide that the recovery of the costs of the Federal Transmission system shall be equitably allocated between Federal and non-Federal power utilizing such system. This requires BPA to align projected costs with projected revenues, and proscribes cross-subsidization between services." Powerex Br., BP-12-B-PX-01, at 14. Powerex argues that consumption of reserves attributed to Transmission in the payment of financial obligations associated with Power could result in higher Transmission rates, and that this would be a violation of equitable allocation. *Id.*, Powerex Br. Ex., BP-12-R-PX-01, at 5. Powerex argues that BPA's proposal does not adequately ensure repayment of any consumed Transmission reserves and therefore does not meet FERC's standards. Powerex Br. Ex., BP-12-R-PX-01, at 6-7.

Powerex further notes that, in the event that some of those reserves are consumed in paying financial obligations associated with Power, BPA will leave the full amount of reserves attributed to TS on BPA's books, and argues that BPA asserts this tracking satisfies the "separate accounting" obligation FERC has defined for BPA. Powerex Br., BP-12-B-PX-01, at 15. Powerex argues that if the reserves attributed to transmission have been so consumed, and are thus unavailable to serve Transmission purposes, the "practical effect" of such consumption "would be the same as if BPA had failed to separately account for these reserves in the first place," and thus violates the separate accounting requirement. *Id.*, Powerex Br. Ex., BP-12-R-PX-01, at 4.

JP05 argues that BPA's reserves proposal does not violate the separate accounting requirement. JP05 Br., BP-12-B-JP05-01, at 5.

BPA Staff's Position

BPA is required to equitably allocate the costs of the transmission system between Federal and non-Federal uses of the system. Lovell and Mandell, BP-12-E-BPA-37, at 5. The *reliance on* TS reserves by PS does not cause cost increases for TS. *Id.* at 16. Staff disagrees “that consumption of reserves attributed to TS by PS violates cost causation. The costs will still be allocated to PS, and PS will need to restore the funds in the future.” *Id.* at 17.

FERC has ruled that BPA may choose to temporarily apply revenues from one function to the other, and if it does so, it must account for the funds and repay them from the appropriate revenues. Lovell and Mandell, BP-12-E-BPA-37, at 15.

Evaluation of Positions

Powerex contends that PS’s consumption of reserves attributed to TS to pay its financial obligations could result in higher Transmission rates, which violates the equitable allocation standard in the Transmission System Act and Northwest Power Act. Powerex Br., BP-12-B-PX-01, at 14. As in its other arguments, Powerex blurs the distinction between PS’s reliance upon reserves attributed to Transmission for purposes of ratesetting and the possible consumption of such reserves for payment of PS’s financial obligations. The reserves proposal does not entail the consumption of TS reserves to pay PS obligations.

The concept of equitable allocation, as interpreted by FERC, requires BPA to “provide a readily identifiable accounting of its transmission system costs and the revenues generated from its use, along with the status of repayment of each major segment investment in transmission facilities.” 25 FERC ¶ 61,140, at 61,375 (1983), *citing* 20 FERC ¶ 61,142, at 61,315 (1982). BPA provides this separate accounting. The reliance by PS on reserves attributed to TS does not impact any costs properly attributed to PS or TS in this proceeding. BPA Staff’s reserves proposal does not allocate PS costs to TS revenues or vice versa. In the event that reserves attributed to one business line are consumed by the other, the costs will still be allocated to the proper business line. Lovell and Mandell, BP-12-E-BPA-37, at 17. Therefore, equitable allocation of Transmission system expenses, as required by the Transmission System Act and the Northwest Power Act, is not affected by BPA Staff’s reserves proposal.

Powerex further contends that the consumption of reserves attributed to TS violates the separate accounting provisions articulated by FERC. This is not a new circumstance, however, and FERC previously determined that BPA may temporarily apply the revenues from one function to the other. FERC held that

Bonneville asserts the right to apply revenues from one function, such as transmission, to temporarily support unrecovered costs of the other function. We have no objections to Bonneville’s doing so. However, the Commission has previously recommended that, if Bonneville chooses to temporarily apply revenues from one function to the unrecovered costs of the other function, Bonneville account for these funds, repay them from the appropriate revenues, and charge the costs to the appropriate customers.

54 FERC ¶ 61,235 at 61,693 (1991). FERC made no exception to this endorsement for cases in which any particular “practical effect” may occur. The main harm Powerex argues about—the possible consumption of reserves attributed to Transmission—is possible not because of BPA Staff’s reserves proposal but because of the unitary nature of BPA. Lovell and Mandell, BP-12-E-BPA-37, at 14. BPA Staff’s reserves proposal includes tracking and replenishment features to adequately implement separate accounting as required by FERC.

Powerex argues that “BPA’s proposal would fail to adequately assure repayment of reallocated Transmission reserves to Transmission customers, and thus would not meet FERC’s standards.” Powerex Br. Ex., BP-12-R-PX-01, at 6-7. FERC has made no requirement that BPA provide a concrete plan or timeline to assure repayment in the event that some reserves allocated to one business line are consumed due to the other’s actions; FERC has stated only that, should revenues from one function be applied to support the costs of the other, the revenues must be accounted for, repaid from the appropriate revenues, and charged to the appropriate customers. 54 FERC ¶ 61,235 at 61,693 (1991). Therefore, *the potential for consumption* is not violating FERC’s standards as Powerex has asserted. BPA has, in fact, created a concrete mechanism for replenishing any reserves attributed to TS used to pay PS obligations (the requirement that the CRAC threshold be set at least as high as the equivalent of \$0 in reserves for risk attributed to PS). Lovell *et al.*, BP-12-E-BPA-15, at 52. Powerex argues that this concrete mechanism is not “adequate,” but it offers no alternative, or even a suggestion of what “adequate” means in this situation.

Decision

BPA’s reserves proposal does not violate the Transmission System Act or the Northwest Power Act’s requirement of “equitable allocation” or the corollary requirement for separate accounting standards.

Issue 2.5.1.3.5

Whether BPA should rely first on the Treasury Facility for risk mitigation and only after that on reserves attributed to Transmission.

Parties’ Positions

Powerex argues that “BPA should rely first on the Treasury Facility for the purpose of mitigating risk for PS.” Powerex Br., BP-12-B-PX-01, at 18. Powerex argues that this would “lessen the potential impact on Transmission customers.” *Id.* at 19.

Northwest Wind Group states, “if the Administrator goes forward with this proposal, NWG recommends that transmission financial reserves be used as a last resort, not a first resort.” NWG Br., BP-12-B-NG-01, at 92.

BPA Staff's Position

Staff states that “[p]rescribing an order in the rate proceeding will do nothing to increase the assurance that TS customers will be kept whole, and may restrict BPA Finance’s ability to manage liquidity in the most prudent manner.” Lovell and Mandell, BP-12-E-BPA-37, at 9. The possibility of harm to Transmission customers arises only if all of the liquidity available to BPA for payment of financial obligations associated with Power has been exercised—that is, only if both the Treasury Facility and reserves attributed to Transmission have been exercised to their fullest extent. *Id.* at 10. Staff proposed that if Transmission reserves are consumed first, and the Treasury Facility is not fully consumed, and there were Transmission needs for the reserves attributed to it, BPA would assume that it would exercise the Treasury Facility to make the needed reserves available for the Transmission purposes, thus preventing harm to Transmission customers. *Id.*

Evaluation of Positions

In the Initial Proposal, Staff proposed to rely on both reserves attributed to transmission and the Treasury Facility for Power TPP purposes. Staff proposed that no order (*e.g.*, first versus second) would be prescribed for that reliance. Hence, it is reasonable to infer that when Powerex and Northwest Wind Group argue that if reserves for risk attributed to Power are exhausted, BPA should “rely first on” or “use first” the Treasury Facility, they mean that BPA should exercise the Treasury Facility to generate cash for payment of financial obligations associated with Power before disbursing reserves attributed to Transmission for such payments.

Powerex claims that relying on the Treasury Facility first would lessen the potential impact on Transmission customers. Powerex Br., BP-12-B-PX-01, at 19. However, Powerex fails to describe how this order would reduce the potential for harm. Northwest Wind Group also fails to describe why an order of use should be prescribed.

The issue regarding the order of exercising either the Treasury Facility or TS reserves is an internal financial policy matter that will be made if and when BPA is faced with the decision. However, as noted, Staff’s proposal to exercise the Treasury Facility—should capacity remain—to make any reserves that are both attributed to Transmission and needed by Transmission available to Transmission is reasonable, and renders moot the issue of the order of applying the Treasury Facility and reserves attributed to Transmission to any shortfall in reserves attributed to Power.

Decision

BPA need not rely on or exercise the Treasury Facility before reserves attributed to Transmission. A decision on the ordering of such use is an internal financial policy matter.

Issue 2.5.1.3.6

Whether BPA should reduce to \$100 million the reliance for Power TPP purposes on reserves attributed to Transmission to align such reliance with the \$100 million first phase of the CRAC.

Parties' Positions

Powerex argues that BPA should not rely for Power TPP on an amount of reserves attributed to Transmission that is greater than the size of the first phase of the CRAC. Powerex Br., BP-12-B-PX-01, at 18. Powerex further argues that Staff's proposal entails a significant possibility that full replenishment of any reserves attributed to Transmission that are consumed might be delayed to future rate periods, and this is not acceptable. *Id.* at 19.

Powerex states that "BPA has failed to ensure that any replenishment necessary will be completed in a sufficiently timely manner to keep Transmission customers whole in future rate periods." *Id.* at 3. Powerex argues that "BPA has failed to propose a commitment to ensure full restoration of reserves attributed to Transmission by the end of the rate period...." *Id.* at 5.

BPA Staff's Position

Staff states:

We believe that the proposed CRAC methodology is adequate. Reserves attributed to TS and the Treasury Facility are relied upon as liquidity tools. Any combination of the two liquidity tools could be used; therefore, the relationship between the parameters of the CRAC and the level of reliance on TS reserves—one of two sources of liquidity—is not very important. BPA must be concerned with not only the PS ability to replenish TS reserves, but also the PS ability to repay any Treasury Facility usage. Powerex's proposed methodology prescribes that if PS were to rely on only \$10 million of reserves attributed to transmission, then the CRAC would be set to recover 100 percent only up to \$10 million and then 50 percent after that. We do not believe that setting the CRAC in such a way—tying the size of the CRAC amount that is to be recovered dollar-for-dollar exactly to the level of reliance on TS reserves—is necessary.

Lovell and Mandell, BP-12-E-BPA-37, at 10.

Staff continues, "[w]hile the CRAC will recover from rates the amount calculated by the CRAC formula, the actual amount of liquidity replenishment that will occur cannot be known with certainty. PS net revenue uncertainty in the following year may result in BPA's reserves increasing by more or less than the amount of the CRAC revenues." *Id.* at 28.

Evaluation of Positions

Powerex has argued repeatedly that BPA should commit to a specific time by which any reserves attributed to Transmission that are consumed will be replenished. *See, e.g.*, Powerex Br., BP-12-B-PX-01, at 3 and 5. Powerex's argument on this issue is part of the larger timely replenishment issue. Powerex implies that reducing the reliance for Power TPP purposes on reserves attributed to Transmission to the size of Phase 1 of the CRAC would significantly accelerate and increase the assurance of replenishment of reserves. Let us examine that implied assertion. Suppose reserves for risk attributed to Power were fully exhausted, and suppose further that an additional

\$150 million of cash was needed to pay obligations associated with Power, and yet further that reserves attributed to Transmission were tapped for this purpose.

According to the terms of Staff's proposal, a two-phase CRAC would be implemented for the subsequent fiscal year. Phase one would recoup 100 percent of the first \$100 million needed, or \$100 million; phase two of the CRAC (applying to rates in the same years as phase one) would recoup 50 percent of the remaining reserves shortfall (up to a maximum total for the two phases of \$300 million), or \$25 million in this example for phase two. Thus, the CRAC Staff has proposed would result in a CRAC of \$125 million for the next year. Powerex's suggestion would reduce the reliance on reserves attributed to Transmission to \$100 million. Under this proposal, only \$100 million of reserves attributed to Transmission would be used for Power TPP purposes in the rate proposal. However, as Staff has argued, the possibility that reserves attributed to one function could be used to pay obligations for the other function exists with or without BPA Staff's reserves proposal. Therefore, the amount of reserves attributed to Transmission that might be consumed paying bills is not strictly tied to the amount of reserves relied upon for the Power TPP calculations.

Suppose for the sake of the next argument, though, that under Powerex's proposal, only \$100 million of reserves attributed to Transmission are actually consumed, and \$50 million of the Treasury Facility is exercised. Thus, a CRAC of \$125 million, the same as under Staff's proposal, would be implemented. No parties have argued in brief that one of the two sources of liquidity Staff proposed relying on should be replenished before the other. Staff also does not propose an order for application of CRAC-generated reserves for replenishing the two sources of liquidity if both have been exercised. It is possible that the \$50 million of Treasury Facility borrowing would be replenished first, leaving the total amount of CRAC revenue available for replenishing Transmission reserves short of the amount consumed by \$25 million, the same amount as under the Staff-proposal example. (Note that Staff proposed to assume that if the consumed Transmission reserves are needed for Transmission purposes, BPA would exercise the Treasury Facility to make the needed reserves available. Lovell and Mandell, BP-12-E-BPA-37, at 10. Logically, this assumption would be extended to this example so that if the consumed Transmission reserves were needed for Transmission purposes, only \$25 million of the Treasury Facility borrowing would be repaid, and the full \$100 million of reserves attributed to Transmission would be replenished.)

Suppose, though, that the two examples result in different degrees of replenishment—that under Staff's proposal, CRAC revenues are \$25 million too small to entirely replenish consumed reserves attributed to Transmission, and that under Powerex's proposal, CRAC revenues are as large as the consumed reserves. Does this difference amount to a significant acceleration or assurance of replenishment of reserves? Staff argued that the unavoidable uncertainty in PS net revenue makes it impossible to commit to a specific timetable for replenishment. *Id.* at 14. For replenishment of reserves attributed to Transmission consumed during FY 2012 to be complete by the end of FY 2013, Power cash flow would need to be \$25 million or higher under Staff's proposal, and would need to be \$0 or higher under Powerex's proposal. How much more likely is full replenishment by the end of FY 2013 in the Powerex example than in the Staff example?

One of the input files for the ToolKit from BPA’s Initial Proposal, the RiskMod Output file (“RiskMod-Output_BP-12_InitProp_19-Nov-10.xls,” available at BPA’s BP-12 Rate Proceeding Web site under BPA Models and Data Sets, contains data that may illuminate this. Tab “NetRev_Stats” shows percentiles for Power net revenue for FY 2013. There is a 55 percent chance of PS net revenue being at least negative \$14.2 million, a 50 percent chance of PS net revenue being at least \$22.6 million, and a 45 percent chance of PS net revenue being at least \$61.3 million. Interpolating, it is about 53.1 percent likely that PS net revenue will be at least \$0, and about 49.7 percent likely that PS net revenue will be at least \$25 million. This is a difference of 3.4 percentage points. This is not a significant difference in the rate of replenishment or the likelihood of full replenishment in the next year.

A shortfall of less than \$150 million would show even less significant difference in pace or surety of replenishment. The difference calculated here required making several assumptions designed to emphasize the difference between Powerex’s proposal and Staff’s proposal; actual circumstances could make the difference in practice even smaller.

Powerex’s proposal would not significantly increase the rate of replenishment.

Decision

BPA need not limit the reliance for Power TPP purposes on reserves attributed to Transmission to \$100 million to align such reliance with the \$100 million first phase of the CRAC.

Issue 2.5.1.3.7

Whether Power Services will rely upon reserves attributed to Transmission Services in order to mitigate TPP risk in the BP-12 rate proposal.

Parties’ Positions

JP05 supports BPA’s proposal to rely on TS reserves to mitigate TPP risk. JP05 Br., BP-12-B-JP05-01. JP05 asserts that BPA’s proposed methodology is legally sound and defensible. *Id.*

Northwest Wind Group opposes Staff’s proposal to use transmission financial reserves of \$150 million or more to lower rates to its power customers. NWG Br., BP-12-B-NG-01, at 92.

Powerex argues that “BPA’s proposed reliance on reserves attributed to Transmission ... creates significant uncertainty for BPA’s Transmission customers.” Powerex Br., BP-12-BP-PX-01, at 3. Powerex also states that “BPA has failed to ensure that any replenishment necessary will be completed in a sufficiently timely manner to keep Transmission customers whole in future rate periods.” *Id.* Powerex states that BPA’s reserves reliance is “not BPA’s standard course of business....” Powerex Br. Ex., BP-12-R-PX-01, at 6.

BPA Staff's Position

A new criterion has been added for determining the threshold for the CRAC to ensure that Power rates will quickly begin to restore any PS-related consumption of liquidity. Lovell, *et al.*, BP-12-E-BPA-15, at 50. In the event of consumption of reserves, TS will be credited with any reserves and related interest that would have been earned in the absence of consumption. *Id.* at 50-51. Reserves attributed to TS in excess of those needed for TS risk mitigation and other purposes are a prudent source of liquidity for PS to rely upon for TPP risk mitigation in ratesetting. *Id.* at 48-51; Lovell and Mandell, BP-12-E-BPA-37, at 2-15.

Evaluation of Positions

Powerex raised many objections to this proposal, evaluated earlier in this section of the ROD. Staff provided many assurances that BPA intends to keep Transmission customers whole, and that Staff had created mechanisms designed to do that. The residual potential for harm to Transmission customers, in spite of the mechanisms Staff proposed, is due to the unitary nature of BPA, not to BPA's reserves proposal. In the BP-12 Transmission risk analysis, BPA determined that at least \$150 million in reserves attributed to Transmission could be relied upon by PS for mitigating TPP risk in ratesetting. Transmission Revenue Requirement Study, BP-12-FS-BPA-07, section 2.2. Whether BPA adopts the reserves proposal or not, all of BPA's financial reserves, including at least \$150 million in reserves attributed to Transmission that are beyond the needs for reserves identified in the Transmission Revenue Requirement Study, are available to BPA to pay any of his financial obligations.

Powerex argues that the Draft ROD "obscures the fact that BPA has very rarely, if ever, put forward similar reserve-sharing proposals as part of past rate cases. This is simply not BPA's standard course of business, no matter how the Draft ROD tries to characterize it." Powerex Br. Ex., BP-12-R-PX-01, at 6. While it is irrelevant whether a reliance on reserves attributed to TS for risk mitigation is "BPA's standard course of business," such reliance did occur in the WP-07 case. PS relied upon \$55 million in reserves attributed to TS in the first fiscal year of that rate period for PS TPP purposes. Risk Analysis Study, WP-07-FS-BPA-04, at 44.

In the Final Proposal risk analysis, the PS TPP is higher than 95 percent without any reliance for TPP purposes on reserves attributed to Transmission, making such reliance unnecessary for the purpose of meeting BPA's 95 percent TPP standard in this rate period. Power Risk and Market Price Study, BP-12-FS-BPA-04, section 3.2.1.3.

Decision

Power Services will not rely on reserves attributed to TS for Power TPP purposes.

2.5.2 Market Price Forecast

The gas and electricity market price forecasts are part of the Power Risk and Market Price Study, BP-12-FS-BPA-04. The market price forecast is an output of the AURORAxmp model and is a function of many variables, including regional gas price forecasts, WECC-wide loads,

transmission availability, committed forward power transactions, and resource data. It is used in calculating the wholesale power rates for FY 2012–2013. The documentation supporting the results of the market price forecast is presented in the Power Risk and Market Price Study Documentation, BP-12-FS-BPA-04A. The gas and electricity market price forecasts are described in the direct testimony of Kujala *et al.*, BP-12-E-BPA-14.

The forecasts of electricity market prices are used for (1) the secondary revenue forecast, BP-12-FS-BPA-04, section 2.6.3; (2) augmentation purchase costs, BP-12-FS-BPA-04, section 2.6.2; (3) the risk analysis, BPA-12-FS-BPA-04, section 2.5.2; (4) the variable cost component of generation input capacity, BPA-12-FS-BPA-04, section 3.4; (5) utility average system costs, BPA-12-FS-BPA-01, section 8; and (6) rate design, BPA-12-FS-BPA-01, section 3.

BPA is updating the inputs for the gas and electricity market price forecasts for the Final Proposal in a manner that is consistent with testimony of Kujala *et al.*, BP-12-E-BPA-14, Section 6.

No issues related to the market price forecast were raised by any party.

2.6 Power Rate Development

2.6.1 Introduction

The Power Rate Development section of this ROD encompasses cost allocation, rate design, implementation of TRM rate design in ratesetting, power rate schedules, and general rate schedule provisions.

The Power Rates Study (PRS) explains the processes and calculations used to develop the rates and billing determinants for BPA's wholesale power products and services. The Power Rates Study serves three primary purposes: (1) to demonstrate that the proposed rates have been developed in a manner consistent with statutory direction, including the initial allocation of costs and the subsequent reallocations directed by statute; (2) to set rates consistent with agency policy; and (3) to demonstrate that the proposed rates have been set at a level that recovers the allocated power revenue requirement for the upcoming rate period.

The Northwest Power Act, 16 U.S.C. § 839, is the most significant ratemaking directive to BPA. Section 7 directs the allocation of costs, which is performed in the cost of service analysis, and a set of rate directives providing further guidance on how individual rates are to be derived. BPA rates must follow the ratesetting directives of section 7, but, as characterized in the legislative history of the Northwest Power Act, the rate directives govern the amount of revenue BPA collects from each class of customers, not the rate form. Section 7 reserves rate design (how the revenue is collected) to the Administrator.

The cost of service analysis and the other ratemaking steps are programmed into a spreadsheet model, RAM2012, for purposes of calculating power rates. The Power Rates Study describes

how the tiered Priority Firm Power Public rate is designed following the cost of service and rate directives ratemaking steps. The rate design for the PF Public rate was established in the TRM.

An underlying policy for BP-12 ratesetting is that price signals sent by the PF, IP, and NR rate schedules should be similar to the extent possible. Bliven *et al.*, BP-12-E-BPA-11, at 29. To that end, the demand charge is designed to send a price signal to reflect the cost associated with the use of BPA's capacity. *Id.*; see ROD section 2.6.3. The PF, IP, and NR rate schedules include the same demand rates. Bliven *et al.*, BP-12-E-BPA-11, at 29. The general method used to calculate the PF Tier 1 demand charge is also used for calculating the demand billing determinant for the IP and NR rate schedules. *Id.* at 29-30. See ROD section 2.6.4 for further discussion of the IP rate.

To reflect the new rate design, the Priority Firm Power rate schedule and associated GRSPs needed to be revamped. Bliven *et al.*, BP-12-E-BPA-11, at 30. The changes in the demand billing determinants for the NR and IP rate schedules resulted in changes to those rate schedules also. *Id.*

2.6.2 Service to New Publics

Jefferson County PUD is the first consumer-owned electric utility to form under the CHWM contract. Bliven *et al.*, BP-12-E-BPA-11, at 33-34. Accordingly, Jefferson County PUD now has the right to buy power under the tiered rate structure, including load served at a Tier 1 rate. *Id.* Jefferson County PUD will be eligible to begin purchasing power at the Tier 1 PF rate starting July 1, 2013. *Id.* A CHWM is being developed for Jefferson PUD in accordance with section 4.1.6.2 of the TRM.

Any service to Jefferson prior to July 1, 2013, will be subject to the Unanticipated Load Rate, described in GRSP II.U. As discussed in ROD section 1.2.2.2, Jefferson County PUD's CHWM has not been finalized in time to be included in the BP-12 rates. Therefore, for calculation of the BP-12 rates, BPA is using the best estimate of Jefferson's CHWM and its load forecast.

2.6.3 Demand Rate

2.6.3.1 Introduction

The purpose of rate design is to define the methods and criteria used for collecting the revenue requirement allocated to specific rate classes from power sales to those classes. BPA rates must follow the ratesetting directives of section 7 of the Northwest Power Act, but, as clearly stated in the legislative history of the Northwest Power Act, the rate directives govern the amount of revenue BPA collects from each class of customers, not the rate form used to collect that revenue from each class of customer. H.R. Rep. No. 96-976, Pt. II, 96th Cong., 2nd Sess. 53 (1980). In Northwest Power Act section 7(e), Congress reserves rate design (how the revenue is collected) to the Administrator. *See also* ROD section 1.1.2 and Issue 2.1.1.2.

Rate design is applied after BPA has allocated its total power revenue requirement to five rate pools. The five rate pools are Priority Firm Public Power, Priority Firm Exchange Power,

Industrial Firm Power, New Resources Firm Power, and Firm Power Products and Services. PRS, BP-12-FS-BPA-01, at 50. Rate design does not change the amount of the revenue requirement that is allocated to each of the five rate pools. *Id.* Rather, rate design determines how the revenue requirement is to be collected through rates for each of the five rate pools. *Id.* One purpose of rate design is to target the revenue collection within a particular rate pool and to distinguish between different types of service and power consumption of individual wholesale power customers. *Id.* Another purpose is to provide price signals to customers to encourage more efficient power usage and differentiate between the relative market value of the products and services BPA offers to its customers. *Id.*

The subsections that follow review the issues that were raised by rate case parties in their briefs concerning the rate design used in the development of BPA's FY 2012–2013 power rates. The issues address the determination of the PF Public demand rate and the Industrial Firm Power demand rate billing determinant.

2.6.3.2 Issues

Issue 2.6.3.2.1

When determining the capital costs for the marginal resource, whether BPA should use (1) the capital costs for an independent power producer (IPP) embedded in the Council's Microfin model or (2) the capital costs associated with a municipal/PUD embedded in the Council's Microfin model.

Parties' Positions

JP01 argues that BPA should use the IPP financing assumptions in the Council's Microfin model rather than the model's municipal/PUD assumptions. JP01 Br., BP-12-B-JP01-01, at 12; Murphy, Oral Tr. at 224-225. JP01 contends that it is not reasonable for BPA to assume it could acquire capacity from a developer with municipal/PUD tax-exempt financing. *Id.* JP01 states that all of the major resources, excluding conservation, BPA has acquired since the passage of the Northwest Power Act have been from IPPs. JP01 Br., BP-12-B-JP01-01, at 12. JP01 contends that it is almost certain that the only type of developer BPA could look to for capacity would be an IPP, which would have higher financing costs than a public agency would have. *Id.*; Murphy, Oral Tr. at 225-226. JP01 argues that using the municipal/PUD assumption in the Microfin model is inconsistent with the TRM, which provides that the demand rate calculation may be based on the market price of capacity if a viable capacity market develops in the Pacific Northwest. JP01 Br., BP-12-B-JP01-01, at 12. JP01 contends that because IPPs would likely have a significant role in this future capacity market, the financing assumptions should reflect this fact. *Id.* JP01 also requests that if BPA adheres to Staff's proposal to use municipal/PUD financing assumptions with BPA-backed bonds, that the Record of Decision explicitly state that the decision does not establish any precedent for future rate cases. *Id.* at 14; Murphy, Oral Tr. at 226. JP01 argues that the demand rate "should fully compensate Bonneville for the cost [of] capacity." Murphy, Oral Tr. at 227.

JP07 and Snohomish both support JP01's positions with regard to the demand rate calculation. JP07 Br., BP-12-B-JP07-01, at 1; Snohomish Br., BP-12-B-SN-01, at 9.

JP02 and WPAG support Staff's use of the capital costs associated with the municipal/PUD financing assumptions in the Microfin model. JP02 Br., BP-12-B-JP02-01, at 5; WPAG Br., BP-12-B-WG-01, at 49; JP02 Br. Ex., BP-12-R-JP02-01, at 4-5. JP02 and WPAG state that the TRM rate design results in the demand rate sending a price signal, and the demand rate is not intended to reflect BPA's costs to acquire such a marginal resource. JP02 Br., BP-12-B-JP02-01, at 5; WPAG Br., BP-12-B-WG-01, at 49; JP02 Br. Ex., BP-12-R-JP02-01, at 5. JP02 and WPAG argue that it is irrelevant whether BPA could or could not reasonably acquire a capacity resource at the level of the calculated demand rate, because the sole function of the rate is to send a price signal to customers. JP02 Br., BP-12-B-JP02-01, at 5; WPAG Br., BP-12-B-WG-01, at 49.

BPA Staff's Position

Staff agrees with all parties that one intent of the demand rate is to provide a price signal. Fisher *et al.*, BP-12-E-BPA-41, at 2. Staff constructed the demand rate based on an estimated cost to BPA for new capacity with the assumption that a municipal/PUD would develop the resource for BPA and that BPA would back the bonds to gain a favorable debt financing rate. PRS Documentation, BP-12-E-BPA-01A, at 101. The term and debt financing assumptions for a municipal/PUD developer are contained in the Council's Microfin model, and the debt rate is consistent with BPA's forecast of Third-Party Tax-Exempt Borrowing rates. Fisher *et al.*, BP-12-E-BPA-18, at 21.

Evaluation of Positions

JP01, Snohomish, and JP07 contend that it is not reasonable for BPA to use the municipal/PUD financing assumptions contained in the Council's Microfin model. JP01 Br., BP-12-B-JP01-01, at 12; JP07 Br., BP-12-B-JP07-01, at 1; Snohomish Br., BP-12-B-SN-01, at 9. These parties argue that any acquisition of a capacity resource by BPA would be from an IPP, which would entail more costly financing than a public agency could realize. JP01 Br., BP-12-B-JP01-01, at 12; JP07 Br., BP-12-B-JP07-01, at 1; Snohomish Br., BP-12-B-SN-01, at 9. JP01 states that all of the resources BPA has acquired since the passage of the Northwest Power Act have been from IPPs, and therefore BPA cannot reasonably assume it would acquire such a resource from a municipal/PUD developer. JP01 Br., BP-12-B-JP01-01, at 12.

The argument advanced by JP01, Snohomish, and JP07 has changed from that in their direct case. JP07 (which includes both Snohomish and the members of JP01) argued in testimony that the municipal/PUD financing assumption was not reasonable because BPA would acquire a capacity resource only to integrate variable resources. Hill *et al.*, BP-12-E-JP07-01, at 6. As such, JP07 contended, under section 9(f) of the Northwest Power Act BPA could not certify that the acquisition was made to serve load pursuant to section 5 of the Act. *Id.* Because the acquisition would not be to serve section 5 loads, the project would not be eligible for tax-exempt financing. *Id.* at 7. This argument was dropped by JP01, Snohomish, and JP07 after JP01 conceded to Staff's rebuttal to their 9(f) argument. JP01 Br., BP-12-B-JP01-01, at 13.

JP01 argues, among other things, that BPA has never acquired the output of a municipal/PUD financed project, excluding conservation, since the passage of the Northwest Power Act, and it is therefore unreasonable to assume for the purposes of the calculation of the demand rate that it would in the future. JP01 Br., BP-12-B-JP01-01, at 12.

In response to the 9(f) argument, Staff notes in its rebuttal testimony that the demand rate is intended to send a price signal to PF Public customers for both load service and hour-to-hour support for variable resources that are being applied to PF Public customer load. Fisher *et al.*, BP-12-E-BPA-18, at 20. Staff does not directly address the contention that all BPA resource acquisitions since the passage of the Northwest Power Act were from IPPs, because JP01 raised the issue for the first time in brief.

JP01's assumption regarding the source of BPA's prior resource acquisitions is wrong. BPA has a long history of acquiring the output of resources from municipal/PUD developments. Columbia Generating Station and Cowlitz Falls are some of the examples of municipal/PUD financing using BPA-backed bonds. Idaho Falls and Wauna are other examples of resources that BPA has acquired from municipals and PUDs. Given BPA's history, it is not unreasonable to use a municipal/PUD acquisition assumption.

JP01, JP02, and WPAG argue that a particular financing assumption is more consistent with the intent of the TRM. JP02 and WPAG contend the sole purpose of the demand rate in the TRM is to send a price signal. JP02 Br., BP-12-B-JP02-01, at 5; WPAG Br., BP-12-B-WG-01, at 49; JP02 Br. Ex., BP-12-R-JP02-01, at 5. Both JP02 and WPAG state that it is irrelevant whether BPA could acquire a capacity resource at the level of the calculated demand rate. JP02 Br., BP-12-B-JP02-01, at 5; WPAG Br., BP-12-B-WG-01, at 49.

JP01, JP02, and WPAG do not present arguments wholly consistent with the TRM. While the demand rate is designed to send a price signal, the calculation of the demand rate cannot be totally divorced from the costs associated with BPA's acquisition of the output of the marginal resource. The TRM uses the fixed costs associated with the marginal capacity resource to emulate the costs associated with what it might cost BPA to acquire the capacity. The TRM provides that:

BPA will identify the marginal capacity resource and the annual fixed costs associated with that resource for each Rate Period....Such marginal capacity resource may be based on BPA's Resource Program and/or costs of BPA's recent capacity additions. Or it may be based on third-party sources, which may include, but are not limited to, the Energy Information Administration, EPRI Technical Assessment Guide, the Northwest Power and Conservation Council, and Integrated Resource Plans of the Pacific Northwest electric utilities.

BP-12-A-03, section 5.3.6. The TRM ROD states that the objective of the Demand Charge is to pass on to customers the actual cost of capacity. TRM-12-A-01, at 76. While there are several options under the TRM for the identification of the marginal resource, the first two sources listed are from BPA itself and include either a forecast of a future resource acquisition cost in BPA's

Resource Program or the cost of a resource actually acquired by BPA. Even though there are other third-party options listed, the implication of listing the BPA resources is that these other sources should be representative of the potential cost to BPA.

In contrast, JP01 argues that the TRM supports the use of the IPP financing assumptions. JP01 Br., BP-12-B-JP01-01, at 12. JP01 points out that the TRM provides that BPA may base the demand rate on market prices from a viable PNW capacity market. While no such market exists at this time, JP01 nevertheless speculates that IPPs will likely play a large role in any future capacity market in the PNW. *Id.* Because of this anticipated IPP involvement, JP01 contends it would be inconsistent with the TRM to use the municipal/PUD financing assumptions. *Id.* Whether IPPs play a significant role in some yet-to-be developed capacity market in the PNW may be unrelated to the cost of a capacity acquisition to BPA to meet its PF Public load obligations. Since there is no viable capacity market available to BPA, BPA cannot use it as a possible source of information, let alone determine if BPA is likely to purchase capacity from that market to meet its PF Public load obligation.

Staff proposes to use the cost assumptions from a third-party source (Council's Microfin model) to forecast capital costs for the marginal resource. Fisher *et al.*, BP-12-E-BPA-18, at 21. Staff believes that municipal/PUD financing assumptions are more appropriate to determine what it would cost BPA to acquire the output of a capacity resource. As noted above, BPA has a history of acquiring the output of resources with municipal/PUD financing with BPA-backed bonds. Because BPA has not made an actual capacity resource acquisition to serve PF Public loads during the Regional Dialogue period, BPA must project the possible future cost it may incur for a capacity resource acquisition. Given there are historical examples of resource acquisitions made with municipal/PUD financing costs with BPA-backed bonds, this approach is reasonable to value future marginal resource costs. The municipal/PUD financing option with BPA-backed bonds would likely be the least-cost financing option and thus the option first sought by BPA. Therefore, the use of the Council's data set with municipal/PUD financing backed by BPA reflects a reasonable approach as well as the preferred and first-sought method of acquiring additional capacity from a third party.

While BPA will use a municipal/PUD approach for purposes of establishing a demand rate for this rate period, it is possible that circumstances could change that would no longer make it appropriate to use the Council's data or some assumption within the Council's model. As stated by the TRM, BP-12-A-03, section 5.3.6, the identification of the appropriate resource and its costs "for each Rate Period" used for the demand rate will be determined in each 7(i) Process, and the source of the data as well as the assumptions used within that data source will be revisited. BPA interprets the TRM to expressly state the assurance that JP01 seeks that there is no precedent accorded to the BP-12 demand rate findings.

JP01 argues that the demand rate "should fully compensate Bonneville for the cost [of] capacity." Murphy, Oral Tr. at 227. But compensation is not the issue in this proceeding. BPA does not expect to incur new costs of capacity to serve PF Public load growth or supply Resource Support Services during the BP-12 rate period. What is important in the instant case is whether the level of the demand rate is sufficient to induce public utilities to investigate and procure

resources and programs that would reduce their demand charges. BPA believes that the modified Staff proposed demand rate based on the municipal/PUD financing should be sufficient to produce the desired effects. Whether it is sufficient will be discussed in future rate proceedings.

Decision

BPA will use a municipal/PUD financing assumption with BPA-backed bonds for calculating the capital cost portion of the marginal resource. The municipal/PUD financing with BPA-backed bonds assumption in the Council's Microfin model is a reasonable projection of possible future capacity costs BPA may incur to meet PF Public load. In addition, it represents the preferred least-cost financing method to the region and the method first sought by BPA. BPA will revisit the issue in the next rate case to determine if the approach used in this proceeding is still reasonable.

Issue 2.6.3.2.2

Whether BPA should assume additional costs for property taxes or in-lieu property taxes in the demand rate calculation.

Parties' Positions

JP01 argues that property taxes should be fully reflected in the fixed costs of the marginal capacity resource and that the 1 percent upward adjustment to direct capital costs to cover "social justice costs" embedded in the Council model will not be sufficient to cover an ongoing stream of in-lieu property tax payments. JP01 Br., BP-12-B-JP01-01, at 14.

JP07 and Snohomish support JP01's position with regard to the demand rate calculation. JP07 Br., BP-12-B-JP07-01, at 1; Snohomish Br., BP-12-B-SN-01, at 9.

JP02 argues that property taxes should not be included in the demand rate calculation. JP02 Br., BP-12-B-JP02-01, at 7; JP02 Br. Ex., BP-12-R-JP02-01, at 4.

BPA Staff's Position

Staff uses the Council's Microfin model as the source for the all-in capital costs (in which direct capital costs are included) of an LMS-100 combustion turbine. Fisher *et al.*, BP-12-E-BPA-18, at 21. Staff believes the Council has already accounted for in-lieu property tax costs that could be incurred by a public entity that is exempt from property taxes by means of a 1 percent upward adjustment to the direct capital costs. Fisher *et al.*, BP-12-E-BPA-41, at 7.

Evaluation of Positions

JP01 contends that the 1 percent upward adjustment in the direct capital costs embedded in the Microfin model does not fully account for the ongoing stream of property taxes. JP01 Br., BP-12-B-JP01-01, at 14. JP02, in contrast, contends BPA should not assume any additional

amount for property taxes. JP02 Br., BP-12-B-JP02-01, at 7; JP02 Br. Ex., BP-12-R-JP02-01, at 4.

The Microfin model calculates the all-in capital costs, which include a 1 percent upward adjustment to the direct capital costs to capture certain “social justice” costs. Fisher *et al.*, BP-12-E-BPA-41, at 7. Payments in lieu of property taxes are considered social justice costs. Therefore, the Council has already included a cost provision to cover social justice costs such as in lieu of property tax. *Id.*

Given the decision to assume municipal/PUD development of the capacity resource (see Issue 2.6.3.2.1), it would be inappropriate to add additional costs for property taxes, because public entities are exempt from property taxes. While municipal/PUD projects may be subject to in-lieu fees, the 1 percent upward adjustment used by the Council reasonably accounts for this possible cost that is often a product of plant-specific negotiations between state and local government entities. As with the decision to use the municipal/PUD financing assumptions, the decision on property taxes may change in the future if circumstances dictate.

Decision

BPA will not include additional costs for property taxes or in-lieu property taxes in the demand rate calculation since the cost for property taxes is adequately accounted for in the 1 percent adjustment on direct capital costs.

Issue 2.6.3.2.3

Whether BPA should use the assumptions for fixed O&M developed by California Energy Commission (CEC) as opposed to the fixed O&M data from the Council’s Sixth Power Plan to determine the fixed costs of the marginal resource (General Electric LMS-100 gas fired combustion turbine) used to establish the Tier 1 demand rate.

Parties’ Positions

Snohomish and JP01 contend that BPA should use the fixed O&M costs provided by the CEC. Snohomish Br., BP-12-B-SN-01, at 7-8; JP01 Br., BP-12-B-JP01-01, at 15. Snohomish and JP01 state that the CEC data set is more robust because it includes multiple project data points, as compared to the Council’s, which includes only one. Snohomish Br., BP-12-B-SN-01, at 7-8; JP01 Br., BP-12-B-JP01-01, at 15. These parties state that the possibility of an inconsistency between the Council’s data and the CEC’s does not outweigh using the larger CEC data set. Snohomish Br., BP-12-B-SN-01, at 8; JP01 Br., BP-12-B-JP01-01, at 15.

JP07 supports JP01’s position with regard to the demand rate calculation. JP07 Br., BP-12-B-JP07-01, at 1.

WPAG and JP02 contend that BPA should use the Council’s data set for O&M costs. WPAG Br., BP-12-B-WG-01, at 48; JP02 Br., BP-12-B-JP02-01, at 4.

BPA Staff's Position

In the Initial Proposal, Staff uses the CEC's data set for the fixed O&M portion of the costs associated with the LMS-100 rather than the Council's data set, primarily because the CEC data had a larger sample size (six v. one). Fisher *et al.*, BP-12-E-BPA-18, at 21. JP02 and WPAG argue that BPA should not mix sources of information. Carr *et al.*, BP-12-E-JP02-01, at 8; Saleba *et al.*, BP-12-E-WG-01, at 46. WPAG and JP02 are concerned that there might be an inconsistency between data sets that could lead to double counting of costs. Carr *et al.*, BP-12-E-JP02-01, at 8; Saleba *et al.*, BP-12-E-WG-01, at 46. They also testify that the Council's data set is somehow more compatible with the TRM. Carr *et al.*, BP-12-E-JP02-01, at 8; Saleba *et al.*, BP-12-E-WG-01, at 46.

In rebuttal testimony Staff determines that there is merit to JP02 and WPAG's request to rely on the Council's data. Fisher and Bliven, BP-12-E-BPA-41, at 5. Staff states that in order to avoid the possibility of double-counting costs or neglecting to include certain costs by mixing data sources, it will rely solely on the Council's data set. *Id.*

Evaluation of Positions

In rebuttal testimony, Staff modified its Initial Proposal in favor of using the Council's fixed O&M data as opposed to the larger data set compiled by the CEC. Fisher and Bliven, BP-12-E-BPA-41, at 5. The primary reason for the change was to avoid any inconsistency between the data sources. *Id.* Staff's Initial Proposal uses the Council's data for all inputs other than the fixed O&M costs. Fisher *et al.*, BP-12-E-BPA-18, at 21. Although Staff does not believe the Council's data set is more compatible with the TRM, as WPAG and JP02 argue, Carr *et al.*, BP-12-E-JP02-01, at 8; Saleba *et al.*, BP-12-E-WG-01, at 46, it nevertheless recognizes that the use of different data sets raised the potential for double-counting or neglecting to count certain costs. Fisher and Bliven, BP-12-E-BPA-41, at 5.

Snohomish and JP01 argue that the larger CEC data set is more robust and should be used; they contend that this fact outweighs the possibility of double-counting costs. Snohomish Br., BP-12-B-SN-01, at 7-8; JP01 Br., BP-12-B-JP01-01, at 15.

Snohomish and JP01 do not identify any material problem with the Council's O&M data set. Instead, their concern is solely with the number of plants in the respective data sets. The CEC set contains the data from 6 plants, while the Council's contains only one plant. Fisher *et al.*, BP-12-E-BPA-18, at 21. However, the mere fact that there are more plants in the CEC data set is not in itself evidence that the data set better reflects the O&M costs for a plant in the Pacific Northwest. The CEC's data is focused on the cost to California, whereas the Council's data is focused on the cost to the Pacific Northwest. Neither Snohomish nor JP01 presents any evidence demonstrating that the CEC data better reflects the costs associated with a PNW plant. Additionally, the potential for double-counting of costs cannot be brushed aside as Snohomish and JP01 ask BPA to do. Because the CEC's data is obtained from a variety of sources that assemble the data differently, there is no way of knowing for certain whether the CEC's data set consistently accounts for the fixed O&M costs. The CEC specifically points out possible

inconsistencies with sources of information: “Conceptually, fixed O&M comprises those costs that occur regardless of how much the plant operates. The costs included in this category are not always consistent from one assessment to another....” JP02, BP-12-E-JP02-01, at 9-10.

Given there is no evidence on the record demonstrating that there is anything wrong with the Council’s data, along with the recognition that different data sources could result in double-counting or failing to count some costs, the use of the Council’s O&M data is reasonable. If future research leads to a better understanding of the costs included in each dataset, this issue may be revisited. This use of a single source of data is also consistent with Issue 2.6.3.2.4 below, which is an issue that stems from a term (O&M) that generally encompasses all costs other than capital costs but is often reported in granular cost categories for informational purposes.

Decision

The demand rate will be based on the O&M costs of the marginal resource from the Council’s Sixth Power Plan.

Issue 2.6.3.2.4

Whether BPA should include fixed fuel transportation and insurance costs as part of the O&M costs used to establish the Tier 1 demand rate.

Parties’ Positions

WPAG contends that the fixed fuel transportation and insurance costs should not be included as part of the O&M costs used to establish the demand rate. WPAG Br., BP-12-B-WG-01, at 49; WPAG Br. Ex., BP-12-R-WG-01, at 13. According to WPAG, the language of the TRM specifies that the demand rate should be based upon the “annual fixed costs (capital and O&M) of the marginal capacity resource.” WPAG Br., BP-12-B-WG-01, at 49, *citing* TRM-12-A-02, section 5.3.6. *See also* WPAG Br. Ex., BP-12-R-WG-01, at 13. While acknowledging that in some contexts fixed costs include fuel transportation and insurance costs, WPAG notes that “the definition of ‘fixed’ includes commitments or obligations that cannot be changed in the short term.” WPAG Br., BP-12-B-WG-01, at 49. WPAG states that because fuel transportation and insurance can vary on even a monthly basis, they are outside the scope of fixed costs. *Id.*

WPAG argues that the Council’s Sixth Power Plan does not include insurance costs as part of the fixed O&M cost and the fixed fuel transportation costs are properly categorized as part of the “other consumables” in the Council’s definition of variable O&M costs. WPAG Br. Ex., BP-12-R-WG-01, at 15.

JP02 contends that Administrator should adhere to the plain reading of the TRM when calculating the demand rate, which JP02 contends would not include insurance and fixed fuel costs. JP02 Br., BP-12-B-JP02-01, at 7; JP02 Br. Ex., BP-12-R-JP04-01, at 5. JP02 claims the

parenthetical “(capital & O&M)” was meant to be an all-inclusive list. JP02 Br., BP-12-B-JP02-01, at 7; JP02 Br. Ex., BP-12-R-JP04-01, at 6.

JP01 and Snohomish contend that fixed fuel costs and insurance should be included in the demand rate, since they are incurred whether or not a plant is operating. JP01 Br., BP-12-B-JP01-01, at 14; Snohomish Br., BP-12-B-SN-01, at 7. JP01 states, “Staff correctly recognizes that such costs are part of the ‘capital and O&M’ costs identified in 5.3.6 of the TRM.” JP01 Br., BP-12-B-JP01-01, at 14.

JP07 supports JP01’s position with regard to the demand rate calculation. JP07 Br., BP-12-B-JP07-01, at 1.

BPA Staff’s Position

The demand rate is based upon the annual fixed costs (capital and O&M) of the marginal capacity resource. PRS, BP-12-E-BPA-01, at 75. Staff includes fixed fuel and insurance costs in these annual fixed costs. *Id.* at 76; PRS Documentation, BP-12-E-BPA-01A, at 101. Staff argues that the fact that fixed fuel transportation and insurance costs can vary does not change the fact that they are part of the annual fixed costs of the resource. Fisher *et al.*, BP-12-E-BPA-41, at 3. Staff notes that it is not the potential for annual variability that makes a cost a fixed or variable cost, but rather whether it is dependent on the production or operations of the plant. *Id.* at 4. The fixed fuel and insurance costs are independent from the operation of the plant and as such are part of the annual fixed costs. *Id.* Staff does not believe including fixed fuel and insurance is inconsistent with the TRM. Staff stated that it does not believe the “(capital and O&M)” parenthetical in the TRM was meant as an exclusive list, and even if it was, fixed fuel and insurance are elements of O&M. *Id.* at 2.

Evaluation of Positions

WPAG argues that fixed fuel transportation costs and insurance are not part of the fixed costs of the plant’s O&M. WPAG Br., BP-12-B-WG-01, at 49; WPAG Br. Ex., BP-12-R-WG-01, at 15. While acknowledging that in some contexts fixed costs include fuel transportation and insurance costs, WPAG notes that “the definition of ‘fixed’ includes commitments or obligations that cannot be changed in the short term.” WPAG Br., BP-12-B-WG-01, at 49. WPAG provides no authority for its unique definition of a fixed cost.¹⁹

Staff cites Black’s Law Dictionary for a definition of a fixed cost. Fisher and Bliven, BP-12-E-BPA-41, at 3-4. Black’s defines a fixed cost as: “A cost whose value does not fluctuate with changes in output or business activity; esp., overhead expenses such as rent, salaries, and depreciation.” *Id.* at 4, *citing* Black’s Law Dictionary, 398 (9th Ed. 2009). Given that insurance and fixed fuel transportation costs do not fluctuate with plant operations, they are clearly within the scope of this definition of fixed O&M costs. *Id.* It is not the potential for annual or monthly

¹⁹ Although counsel for WPAG stated in oral argument that the source was a footnote in some economic text book, (Oral Tr. at 170) a review of WPAG’s brief as well as the direct testimony of Saleba *et al.*, BP-12-E-WP-01, fails to provide the actual source of this definition. This shortcoming was noted in the Draft ROD, and WPAG in its brief on exceptions did not provide any support for the definition.

variability that makes a cost a fixed or variable cost, but rather whether the cost is dependent on the production or operations of the plant. *Id.* The fixed fuel and insurance are independent from the operation of the plant and as such are part of the annual fixed costs. *Id.*

Including fixed fuel and insurance is also not inconsistent with the TRM. The “(capital and O&M)” parenthetical in the TRM clearly includes O&M; fixed fuel and insurance are elements of O&M. *Id.* at 2.

It should also be noted, as discussed in Issue 2.6.3.2.3 above, that WPAG and JP02 argue against the use of the CEC’s estimate for fixed O&M due to possible overlap and double-counting of costs. WPAG Br., BP-12-B-WG-01, at 48; JP02 Br., BP-12-B-JP02-01, at 4. Also, as discussed in Issue 2.6.3.2.3 above, Snohomish and JP01 state that the possibility of an inconsistency between the Council’s data and the CEC’s data does not outweigh using the larger CEC data set. Snohomish Br., BP-12-B-SN-01, at 7-8; JP01 Br., BP-12-B-JP01-01, at 15. Both of these arguments are inconsistent with these parties’ respective conclusions regarding whether fixed O&M should include the cost of insurance and fixed fuel transportation. WPAG and JP02 acknowledge in one argument that reporting of O&M costs can vary by source, yet imply an industry-accepted definition that excludes fuel transportation and insurance in another. Just as inconsistently, Snohomish and JP01 contend small possibilities of overlap of O&M definitions, yet agree with Staff that insurance and fuel transportation costs are encompassed under the umbrella of O&M but are sometimes reported separately by the Council for informational purposes.

JP02 notes that the TRM describes fixed costs as follows: “annual fixed costs (capital and O&M) of the marginal capacity resource.” JP02 Br., BP-12-B-JP02-01, at 7. JP02 contends that the parenthetical “(capital & O&M)” limits annual fixed costs used to set the demand rate to only those items specified in the parenthetical. *Id.*; JP02 Br. Ex., BP-12-R-JP02, at 6. Because fixed fuel and insurance are not specifically noted, JP02 contends they cannot be included as part of the annual fixed cost. JP02 Br., BP-12-B-JP02-01, 7-8. JP02 references section 5.4 of the TRM as additional support for this argument. JP02 Br. Ex., BP-12-R-JP02-01, at 6. JP01 and Snohomish, on the other hand, support Staff’s proposal and state that fixed fuel costs and insurance should be included in the demand rate since they are incurred whether or not a plant is operating. JP01 Br., BP-12-B-JP01-01, at 14; Snohomish Br., BP-12-B-SN-01, at 7.

As Staff notes in rebuttal testimony, this restrictive interpretation ignores statements made in the TRM ROD that state the demand charge should reflect the actual cost of the capacity. Fisher and Bliven, BP-12-E-BPA-41, at 2. The TRM ROD states:

The price signals sent through the Demand Charge are an important aspect of the Regional Dialogue Policy. One of these policy goals is the promotion of regional electric infrastructure. RD Policy, at 5. BPA staff testified that it believes the price signal associated with Demand Charge will pass on to customers *the actual cost of capacity* and will encourage new resource development, as well as better inform customers’ resource development decisions. Cherry, *et al.*, TRM-12-E-BPA-02, at 15. The Demand Charge also supports BPA’s second RD Policy goal of keeping Tier 1 Rates low and stable. RD Policy, at 6. The RD Policy states that

BPA will keep Tier 1 Rates low and stable by limiting the amount of energy that is included in the Tier 1 System Resources. However, BPA will also need to acquire capacity to meet its demand obligations. Unlike with energy, the TRM does not place a limit on the amount of additional demand placed on BPA. This means customers have a potentially unlimited access to capacity. *Therefore, without the inclusion of a marginal price signal with the Demand Charge, there is no mechanism for collecting these added costs, thus jeopardizing the goal of low and stable rates.*

Id., citing TRM-12-A-01, at 76 (emphasis added). The TRM ROD specifically states that the demand rate is intended to be based on the “actual cost of capacity.” *Id.* at 3. It does not say that the demand rate would be based on only those costs listed in the parenthetical of the TRM. The TRM ROD explains that the purpose of the Demand Charge is to capture the entire fixed cost of marginal capacity and not a subset of the fixed costs. Including fixed fuel and insurance costs in the demand rate calculation ensures that the entire cost of the additional capacity is reflected in the rate. *Id.* Failure to account fully for all of the fixed costs would erode the value of Tier 1 and undermine the underlying theory behind BPA’s tiered rates. *Id.*

With regard to JP02’s reference to section 5.4 of the TRM, this section of the TRM addresses the prohibition on adding core charges beyond those specified in section 5 of the TRM. (The core charges are Customer Charges, Load Shaping Charge, and Demand Charge). Section 5.4 does not speak to the appropriate costs or the methodology that should be used to calculate the demand rate, as JP02 suggests. Consequently, section 5.4 provides no guidance regarding whether it is appropriate to include fuel transportation and insurance costs in the calculation of the demand rate. Section 5.4 is only relevant to the extent BPA or a party was proposing an additional core charge not detailed in section 5 of the TRM.

JP02 and WPAG further contend that the Council’s definition of fixed O&M does not include insurance costs. JP02 Br. Ex., BP-12-R-JP04-01, at 5; WPAG Br. Ex., BP-12-R-WG-01, at 15. Both WPAG and JP02 point to tables in the Appendix of the Council’s Sixth Power Plan where property taxes and insurance were excluded from the presentation of the fixed O&M costs. While the Appendix excluded insurance costs, the Council’s Plan does not support a single definition of costs that should be included in fixed O&M. The example cited by JP02 and WPAG is a circumstance where the Council broke out certain fixed costs to provide a more granular and less resource-location-dependent summary of resource costs. Under this less-specific resource presentation, the Council did not include insurance and property taxes in fixed O&M, presumably because these elements are very resource- and location-specific. The decision to exclude these costs does not mean that insurance or property taxes are not part of the fixed O&M cost. These are costs that are part of the fixed O&M costs of operation of the resource and as such should be included in the calculation of the demand rate. Furthermore, the Council’s Microfin model, which is used to calculate the demand rate, specifically included property tax and insurance as part of the fixed O&M costs. Fisher *et al.*, BP-12-E-BPA-41, at 4.

WPAG also contends that the Council considers fuel transportation to be a variable O&M cost. WPAG Br. Ex., BP-12-R-WG-01, at 15. WPAG arrives at this conclusion through the combination of the Council’s lack of excluding it from fixed O&M and the Council’s definition

of variable O&M which includes “other consumables.” WPAG fails to explain why fuel transportation costs somehow fits within the definition of “other consumables.” The Council does consider fuel transportation to be a fixed cost. Fisher *et al.*, BP-12-E-BPA-41, at 4-5. Specifically, “Pipeline costs include three general types of costs: capacity charges, commodity charges, and in-kind fuel costs. Capacity costs are by far the largest component of the transportation cost, and they are considered to be fixed.” Sixth Power Plan, Appendix A, at 11.

Furthermore, it would be a mistake to assume that the TRM intended to exclude known fixed costs, be it capital or O&M, from the demand rate calculation. The fact that a particular data source used a particular nomenclature or chose to categorize fixed capital or O&M costs so as to provide more granular information behind the end result is not determinative. It should also be noted that the Council often separately identifies fixed fuel costs when it categorizes fixed costs. This, by itself, does not imply that the Council would not consider fixed fuel a subcategory of fixed O&M. Both fixed fuel and insurance costs are properly considered part of the fixed O&M of the resource.

BPA does not need to reach to whether the JP02 claim that the parenthetical “(capital & O&M)” was meant to be an all-inclusive list, JP02 Br., BP-12-B-JP02-01, at 7, is the appropriate interpretation of the TRM. Given the instant question, the items are clearly within the intended meaning of O&M. Whether the parenthetical includes or excludes other items is best determined based on the specific question being asked at the time future demand rates are being determined. While the term “O&M” is quite broad, BPA is not prepared to state that it is so broad that it would sweep any potential claim that might arise in the future.

Decision

Fixed fuel and insurance are encompassed in the definition of fixed O&M and thus are appropriately included in the Tier 1 demand rate calculation.

Issue 2.6.3.2.5

Whether BPA should include in the design of the IP rate a demand billing determinant reduction parallel to the Contract Demand Quantity (CDQ) found in the design of the PF Public rate.

Parties’ Positions

Port Townsend contends that the CDQ methodology should be applied to the IP rate to remove the adverse impacts of the higher demand rate. Port Townsend Br., PT-12-B-PT-01, at 2. Port Townsend argues that such application is necessary to ensure consistency of the IP rate with BPA’s statutory rate directives. *Id.* Port Townsend states that absent a consistent CDQ adjustment in the IP rate, Port Townsend will pay demand charges based on a billing determinant that is inconsistent with and higher than the wholesale rate billing determinant applicable to comparable COU customers. *Id.* at 3.

BPA Staff's Position

In the Initial Proposal, Staff testifies that there is no need for an adjustment to the demand billing determinant for customers purchasing under the IP rate due to the fact that they have a flat load and consequently would not be exposed to any Demand Charge. Fisher *et al.*, BP-12-E-BPA-18, at 32. Port Townsend points out that their load is not flat and that they would experience a demand charge that would have an annual cost of \$222,823. Muehlethaler, BP-12-E-PT-01, at 3. In rebuttal, Staff concedes that Port Townsend would be exposed to some demand charge but disputes the financial impact of the demand charge on Port Townsend. Clark *et al.*, BP-12-E-BPA-38, at 9. While Staff's rebuttal does not support the creation of a CDQ or some other similar reduction in the demand billing determinant for Port Townsend, Staff modifies its position to a degree, characterizing its position as neutral due to the fact that it is primarily an issue of cost allocation among customers taking service at the IP rate. *Id.* at 10.

Evaluation of Positions

Port Townsend asks for an adjustment to its demand billing determinant akin to the CDQ provided to Load Following customers under the TRM. Port Townsend Br., PT-12-B-PT-01, at 2. In the Initial Proposal, Staff proposes to use the same demand rates and billing determinant methodology for the IP rate as it proposes to use with the PF rates, except that the Initial Proposal does not contain any adjustment to the IP demand billing determinant as the PF rates do with the CDQ. Fisher *et al.*, BP-12-E-BPA-18, at 29-30. In most cases, BPA has used the same demand rates and billing determinants for the PF, IP, and NR rates as far back as 1979, and Staff proposes to continue to maintain the symmetry among the three rates. *Id.* at 30. The purpose of the demand charge is to send a price signal to customers. *Id.* Symmetry among rate schedules is reasonable because capacity has the same value no matter which rate a customer is purchasing under. *Id.* In the Initial Proposal, Staff does not propose any CDQ-like adjustment to the IP demand billing determinant due primarily to an assumption that all DSIs are served at a load factor of approximately 100 percent, and as such no DSI would be exposed to a Demand Charge. *Id.* at 32. Port Townsend points out that it does not have a flat load and would experience some demand charge. Muehlethaler, BP-12-E-PT-01, at 2. While there was originally some dispute over the magnitude of impact of the demand charge on Port Townsend, Staff and Port Townsend now agree that the demand charge would have some impact on Port Townsend. Clark *et al.*, BP-12-E-BPA-38, at 9; Port Townsend Br., BP-12-B-PT-01, at 2-3.

While Port Townsend specifically asks for a CDQ, the CDQ is a billing element specifically reserved to COUs. While BPA does not believe that it can apply the CDQ itself to Port Townsend, a virtually identical billing element could be developed for the IP rate schedule. Given the objective to maintain the symmetry of the demand charge among the various rate schedules (PF, IP, and NR), incorporating a CDQ-like adjustment to the demand billing determinant for customers purchasing under the IP rate schedule appears reasonable. This adjustment to the demand billing determinant will mirror in many respects the CDQ. However, BPA clarifies that if, in the future, Port Townsend is no longer a direct service industry of BPA, the adjustment to the demand billing determinant will not be transferable to utility service. Any utility serving some or all of Port Townsend's load that is also eligible for a CDQ will not be able to assume the adjustment granted Port Townsend but instead will have its CDQ calculated

in accordance with the terms of the TRM. Likewise, if Port Townsend moves a portion of its load to a utility, any adjustment to the demand billing determinant will be modified to account for the change in the load. This decision is based on the evidence included in the record for this rate case under the current service provided to customers purchasing under the IP rate schedule. Future service provided to customers purchasing under the IP rate schedule may require BPA to revisit this approach and its applicability.

Decision

Customers purchasing under the IP rate schedule will be eligible for an adjustment to the demand billing determinant similar to the CDQ granted PF customers for this rate period. In the event some or all of the IP load is transferred to a utility, the utility will not be able to assume the adjustment, and the load still served by BPA will have the billing determinant adjustment modified to account for the change.

2.6.4 IP Rate Development

2.6.4.1 Introduction

This section addresses issues raised in connection with development of the IP rate, which is applicable to power sales contracts of direct service industrial customers (DSIs). The rate is developed pursuant to the standards articulated in section 7(c) of the Northwest Power Act. 16 U.S.C. § 839(c)(1)–16 U.S.C. § 839e(c)(3).

One issue addressed by Alcoa in its brief is not addressed below: whether there should be a direct allocation of costs associated with the low density discount (LDD) and the irrigation rate discount (IRD) to the IP rate. Alcoa Br., WP-12-B-AL-02, at 14-15. This issue was raised by the JP04 panel in its direct testimony. Deen *et al.*, BP-12-E-JP04-01, at 9. In rebuttal testimony, BPA Staff explained that the IP rate was subject to such an allocation indirectly because it is based initially on the preference rate, the rate to which those costs are allocated. Clark *et al.*, BP-12-E-BPA-38 at 3-5.

On cross-examination, JP04 accepted BPA’s explanation as being an appropriate means of allocating such costs, stating that it had “been convinced by Bonneville that the IP rate is receiving an allocation of [LDD and IRD] costs through the IP/PF link.” Cross-Ex. Tr. at 29. The JP04 panel characterized BPA’s methodology, described in rebuttal testimony, as an “alternative method ... of getting to the same result.” *Id.* The issue has not otherwise been raised in briefing. As a consequence, BPA is treating the issue as moot, and no further evaluation is being provided in this ROD.

2.6.4.2 Ratemaking Standard for Development of IP Rate Generally

Issue 2.6.4.2.1

Whether BPA is required to make a separate and independent showing that the IP rate is consistent with sound business principles.

Parties' Positions

JP04 states that BPA should be required to make a separate showing that the IP rate is “consistent with sound business principles.” JP04 Br., BP-12-B-JP04-01, at 2; JP04 Br. Ex., BP-12-R-JP04-01, at 3. Such a standard, JP04 argues, would prohibit BPA from allocating to the preference rate any costs connected with providing DSI service. JP04 Br., BP-12-B-JP04-01, at 2-4. JP04 contends that the Draft ROD mistakenly conflates the statutory requirement (1) to act in accordance with “sound business principles”; (2) to ensure cost recovery; and (3) to ensure Treasury repayment. JP04 Br. Ex., BP-12-R-JP04-01, at 3. JP04 argues that the “sound business principles” standard is one that must be abided by in concert with the obligation to ensure cost recovery and Treasury repayment. *Id.* JP04 contends that the “sound business principles” standard is therefore applicable to the way the agency implements the rate directives to implement the IP rate. *Id.* at 6.

Alcoa responds to arguments raised in PPC’s Pre-Hearing Statement. Alcoa Br., BP-12-B-AL-02, at 15-18. Alcoa states that PPC suggests an impermissible ratemaking standard that would render the statutorily required IP rate a nullity and that statutory preference to power does not establish any preference as to price. *Id.*

In Alcoa’s brief on exceptions, it argues that the “sound business principles” standard cannot be applied uniquely to the IP rate. Alcoa Br. Ex. BP-12-R-AL-01 at 3. Instead, the “sound business principles” standard applies to all rates. *Id.* at 4.

PPC’s brief does not specifically follow up on its previous line of argument, however. PPC Br., BP-12-B-PP-01. JP04, however, does raise arguments that are similar in many respects. JP04 Br., BP-12-B-JP04-01, at 2-5. Alcoa’s arguments seem equally responsive to JP04’s position, and BPA is evaluating that portion of Alcoa’s brief in this subsection.

BPA Staff’s Position

Staff did not offer a position because this issue is first raised on brief as a legal issue. However, Staff notes that BPA should not make a separate determination that the IP rate is consistent with sound business principles. The requirement that BPA’s rates be consistent with sound business principles is satisfied by setting rates consistent with the statutory rate directives so as to recover fully BPA’s cost and achieve a high probability that Treasury payments will be made on time and in full. 16 U.S.C. § 839e(a)(1); *CEC*, 909 F.2d 1298.

Evaluation of Positions

Alcoa notes that the Northwest Power Act was enacted to “assure the Pacific Northwest of an adequate, efficient, economical and reliable power supply.” Alcoa Br., BP-12-B-AL-02, at 13, *citing* 16 U.S.C. § 839(2). Alcoa states that application of a “consistent with sound business principles” standard, as contemplated by JP04, would thwart the legislative purposes of the Northwest Power Act: “As a general threshold matter, any standard that has the effect of denying a statutory class of BPA’s customers (like the DSIs) access to that power supply must be viewed with extreme skepticism.” *Id.* at 13.

In Alcoa’s brief on exceptions, it argues that the “sound business principles” standard cannot be applied uniquely to the IP rate. Alcoa Br. Ex. BP-12-R-AL-01 at 3. Instead, the “sound business principles” standard applies to all BPA rates. *Id.* at 4.

In support of its position, Alcoa states that the Northwest Power Act was carefully designed to allocate power to three customer classes and to achieve a balance with respect to allocation of costs imposed by provisions of the Act. In this connection, Alcoa notes that, pursuant to the statutory requirements, “DSIs buy power at rates above the rate applicable to the COUs” and this differential helps finance the residential exchange program, which provides benefits to the small farm and residential customers of the IOUs. *Id.* at 13, *citing* *Alcoa v. Cent. Lincoln Util. Dist.*, 467 U.S. 393, 398-400. Alcoa also notes that the residential exchange program is a money-losing program for BPA in that it requires BPA to exchange its low-cost resources for higher-cost resources used by the IOUs to provide service to their residential and small farm loads. *Id.* at 14. Alcoa concludes that “[t]his careful statutory balance was intended to create generally comparable prices between the COUs and the IOUs, and between DSIs and other industrial consumers in the region that purchased their power from the COUs.” *Id.* at 14, *citing* 16 U.S.C. § 839(c)(1)(B).

Alcoa also argues that application of such a standard would be in conflict with the *PNGC I* opinion, which Alcoa interprets to require that any offer of power to a DSI must be at the IP rate: “If BPA elects to provide service to the DSIs, it must provide such power at the IP rate.” *Id.* at 12, *citing* *Pac. Nw. Generating Coop., et al. v. Dept. of Energy*, 550 F.3d 846 (9th Cir. 2008), *amended on denial of reh’g*, 580 F.3d 792 (9th Cir. 2009) (*PNGC I*) and section 7 of the Northwest Power Act. Alcoa also argues that application of a standard not embodied in the ratemaking directive would impose “an impermissible ratemaking standard that would render the statutorily required IP rate a nullity.” *Id.* at 15. Alcoa makes a number of points in support of this contention.

First, Alcoa notes that section 7(c) of the Northwest Power Act requires that the rate applicable to sales to DSIs requires that it be established at a level “which [BPA] determines to be equitable in relation to the rates charged by the [preference] customers to their industrial consumers in the region.” *Id.* at 15. This provision, Alcoa argues, means that BPA is obligated, if it decides to offer power to a DSI, to do so at rates “that are roughly comparable to the rates charged by COUs to their industrial customers, not at the new resources rate.” *Id.* Alcoa also maintains that the JP04 proposal would convert the section 7(c) IP rate directive into a nullity and therefore violate the Ninth Circuit’s “rule that statutes should not be construed in a manner which robs

specific provisions of independent effect [and requiring the Court] to reject interpretations that would render a statutory provision surplusage or a nullity.” *Id.* at 16, quoting *In re Cervantes*, 219 F.3d 955, 961 (9th Cir. 2000). In this connection, Alcoa observes that, in *PNGC I*, the court considered the implications if BPA had unbridled discretion to sell power to the DSIs at market rates:

BPA, if acting rationally and in accordance with its ‘mandate to operate with a business-oriented philosophy’ ... would never sell power to the DSIs at the IP rate. Why would Congress have required BPA to ‘establish’ a rate, specified the formula it would be ‘based upon’, and state that ‘the rate or rates’ are ‘applicable to [DSI] customers ... if the rate could not possibly apply to any sale?’

Id. at 17, quoting *PNGC I*, 580 F.3d at 813.

Alcoa also argues that preference to power does not mean that preference customers have an absolute preference regarding the price of power. *Id.* at 17. In support of this contention, Alcoa notes that the Ninth Circuit has previously held that “nothing in section 7(b)(1) precluded BPA from considering the costs of [FBS Replacement] resources when calculating its preference rate, even though BPA would not have incurred such costs absent its DSI contracts.” *Id.*, citing *Golden Northwest Aluminum v. BPA*, 501 F.3d 1037, 1045-47 (9th Cir. 2007). Alcoa also points to the Ninth Circuit’s rejection of the argument that preference customers were entitled “to purchase not just available power, but the cheapest available power.” *Id.* at 17-18, quoting *Central Lincoln II*, 735 F.2d at 1125.

JP04 argues that the IP rate is legally defective because BPA has provided no evidence in the record that the IP rate is, independent of all other rates, “consistent with sound business principles.” JP04 Br., BP-12-B-JP04-01 at 2. In support of this contention, JP04 first discusses the *PNGC I* and *II* opinions and reaches the following conclusion: “BPA staff has put nothing on the record in this rate case to show that it has met the ‘sound business principles’ standard in setting the IP rate. The agency must do so.” *Id.* at 4, citing *Pac. Nw. Generating Coop, et al., v. Bonneville Power Admin.*, 580 F.3d 828 (9th Cir. 2009), amended on denial of reh’g, 596 F.3d 1065, 1074 (9th Cir. 2010) (*PNGC II*). JP04 develops the argument further by noting that:

...BPA’s rate proposal will incur significant costs on preference customers to provide DSI service at the IP rate. And, even if BPA might have met a financial standard for the term of the current DSI contract, staff has not provided in this rate case justification for a time extension to this subsidy for the full rate period. Therefore [*sic*] the IP rate in this case, [*sic*] is not consistent with ‘sound business principles.’ ... If the Administrator cannot show on the record that the IP rate proposal meets this standard, he must alter the IP rate and assumptions regarding load to be served at that rate accordingly.

Id. at 4.

BPA’s primary obligation with regard to the IP rate is to ensure that it is developed consistent the section 7 rate directives contained in the Northwest Power Act. The IP rate is developed using sections 7(c)(1), 7(c)(2), 7(c)(3), and 7(b)(3) of the Northwest Power Act. Section 7(c)(1)(B)

provides that, after July 1, 1985, the rates to DSI customers will be set “at a level which the Administrator determines to be equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers in the region.” “Equitable in relation” is defined pursuant to section 7(c)(2) as basing the DSI rate on BPA’s “applicable wholesale rates” to its COU customers plus the “typical margins” included by those customers in their retail industrial rates. Section 7(c)(3) provides that the DSI rate is to be adjusted to account for the value of power system reserves provided through contractual rights that allow BPA to restrict portions of the DSI load. This adjustment is made through a Value of Reserves credit. Section 7(b)(3) provides for an allocation of rate protection costs not recovered from PF Public rate customers by means of section 7(b)(2). Thus, the rate for the DSIs, the IP rate, is set equal to the applicable wholesale rate, plus the typical margin, plus the VOR credit, subject to the DSI floor rate test and the outcome of the determination of PF Public rate protection.

JP04 contends that the IP rate should be subject to some unspecified independent analysis of whether that rate conforms to a “sound business principles” standard. JP04 Br. Ex., BP-12-R-JP04-01, at 3. JP04 argues there is no evidence in the record to support the fact that the IP rate meets this standard. *Id.* at 4. JP04’s apparent basis for this is concern that DSI service will add costs to the PF rate. JP04 Br., BP-12-B-JP04-01 at 4. What JP04 is asking for is the creation of a new IP rate that does not financially impact the PF rate. Increasing the IP rate to avoid placing any costs on the PF rate would require BPA to deviate from the 7(c) rate directives.

BPA does not agree that there is any requirement for an independent analysis to determine whether the IP rate or any BPA rate, specifically conforms to the “sound business principles” standard. However, even assuming *arguendo* that the standard did apply to the development of the IP rate, the IP rate meets the standard. As noted above, BPA’s primary obligation with regard to the development of the IP rate is to do so consistent the statutory rate directives and in this proceeding BPA develops the IP rate consistent with these statutory directives. To the extent BPA intentionally deviates from the rate directives in the establishment of the IP or any other rate, it opens itself and the rates to legal challenges. Such an action by BPA may be viewed by the court as inconsistent with “sound business principles.” Section 7(c) does not allow BPA to consider the financial impact of the IP rate on the PF rate as a separate consideration that would be viewed under a “sound business principles” test.

The Ninth Circuit has also found that the responsibility of “encouraging ... the lowest possible rates to consumers” is not a mandate to set the lowest rates possible without regard to any other business or legal precept:

Also, the statutes do not dictate that BPA always charge the lowest possible rates. 16 U.S.C. § 838g directs that rates be set “with a view to encouraging ... the lowest possible rates to consumers....” The words “with a view to encouraging” do not constitute a statutory command that the prices charged to consumers always be the lowest possible. Moreover, nearly every action by BPA has some arguable impact on future rates. If the strict interpretation of the “lowest possible rates” standard [were made] ... the discretion that Congress vested in the Administrator would be eliminated.... In addition, the direction to charge the

lowest possible rates is tempered by the addition of the clause “consistent with sound business principles.” 16 U.S.C. § 838g.

CEC, 909 F.2d at 1307.

Moreover, as Alcoa has indicated, the Court has never held that preference customers have an absolute preference to price as well as supply, a tenet which seems to be at the heart of JP04’s desire to subject a stand-alone business principles test to the IP rate:

[A]n interpretation of section 5(a) allowing preference customers to exercise the preference after their firm power needs are met but before the firm power requirements of the nonpreference customers are satisfied would subject BPA to conflicting obligations under the Act. BPA could honor the section 5(a) preference only at the risk of breaching its firm power obligations to the nonpreference customers. *See* 16 U.S.C. § 839c(b), (c), (d), (f).

PPC’s premise is that the preference entitles its members to purchase not just available power, but the cheapest available power. PPC bases its contention on language in the House Commerce Committee Report that reads:

[S]pecific provisions incorporated in the Committee Amendment are designed to protect the entitlement of both existing and new preference customers to the full Federal base system. *These provisions seek to protect preference as to both supply and price.*

House Report, Part I, *supra*, at 34 (emphasis supplied).

That language, however, is not dispositive. The statute itself couches the preference in terms of “power sales,” not price. *See* 16 U.S.C. § 839c(a). In addition, the section-by-section analysis of the Act states that section 5(a), the preference clause, must be read “in tandem with” other provisions of the Act. *BPA Legislative History* at 84. One of those provisions is section 7(b), 16 U.S.C. § 839e(b), which contains a rate ceiling for preference customers. The conclusion to be drawn from reading sections 5(a) and 7(b) together is that while section 5(a) protects the preference customers’ access to power supply, section 7(b) protects their right to purchase power at a reasonable price. *See BPA Legislative History* at 84-85. *See also Western Area Power Administration*, 25 FERC ¶ 61,325 (1983). Neither *Central Lincoln I*, the statutory language, nor the legislative history indicate that the preference was violated in this case.

Central Lincoln II, 735 F.2d. *See City of Seattle v. Bonneville Power Administration*, 813 F.2d 1364, 1367 (9th Cir. 1987) (Northwest Power Act “restricts BPA only to ‘sound business principles’ in setting rates to meet its revenue requirements.”) and *Department of Water and Power of City of Los Angeles v. Bonneville Power Admin.*, 759 F.2d 684 (9th Cir. 1985) (“history of BPA’s enabling legislation further demonstrates that Congress has repeatedly required BPA to operate in a manner which assures that the agency is fiscally self supporting”); *see also* 16 U.S.C. § 832f (BPA rate schedules designed to recover BPA costs); H.R.Rep. No. 590, 1964 U.S. Code Cong. & Ad. News at 3343 (statute designed to put BPA back on sound financial ground); 16 U.S.C. § 838g(2) (rate schedules to be based upon BPA need to recover

operating and capital costs); 16 U.S.C. § 839e(a)(1) (rates to be designed consistent with sound business principles and with need to recover BPA costs); H.R.Rep. No. 976, Part I, 1980 U.S. Code Cong. & Ad. News at 6001 (BPA must be self supporting and must maintain financial independence subject to congressional oversight). JP04's reliance on the Ninth Circuit's opinions in *PNGC I* and *II*, by contrast, is misplaced.

BPA's foremost objection to JP04's use of the *PNGC* opinions is that those two opinions do not deal with ratemaking. They deal only with the Administrator's marketing decision, *i.e.*, whether to offer a contract to the DSIs and, if so, on what terms and conditions. This situation is governed by the standard that should apply in the ratemaking context, where BPA's primary business objective, as discussed above, is to ensure that BPA will recover its costs of doing business and achieve a high probability that it will make its Treasury payments on time and in full. *Golden NW* was a challenge to BPA's 2002 rates where the court found that decisions to enter into contracts and the ratemaking determinations that may be necessary as a result of entering into such contracts are two separate and distinct final actions that can be reviewed separately by the Court:

To the extent petitioners here seek to challenge BPA's authority to enter into successor contracts with DSIs, their claim is barred by res judicata. We previously held in an unpublished disposition that petitioners' attempt to contest the validity of BPA's power sales to its DSI customers was untimely. *Blachly-Lane Elec. Coop. Ass'n v. U.S. Dep't of Energy*, 79 Fed. Appx. 975, 977 (9th Cir. 2003). Because "[p]ower sale contracts are final agency actions," the 90-day statute of limitations begins to run from the date such contracts are executed. *Id.*; see also 16 U.S.C. § 839f(e)(1)(B) (providing that power sales are final agency actions subject to judicial review).

Id. at 1043. Thus, the Ninth Circuit understands that the decision to offer a DSI contract is separate and distinct from a decision involving how to set the rate that will be applicable to that contract. The *PNGC* opinions say nothing that would indicate that they were reaching beyond the initial marketing decision to make power available to the DSIs. If anything, *PNGC I* stands for the proposition that when BPA makes power available to DSIs, it must do so at the IP rate, which must be set in accordance with the statutory directive:

We conclude that BPA's interpretation of its governing statutes as providing authority to sell surplus power to the DSIs under § 839c(f) at an FPS rate without first offering to sell that amount of power under either § 839c(d) or § 839c(f) at a rate set under § 839e(c) is not reasonable. The statutory text of the [Northwest Power Act], the agency's own prior interpretation of the Act, and the [Act's] legislative history, are all to the contrary. We therefore hold that BPA improperly refused to offer the aluminum DSIs energy at a rate set under § 839e(c) before selling them power at an FPS rate.

PNGC I, 580 F.3d at 818. Moreover, the court in *PNGC I* made clear its belief that Congress had established the IP rate specifically for the benefit of the DSI customers:

[A]s already discussed, the [Northwest Power Act] requires BPA to offer its DSI customers firm power at the IP rate before it offers those customers an FPS rate.

But once a DSI refuses to buy power at the rate to which it is statutorily entitled (i.e., the IP rate), it has surrendered *the primary benefit that the class of DSI customers receives under the [Act]* and becomes subject to the same treatment as any other in-region customer seeking to purchase surplus firm power.

Id. at 826 (emphasis added). The court also indicated its understanding that the nature of this “primary benefit,” as defined by Congress was that “after June 1985 the rate applicable to BPA direct service industrial customers will be based upon the retail rates applicable to industry served by BPA preference utility customers.” *Id.* at 815 (citing S. Rep. 96-272 at 56). Neither did the court in any way suggest that it was questioning the holding in *Golden NW*, which (as Alcoa notes) held that it is permissible to include the cost of FBS replacement resources in the preference rate, even if those resources may ultimately be used to provide service to DSI customers who pay the IP rate. *Golden NW*, 501 F.3d at 1045-47. For further discussion of *Golden NW*, see the discussion of the following issue.

BPA will not adopt the JP04 proposal because it is not in accord with law relevant to BPA’s ratemaking or with respect to the Ninth Circuit’s general approach to applying “sound business principles” language to the Administrator’s decisionmaking. Evaluating BPA’s new responsibilities under the Northwest Power Act, the Ninth Circuit stated:

BPA’s new, more typically governmental responsibilities suggest the propriety of even greater deference to the Administrator’s decisions. He must continue to run BPA like a business on a sound financial basis, enabling it to repay its debt to the federal treasury in a timely fashion, while discharging costly new public duties assumed after the Northwest Power Act’s passage....

[T]he “gap” Congress left for the Administrator is how best to further BPA’s business interests consistent with its public mission. The statutes governing BPA’s operations are permeated with references to the “sound business principles” Congress desired the Administrator to use in discharging his duties. See 16 U.S.C. §§ 825s, 838g, 839e(a)(1). See also *Department of Water & Power*, 759 F.2d at 693 (“To the extent that [BPA’s challenged transmission allocation policy] is designed to mitigate projected deficits, [it] is not only statutorily authorized but statutorily mandated.”). Thus, although Congress did not prescribe the parameters of the Administrator’s authority, it granted BPA an unusually expansive mandate to operate with a business-oriented philosophy. Accordingly, it seems particularly wise to defer to the agency’s actions in furthering its business interests, especially when the agency is responding to unprecedented changes in the market resulting from deregulation. ... We are not to debate the wisdom of any BPA business decision unless that decision is so manifestly unreasonable as to rise to the level of being arbitrary and capricious. See, e.g., *California Energy Comm’n*, 909 F.2d at 1306.

Association of Public Agency Customers v. Bonneville Power Administration, 126 F. 3d 1158, 1170 (9th Cir. 1996). It cannot reasonably be argued that BPA’s decision to retain its longstanding historical approach to developing the IP rate consistent with the statutory directives is inconsistent with sound business principles or arbitrary and capricious. Further, contrary to

JP04's assertions, the rate proceeding record is replete with evidence showing how BPA has conformed to that standard.

Based on the statutory framework governing BPA's ratesetting and the Ninth Circuit's interpretations thereof, it is legally sufficient, and an exercise of sound business judgment, to ensure that BPA's rates, in the aggregate, are designed in accordance with the statutory command of encouraging the lowest rates possible to consumers, consistent with sound business principles. To argue otherwise insinuates that Congress placed into the Northwest Power Act the contradictory view that a rate established according to statutory rate directives could somehow be found to conflict with the sound business principles standard. Moreover, it is legally permissible to allocate the costs of FBS replacement resources to the PF rate. *See Golden NW*, 501 F.3d, at 1043-1047. Finally, the *PNGC I* and *II* opinions do not require BPA to alter its method of establishing the IP rate.

Decision

BPA will not alter its fundamental ratemaking practices, and its longstanding interpretation of what it means to develop rates "consistent with sound business principles," by imposing a stand-alone "business principles" test on the IP rate.

Issue 2.6.4.2.2

Whether BPA should apply an independent DSI-targeted CRAC to the IP rate in order to true up forecast costs to actual costs.

Parties' Positions

WPAG's arguments regarding the IP rate center on the fact that in this rate proceeding "BPA expects the projected two-year revenues from the DSIs to be \$215.5 million, and the two-year costs of such service to be \$273.2 million." WPAG Br., BP-12-B-WG-01, at 36, *citing* BPA response to NR-BPA-1. In other words, as WPAG sees it, BPA is imposing on the preference customers a cost of \$55.6 million that they should not have to bear. *Id.* WPAG states that ensuring that DSIs bear the full cost of providing them with power service is consistent with a number of recent BPA policy initiatives: "BPA has implemented a policy to ensure that customers pay the costs that BPA incurs to provide them service, and to eliminate to the extent practicable cross-subsidies between customers. The shift in power costs from the DSIs to the preference customers is out of step with this policy." *Id.*

WPAG also notes that "BPA is under no legal obligation to offer the DSIs any service at all." *Id.* at 36, *citing PNGC I*, 580 F.3d at 807, 811-812. WPAG also recognizes that, if BPA does offer power to the DSIs, "BPA is obliged to offer the DSIs service at the IP rate calculated in accordance with the rate directives contained in § 7(c) of the [Northwest Power] Act." *Id.*, *citing PNGC I* at 817-818. WPAG argues, however, that "there is nothing in that section of the [Northwest Power] Act, nor in the *PNGC* decision, that prohibits BPA from including in that rate a cost recovery adjustment clause ("CRAC") that would permit BPA to collect from the DSIs the

cost of providing them service that are not otherwise recovered from the DSIs under the IP base rate.” *Id.* at 37.

In support of its recommendation, WPAG notes that CRACs are not unusual: “BPA has for many years included CRACs in both the PF and the IP rates, which CRACs have been designed to trigger using a variety of financial indicia.” *Id.*, citing the Power Rate Schedules, BP-12-E-BPA-09, at 31-35; Bliven *et al.*, BPA-12-E-BPA-11, at 20-21; Lovell *et al.*, BP-12-E-BPA-15, at 51-58. WPAG concludes by arguing that “[a] CRAC to recover the unrecovered costs of providing service (or providing a credit should such costs be lower than the IP revenues) would be consistent with this historical approach, and would bring the rates to the DSIs in line with those being charged to preference customers.” *Id.* at 37.

Alcoa’s arguments are responsive to this issue, as well as the one posited by JP04, and are summarized in the Evaluation of Issue 2.6.4.2.1, above. Alcoa Br., BP-12-B-AL-02, at 15-18; Alcoa Br. Ex. BP-12-R-AL-01 at 3.

BPA Staff’s Position

The IP rate has been set according to the formula detailed in section 7(c) of the Northwest Power Act. Clark *et al.*, BP-12-E-BPA-38, at 2-3. Staff does not believe that the formula is based on principles of cost causation, as would be required by WPAG’s proposal to apply a cost causation CRAC to the IP rate. *Id.*

Evaluation of Positions

Regarding the development of the IP rate, Staff testified as follows:

When BPA provides service to the DSIs at the IP rate, BPA is obligated to adhere to the statutory rate directives set forth in section 7(c) of the Northwest Power Act, just as the PF rate under the TRM must adhere to section 7(b). Section 7(c)’s primary directives are:

1. the IP rate shall be established at a level that the Administrator determines to be equitable in relation to the retail rates charged by BPA’s public body and cooperative customers to their industrial customers;
2. the IP rate shall be based upon the Administrator’s applicable wholesale rates to such public body and cooperative customers plus the “typical margins” included by such customers in their industrial rates; and
3. determining the level of the industrial margin requires BPA to take certain factors into consideration and directs BPA to account for the value of any reserves provided by the DSIs.

Clark *et al.*, BP-12-E-BPA-38, at 2, citing 16 U.S.C. § 839e(c). Thus, the testimony makes clear that BPA’s primary obligation is to interpret and apply the applicable rate directives in the manner intended by Congress. As the testimony also notes, BPA views the statutory mandate as essentially creating a formula rate that is not based on principles of cost causation:

As directed by section 7(c), the rate for the DSIs, the IP rate, is set equal to the applicable wholesale rate and then is adjusted by the typical margin, the value of reserves (VOR) credit, and any supplemental rate charge due to a reallocation of costs arising from the section 7(b)(2) rate test. Section 7(c) defines the IP rate as a formula rate, not an allocated cost-based rate. The applicable wholesale rate upon which the IP rate is based is the load-weighted average of the PF Public rate and any purchases by preference customers under the NR rate. 1986 IP-PF Rate Link ROD, IP-PF-86-A-02, at 6. In this BP-12 rate proceeding, because there is no preference customer NR load, the IP rate is based solely on the [PF Public] rate....

Id. at 3-4. Thus, as BPA Staff views its ratesetting responsibilities, the IP rate is set according to a statutory formula that is not predicated on the cost causation principles that would guide implementation of the DSI-targeted CRAC recommended by WPAG. Based on this and the discussion below, BPA concurs with Staff's approach to setting the IP rate.

In response to WPAG's argument, BPA believes that, in the first instance, WPAG's reliance on the mere fact that an explicit statutory provision does not "prohibit" a particular action is a slippery slope at best in this instance. First, as Alcoa notes, there is an explicit rate directive that governs how the IP rate shall be developed. 16 U.S.C. 839e(c)(1). Alcoa seems to argue that departing from those explicit commands could be considered an abuse of discretion. That may or may not be the case, but it is certain that departures from such explicit provisions would be, at most, an exercise of the Administrator's discretion that would require a careful examination of all relevant legal requirements. Thus, Alcoa's point cannot be totally ignored to the extent that it stands for the proposition that it would not be reasonable to conclude that the absence of an explicit authorizing statute means that explicit statutory provisions can be ignored.

Alcoa argues, in this connection, that since 1985 a central tenet of the statutory scheme is that the rate applicable to DSI sales shall be "equitable" in relation to the rates paid by the industrial customers of BPA's preference utility customers and based on the applicable rate charged for their wholesale purchases from BPA, *i.e.*, the preference rate, plus the typical margins that the utility may pass through to such customers minus a credit for the value of reserves provided by DSI customers. Based on that standard, Alcoa brings into question whether the CRAC proposed by WPAG, based on principles of cost causation, would achieve the goal articulated by Congress that the rate be "equitable" in relation to the rates by the industrial customers of BPA's preference customers. Alcoa, BP-12-B-AL-02, at 15; Alcoa Br. Ex, BP-12-R-AL-01, at 5.

Indeed, as already described, the statute does set forth a detailed formula that could reasonably be seen as the specific methodology that should be followed to achieve that equitable relationship:

The rate or rates applicable to direct service industrial customers shall be established ... for the period beginning July 1, 1985, at a level which the Administrator determines to be *equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers in the region.*

16 U.S.C. §§ 839e(c)(1) and 839e(c)(1)(B) (emphasis added). The statute further provides that this determination:

shall be based upon the Administrator’s applicable wholesale rates to such public body and cooperative customers and the typical margins included by such public body and cooperative customers in their retail industrial rates but shall take into account—

the relative costs of electric capacity, energy, transmission, and related delivery facilities provided and other service provisions, and

direct and indirect overhead costs

all as related to the delivery of power to industrial customers, except that the Administrator’s rates during such period shall in no event be less than the rates in effect for the contract year ending on June 30, 1985.

16 U.S.C. §§ 839e(c)(2). The rate directive also requires that BPA “shall adjust such rates to take into account the value of power system reserves made available to the Administrator through his rights to interrupt or curtail service to such direct service industrial customers.” *Id.*

Thus, the rate formulation describes the overall goal as achieving equity between the rates paid by DSIs and the rates paid by the industrial customers of BPA’s preference customers. It then establishes a formula to be used in connection with achieving that goal. The formula starts with the “applicable” preference rates and adds a typical retail margin. In other words, the statutory formula is set up explicitly to result in a rate that approximates the rate that would normally be paid by industrial customers of BPA’s preference customers that are being served through preference customer access to the Federal power system. Such customers are not targeted by the statute in any way that suggests they should be charged more than that amount or be subject to a BPA-imposed mechanism to implement principles of cost causation.

While WPAG and other preference interest groups often point to *PNGC I* and *II* as being entirely tilted toward preference interests at the expense of DSI service, it is significant that, as indicated above, the court in *PNGC I* required that BPA offer the IP rate when BPA exercises its authority to provide service to DSI customers and declared the IP rate be the “primary benefit” that DSI customers receive under the statutory framework. *PNGC I*, 580 F.3d at 826. As also noted, the court expressed its understanding that the nature of the rate was to create an equitable relationship between the rates of DSI customers and the rates paid by the industrial customers of BPA’s preference customers. *Id.* at 815. It is reasonable to conclude that the court might well look askance at implementation of the CRAC proposed by WPAG, and determine that a mechanism such as the one proposed by WPAG would be an abuse of discretion because it would essentially nullify the primary benefit that Congress intended to provide the DSIs. As Alcoa points out, statutory interpretations that would render a statutory provision a nullity are not permitted pursuant to the Ninth Circuit’s “rule that a statute should not be construed in a manner which robs specific provisions of independent effect,” requiring the Court “to reject interpretations that would render a statutory provision surplusage or a nullity.” *Alcoa Br.*, BP-12-B-AL-1, at 16, quoting *In re Cervantes*, 219 F.3d 955, 961 (9th Cir. 2000).

Additionally, it should be recognized that CRACs have more typically been aimed at striking a balance by ensuring that financial risks are mitigated without exerting immediate upward pressure on rates. They have not generally been intended to introduce the concept of cost causation targeted at a single customer class. Instead, they have generally been designed to promote the fundamental ratemaking objectives of ensuring cost recovery and achieving a high probability of making Treasury payments in full and on time. It is important to recognize as well that the IP rate has customarily been subject to such CRACs when they have been generally applicable to the PF rate. Moreover, WPAG's concerns regarding cost recovery are simply not implicated where BPA has set rates, including the IP rate, to recover its costs even in the most adverse water conditions on record. WPAG's real concern is not cost recovery, but cost allocation.

Thus, contrary to WPAG's arguments, there simply are not any "unrecovered costs" associated with DSI service. The costs associated with DSI service are fully recovered through rates. The WPAG argument is relevant only to how costs should be allocated to various rates. Thus, despite the superficial appeal of WPAG's argument that BPA has used CRACs before and should now target the IP rate with a cost causation CRAC, WPAG's suggestion should be approached with some degree of skepticism. In that connection, BPA does not believe it is reasonable to conclude, as WPAG has apparently done, that Congress intended the DSI rate to be a rate based on principles of cost causation or that the Ninth Circuit Court of Appeals has interpreted the ratemaking directive in such a manner.

Instead, a fair reading of the statute indicates that the IP rate is essentially a formula rate that attempts to achieve an equitable balance between the rates paid by industrial customers of BPA's preference customers and the rates that should be paid by DSI customers. The Ninth Circuit has recognized only that the IP rate is a "cost-based" rate, not a "cost causation" rate. This is an appropriate view because the IP rate cannot be developed, in compliance with the statutory requirements, based strictly on principles of cost causation. The reason is that the statute requires inclusion of costs in the IP rate that are totally unrelated to providing DSI service.

The first of these requirements is inclusion of the industrial margin, a surcharge to the IP rate that is designed to achieve equity between two groups (industrial customers of preference utilities and DSIs), not to recover costs associated with providing DSI service. 16 U.S.C. § 839e(2). The second is the section 7(b)(3) cost re-allocation, which imposes on DSIs costs associated with the Residential Exchange Program, again a cost that bears absolutely no relationship to the costs of providing DSI service. In the event that a settlement of REP obligations is reached, BPA still contemplates allocating a portion of the costs to the IP rate. 16 U.S.C. §839e(b)(3). Together, these costs result in an IP rate that is presently considerably higher than the PF rate. To be specific, the IP-10 rate is on average higher than the PF Public rate by approximately \$8.00/MWh. The IP-12 rate exceeds the melded PF rate by about \$6.05/MWh. PRS Documentation, BP-12-FS-BPA-01A, Tables 2.5.7.2 and 2.5.7.3. It would be unreasonably selective to target the DSIs for total recovery of costs associated with providing DSI service while at the same time continuing to burden the DSI rate with additional charges that have nothing to do with the costs of providing such service.

Moreover, the Ninth Circuit, as noted by Alcoa, has held that it is permissible to include the cost of FBS replacement resources in the preference rate, even if those resources may be used to provide service to DSI customers that pay the IP rate. *Golden NW*, 501 F.3d at 1045-47. It may be helpful to review the facts of that case and the arguments made in support of various contentions:

BPA proposed to sell to the DSIs 1440 aMW of firm power.... BPA also determined that its existing power generation capabilities would be inadequate to supply both its DSI and other customers. BPA estimated in the Initial ROD that it would need to acquire approximately 1562 aMW of additional power to meet the needs of these customers. It explained that it would classify most of this additional power as “Federal base system” (FBS) replacements.... BPA estimated that declines in the capability of its primary FBS resources allowed it to purchase up to 2669 aMW of replacement FBS resources—“far more than the amount of power” it actually planned to acquire.

[BPA] explained that the Northwest Power Act expressly grants BPA the authority to “purchase power to replace reductions in the capability of the FBS and [to] acquire power to meet its forecasted contractual obligations to all its customers.” Supplemental ROD. BPA further concluded that “the FBS is a single resource pool, not a segmented resource to be divided into separately priced portions that serve any particular customer class.”

* * * *

Petitioners construe FBS resources as referring only to BPA's “unaugmented” power generation capabilities. According to petitioners, as long as preference customer loads do not exceed BPA’s unaugmented FBS resources, section 7(b)(1) requires BPA to charge its preference customers rates that recover no more than the cost of those resources. BPA, joined by intervenor Alcoa, counters that it is entitled to charge preference customers a rate that reflects the total cost of all FBS resources, including resources acquired to replace losses in the generation capabilities of BPA's primary resources.

Id. In *Golden NW*, BPA had contractual obligations to the DSIs, and other contractual obligations, and its rate case forecast showed that there might not be sufficient existing resources available to meet those obligations. Therefore, BPA set its rates based on the assumption that it might be required to augment the FBS through purchases of replacement resources. Factually, the situation in this rate proceeding is virtually identical. BPA has contractual obligations for providing DSI service. It has forecast a potential need to make market purchases of FBS replacement resources to meet those and other obligations. The arguments presented by preference customer interests are virtually the same: to the extent BPA must make additional purchases beyond the unaugmented FBS, then the costs of those resources must be allocated to the DSIs. Both the “business standards” test proposed by JP04 and the DSI cost causation CRAC proposed by WPAG (discussed below) are, for all intents and purposes, designed to achieve this same result.

The Court, however, rejected such arguments:

We conclude that BPA’s approach does not contravene the Northwest Power Act and related provisions. Contrary to petitioners’ claim, FBS resources are not limited to “unaugmented” FBS resources. Rather, the statutory definition of FBS resources expressly includes “resources acquired by [BPA] in an amount necessary to replace reductions in capability of [BPA’s primary resources].” *Id.* § 839a(10). Section 6 of the NWPA confirms BPA’s authority to acquire “sufficient power ... to meet [its] contractual obligations.” *Id.* § 839d(a)(2); *see also Alcoa*, 467 U.S. at 384, 104 S. Ct. 2472 (noting that “[o]nce a contract between BPA and a customer is signed, ... the Project Act makes clear that the contract is ‘binding in accordance with the terms thereof’ ” (quoting 16 U.S.C. § 832d(a))). BPA took this language to mean that, once it had satisfied the needs of its preference customers, it could use any remaining FBS resources—including FBS replacement resources—to supply its DSI customers.

Once FBS replacement resources were acquired, nothing in section 7(b)(1) precluded BPA from considering the costs of those replacement resources when calculating its preference rate, even though BPA would not have incurred such costs absent its DSI contracts. If FBS resources include both primary and replacement resources, and if BPA must recover “the costs of that portion” of FBS resources needed to supply preference customer loads, then it follows that BPA may impose rates based on the average cost of FBS resources as a whole. This result is consistent with *Central Lincoln People’s Utility District v. Johnson*, 735 F.2d 1101 (9th Cir. 1984), which rejected the premise that preference customers were entitled “to purchase not just available power, but the cheapest available power.” *Id.* at 1125.

Id. at 1045-1046. Thus, BPA’s determination that the cost of FBS replacements could be allocated to the PF rate was sustainable. Of course, it was also equally true that the DSIs would pay some significant portion of such costs. Since the IP rate is based on the PF rate, revenues from DSI sales would defray such cost to a large extent, if not totally. The Court found further that this construct did not violate principles of preference, as contemplated in the statutory framework:

BPA’s approach is not contrary to the general statutory preference provisions on which petitioners rely. Section 4 of the Bonneville Project Act, for example, requires that BPA “shall at all times, in disposing of energy at said project, give preference and priority to public bodies and cooperatives.” 16 U.S.C. § 832c(a). Similarly, section 5(a) of the [Northwest Power Act] provides that “[a]ll power sales under this chapter shall be subject at all times to the preference and priority provisions of the Bonneville Project Act.” *Id.* § 839c(a); *see also id.* § 839g(c). We have explained that these provisions “protect[] the preference customers’ access to power supply”; they do not speak directly to price. *See Cent. Lincoln*, 735 F.2d at 1125; *see also Alcoa*, 467 U.S. at 393, 104 S. Ct. 2472 (noting that “the preference system merely determines the priority of different customers when the Administrator receives ‘conflicting or competing’ applications for

power”). There is no allegation here that BPA failed to provide the power necessary “to meet the firm power load” of its preference customers. 16 U.S.C. § 839c(b)(1).

... We agree that section 7(b) provides price benefits to preference customers in the form of a “rate ceiling.” *Id.* at 34. We also agree that the legislative history contains some indications that Congress did not intend for preference customers to bear the costs of acquiring FBS replacement resources. *See, e.g., id.* (explaining that “preference customers’ cost of power from BPA will not exceed the costs they would have paid for power if ... [they] were served from *available* Federal base system resources” (emphasis added)); H.R.Rep. No. 96-976, pt. 2, at 36 (1980) U.S. Code Cong. & Admin. News 1980, pp. 6023, 6034 (stating that “[t]he lowest rates will be reserved for the normal loads ... of preference utilities”).

BPA’s rate determination, however, accords with the notion that preference customers enjoy price benefits. After all, the preference rate will always be lower than even the lowest possible DSI rate, which consists of the preference rate plus “the typical margins included by [preference customers] in their retail industrial rates.” 16 U.S.C. § 839e(c)(2).... We therefore hold that BPA’s decision to set a preference rate that reflects the cost of FBS replacement resources was based on a permissible construction of the [Northwest Power Act].

Id. at 1046-1047 (emphasis added). Thus, the cases are clear that BPA’s current IP rate proposal is supported by both statutory and case law.

BPA cannot reasonably conclude that Congress would have intended the result advocated by WPAG. This view is particularly well-founded in light of the fact that the Ninth Circuit has held that it is permissible to include the cost of FBS replacement resources in the preference rate, even if those resources may be used to provide service to DSI customers. *Golden NW*, 501 F.3d at 1045-1047. This finding is further reinforced by *PNGC I*. There, Alcoa argued that basing its sales on the FPS rate was inappropriate because DSIs were entitled to be served at a cost-based rate. *PNGC I*, 580 F.3d at 812. The Court agreed, finding that the IP rate was the applicable cost-based rate, making no reference to the *Golden NW* finding with regard to BPA’s allocation of costs associated with FBS replacement resources. *Id.* at 802 (stating that the IP rate is “applicable to [firm power sales] made to direct service industrial customers,” is “established” pursuant to the requirements of § 839e(c), and “[l]ike the PF rate, it is a cost-based rate,” *citing* 16 U.S.C § 839e(c)); *see also id.* at 812-818.

Finally, WPAG contends that “BPA has implemented a policy to ensure that customers pay the costs that BPA incurs to provide them service, and to eliminate to the extent practicable cross-subsidies between customers.” WPAG Br., BP-12-B-WG-01, at 36. WPAG posits that the “shift in power costs from the DSIs to the preference customers is out of step with this policy.” *Id.* WPAG’s argument does not correctly portray BPA’s policies. BPA has instituted a tiered rate policy that ensures that public body customers pay the incremental costs to serve their load growth. But this policy does not price the entire amount of service to public body customers at the marginal cost of service, as WPAG argues should be done for the DSIs. In total, the public body customers receive the benefits of the embedded cost of Federal system resources. In rate

design, BPA sets Tier 2 rates so that they recover the costs to serve utilities that choose to place their Above-RHWM loads on BPA. The same conditions do not hold for the DSIs. While BPA views service to the DSIs as discretionary, this does not mean that the DSIs are incremental loads after service to Below-RHWM loads. The rates to the DSIs are not tiered, in part because BPA is not obligated, unlike with public body customers, to meet whatever requirements the DSIs might choose to place on BPA. Thus, any cost segregation of certain costs to the DSIs is not necessary in the manner established by the tiering of the PF rate.

BPA's final decision on this issue must be predicated on a reasonable interpretation of relevant statutory provisions with the additional guidance of interpretations made by the Ninth Circuit. The statute states that the IP rate must be equitable in relation to the rates paid by the retail industrial customers of BPA's preference utility customers. It is legitimate then to ask whether it would promote the kind of equitable relationship that Congress had in mind to impose on the IP ratepayers a targeted CRAC when there is no evidence to suggest that the industrial customers of preference utilities are subject to anything comparable. Moreover, it is not reasonable to assume that the IP rate should be based on principles of cost causation when the rate directive requires inclusion of costs in the IP rate that are totally unrelated to cost causation. Finally, Ninth Circuit precedent is fully in accord with the position adopted by BPA, as reflected in the *Golden NW* case, where the court explicitly countenanced including the cost of FBS replacement resources in the PF rate even when some of those replacements would be used to provide service to DSI customers.

Decision

BPA will not adopt the DSI-targeted CRAC proposed by WPAG. The IP rate is essentially a formula rate that can lead to some degree of costs being allocated to the preference rate in the ratemaking process. That result, however, is one of the many trade-offs embodied in the Northwest Power Act.

2.6.4.3 Industrial Margin

Section 7(c) of the Northwest Power Act requires that the IP rate shall include "the typical margins included by such public body and cooperative customers [*i.e.*, those preference customers serving industrial loads] in their retail industrial rates." 16 U.S.C. §839e(c)(2). The statute provides additional guidance, stating that this determination shall take into account

- 1) the comparative size and character of the loads served,
- 2) the relative costs of electric capacity, energy, transmission, and related delivery facilities provided and other service provisions, and
- 3) direct and indirect overhead costs.

16 U.S.C. §§ 839e(c)(2), 839e(c)(2)(A), 839e(c)(2)(B), and 839e(c)(2)(C). Only the issue of whether revenue taxes should be included in the margin has been raised in the BP-12 rate proceeding, as it has been in a number of prior proceedings.

Issue 2.6.4.3.1

Whether revenue taxes should be included in the calculation of the typical industrial margin.

Parties' Positions

JP04 argues, as did preference customers in 1996, that the determination of whether revenue taxes should be included in the industrial margin should not be based on the number of preference customers that serve industrial load of any size. JP04 Br., BP-12-B-JP04-01, at 5. Instead, as argued in the WP-96 proceeding, JP04 maintains that BPA should use the smaller sample used in the margin study, which is limited to preference utilities serving industrial load of 3 aMW or greater. *Id.* at 6. Based on that sample, JP04 argues, revenue taxes are typical because a majority of such utilities are located in the State of Washington, the only state in BPA's service territory that levies revenue taxes. *Id.*

Alcoa is supportive of Staff's rebuttal testimony outlining the history of this issue and concluding that revenue taxes should not be included in the industrial margin. Alcoa Br., BP-12-B-AL-02, at 9-12; Alcoa Br. Ex., BP-12-R-AL-01, at 5. The issue of revenue taxes has been a contentious subject in a number of rate proceedings. Alcoa notes correctly that BPA addressed the same issue raised in this proceeding in 1996 and correctly included that revenue taxes should be excluded from the "typical industrial margin" calculation required by section 7(c)(3) of the Northwest Power Act. Alcoa Br., BP-12-B-AL-02, at 10-11. At that time, BPA concluded that revenue taxes are not "typical" because the majority of BPA's preference customers serving industrial load of any size are not subject to revenue taxes. *Id.* at 10.

In its brief on exceptions, JP04 requested clarification whether the draft decision in the Draft ROD regarding the failure to appeal the decision on the treatment of revenue taxes in 1996 means that parties are now barred from raising this issue again. JP04 Br. Ex., BP-12-R-JP04-01, at 7. JP04 contends that the statement in the Draft ROD that there was a "sense of finality" regarding the 1996 decision seems contradicted by the statements that parties are not bound by precedent. *Id.*

BPA Staff's Position

BPA has now reviewed the issue of whether revenue taxes should be included in the typical industrial margin in a total of four prior rate proceedings. Bliven and Cherry, BP-12-E-BPA-36, at 22-33. The issue presented in this case is one of the same issues that was raised in the WP-96 proceeding, in which BPA first determined that revenue taxes should be excluded from the margin. *Id.* at 23. Staff does not believe that JP04 has provided any good reason why BPA should reverse a policy that has been in place for 15 years. *Id.* at 31.

Evaluation of Positions

Alcoa notes that BPA has previously rejected the position taken by JP04 that revenue taxes are typical because the majority of customers participating in the Margin Study survey are located in the State of Washington. Alcoa Br., BP-12-B-AL-01, at 9. Alcoa further states that "BPA has consistently concluded, after careful legal analysis, that the Washington state revenue tax is

atypical for the region.” *Id.* at 10, *citing* Speer, BP-12-E-AL-02, at 6. Alcoa observes that in the WP-96 rate proceeding, “BPA evaluated how many utilities serving industrial retail load of any size (as opposed to ‘qualified utilities’ participating in the margin study) charge a revenue tax.” *Id.*, *citing* Bliven and Cherry, BP-12-E-BPA-36 at 24-25. The result of this evaluation was, as Alcoa describes, that “[o]ut of 81 utilities serving industrial load, only those located in Washington were subject to revenue taxes” and therefore revenue taxes were not “typical” for the region as a whole. *Id.* at 10-11, *citing* Bliven and Cherry, BPA-12-E-BPA-36, at 27. *See also* Alcoa Br. Ex., BP-12-R-AL-01, at 6.

Alcoa then turns to the WP-02 rate proceeding, where “BPA prepared a ‘comprehensive analysis’ concluding that Washington was the only state in the region that levied a revenue tax” and BPA found further that “of the 83 preference utilities serving industrial load, only 32 were located in Washington.” *Id.* at 11, *citing* Bliven and Cherry, BP-12-E-BPA-36 at 27. Alcoa notes that, once again, BPA found that revenue taxes were not “typical” for purposes of calculating the industrial margin. *Id.* at 11, *citing* Bliven and Cherry, BP-12-E-BPA-36, at 27. Alcoa next notes that in the WP-10 proceeding BPA once again found that revenue taxes were not “typical” and BPA noted, as it had previously, that in determining which cost categories are relevant to the margin calculation BPA must examine the margins charged by all preference utilities serving industrial loads, not a select group of such customers. *Id.* at 10, *citing* WP-10 ROD at 374.

Finally, Alcoa re-emphasizes the fact that BPA has consistently found revenue taxes are not typical and has, in fact, addressed the same issue raised by JP04 in this proceeding: “[The JP04] position ignores BPA’s long-held interpretation that, when determining which costs are “typical,” *all* utilities serving industrial load should be considered (not just ‘qualifying utilities’ that participate in the margin study). BPA’s analysis in this case demonstrates that of the 96 utilities within the region that serve industrial load of any size, only 38 (39.6%) are located in Washington.” *Id.* at 12, *citing* Bliven and Cherry, BPA-12-E-BPA-36, at 32. In summary, Alcoa essentially relies on Staff’s rebuttal testimony as support for its contention that revenue taxes should once again be excluded from the margin.

JP04 disagrees with Alcoa and states BPA was incorrect in proposing to once again exclude revenue taxes from the industrial margin calculation. In support of its argument, JP04 makes the following assertion: “Staff’s reasoning for excluding Washington state revenue taxes centered, essentially, on BPA having excluded such taxes in the past.” JP04 Br., BP-12-B-JP04-1, at 5, *citing* Clark *et al.*, BP-12-E-BPA-17, at 7, and also referring to the WP-96 ROD, WP-96-A-02, at 180, and the WP-10 ROD, WP-10-A-02, at 373-378. JP04 then expands on this theme: “Staff seems to rely primarily on precedential argument to make its case, concluding that BPA should exclude Washington state revenue taxes from the margin calculation in this case because it has done so in the past.” *Id.* In this connection JP04 seems to suggest that BPA cannot rely on precedent dating from 1996 (the second time that BPA was required to calculate the industrial margin) because it included revenue taxes in the industrial margin the first time the calculation was made in 1985. *Id.* at 7.

BPA does not agree with JP04's characterization of Staff's rebuttal testimony. Staff did offer in rebuttal a comprehensive review of the decisions that have been made on this issue throughout the years. Bliven and Cherry, BP-12-E-BPA-36, section 5. However, BPA is not maintaining that it is bound by precedent. To the contrary, BPA understands that an agency is empowered to change its policies when it is reasonable to do so. At the same time, however, it is significant that the very same issue raised by JP04, in this instance, is identical to an objection raised in 1996 and fully addressed by BPA at that time. *Id.* at 31. BPA's policy of excluding revenue taxes has been in place since that time, and it is incumbent upon JP04 to show why circumstances have changed in a manner that would compel BPA to reverse this longstanding policy. *Id.*

It may be that such a change in longstanding policy would not be accorded the same deference by the Ninth Circuit that it might have been entitled to in 1996, when the issue was first addressed. *West Coast Truck Lines, Inc. v. Weyerhaeuser Co.*, 893 F.2d 1016 (9th Cir. 1990). When an agency reverses a prior policy or statutory interpretation made by that agency, the conclusion is accorded less deference than is ordinarily extended to agency determinations. *Id.*, citing *INS v. Cardoza-Fonseca*, 480 U.S. 421, 446 n.30, 107 S. Ct. 1207, 1221 n.30, 94 L.Ed.2d 434 (1987), and *Watt v. Alaska*, 451 U.S. 259, 273, 101 S. Ct. 1673, 1681, 68 L.Ed.2d 80 (1981). Moreover, an agency will be required not only to show that its new policy is reasonable, but also to provide a reasonable rationale supporting its departure from prior practice. *Id.*, citing *Motor Vehicles Mfrs. Ass'n of the United States v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 42, 103 S. Ct. 2856, 2866, 77 L.Ed.2d 443 (1983) (overturning an agency reversal because the agency had provided no explanation for its change in policy), and *Mesa Verde Constr. Co. v. Northern Cal. Dist. Council of Laborers*, 861 F.2d 1124, 1130-34 (9th Cir. 1988) (*en banc*) (upholding an agency reversal after finding that the previous policy had been unworkable in practice). However, a reversal of prior policy or statutory interpretation does not wholly vitiate our deference to agency determinations. *Id.*, citing *NLRB v. International Ass'n of Bridge, Structural and Ornamental Ironworkers*, 434 U.S. 335, 351, 98 S. Ct. 651, 660, 54 L.Ed.2d 586 (1978). Thus, the Ninth Circuit recognizes that such a reinterpretation of a prior view can be justified and the agency still is entitled to deference even though "the consistency of an agency's interpretation is one relevant factor in judging its reasonableness." *Id.* In such a situation, the agency will still be entitled to deference "so long as the agency acknowledges and explains the departure from its prior views." *Id.*, citing *Mobil Oil Co. v. EPA*, 871 F.2d 149, 152 (D.C. Cir. 1989).

A primary purpose of Staff's rebuttal testimony on this issue was to point out to rate proceeding parties that this situation is made even more extraordinary than usual by the fact that the very same issue was raised in 1996 and BPA made a final decision on that issue, which was not taken up on appeal. Bliven and Cherry, BP-12-E-BPA-36 at 24-27. JP04 questions whether the failure to take this matter up on appeal would bar them from raising the issue again. JP04 Br. Ex., BP-12-R-JP04-01, at 7. As JP04 notes, such a policy would lead to a unnecessary litigation. *Id.* While BPA agrees that the decision not to appeal the matter to the Ninth Circuit does not bar a party from raising the matter again in subsequent rate cases, absent a change in the underlying facts or circumstances, parties should not expect a different result.

With respect to the 1996 determination, the testimony stated, in pertinent part:

BPA determined that, to decide whether to include revenue taxes in the margin, it would be more appropriate to determine how many BPA public body and cooperative customers serving industrial retail load of any size do so [*i.e.*, pay revenue taxes], not merely how many utilities participating in the Margin Study do so. ... BPA has always recognized that there are two separate and unrelated issues involved in developing a typical margin calculation. This is true going back to the WP-85 rate proceeding. First, looking at the different categories of utility costs, BPA must determine which costs are appropriately included in the margin. This determination is made independently from the sample. Having made this determination, BPA must calculate the level of costs, in mills per kilowatthour, for each cost category. The margin study sample is used for only the latter determination.

Id. at 24-25, *citing* the WP-96 ROD, WP-96-A-02, at 179-180.

For the next 15 years, BPA continued to implement that decision based on the final decisions in the WP-96 ROD. In such a situation, changing such a longstanding policy cannot be taken lightly. Given that the “consistency of an agency’s policy” is a relevant factor, it is not unfair to expect a party requesting a change in such policy to acknowledge that it is seeking a change in prior policy and articulate reasons other than the ones previously offered in support of such a change in longstanding policy. JP04 fails on both scores.

JP04 simply insists that “the test for determining the ‘typical’ margin for the study should be whether a majority of preference customers serving loads qualifying for the margin study are located in Washington.” JP04 Br., BP-12-B-JP04-01, at 5, *citing* Deen *et al.*, BP-12-E-JP04-01, at 10. From this, JP04 concludes that revenue taxes are “typical” because a majority of preference utilities eligible for inclusion in the industrial margin study are located in the State of Washington. *Id.*, *citing* Deen *et al.*, BP-12-E-JP04-01, at 11.

JP04 argues that BPA’s method of determining whether revenue taxes should be included in the industrial margin is fatally flawed: “The test cannot be, as BPA staff would have it, how a majority of all preference customers with industrial loads are situated. The question of how preference customers that do not qualify for inclusion in the margin study are situated is simply not relevant under BPA’s own methodology—that is, under the margin study itself.” *Id.* at 6. However, this argument brings nothing new to the discussion that was not apparent in 1996, when this argument was first raised. As indicated above, at that time, BPA did in fact find the test is “how a majority of all preference customers with industrial load are situated” with respect to the issue of whether revenue taxes should be included in the industrial margin calculation. WP-96 ROD, WP-96-A-02, at 179-180. The issue was not advanced on appeal, and so BPA has continued to rely on that determination.

This finding is also relevant to the issue of JP04’s argument to the effect that, if BPA is going to bind itself to precedent, then it should be bound to the precedent established in 1985, when revenue taxes were included in the margin. First of all, as previously indicated, BPA is not

asserting that it is bound by precedent. BPA is simply determining whether the JP04 testimony and brief are sufficient to compel a change in a policy that is current and longstanding, particularly when the same issue has been fully addressed in the past.

It is true, as Staff pointed out in rebuttal testimony, that the first time BPA calculated the industrial margin in 1985, revenue taxes were included in the industrial margin. This fact is explicit in the rebuttal testimony:

The first time BPA calculated the industrial margin was in the 1985 rate proceeding. In response to BPA's Initial Proposal, several parties presented three databases for possible use in the margin study. The Administrator chose the database that he believed "... allows flexibility and "... disaggregates[s] costs charged to retail industrial customers for the purpose of determining utility industrial margins."

Bliven and Cherry, BP-12-E-BPA-36, at 23-24, *quoting* the WP-85 ROD, WP-85-A-02. The rebuttal testimony also indicates that, in part because the industrial margin issues had been so controversial in 1985, for practically a decade thereafter, the industrial margin calculation was converted to a mechanistic application of the GNP implicit price deflators pursuant to an agency determination known as the 1986 IP-PF Link. *Id.* at 30.

Thus, when BPA addressed the industrial margin in 1996 for only the second time, inclusion of revenue taxes cannot be considered a longstanding policy. It can only be said that much time had elapsed since BPA had first made the margin calculation. When BPA reviewed the issue of revenue taxes in 1996, it noted first that no evidence had actually been presented in the 1985 rate case record with respect to whether or not revenue taxes should be included in the margin. That issue had apparently not been raised through submission of evidence. Thus, it was appropriate for BPA to revisit the issue with due consideration to the prior lack of evidence on the threshold issue of the whether revenue taxes should be included in the industrial margin.

Examining prior practices with respect to whether a cost category should be included in the margin study or not, BPA determined that its practice had not been to rely exclusively on the margin study sample when considering whether costs categories are includible. Ultimately, BPA decided to change the initial policy of including revenue taxes in the industrial margin because it recognized that, for determining whether other categories of costs should be included in the industrial margin, BPA had relied on the larger sample of preference customers serving industrial load of any size, not a smaller sample: "In the WP-85 rate case, four cost categories were in dispute: non-BPA funded conservation costs, transmission costs, legal expenses related to generation resources, and revenue taxes." *Id.* at 26, *citing* the WP-85 ROD, WP-85-A-02, at 134-140.

With respect to conservation costs, the issue was whether such costs should be considered production costs, which are not included in the industrial margin, or customer service costs, which are included. *Id.* The relevant issue regarding transmission costs was whether such costs "could be segregated from distribution costs. For these issues, as well as the issue of revenue taxes, no one raised any issue with respect to the appropriate sample to use when considering the

initial question of what costs are to be included in the industrial margin. *Id.* However, with respect whether legal expenses were administrative/general expenses or related to power production, “this question was framed in terms of the population of utilities with retail industrial customers rather than in terms of utilities included in the sample.” *Id.*

Thus, in 1996, upon further consideration of the issue, BPA determined that revenue taxes were not inherently a cost incurred through utility operations related to the production, distribution, and sale of power. Instead, they arise only when a “state government imposes them to raise the state’s revenues.” *Id.* For that reason, BPA decided that it would be more appropriate to determine whether revenue taxes were “typical,” for the purpose of calculating a “typical industrial margin,” by referring to the larger sample of all preference utilities serving industrial load of any size, and not the smaller sample of utilities serving industrial load of 3.5 aMW or greater. *Id.* By adopting this course, BPA believed then, as it does now, that the result is an industrial margin is “more representative” than the one that would result from including revenue taxes, which “would artificially distort that calculation.” *Id.* Using the larger sample, BPA determined that revenue taxes are not “typical,” as intended by the statutory obligation to calculate a “typical industrial margin,” because only the State of Washington levies revenue taxes. Well under half of the preference utilities serving industrial load of any size reside in the State of Washington. BPA Staff believed then, and continues to believe now, that the larger sample is the appropriate mechanism for determining which cost categories should be included in the margin study as a threshold matter.

JP04 counters that “BPA has established a process for calculating the margin, and so it must consistently stick with this process in both setting the margin and determining whether the Washington revenue taxes included in that margin study.” JP04 Br., BP-12-B-JP04-01, at 7. This approach, JP04 suggests, would be more in keeping with the statutory guidance that refers to the industrial margin being based on “comparable” loads. *Id.* at 7. As pointed out above, however, BPA provided a reasonable rationale in 1996 for not including revenue taxes in the industrial margin. The more limited sample may be useful for the margin calculation itself, but it is not necessarily relevant to determining the threshold issue of which cost categories should be relevant to the margin calculation.

As noted in rebuttal and elsewhere, BPA has taken the view, not only with respect to revenue taxes but also other issues, that this initial determination should be predicated on the larger sample of preference customers serving industrial load of any size. This use of the larger sample makes sense because it is likely to achieve a more accurate picture of how many utilities are actually subject to revenue taxes rather than a survey that could be skewed by a more limited sample and where participation is voluntary. Further, in contrast to the more limited sample used for margin study itself, use of the larger sample for such determinations is not inherently burdensome or inefficient as it would be if used for the margin calculation survey.

It is also worth questioning whether the 3.5 aMW or greater limitation truly achieves a meaningful standard for “comparative” types of loads. After all, a 3 MW load is not truly comparable to even the Port Townsend load of 20.5 aMW and is very small in comparison to aluminum smelter loads of Alcoa and CFAC. Yet it is also true that if such large numbers were

used as the limit for participation in the margin study, BPA would be unable to achieve a sample that was meaningful on a statistical level. As pointed out in rebuttal, BPA has in the past taken other steps to recognize the issue of comparability of loads:

BPA's approach has generally been to recognize size and character of load in the context of costs that relate to the production and delivery of power. A good example is that, in the past, BPA made a character of load adjustment to account for the fact that the top quartile of DSI load was nonfirm service. Another example is that, in the past, BPA made a size of load adjustment to account for the lower per-kilowatthour costs of delivery facilities installed to serve the large DSI loads. These are described in the 1986 IP-PF Rate Link Proposal ROD. ... In more recent times, there has been no top quartile of nonfirm load, and service to DSI load has been provided on a firm basis. Thus, there is no need to apply a character of load adjustment for the nonfirm nature of the load. Also, BPA takes into account the lower costs of delivery facilities by substituting BPA's delivery charge for the distribution costs experienced by utility customers serving smaller industrial loads, as small as 3.5 MW as opposed to the 20.5 MW Port Townsend load and the 320 MW Alcoa load.

Bliven and Cherry, BP-12-E-BPA-36, at 30 -31. Thus, it is not entirely accurate to say that BPA's primary goal in limiting the margin study to a smaller sample was to achieve comparability. As noted earlier, the calculation of the margin study in 1985 was very contentious, with both PPC and the DSIs introducing their own studies into evidence. In 1996, BPA adopted a single study methodology, relying on PPC to collect the data and providing access to all parties. Thus, the more reasonable way of characterizing the 3.5 aMW or greater limit was to create a margin study sample that would be statistically meaningful without imposing too great a burden on PPC in collecting the information, making it administratively inefficient for BPA, and avoid creating additional reporting requirements that would be applicable to a large number of preference customers. At the same time, this methodology can be contested in a meaningful way in the rate proceeding, as is evidenced by the number of times the revenue tax issue has been raised.

In the final analysis, JP04 has not provided any new facts or circumstances that would convince BPA not to adopt a policy that has been in place since 1996 and which was adhered to in making similar determinations prior to that:

JP04 offers no new or valid reason why BPA should now change its policy decision not to include revenue taxes in the industrial margin. The issue raised by JP04 is virtually identical to the issue raised in WP-96 regarding whether BPA should base its analysis on (a) the margin study sample of public body and cooperative utility customers serving industrial load with a peak of 3.5 MW or more or (2) the larger sample of all BPA public body and cooperative utility customers serving industrial load. ...

Our review has shown that BPA's policy from the first time the industrial margin was calculated has been to base decisions regarding which cost categories should

be included in the margin on the full set of BPA's public body and cooperative customers servicing industrial load.

Bliven and Cherry, BP-12-E-BPA-36, at 31. When BPA changed course in 1996, it did so by acknowledging the fact that it made a different determination in 1985 and providing a reasoned explanation of why it was changing course. JP04's proposal does not provide any compelling reason why circumstances now indicate that BPA should change course with respect to its use of the larger population of all preference utilities serving industrial load any size in connection with determining whether revenue taxes should be included in the industrial margin. As shown above, BPA is not, as suggested by JP04, simply relying on historical precedent. Instead, BPA is focused primarily on the fact that this very same issue was addressed in 1996, when BPA rejected this very same argument.

Another reason Staff's testimony comprehensively summarizes the history of this issue is to inform parties of the issues that have been raised in connection with the revenue tax issue over the course of the past 15 years. Besides the 1985 and 1996 proceedings, the issue was raised in the following proceedings:

1. In the WP-02 rate proceeding, BPA addressed the issue of whether franchise fees levied in Oregon and Idaho were the equivalent of the Washington revenue tax, and if so, whether revenue taxes should be included in the industrial margin. BPA responded with a comprehensive analysis of the statutory provisions from Oregon and Idaho that had been cited, concluding that the taxes identified by the parties were not revenue taxes and finding that Washington was the only state in the region that levied a revenue tax. *Id.* at 27, *citing* the WP-02 ROD, WP-02-A-02, at 15-3 to 15-15.
2. In the WP-10 rate proceeding, it was argued that revenue taxes should be included in the industrial margin because all of the remaining DSI facilities are located in the State of Washington. BPA responded by pointing out that such a consideration is irrelevant based on a clear statutory directive providing that the rate applicable to DSI sales must be "equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers in the region." *Id.* at 28-29, *citing* the WP-10 ROD, WP-10-A-02, at 373-378.

Thus, the issue whether revenue taxes should be included in the industrial margin has now been addressed and decided in a total of four prior rate proceedings. BPA hopes that providing a comprehensive discussion of the history of this issue may avoid the type of unnecessary repetition that has taken place in this rate case as a result of JP04 raising an issue that was already addressed in a prior rate proceeding. The discussion of the history of this issue shows that BPA has always encouraged the introduction and analysis of new issues raised by the parties. Moreover, as pointed out earlier, BPA can also revisit issues at any juncture in order to take account of new facts, changes in circumstances, additional information, or new arguments related to the same topic. In this particular case, after much consideration of the lengthy history of how BPA has viewed the issue of revenue taxes, as well as analysis of JP04's testimony and

briefing, the Administrator finds that no change in BPA’s longstanding position is warranted at this time.

Decision

Following BPA’s established method, and absent a change in the underlying facts or circumstances since such establishment, revenue taxes will not be included in the calculation of the typical industrial margin.

2.6.4.4 Value of Reserves Credit

Section 7(c) of the Northwest Power Act requires that, when establishing the rate applicable to sales to the DSIs, BPA “shall adjust such rates to take into account the value of power system reserves made available to the Administrator through his rights to interrupt or curtail service to such direct service industrial customers. As a condition of their current contracts, DSIs are required to provide BPA with non-spinning contingency reserves. When necessary to respond to various power system conditions, as defined in the contracts, BPA may call upon the DSIs on 10 minutes’ notice to interrupt or curtail up to 10 percent of their loads for up to 105 minutes. As a consequence, BPA is required in this rate proceeding to determine the level of the rate credit required to account for the value of those reserves.

Issue 2.6.4.4.1

Whether the proposed value of reserves credit overcompensates the DSIs for the reserves provided pursuant to their contracts.

Parties’ Positions

JP04 argues that the value of reserves credit is inflated and should be reduced significantly based on the limited number of times the reserves are actually called upon. JP04 Br., BP-12-B-JP04-01, at 8-10. JP04 also questions whether BPA has a need for the DSI reserves and has adequately investigated the cost of other sources for equivalent contingency reserves. *Id.* at 10-11.

Alcoa states that BPA has correctly valued the reserves that DSIs provide under their contracts by relying on the same embedded cost methodology that it uses to value its own generation inputs that Power Services provides Transmission Services in support of performing its obligations as balancing authority. Alcoa Br., BP-12-B-AL-02, at 2; Alcoa Br. Ex., BP-12-R-AL-01, at 6-7. Alcoa requests that BPA include in the ROD the “observation” that not only is BPA required by the Northwest Power Act to acquire reserves from the DSIs, BPA has the obligation to compensate the DSIs for such reserves “made available” to BPA. Alcoa Br. Ex., BP-12-R-AL-01, at 7.

BPA Staff Position

Staff believes that it has proposed a reasonable means of valuing the DSI-provided reserve. Clark *et al.*, BP-12-E-BPA-38, at 13. Based on testing and experience, BPA has concluded that the demand-based reserves provided by DSIs are the functional equivalent of the generation inputs provided by Power Services in connection with fulfilling BPA’s reserve obligations. *Id.* Because they are functional equivalents, and are in fact relied upon in real time to meet a portion of Power Services reserve obligation, it is reasonable to employ the same cost methodology for both types of reserves, *i.e.*, BPA-provided generation inputs and DSI reserves. *Id.* Access to DSI reserves frees up generation capacity that can then be used for other purposes. *Id.*

Evaluation of Positions

Alcoa begins by asserting that “[t]he plain language of the Pacific Northwest Electric Power Planning and Conservation Act ... mandates that BPA adjust the IP rate by the values of reserves.” Alcoa Br., BP-12-B-AL-02, at 2; Alcoa Br. Ex., BP-12-R-AL-01, at 7. In support of this view Alcoa cites to 16 U.S.C. § 839e(c)(3): “The Administrator shall adjust [the IP rate] to take into account the value of power system reserves made available to the Administrator through his rights to interrupt or curtail services.” Alcoa Br., BP-12-B-AL-02, at 3. Moreover, Alcoa notes, “[t]he Ninth Circuit has repeatedly recognized the value of DSI reserves.” *Id.*, citing *Southern California Edison Co. v. Jura*, 909 F.2d 339, 343 (9th Cir. 1990); *Ass’n of Pub. Agency Customers v. BPA*, 126 F.3d 1158, 1164, 1175 (9th Cir. 1997), and *PNGC II*, 596 F.3d at 1074.

Alcoa next turns to the provisions of its current power sales contract with BPA, which define the scope of Alcoa’s obligation to provide BPA with contingency reserves: “BPA can call up to 10% of Alcoa’s firm power under the Contract [and] Alcoa must make the reserve power available within 10 minutes of a call from BPA, and the power must remain available for up to 105 minutes.” *Id.* at 4. Alcoa then discusses the frequency with which it has been called upon by BPA to provide reserves during system events, as defined by contract. Alcoa states that from January 11 through November 24, 2010, Alcoa provided reserves at least 23 times, providing on average a reduction in Alcoa’s power usage of 42 MW for nearly two hours, and Alcoa has generally exceeded the 10 per cent requirement set for in the Contract. *Id.*

Alcoa also argues that the arguments posited by the JP04 panel supporting a lower value of reserves credit should be rejected. First, Alcoa argues that BPA should disregard the JP04 argument that reserve valuation should be based on the number of times they are called upon. *Id.* at 6. Alcoa states that Congress did not intend such a result, maintaining that, prior to enactment of the Northwest Power Act, BPA paid for reserves based on each interruption. *Id.* Alcoa maintains that Congress thought that such a framework “impeded BPA from actually exercising its interruption rights,” which (according to Alcoa) is why Congress used the “made available to the Administrator through his rights to interrupt or curtail [DSI service]” language with the specific purpose of rejecting an approach driven by the number times reserves were called upon. *Id.*

The “made available,” language, Alcoa suggests, refers to the fact that the DSI reserves are “available” to BPA at all times, not merely on those occasions when DSIs are actually provided with notification that they are required to curtail their loads in response to a system event. *Id.* Thus, Alcoa argues, JP04’s recommendation should be rejected because it fails to account for the stand ready value of the reserves: “Alcoa’s reserves are consistently ‘available’ throughout the day. The FY 2012–2013 VOR, therefore, was properly calculated to reflect the fact that Alcoa’s power is available for interruption throughout the day, and that BPA can essentially interrupt Alcoa’s power at will.” *Id.*; *see also* Alcoa Br. Ex., BP-12-R-AL-01, at 7.

Alcoa also argues that BPA should reject JP04’s suggestion that BPA could satisfy its reserve obligations more economically by purchasing reserves on the hourly spot market rather than obtaining them from DSI customers. Alcoa Br., BP-12-B-AL-02, at 6. Alcoa makes a number of points in this connection. First, Alcoa notes that as a balancing authority and member of the Northwest Power Pool Reserve Sharing Group, BPA is obligated to maintain a level of operating reserves “to address unanticipated fluctuations in power generation and load.” *Id.* at 6-7. Alcoa also recognizes that BPA may access reserves provided by the Reserve Sharing Group only after BPA has exhausted all of the reserves that it is required to carry pursuant to the standards of the Western Electricity Coordinating Council. *Id.* at 7. Alcoa also notes that WECC formulates requirements for the types of non-spinning contingency reserves that are acceptable and that hourly spot market purchases are not an acceptable type of contingency reserve. *Id.*

Finally, Alcoa challenges the weight and sufficiency of the testimony proffered by JP04 in this regard. *Id.* at 8. First, Alcoa notes that under cross examination, the JP04/PNGC witness admitted that he was not familiar with and is therefore not an expert in the WECC standards and NWPP Reserve Sharing Group (RSG) requirements that govern the types of reserves that BPA may use to fulfill its role as a balancing authority. *Id.* at 8, *citing* Cross-Ex. Tr. at 64-65. Second, Alcoa states that the JP04 witness also admitted that spot market prices are volatile and unpredictable, thereby undermining the JP04 argument that spot market prices would be cheaper than the value of reserves credit BPA has ascribed to the reserves provided by Alcoa. *Id.* at 8, *citing* Cross-Ex. Tr. at 65. Finally, Alcoa notes that the JP04 witness failed to account for the fact that, in those cases where BPA requires Alcoa to reduce its energy consumption, energy is usually replaced at a later time and can be replaced during light load hours, when the value of the energy is less than it would be during heavy load hours, when most interruptions take place. *Id.* at 9, *citing* PRS, BP-12-E-BPA-01, Exhibit F, sections 6 and 7; Cross-Ex. Tr. at 71-74; and Deen *et al.*, BP-12-E-JP04-01, at 11.

In the final analysis, Alcoa is supportive of BPA’s approach to fulfill its responsibilities under the Northwest Power Act for ensuring that DSI load provides BPA “firm power reserves” pursuant to section 5(d) and adjusting the IP rate to account for the value of those reserves pursuant to section 7(c). Alcoa also recognizes the operational significance of BPA’s compliance with the requirements of WECC, the regional organization responsible for developing requirements that must be adhered to in order to maintain the reliable operation of the Pacific Northwest power system and BPA’s important role as regional balancing authority. In light of the JP04 testimony, it is also appropriate to note that the primary witness supporting the JP04 testimony admitted on cross examination that he lacked expertise in this particular area.

JP04 recognizes that section 5(d)(1)(A) of the Northwest Power Act “requires the sales by BPA to DSI customers ‘provide a portion of the Administrator’s reserves for firm power loads within the region.’” JP04 Br., BP-12-B-JP04-01, at 9, *citing* 16 U.S.C. § 839c(d)(1)(A). Even this statement, however, is at odds with the JP04 direct case. In testimony, JP04 maintained that BPA was under no obligation to acquire DSI-provided reserves and should not do so unless it could demonstrate the Federal power system insufficient to provide the full complement of required reserve inputs:

Q: Is this valuation [i.e., the value of reserves credit] appropriate?

A: No. BPA has demonstrated no need for DSI operating reserves. BPA’s Generation Inputs Study does not demonstrate that BPA is able to carry less contingency reserves or avoid a cost that it would otherwise incur in the absence of reserves available from the DSIs.

* * * *

To the extent that BPA is able to meet its contingency reserve obligations without DSI contribution and without a need to incur additional cost, the economic value of DSI reserves to BPA is zero and should be reflected as such. In the absence of evidence to the contrary we assume this is the case given the general flexibility of the FCRPS and given that BPA has had no known difficulties meeting its obligations during recent years when it was not receiving any reserves from DSI customers.

Deen *et al.*, BP-12-E-JP4-01, at 11-12. The reason for this apparent change in perspective is not stated.

Nonetheless, JP04 challenges whether BPA really needs to access DSI reserves and proposes that BPA should either set the value of reserves credit “at no more than \$0.032 per MWh (\$0.95 [divided by] 30) if BPA expects to curtail Alcoa at the same rate that it has under Alcoa’s current contract during 2010.” JP04 Br., BP-12-B-JP04, at 14. Alternatively, BPA could “relieve Alcoa of that burden [of providing contingency reserves] by setting the VOR Credit at \$1 per year and not curtailing Alcoa unless BPA has no objective operational alternative including NWPP RSG reliance, in which case BPA could credit Alcoa according to the spot market price prevailing at the time of curtailment.” *Id.*

With respect to the VOR, BPA’s testimony initially states:

The IP rate is not a cost-based rate, and its final rate level is not determined by the allocation of costs. The final IP rate level is determined by a formula set out in section 7(c) of the Northwest Power Act. Because the IP rate is a formula rate based on the Administrator’s applicable wholesale rate (*i.e.*, the PF rate), it is inappropriate to suggest that the IP rate under-recovers the costs of serving the DSI loads. The statutory formula indirectly takes cost of service into account. Only costs allocated to the PF rate can be included in the IP rate (with the exception of costs allocated to the IP rate pursuant to section 7(b)(3)). Thus, if the

costs of DSI reserves are not allocated to the PF rate, they cannot be included in the IP rate.

Clark *et al.*, BP-12-E-BPA-38, at 5. The testimony describes the legal basis for its approach to establishing the VOR credit and reiterating its approach of treating the development of the IP rate as implementing a formula rather than applying principles of cost causation:

Moreover, section 7(c)(3) of the Northwest Power Act directs BPA to apply a VOR credit to the IP rate: “The Administrator shall adjust such rates to take into account the value of power system reserves made available to the Administrator through his rights to interrupt or curtail service to such direct service industrial customers.” Because the VOR credit is mandated by the rate directives in the Northwest Power Act, there can be no cost under-recovery associated with the IP rate, because the IP rate is not a cost-based rate and, pursuant to the statutory rate directives, it is not based on cost causation. Similar to the way the IP rate is set overall, the VOR credit is an application of a specific rate formula that does not require an assessment of cost recovery or cost allocation principles.

Id. at 6. Again, BPA concurs with Staff’s general approach to the VOR credit.

Moreover, BPA finds JP04’s VOR proposals seriously flawed for a number of other reasons. First and foremost, the JP04 proposals ignore the value of capacity that must stand ready at all times to provide reserves during a system event and focus solely on the energy value ascribed to reserves when they are actually called upon to provide energy during a system event. The first option proposed by JP04 totally ignores the significant “stand ready” value of having capacity available to respond to contingency events. This “stand ready” value of the capacity made available to provide operating reserves is described and discussed extensively in the Generation Inputs Study, BP-12-FS-BPA-05, and associated testimony, Chen *et al.*, BP-12-E-BPA-26.

BPA establishes the quantity of operating reserves that it is required to carry by reference to applicable standards developed by the North American Reliability Council (NERC), the Western Electricity Coordinating Council (WECC), and the Northwest Power Pool (NWPP). Generation Inputs Study, BP-12-FS-BPA-05, at 75. BPA is a “balancing authority” for purposes of WECC’s reliability requirements. The current WECC standard requires each balancing authority area to maintain sufficient Operating Reserve. BPA assumes the NERC Disturbance Control Standard BAL-STD-002-0 will continue to be in effect for FY 2012 and that the Commission will approve BAL-STD-002-WECC-1 by FY 2013. *Id.* at 76-77.

The amount of Operating Reserve using BAL-STD-002-0 must be equal to the greater of:

- a) The loss of generating capacity due to forced outages of generation or transmission equipment that would result from the most severe single contingency; or
- b) The sum of five percent of the load responsibility served by hydro generation and seven percent of load responsibility served by thermal generation.

In addition to this standard, each NWPP member with wind generation in its balancing authority area must maintain Operating Reserve equal to five percent of the wind generation for which the balancing authority has load responsibility. *Id.* at 76.

The amount for proposed BAL-STD-002-WECC-1 must be equal to the greater of:

- a) The loss of the most severe single contingency; or
- b) The sum of three percent of the load (generation minus station service minus net actual interchange) and three percent of the load of net generation (generation minus station service).

Id. at 78.

After adjusting for reserves provided by third parties through self-supply, the analysis yields the Operating Reserve obligation to be provided by BPA, equal to 610.2 MW in FY 2012 and 500.0 MW for FY 2013 (555.1 average in FY 2012 and 2013). *Id.* at 80.

To calculate the reserve cost allocation, BPA adds the capacity of the independent hydro projects that are capable of providing operating reserve to the Big 10 projects. *Id.* at 81. *See* Generation Inputs Study, BP-12-FS-BPA-05, at 80-83, and Chen *et al.*, BP-12-E-BPA-26, at 8-11.

Staff devotes all but one paragraph of the section entitled “Allocating Cost for Operating Reserves” to discussing the embedded cost methodology used in connection with the standing ready capacity value of reserves. Chen *et al.*, BP-12-E-BPA-26. A single paragraph is dedicated to describing the costs associated with those occasions when the operating reserves are actually called upon to produce energy during a contingency event on the power system. JP04 focuses solely on that one paragraph. Such a focus is inappropriate because, as stated in connection with balancing reserves, the Study states: “Stand ready costs are distinct from actually deploying balancing reserve capacity within the hour in response to a need.” Generation Inputs Study, BP-12-FS-BPA-05, at 64. The statement is equally applicable to determining the value of operating reserves standing ready to respond on demand to unplanned system events.

Suffice to say that when all relevant embedded costs are considered for supplemental non-spinning reserves, such reserves are accurately valued at \$6.96 per kW per month, comprised of only an embedded cost allocation. *Id.* at 82. In closing, the testimony does refer to the costs incurred when reserve capacity is actually called upon to provide energy during a system event:

When Operating Reserve is utilized to provide energy, that energy is priced based on an hourly energy index in the Pacific Northwest, or an alternative index if an adequate hourly index is not available, as determined by BPA.

Id. As shown above, however, that piece of the valuation discussion accounts for only one small part of the value of supplemental non-spinning reserves such as those provided by the DSIs.

Because of this lack of understanding of the value of reserves, JP04 proposes a second option of calling on the DSI reserves as a last resort and then paying only a token amount in consideration of their value. JP04 Br., BP-12-B-JP04, at 14. This proposal is equally flawed because it

undermines the value of reserves based on the order in which they are called in the deployment stack, with those positioned last in the stack being accorded less value than those called on earlier. In the WP-10 rate case, it was assumed that, in accordance with typical industry practice, demand side resources (such as DSI reserves) would be last in the deployment stack. Staff agreed with the IOU rebuttal testimony stating that position in the stack had little or no bearing on the value of reserves:

We have not fully analyzed all these limitations and considerations, but due to the IOUs' point that standing ready has value; the new information provided through BPA-AL-01, Exhibit 1; and the assumption that load-based reserves would be deployed last, the stand ready value of the reserve provided by a power sale to a DSI gives BPA roughly full value in that it can displace operational capacity that would have otherwise been utilized as Supplemental Operating Reserve. Therefore, we propose not to derate the value of reserve in this rate case.

Fisher *et al.*, WP-10-E-BPA-36, at 15. The only circumstance that has changed is that BPA no longer assumes that DSI reserves will be deployed last. Also, it is worth noting that BPA does not place different values on its own generation inputs used to provide reserves based on their position in the deployment stack. Again, doing so would not be reasonable given the high value of the capacity that must be standing ready in order to fulfill BPA's reserve requirements.

Finally, as a strictly evidentiary matter, there is nothing in the record to support the proposal made by JP04. As noted above, the JP04 proposal was predicated on a view that BPA was not required to acquire DSI-provided reserves and should not do so:

BPA has demonstrated no need for DSI operating reserves. BPA's Generation Inputs Study does not demonstrate that BPA is able to carry less contingency reserves or avoid a cost that it would otherwise incur in the absence of reserves available from the DSIs.

Deen *et al.*, BP-12-JP04-E-01, at 11. The only testimony that offered an alternative to this proposal was offered by PNGC. That testimony proposed that, in lieu of acquiring reserves from the DSIs, BPA should purchase any additional reserves need by BPA on the hourly spot market:

The hourly market prices shown in Column J [of Exhibit A], observed and contemporaneously recorded by PNGC staff at the times of the Alcoa curtailments, reflect that BPA could have paid relatively modest spot market prices for contingency reserves had BPA not burdened itself with obtaining non-spinning contingency reserves from the DSIs. We do not believe that circumstances would be materially different for the BP-12 rate period, when BPA proposes an increased VOR credit.

Brawley, BP-12-E-PN-02, at 8-9. However, accessing the hourly spot market to respond to a system emergency would not be in compliance with WECC standards, which require that balancing authorities have a specified quantum of reserves available at all times to respond to events that threaten system reliability: "Operating Reserves shall be calculated such that the amount available which can be fully activated in the next ten minutes will be known at all times." WECC Standard BAL-STD-002-0, at 2. In other words, all reserves have to be available

in the here and now, and at all times, to respond, in the case of non-spinning contingency reserves, within ten minutes. It is not at all clear why a party apparently would believe that hourly spot market purchases could satisfy that standard. This is not to say that, in the future, market alternatives will not be available, or are totally outside the realm of what is possible. It is simply to say that, pursuant to the WECC regulatory requirements, a balancing authority cannot simply call up a power marketer on ten minutes' notice and demand that the market make power available in response to a contingency event, as described by the witness. Furthermore, it is not clear that a more viable market approach, should one materialize, would be a more economical product.

In support of this recommendation, the witness relies on a statement taken out of context from Staff's own testimony valuing the generation inputs provided by Power Services in support of its own reserve obligations:

When Operating Reserve is utilized to provide energy, that energy is priced based on an hourly energy index in the Pacific Northwest, or an alternative index if an adequate hourly index is not available, as determined by BPA.

Brawley, BP-12-E-PN-02, at 9, *citing* Chen *et al.*, BP-12-E-BPA-26, at 11. As shown above, however, reliance on this statement is misleading in that it fails to account for the bulk of Staff's testimony regarding the value of capacity that must be standing ready at all times to respond to a system event.

Another proposal made by the PNGC witness is that BPA should access the NWPP RSG rather than acquire DSI reserves:

We believe that placing reliance on the NWPP RSG for the modest increment of non-spinning contingency reserves said to have been supplied by Alcoa from January through November, 2010, would have been far less costly than reducing Alcoa's IP Rate with VOR Credit under the WP-10 [*sic*] rates.

Brawley, BP-12-E-PN-02, at 8. However, this proposal is equally misplaced because BPA cannot access the RSG until it has completely exhausted its own reserves:

BPA is a participating member of the NWPP Reserve Sharing Program for Contingency Reserves. By participating in the Reserve Sharing Program, BPA is better positioned to meet NERC disturbance control standards because BPA will have access to a deeper and more diverse pool of shared reserve resources. Participation in this program also increases efficiency because the shared reserve obligation for the group as a whole is less than the sum of each participant's reserve obligation when computed separately. By sharing reserves, participants are entitled to use not only their own "internal" reserve resources, *but may call on other participants for assistance if their internal reserves do not fully cover a contingency.*

Chen *et al.*, BP-12-E-BPA-26, at 4 (emphasis added). Once BPA has deployed the specified quantum of reserves it is required to have available BPA may only then request from the other members of the NWPP Reserve Sharing to provide the remaining amount to fully cover a

contingency. Thus, RSG reserves cannot be substituted for a portion of the specified quantum of reserves that BPA is required to carry because they may be accessed only after BPA's "internal" reserves have been exhausted.

It is also worth noting that the proposals made by the PNGC witness lack weight and sufficiency because, as Alcoa notes, the witness, on more than one occasion, disavowed having any expertise in the area that is the subject matter of the testimony, *i.e.*, the value of contingency reserves. That value cannot reasonably be discussed without some working knowledge of the environment in which contingency reserves are utilized, their operational characteristics, and the regulations that govern their availability and use.

As noted elsewhere, JP04 has apparently backed away from its earlier view that BPA should not acquire DSI reserves. JP04 now explicitly recognizes that section 5(d)(1)(A) of the Northwest Power Act "requires that sales by BPA to DSI customers 'provide a portion of the Administrator's reserves for firm power loads within the region.'" JP04 Br., BP-12-B-JP04-01, at 9, *citing* 16 U.S.C. § 839c(d)(1)(A). JP04 now submits that the Act provides no guidance regarding the type of reserves that the DSIs should be required to provide or provide insight into how they should be valued, or even whether the value is "necessarily greater than zero." *Id.* at 9.

It is true that the statute provides no guidance on the type of reserves provided by DSIs other than that they "shall provide a portion of the Administrator's reserves for firm power loads within the region." 16 U.S.C. § 839c(d)(1)(B). BPA believes that the standard of review is that interpretation of this provision should not be arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law since it is a technical question best left to the sound discretion of the Administrator. In that vein, the first principle of statutory interpretation that should be noted is that use of the word "shall" generally creates a mandatory duty. *Our Children's Earth Foundation v. U.S. E.P.A.*, 527 F.3d 842 (9th Cir. 2008); *Sierra Club v. Whitman*, 268 F.3d 898 (9th Cir. 2010).

Further, BPA believes that the product that it has designed and incorporated into the DSI contracts conforms with the statutory requirement that DSI reserves provide a "portion" of BPA's reserves for firm power loads. As accurately described by Alcoa, BPA has a contractual right to interrupt up to 10 percent of its DSI load on 10 minutes' notice, for up to 105 minutes, when there is a system event requiring that BPA employ contingency reserves. As stated in Exhibit F of the current contract between BPA and Alcoa:

3. QUALITY AND CHARACTER OF RESERVES

Contingency Reserves provided by Alcoa shall be consistent with North American Electric Reliability Council (NERC), Western Electricity Coordinating Council (WECC), and Northwest Power Pool (NWPP) standards and criteria:

3.1 the Reserve Amount, or the requested portion thereof, must be offline within ten (10) minutes of an Event and pursuant to section 4 of this Exhibit;

3.2 the Reserve Amount, or the requested portion thereof, must be available to be offline for up to one-hundred five (105) minutes.

Exhibit F, Contract No. 10PB-12175, Power Sales Agreement Executed By The Bonneville Power Administration And Alcoa Inc. Language to the same effect is also included in the proposed Power Rate Schedules, BP-12-A-02B, section III.B.18.

BPA believes that this amount and quality provide significant value to BPA without unduly burdening the operating DSI load that must bear some additional cost and inconvenience when BPA does call on reserves. As to JP04's other contention, that the statute provides no guidance with respect to whether the value of reserves credit should be "necessarily greater than zero," BPA disagrees and believes that the explicit statutory language refutes such a statement:

The Administrator shall adjust such rates [*i.e.*, rates applicable to DSI sales] to take into account the value of power system reserves made available to the Administrator through his rights to interrupt or curtail service to such direct service industrial customers.

16 U.S.C. § 839e(c)(3). The congressional command to "adjust such rates" effectively contradicts JP04's argument that the value of reserves credit could be zero because such a finding would, contrary to the statute, not require BPA to "adjust" the rate in any manner. Moreover, because the statute speaks to the "value" to BPA of acquiring such reserves, it would be nonsensical to propose that they would be worth less than zero because, in such a case, they would be a burden, not provide value. Thus, a reasonable reading of the statutory framework does not support JP04's proposal.

JP04 goes on to argue that BPA Staff had "assumed that the agency should value the VOR Credit at the embedded cost of BPA's generating resources used to supply contingency reserves" and that the "credit is forecasted to cost BPA about \$2.8 million per year, in the form of reduced revenues from DSI sales." JP04 Br., BP-12-B-JP04-01, at 12, *citing* Brawley, BP-12-E-PN-02, at 2-4 and PRS Documentation, BP-12-E-BPA-01A, at 119, Table 322. According to JP04, this method of valuing the reserves violates the requirement that BPA "must set rates for the DSIs 'at the lowest rates to consumers consistent with sound business principles.'" JP-04 Br., BP-12-B-JP04-01, at 8, *citing* 16 U.S.C. § 838g. Again, however, JP04's arguments fail because they do not adequately account for the explicit language chosen by Congress in formulating the statutory scheme under the Northwest Power Act. Simply put, since the DSIs are also "consumers," this provision applies equally to the IP rate. Therefore, there is nothing legally inconsistent with BPA's valuation of reserves to the extent that it makes the IP rate lower rather than higher. Such a result is not inconsistent with the "lowest rates possible" mandate; nor is it inherently inconsistent with sound business principles.

Moreover, as discussed elsewhere, the Ninth Circuit has never interpreted this provision in the restricted and narrow fashion proposed by JP04. Instead the Court interprets the standard by giving meaning to all of the words:

Also, the statutes do not dictate that BPA always charge the lowest possible rates. 16 U.S.C. § 838g directs that rates be set "with a view to encouraging ... the lowest possible rates to consumers...." The words "with a view to encouraging" do not constitute a statutory command that the prices charged to consumers always be the lowest possible. Moreover, nearly every action by BPA has some

arguable impact on future rates. If the strict interpretation of the “lowest possible rates” standard [were made] ... the discretion that Congress vested in the Administrator would be eliminated.... In addition, the direction to charge the lowest possible rates is tempered by the addition of the clause “consistent with sound business principles.” 16 U.S.C. § 838g.

CEC, 909 F.2d at 1307.

For JP04, the bottom line is that “the PF rates should not be inflated so that the VOR Credit can be inflated.” JP04 Br., BP-12-B-JP04-01, at 9. As shown elsewhere, the *VOR credit is not inflated*. It is the same value that is placed on Power Services-provided reserves, which is appropriate given that the DSI reserves are the functional equivalent of BPA-provided reserve inputs. Nevertheless, in support of its contention that the VOR credit is improperly inflated and the PF rate thereby improperly inflated, JP04 makes a number of points.

First, JP04 maintains that, in connection with determining the VOR credit, BPA should consider cost causation. This principle is violated if “the Administrator were to allocate to the PF rates the high costs of applying the proposed VOR Credit to DSI sales.” *Id.* at 10. Such an approach, JP04 argues, would improperly “increase the rates paid by its preference customers and inhibit the diversified use of power in the region.” *Id.* As noted above, the statute, through use of the word “shall,” imposed a mandatory duty on BPA to adjust the IP rate to account for the value of any reserves that they provide. To suggest that the cost should be borne by DSIs, or by some other mythical ratepayer that is not a preference customer, defies logic. The DSIs should not be required to pay for a credit owed to them because they somehow “caused” it when Congress enacted the statute. Furthermore, because the statute requires that the IP rate be based on the PF rate, it is the logical rate to absorb any increased costs associated with the reserve credit. Furthermore, preference customers may actually benefit from the DSI-provided reserves. As explained elsewhere, reliance on DSI reserves frees up additional capacity that is available to BPA for other uses. To the extent that the value of those uses equals or exceeds the \$2.8 million VOR credit to the IP rate, then the entire transaction is a “wash.”

JP04 also argues that BPA should “take into account the frequency of its curtailments of DSI loads under the current contract, the value of what is acquired as a result of those curtailments, and the cost of alternatives available to BPA” and BPA has not done so. *Id.* In this connection, JP04 states that BPA’s own data shows “that it had vastly more spinning and non-spinning contingency reserves available to it than was needed on each of the occasions BPA has stated that it curtailed the loads of Alcoa under its current contract.” *Id.*, citing Exhibit B of the brief, Table 1. JP04 concludes by suggesting that BPA has not adhered to sound business principles, which would require BPA to “obtain reserves at the lowest cost.” *Id.* at 11. JP04 also argues that, if BPA were functioning in a business-like fashion it would not have acquired the DSI reserves because “BPA had available to it on each curtailment occasion roughly 50-100 times the amount of non-spinning contingency reserves that it obtained by curtailing Alcoa.” *Id.*, citing Brawley, BP-12-E-PN-02, Exhibit A, BP-12-PN-02-AT-01-E01.

As discussed above, however, this issue really goes to where a particular reserves input is positioned in the deployment stack, a concept that, as noted above, BPA rejected in the WP-10

rate proceeding. BPA does not intend to change its view now, for the reasons stated above. Of course, it is true that BPA carries more reserves than are used most of the time because of WECC requirements, again as identified above. The RSG provides additional backup should a situation develop when BPA's reserves are insufficient to respond to a contingency.

It is also worth pointing out that JP04 is incorrect in its apparent assumption that the reserve requirements in the DSI contracts give BPA an unfettered right to call upon DSI reserves any time it sees fit. That is hardly the case. The terms of the DSI contracts specify the conditions under which BPA may call upon DSI reserves:

When necessary to provide Contingency Reserves, BPA may restrict the Reserve Amount, or the requested portion thereof, for a period of time (Restricted Energy). The Reserve Amount shall equal the amount of Minimum DSI Operating Reserve – Supplemental. Alcoa shall provide the Restricted Energy to BPA by an interruption of its loads in an amount equal to or greater than the amount of such specified Restricted Energy, and in each case shall continue such load interruption for the duration of the Event.

Exhibit F, Contract No. 10pb-12175, Power Sales Agreement Executed By The Bonneville Power Administration And Alcoa Inc. "Event" is defined as follows:

"Event" is a system condition under which PS needs additional power to meet its obligations during a system disturbance. The beginning of an Event shall be identified by alarm notice to the PS Loads Scheduler/Hydro Duty Scheduler of a system disturbance, and the Loads Scheduler will notify Alcoa that Restricted Energy is required. The end of the Event shall occur the earlier of when a) initially established; b) Alcoa's scheduling agent has notified Alcoa that full service has been restored; or c) 105 minutes from the beginning of the Event. An Event shall not include BPA electing not to purchase power for economic reasons, nor shall an Event include circumstances in which BPA elects not to purchase available transmission capacity to avoid the need to impose a restriction.

Id. This language makes it clear that BPA would be in breach of its contractual obligation if it unilaterally determined that it could simply ignore these requirements in order to gain access to those reserves more frequently and use them for purposes that were not intended by the contracting parties.

JP04 further argues that BPA's access to Northwest Power Pool Reserve Sharing Group means that "BPA had to go out of its way *not* to use the RSG instead of curtailing DSI customers." *Id.* at 12. JP04 also notes that "[i]f BPA had used the RSG system, it would have paid spot market prices." *Id.* As noted above, RSG is available only during times when all BPA reserves have been deployed. Also, if BPA were not required by statute to acquire DSI reserves, that would have no bearing on the level of reserves that BPA would be required to carry and deploy before it had access to RSG reserves. The absence of DSI reserves, as noted above, would only serve to require BPA to make more of its generation capacity available to comply with its reserve obligations.

Moreover, the reference to spot market prices in RSG documentation is misleading for the same reason that the reference to spot market prices in Staff's testimony is misleading. It does not provide a complete picture of what is involved. BPA is a member of the RSG. As such, BPA can be called upon to provide other members with reserves when they have fully deployed their own reserves and need additional reserves to respond to a system event. This is how the "stand ready" value is compensated for in the RSG system, *i.e.*, as part of a reciprocal obligation:

Participation in this program [RSG] also increases efficiency because the shared reserve obligation for the group as a whole is less than the sum of each participant's reserve obligation when computed separately. By sharing reserves, participants are entitled to use not only their own "internal" reserve resources, but may call on other participants for assistance if their internal reserves do not fully cover a contingency.

Chen *et al.*, BP-12-E-BPA-26, at 4. A non-member of the RSG would neither have the obligations associated with membership nor be entitled to receive the benefits of having access to a "deeper and more diverse pool" of reserves. Such a non-member would also be required to pay more than spot market prices and to compensate for the capacity value of the reserves, since such a party has not reciprocally obligated itself to provide reserves to other members if such a need arises.

JP04 also challenges BPA's contention that DSI reserves provide value by freeing up hydroelectric capability for "other uses and purposes." JP04 Br., BP-12-B-JP04-01, at 12. Without providing evidence in support of its contention, JP04 maintains that such "other uses and purposes" are likely to be "surplus sales in the spot market or selling some quantity of power at heavy load hour prices and replacing it at light load hour prices." *Id.* In support of this argument, JP04 points to BPA rebuttal testimony that explains what happens when contingent reserve capacity is called upon during a system event or disturbance to bring the system back into load/resource balance by producing energy rather than sitting idle and not producing energy, which is the state when there is not a system event or disturbance. JP04 correctly notes that, during those times, the energy produced is cashed out at spot market prices or the energy is returned. However, as noted above in response to the PNGC testimony, the bulk of BPA Staff's testimony deals with establishing the "stand ready" value of contingency reserves through an embedded cost methodology. Chen *et al.*, BP-12-E-BPA-26.

In sum, the JP04 argument on the value of reserves credit is flawed in many respects, and the JP04 proposals cannot be given much weight in this proceeding. JP04 ignores the embedded cost methodology that was developed to account for the "stand ready" value of those reserves, in spite of the fact that the primary value of reserves is the "stand ready" value that they provide. In the case of generation-based reserves, there is generating capacity being made available 24 hours a day, seven days a week, so that it can be called upon on demand, at any time, any hour, if there is a system event that requires immediate dispatch of energy to maintain the reliability of the electric power system. In the case of demand- or load-based reserves, such as the DSI reserves, it is available to be called upon 24 hours a day, seven days a week, during any contingency event, on demand and with little notice.

JP04 does not provide any compelling explanation as to why the DSI reserves are not, as concluded by BPA, the functional equivalent of reserves provided by BPA. In other words, JP04 provides no insight into the question of why it would be fair for Power Services to collect one amount when providing generation amounts, but insist upon paying a lesser amount for DSIs for providing a product that is equivalent to its own generation inputs.

In the final analysis, the JP04 argument is not supported by the record. In its testimony, JP04 maintained that BPA was not required to buy DSI reserves. On brief, JP04 revises that erroneous view, admitting that the statute requires DSI reserves, but that BPA should simply take some other approach that reduces the value of reserves credit based on the number of times they are used or the order in which they are called in the deployment stack. This argument itself is a variation on the previously enunciated and erroneous views that BPA could purchase reserves on the hourly spot market, which would be inconsistent with WECC reserve-carrying requirements for balancing authorities such as BPA, or, in the alternative, simply access the RSG, which can be used only after BPA exhausts its own reserves. In such circumstances, it cannot reasonably be suggested that JP04's proposals, in their various incarnations, are entitled much weight. Alcoa Br. Ex., BP-12-R-AL-01, at 7.

In conclusion, BPA sales to DSIs are required by statute to “provide a portion of the Administrator’s firm power reserves for the region.” In the ratemaking process, BPA is required by statute to “adjust” the IP rate “to take into account the value” of such power system reserves. BPA has determined that, based on testing and experience, DSI-provided reserves provide the functional equivalent of the generation inputs provided by Power Services in connection with fulfilling BPA’s reserve obligations. Accordingly, it is fair and reasonable to ascribe to the DSI-provided reserves the same value that is derived by the embedded cost methodology used to value BPA-provided generation inputs.

Decision

The value of DSI reserves has been established by an appropriate methodology. Application of this methodology does not, as argued by JP04, overcompensate DSIs for the interruption rights provided under their contract.

2.6.5 Irrigation Rate Discount

The Irrigation Rate Discount (IRD) for the FY 2012–2013 rate period is described in GRSP II.H. The IRD will be applied to eligible irrigation loads as identified in the customer’s CHWM Contract. Such eligible irrigation loads would not increase during the term of the contract. The discount would not apply to loads served at Tier 2 rates.

Issue 2.6.5.1

Whether BPA should modify the Load Shaping Rate to mitigate the impact on customers eligible for the Irrigation Rate Discount.

Parties' Positions

NRU notes that BPA's rate design uses the Load Shaping Charge to send a price signal to its customers. NRU Br., BP-12-B-NR-01, at 7. NRU contends that the seasonality in the rates cause a disproportionate impact on irrigation loads because irrigators are not able to respond to the price signal. *Id.* at 7-8. Although NRU does not make a proposal regarding specific changes it wants to the seasonality in the Load Shaping rate, it nevertheless asks for a "modest adjustment" to the Load Shaping Rate to mitigate what it views as the lost value of the IRD. *Id.* at 9-10.

PNGC supports BPA's approach to the IRD and opposes NRU's proposals. PNGC Br., BP-12-B-PN-01, at 11-12. PNGC is concerned about the need to take such a proposal through the TRM Change Process, the ill will that could be created between public customers, and a potential cost shift to "non-irrigation preference customers." *Id.* at 12.

BPA Staff's Position

The proposal to modify the Load Shaping Rate as a mechanism to modify the impact of the rate design on utilities with irrigation loads is being raised for the first time in brief, and Staff did not address the issue during the BP-12 rate case.

Evaluation of Positions

NRU raises for the first time in brief the request for an unspecified modification to the Load Shaping Rate to offset what it states is the lost value associated with IRD due to the seasonal impact of the Load Shaping Rate. NRU Br., BP-12-B-NR-01, at 9-10. To understand NRU's proposal, it is important to first explain the interrelationship between the Load Shaping Charge and the impact on utilities with large irrigation loads.

Under the TRM, the Load Shaping Charge is designed to recover the costs associated with shaping the Tier 1 System Capability to the Monthly/Diurnal shape of a customer's Actual Monthly/Diurnal Tier 1 Load. TRM-12S-A-03, at section 5.2. The Load Shaping Charge credits or debits a customer's bill to the extent its actual Monthly/Diurnal load is less than (credits) or exceeds (debits) a utility's System Shaped Load. The System Shaped Load is the utility load reshaped to match the shape of the Tier 1 System.

Under the TRM, the Load Shaping Rate is a market price forecast for each Monthly/Diurnal period during the Rate Period. *Id.* at section 5.2.2. Consequently, to the extent a customer's actual load during a month exceeds or is less than its System Shaped Load, the customer is debited or credited at a market rate for the power. The TRM requires BPA to establish in each 7(i) process a market price forecast to be used for the Load Shaping Rate. *Id.* The BP-12 Initial Proposal explained that BPA Staff was proposing to use the market price run (a specific forecast, as opposed to a different specific forecast, the critical water run) to set the Load Shaping Rate. *See Kujala et al.*, BP-12-E-BPA-14, at 1-4, for discussion of market price run and critical water run. In its testimony NRU did not raise any issue with the results of the market price run or the underlying methodology used to determine the forecast.

Because of the design of the Load Shaping Charge, utilities with large irrigation loads will likely experience significant changes to their monthly bills during the year.²⁰ During the summer irrigation months, these utilities' actual load will exceed their System Shaped Load. Consequently, they will experience large Load Shaping Charges. However, these charges will be offset by credits to their bills in the non-irrigation months when their actual loads are less than their System Shaped Loads. An examination of the Initial Proposal shows that the value of the irrigation load is negative; that is, the Load Shaping Charge applied to the irrigation load produces a net credit of about \$228,000 to the utilities with irrigation load. PRS Documentation, BP-12-E-BPA-01A-E04, at 3, line 46.

While the rate design does create swings in cash flow, on balance these irrigating utilities generally do not experience as significant an annual rate increase as utilities without significant irrigation loads. Fisher *et al.*, BPA-12-E-BPA-50, at 8, and Attachments 1 and 2. Furthermore, to the extent these cash flow changes caused by the Load Shaping Charge adversely impact customers, BPA has already committed, through section 5.1.6 of the TRM, to “the maximum extent practicable while ensuring timely BPA cost recovery, accommodate individual customer requests to reshape charges within the Fiscal Year to mitigate adverse cash flow effects on the customers.” TRM-12S-A-03, at section 5.1.6. This is discussed further in Issue 2.6.5.2 below.

It is critical to understand the effects of new rate design on power bills. Under the current WP-10 rates, the effects of irrigation loads on a customer's power bill are isolated to the month of consumption. When the irrigation load consumes electricity, it is charged the rate for that specific time period; it does not affect the power bills of any other month. This is no longer the case under the BP-12 rates. Under the TRM rate design, the effects of a load in any particular time period create effects on all time periods of the year. In the case of irrigation load, the summertime usage results in wintertime bill credits. Therefore, wintertime power bills for utilities with irrigation loads are lower than they would be if there was no irrigation load.

Further, a simple comparison of monthly power bills is no longer appropriate to compare WP-10 rates with BP-12 rates. For example, a megawatthour of irrigation consumption in June would be charged about \$10 under WP-10 rates. Under BP-12 rates, this same megawatthour would be charged the Load Shaping rate of about \$40. But comparing the \$10 charge to the \$40 charge is an apples to oranges comparison. First, the energy rate under WP-10 was a market forecast rate that was scaled down by about 50 percent. Thus the specific rate charged for consumption was half the market forecast. Under BP-12 rates, the Load Shaping rate is set at the full market forecast with no scaling. Thus, one portion of the rate is twice what it was under WP-10. However, in order to not over-collect revenues, rather than scale rates downward as in WP-10 rates, under BP-12 rates the customer charges are lowered. In doing so, the lowered rate is spread throughout the year. Thus, the billing in June will appear to be higher because of the Load Shaping Charge, but the offsetting compensation, formerly incorporated through scaling, is now in each of the months of the year embedded within the customer charges.

²⁰ An important feature of the Load Shaping Charge is that if actual load equals forecast load, there is no net energy purchased at the Load Shaping rates; the Load Shaping Charge in this situation is a comparison of the value difference between the actual load shape and the System Shaped Load.

For these reasons, a utility customer can no longer look at individual monthly power bills to see the effect that any particular class of retail load has on its BPA power bill. It must take into account the effects of the retail load class throughout the year. In order to help BPA's customers understand these effects better, BPA is incorporating into its customer-level rate effects spreadsheet (the Rate Impact Model) the ability to specify a particular subset of the utility retail load and observe the effect of that retail load on the utility's BPA power bill.

NRU does not specify how the Load Shaping Rate should be adjusted to mitigate the impact of the Load Shaping Charge on irrigating utilities. The Load Shaping Rate and its monthly/diurnal shape are derived from the market price run. Kujala *et al.*, BP-12-E-BPA-14, at 1-4. No party took issue with the market price run, and there is no evidence on the record to support changing to a new or different approach. While the market price run will be updated to reflect changes in some of the inputs, there is no basis to reshape the market price run in a manner that would achieve the result NRU apparently desires. In oral argument, NRU explains that it asking BPA to take a look at the Load Shaping rates and to see if some sort of adjustment might be possible to lessen the impact on irrigators. Saven, Oral Tr. at 49-50.

Cowlitz and EWEB responded in oral argument that the load shaping charge was intended to recover the anticipated marginal costs of energy in the 24-hour periods and it should not be manipulated because of the potential for some relatively minor, in the total scheme of things in terms of dollars, impacts on a small number of customers. Murphy, Oral Tr. at 227-228. Cowlitz and EWEB stated that it has a much more important function than that, and it should not be manipulated for that purpose. *Id.*

Cowlitz and EWEB make an important point. The rate design developed in the TRM was the result of careful consideration of many factors, including sending appropriate price signals to utilities and a careful balancing of the portion of BPA's costs that each customer pays. The effects of the new rate design were to be mitigated through the use of other mechanisms; for example, the increased level of the demand rate is mitigated through the incorporation of the Contract Demand Quantity into the billing determinant. For this reason, it is not appropriate to modify the Load Shaping rates solely due to the impact on irrigators. Other mitigation measures are in place to offset the effects of the rate design on irrigation loads.

Further, in order for BPA to change the Load Shaping Charge to accommodate the impact of irrigation loads, there would need to be a change to the TRM. Section 13 of the TRM describes the steps necessary to make changes to the TRM. The requirements are very prescriptive and in this case have not been met in order for BPA to make a change.

Decision

BPA will not modify the Load Shaping Rate to counteract the impact of the Load Shaping Charge on utilities with irrigation loads.

Issue 2.6.5.2

Whether BPA should reshape the Customer Charge to address variability in monthly charges experienced by utilities with irrigation load.

Parties' Positions

NRU contends that reshaping the Customer Charge to address cash flow problems created by the impact of the Load Shaping Charge on utilities with large irrigation loads does not address the retail rate design concerns that would have customers in January paying for obligations incurred in July. NRU Br., BP-12-B-NR-01, at 10. Saven, Oral Tr. at 40-41.

BPA Staff's Position

Staff did not address this issue in testimony.

Evaluation of Positions

NRU's apparent belief that reshaping the Customer Charges does not address the problem associated with the Load Shaping Charge, NRU Br., BP-12-B-NR-01, at 10, highlights an inconsistency between the rate design prescribed in the TRM and how some utilities currently design their retail rates. Apparently, some of the utilities with irrigation load have a retail rate design that allocates all of the BPA charges incurred during a particular month to those customers that purchase in that month. As noted in Issue 2.6.5.1, due to the manner in which the Load Shaping Charge is calculated, utilities with irrigation load will experience relatively high Load Shaping Charges in the irrigation months, as compared to the other times of the year, when there will be a credit to the bill, also caused by those same irrigation loads. Irrigating utilities with a retail rate design that allocates all the power costs of a particular month on a per-unit basis to those customers that purchase power during that month will produce anomalous retail rates. All retail customers will experience a high per-unit charge in the irrigation months, but without a retail rate change, only the non-irrigation load would benefit from the credits during the non-irrigation months.

NRU argues that if "co-ops provide major cost subsidies between customer groups, they could face significant risks, including the potential of whether the Internal Revenue Service believes they are really providing service 'at cost' as a tax exempt entity." Saven, Oral Tr. at 40. NRU cites one of its members, the City of Heyburn, that had an 8 to 9 megawatt load at a potato processing plant. *Id.* at 41. NRU explains that although the Heyburn rates were competitively low, the company sued the city claiming that the company was subsidizing the city's other rate classes. *Id.* This, NRU states, is illustrative of the potential problems NIU members may face if they stray too far from cost-based rates. *Id.*

While BPA does not usually involve itself in retail ratemaking, it does understand cost-based rates and principles of cost causation. Staff has stated that the "bedrock pricing principle for power and transmission rates is cost causation." Mainzer, BP-12-E-BPA-23, at 21. Under BPA's new rate design it is important to recognize that irrigation loads are *causing* wintertime credits such that irrigation utilities' power bills will be lower than they would be without the

summertime irrigation loads. Thus, if the utility fails to take this causation into account in its retail ratemaking, summertime loads will subsidize wintertime loads.

The only way to rectify this inconsistency between BPA's rate design and the utilities' retail rate design is to change one of them. There are several measures available to utilities for identifying the appropriate cost causation of individual retail load classes. One is through the customer charge reshaping. By moving the dollars associated with the irrigation credits from the winter to the summer, wintertime power bills can be adjusted such that the power bills reflect just the impacts (causation) of the wintertime loads. Furthermore, the manner in which the reshaping can be done is very flexible. The wintertime credits could be spread to each time period during the summer to effectuate the same rate increase in each time period, thereby retaining the same shape in BP-12 rates to the utility as is in the WP-10 rates. The wintertime credits could be spread such that the irrigation rate was constant in mills per kilowatthour through the irrigating season, thus removing any effect of BPA's time differentiation in the Load Shaping rates.

While BPA has offered to reshape the customer charges to allow dollars to follow causation, BPA also notes that the utility can do this itself. There is additional information that will not be on the utility's power bill that will be needed, and BPA is willing to assist the utility in getting this information. As mentioned in the discussion of Issue 2.6.5.1 above, BPA is including additional functionality in the Rate Impact Model to help the utility understand the effects of BPA's rate design on particular retail rate classes. The model will not be limited to the effects of irrigation load. For example, if a retail industrial consumer has a relatively flat annual load, the effects of that load on the utility's power bills can also be examined. BPA believes that this additional information will be helpful to customers wishing to understand the impact of the new BP-12 rate design on retail customer classes.

Decision

BPA can reshape the Customer Charge to eliminate cash flow and cost causation issues upon a request by a customer.

Issue 2.6.5.3

Whether BPA should increase the amount of qualifying irrigation load through a change to the GRSPs.

Parties' Positions

NRU proposes that the amount of irrigation load to which the Irrigation Rate Discount is applied should be increased. NRU Br., BPA-12-B-NR-01, at 6, 11. NRU proposes that the increase in the qualifying load should be equal to the sum of a customer's May to September measured irrigation load less the qualifying irrigation load amounts listed in Exhibit D of its CHWM Contract. *Id.* at 13. The increase would be limited to 20 percent of the customer's qualifying irrigation load and would be applicable only if the sum of the customer's May to September measured irrigation load is greater than the qualifying irrigation load amounts. *Id.* at 13-14. In

order to implement the increase in load amounts, and thus irrigation benefits provided to customers, NRU proposes changing the GRSP language regarding the Irrigation Rate Discount True-Up and Reimbursement process by adding a credit to the reimbursement process equal to the increased load amounts multiplied by the IRD. *Id.*

In its brief on exceptions, NRU renews its request for BPA to increase the amount of qualifying load eligible for the IRD. NRU Br. Ex., BP-12-R-NR-01, at 1-2. NRU contends that if BPA does not either modify the Load Shaping Rate or reshape the Customer Charge (Issues 2.6.5.1 and 2.6.5.2) to mitigate the impact on irrigation loads, it should revise the GRSPs to increase the amount of qualifying irrigation load. *Id.* at 3-4.

BPA Staff's Position

The CHWM contracts and the TRM establish the amount of qualifying irrigation load to which the Irrigation Rate Discount is applied, and any changes to the qualifying irrigation load would not be consistent with the TRM. Fisher *et al.*, BPA-12-E-BPA-50, at 14.

Evaluation of Positions

NRU contends that changing the amount of qualifying irrigation load to which the IRD is applied would not require a TRM Change Process. NRU Br., BPA-12-B-NR-01, at 13; NRU Br. Ex., BP-12-R-NR-01, at 3-4. NRU states that the additional credit could be given to customers as part of the Irrigation Rate Discount True-up process. NRU Br., BPA-12-B-NR-01, at 13. NRU states that the TRM specifies that “the details and requirements of the true up will be developed in the applicable rate cases and included in the GRSPs for each applicable Rate Period.” *Id.* Despite the fact that the Regional Dialogue contract specifies the amount of qualifying load, NRU apparently believes that the development of the true-up process in the rate case provides BPA with the opportunity use the GRSPs language to override the stated contractual limitation. *Id.* NRU states that adding additional qualifying load would not require a modification to the CHWM contract or the TRM. NRU Br. Ex., BP-12-R-NR-01, at 3-4. Instead, NRU claims, the GRSPs can be modified to add additional load to the Irrigation True-up process. *Id.*

The CHWM contract signed by each irrigation utility specifies an amount of eligible irrigation load. In addition, the TRM states: “[t]here will be a true-up process at the end of each year’s May to September irrigation season to ensure that the customer experienced the full amount of irrigation load stated in the CHWM Contract.” BP-12-A-03, section 10.3. Despite the provisions in the TRM and the CHWM contract, NRU still contends that it is not necessary to modify either the TRM or CHWM contract in order to increase the amount of the qualifying load. NRU Br. Ex., BP-12-R-NR-01, at 4. NRU points to the contractual provision that states, “[s]ubject to the terms specified in BPA’s Power Rate Schedules and GRSPs,” *id.* at 4, as support for the proposition that BPA can increase the qualifying load through changes to the GRSPs. NRU’s proposal is to modify the true-up such that it increases the contractually specified qualifying load. While it is theoretically possible to modify the GRSPs to include the additional qualifying load, such a change is inconsistent with the specific provisions of the TRM and the CHWM contract.

The TRM specifies “a true-up calculation will determine the amount the customer owes BPA at the end of the irrigation season.” BP-12-A-03, section 10.3. While the TRM does not set forth the details and requirements of the true-up, BPA does not view this lack of specificity as an opportunity to add additional qualifying load. The details and requirements of the true-up process must comport with the objective of the provision, which is to measure the difference between the eligible and actual irrigation load and charge customers if too much discount was paid to them during the irrigation season. Adding additional load to the true-up for the sole purpose of increasing the discount is inconsistent with the underlying objective of section 10.3 of the TRM.

Likewise, modifying the true-up process is inconsistent with the provisions of the CHWM contract. The CHWM contract specifies the amount of qualifying load for each irrigating utility. NRU’s proposal to increase the amount of qualifying load through modifying the true-up process undermines the negotiated provisions of the contract.

The CHWM contract language provides for a cap on the amount of load to which the IRD is applied. The contract also implies that the true-up process is intended to be a process in which BPA takes back dollars if the actual irrigation load is less than the capped amount in the contract. Thus, changing the amount of qualifying load to which IRD is applied would be inconsistent with both the TRM and the CHWM contracts.

NRU requests the increase in qualifying irrigation load as a mitigation of the 15 to 20 percent increase in rates expected for irrigators. NRU Br. Ex., BP-12-R-NR-01, at 4. According to NRU, such action “would reduce the forecasted 14.65 percent rate increase to 12.08 percent” for Big Bend Electric. *Id.* (In NRU’s brief on exceptions, NRU contends it would reduce Big Bend’s rate increase from 18 percent to 11 percent. NRU Br. Ex., BP-12-R-NR-01, at 5.) Contrary to NRU’s contention, Big Bend will see only an 11.56 percent rate increase and not the 14 or 18 percent set forth in its briefs. NRU further contends that increasing the qualifying load will have a minimal impact on the overall PF rate and would significantly reduce the rate increases to the irrigators. NRU Br. Ex., BP-12-R-NR-01, at 5. The cost of the IRD is more than \$19 million per year currently and NRU’s proposal would add approximately \$3.5 million to the costs. Power Rate Study Documentation, Table 2.3.3.1. These costs are borne by the other rates.

Additionally, while BPA does not agree with NRU that is appropriate to increase the qualifying load by modifying the true-up process, BPA is not inclined to increase the qualifying load solely to give certain utilities a larger discount. Irrigating utilities are already receiving a 37 percent discount from the PF rate applicable to non-irrigation loads. Fisher *et al.*, BP-12-E-BPA-50, at 4. This discount comes at a significant cost to BPA’s non-irrigating customers, which must pay the cost of the discount. Power Rate Study Documentation, Table 2.3.3.1. The IRD amounts to more than a \$10/MWh reduction in the power price for irrigation customers. This \$10/MWh reduction is a 45 percent increase over the approximate \$7/MWh discount provided to irrigators for the last 10 years.

While NRU is correct that some irrigators may experience a higher overall percentage rate increase as compared to other PF Public customers, this percentage increase is due in large part to the fact that they have a significantly lower current rate. Consequently, some irrigators will see a larger percentage rate increase as compared to some other utilities. This result is because the overall rate increase is \$3/MWh and will impact the irrigators more on a percentage basis because they start at a lower rate.

Decision

BPA will not increase the amount of qualifying irrigation load.

Issue 2.6.5.4

Whether BPA should establish two Irrigation Rate Discounts.

Parties' Positions

In its rebuttal testimony, NRU argued that if BPA does not increase the amount of qualifying irrigation loads, then BPA should adopt two different IRD rates, one for Load Following customers and another for Slice/Block customers. Carr and Saven, BP-12-E-NR-02, at 6. NRU modified its support for this change in its initial brief, stating that “the resulting difference of 0.1 mills/kWh higher for IRD for Load Following and lower IRD for Slice/Block customers does not rise to the level of significance for NRU to press for the establishment of two different discounts.” NRU Br., BP-12-B-NR-01, at 16.

PNGC supports the approach to the IRD as proposed by BPA, stating that “BPA should follow the plain language of the TRM when setting rates and BPA’s approach does just that.” PNGC Br., BP-12-B-PN-01, at 11. PNGC does not consider having two IRDs to be a good idea. *Id.*

BPA Staff's Position

It would be possible to develop more than one IRD, although any alternative IRDs would not be applicable to customers with CHWM contracts because the terms and conditions of the CHWM contract require BPA to develop the IRD consistent with the TRM. Fisher *et al.*, BP-12-E-BPA-50, at 12. The TRM contains specific provisions with regard to how the IRD is to be developed. *Id.* Absent going through the TRM Change Process set out in Sections 12 and 13 of the TRM, Staff does not believe it is possible to develop an alternative IRD applicable to CHWM Contracts. *Id.*

Evaluation of Positions

NRU argues that if BPA does not either make adjustments to the load shaping rate that are beneficial to summer peaking customers or increase qualifying irrigation loads, then BPA should establish two different IRD rates, one for Load Following customers and another for Slice/Block customers. Carr and Saven, BP-12-E-NR-02, at 6. In its brief, however, NRU admits that it has limited interest in this change because of the limited benefit it provides Load Following

customers. NRU Br., BP-12-B-NR-01, at 16. In any case, PNGC notes that it does not consider two IRD rates a good idea. PNGC Br., BP-12-B-PN-01, at 11. Even assuming NRU is still advocating for such a change, the TRM does not allow multiple IRDs. NRU's proposal would require that the TRM Change Process be used in the development of separate IRDs. Section 10.3 of the TRM provides as follows:

In the applicable 7(i) Process, BPA will propose a *fixed IRMP Percentage*. The IRMP Percentage will be one minus the ratio of 1) *the sum of the IRMP participants' estimated charges at the FPS rates paid under the irrigation rate mitigation product for FY 2009 to 2) the sum of the IRMP participants' estimated charges that would have occurred under May through August HLH and LLH PF energy rates for FY 2009 adjusted for any applicable discounts such as LDD* (BPA estimates that the resulting IRMP percentage will be approximately 30-34 percent).

TRM-12S-A-03, at section 10.3 (emphasis added). Because the TRM describes the IRMP Percentage as "a" fixed percentage (singular) and describes it being calculated with "the sum of the IRMP participants' ..." there does not appear to be any intent to create multiple rates for product selection or individual customers.

In addition to the original TRM language, the TRM Change Process also demonstrates desire for a single IRD discount. The TRM Change language is as follows:

This percentage will be multiplied by the sum of the forecast revenue that irrigation loads will pay through the Composite Customer Charge, the Non-Slice Customer Charge, and the Load Shaping Charge, adjusted for any applicable Low Density Discount, divided by the sum of irrigation loads (expressed in MWh) to derive a dollars per MWh discount.

Bliven *et al.*, BP-12-E-BPA-11, Attachment 1, at 5. The TRM Change language also is clear that the intent was to create a single discount and not a unique discount based on product selection, utility size, or any other form of disaggregation. *Id.*

Decision

BPA will not establish two IRDs.

2.6.6 Composite Cost Pool True-Up

The Composite Cost Pool True-Up is the calculation of the annual Slice True-Up Adjustment for the Composite cost pool. Slice customers will have an annual Slice True-Up Adjustment for actual expenses, revenue credits, and adjustments allocated to the Composite cost pool and to the Slice cost pool for each Fiscal Year. The annual Slice True-Up Adjustment will be calculated for each Fiscal Year after BPA's audited actual financial data for that year are available (usually in November).

Issue 2.6.6.1

Whether BPA should disaggregate, for the Composite Cost Pool True-Up, bad debt expenses associated with a customer's non-payment of its bills containing "mixed transactions" (PF and FPS).

Parties' Positions

JP01 states that BPA's proposal not to disaggregate the bad debt expenses associated with non-payment of preference customer bills containing mixed transactions violates section 2.1 of the TRM and should be rejected. JP01 Br., BP-12-B-JP01-01, at 19. JP01 states that under the principle of cost causation, costs should be allocated to rate classes that benefit from such costs, and to the extent practicable through rate design, be recovered from the customers that benefit from such costs. *Id.* at 4. JP01 states that BPA's proposal not to disaggregate any bad debt expenses associated with a customer's non-payment of bills containing mixed transactions will result in the inclusion of bad debt expenses that are associated with FPS transactions in the Composite Cost Pool True-Up. *Id.* at 18-19. JP01 states that including any bad debt expenses associated with FPS transactions in the Composite Cost Pool True-Up is not appropriate according to the principle of cost causation, because a customer that buys the Slice product does not benefit from revenues from FPS sales. *Id.* at 17.

JP08 concurs with the section of the brief filed by JP01 that addresses the allocation of bad debt expenses. JP08 Br., BP-12-B-JP08-01, at 1.

BPA Staff's Position

BPA cannot reasonably separate any bad debt expense associated with specific product purchases by a customer, because customer payments on bills that contain mixed transactions do not differentiate the payment based upon the type of obligation, meaning that the customer payment amounts are not applied in any particular way or order to each charge on the bill. Lee and Johnson, BP-12-E-BPA-39, at 3.

Evaluation of Positions

Under the Staff proposal, in the true up of the cost pools, bad debt expenses associated with FPS sales will be allocated to the Non-Slice Cost Pool while the bad debt expense associated with PF sales will be allocated to the Composite Cost Pool. Power Rate Study, BP-12-E-BPA-01, at 143-144. The issue here is whether BPA should disaggregate the bad debt expense when the defaulting customer has failed to pay on invoices that contain both PF and FPS transactions. JP01 argues that BPA's proposal not to disaggregate bad debt expenses associated with non-payment of bills containing mixed transactions violates section 2.1 of the TRM and should be rejected. JP01 Br., BP-12-B-JP01-01, at 19. Section 2.1 of the TRM contains Cost Allocation Principles that are used for allocating costs that are not specifically addressed in the TRM. TRM-12S-A-03, section 2.1. JP01 contends the cost causation standard contained in the Cost Allocation Principles ensures that costs are allocated to rate classes that benefit from such costs, and to the extent practicable through rate design are recovered from the customers that benefit from such costs. JP01 Br., BP-12-B-JP01-01, at 4. JP01 claims that BPA's proposal not to

disaggregate any bad debt expenses associated with a customer's non-payment of bills containing mixed transactions will result in the inclusion of bad debt expenses that are associated with FPS transactions in the Composite Cost Pool True-Up. *Id.* at 19. JP01 argues that including any bad debt expenses associated with FPS transactions in the Composite Cost Pool True-Up is not appropriate according to the principle of cost causation, because a customer that buys the Slice product does not benefit from revenues from FPS sales. *Id.* at 17.

Although JP01's arguments are related solely to bad debt expense associated with the non-payment of preference customer bills containing both PF and FPS transactions, BPA's proposal addresses bad debt expense associated with the non-payment of both preference customer bills containing both PF and FPS transactions and direct service industrial customer bills containing both IP and FPS transactions. Lee and Johnson, BP-12-E-BPA-39, at 2. Bad debt expenses can arise out of either type of bills, and are not limited to preference customer bills. Staff proposed that any bad debt expense associated with a sale to a customer that purchases power at both the PF rate and the FPS rate, or a sale to a customer that purchases power at both the IP rate and the FPS rate, would be included for purposes of the Composite Cost Pool True-Up. Power Rate Study, BP-12-E-BPA-01, at 143-144.

JP01 claims that, in essence, BPA will treat all uncollectible amounts due on bills containing mixed transactions at PF and FPS rates as if they reflected 100 percent PF sales, and JP01 states that this is not a reasonable approach. JP01 Br., BP-12-B-JP01-01, at 18-19. JP01 states that BPA should use whatever data are available to it from the bill to make a reasonable allocation of bad debt expenses to the appropriate cost pools. *Id.* at 19. JP01 suggests that if there is nonpayment or partial payment on a mixed transaction bill, it would be reasonable for BPA to assume that the unpaid portion can be disaggregated in the same proportion as the transaction mix, and BPA could thereby exclude the bad debt expense assumed to be associated with FPS sales from the Composite Cost Pool True-Up. *Id.* at 18.

JP01 recognizes that the risk of non-payment of bills containing mixed transactions is low, but because this risk is low, the infrequent occurrence of non-payment of bills containing mixed transactions will mean that the cost of disaggregating such bad debts that do occur also will be slight. *Id.* at 19.

Staff does not agree with JP01's position. *Id.* at 3. It is the payment—or more specifically the non-payment—that determines whether any bad debt expense arises, not the bill. A customer's payment is treated as an aggregate payment that is applied to the *entire* bill without differentiation as to particular charge. *Id.* A declaration of a bad debt expense is not based on the billed transaction, but on the lack of payments made by the customer, and there is no differentiation of the unpaid amount by transaction type or rate. *Id.* According to BPA's accounting policy and general accounting procedures, absent customers differentiating their payments to BPA by transaction type, BPA will not differentiate the partial payment or resulting bad debt expense by transaction type. *Id.* at 3-4. Because BPA has no way of differentiating bad debt expense by transaction type when the bad debt expense arises from non-payment of bills containing mixed transactions, BPA is not violating the TRM Cost Allocation Principles.

BPA believes that the allocation of bad debt from mixed transactions will be entirely contingent on the facts and circumstances of the particular instance of a full or partial non-payment of a power bill. It is very difficult to determine a particular course of action without any specifics to guide this determination. Under the Regional Dialogue Power Sales Agreements, a customer has no ability to differentiate its payments made to BPA, to make partial payments to BPA, or to withhold any payment for any portion of its bill. The customer must pay all amounts billed to it, in full for each month. *See* BPA’s Web site for copies of the Regional Dialogue Power Sales Agreements: BPA Web site under—Power—Regional Dialogue Policy Implementation—Documents/Publications—20-year Regional Dialogue Contracts.

There have been no bad debt allocations at issue since BPA’s decisions to include any bad debt expenses arising from mixed transactions in the Slice True-Up Adjustment Charge calculation. Attachment A, Partial Resolution of Issues with Parties, WP-07-E-BPA-31, at A-1; Wholesale Power Rate Development Study, WP-10-FS-BPA-05, at 37. Given that there have been no bad debt expenses arising from non-payment of bills containing mixed transactions in past and current rate periods, and given that the likelihood of such bad debt expenses arising in the future is low, BPA believes that the preferred course of action would be to defer any determination until such bad debt expense arises, rather than making a decision in the abstract.

Decision

Because no bad debt expense allocation decisions need to be made at this time, this issue is moot.

2.6.7 Unanticipated Load Service

Unanticipated Load Service is proposed to apply to any request for Firm Requirements Power received after February 1, 2011, that results in an unanticipated increase in a customer’s load placed on BPA during the FY 2012–2013 rate period. Power Rate Schedules, BP-12-A-02B, GRSP II.U. ULS is proposed to be available under the PF-12, NR-12, and FPS-12 rate schedules. *Id.*

Issue 2.6.7.1

Whether BPA should offer ULS for the permanent failure of a new non-Federal specified resource intended to serve a utility’s Above-High Water Mark Load.

Parties’ Positions

Snohomish states that it is inappropriate for BPA to offer ULS service under the FPS rate schedule to new Specified Resources that experience permanent failure during the rate period or fail to come online. Snohomish Br., BP-12-B-SN-01, at 10. Snohomish states that the loss of such resources is “explicitly” covered by the Northwest Power Act and that BPA must treat the resource as serving load until BPA has granted the customer resource removal rights. *Id.*

JP02 states that BPA should reject Snohomish’s proposal and supports the inclusion of ULS FPS eligibility for new Specified Resources that experience permanent failure during the rate period or fail to come online and when a New Dedicated Resource cannot be used to serve load due to issues related to transmission access. JP02 Br., BP-12-B-JP02-01, at 11-12, and JP02 Br. Ex., BP-12-R-JP02-01, at 7.

BPA Staff’s Position

BPA Staff’s Initial Proposal did not include ULS eligibility for the permanent failure of a new non-Federal specified resource. Staff proposed expanding ULS FPS availability to include New Specified Resources that are 10 aMW or less that either experience permanent failure during the rate period or fail to come online. Burbank *et al.*, BP-12-E-BPA-40, at 9. Including these two additional circumstances does not absolve a customer for its contractual obligation to serve its Above-RHWM load with a non-Federal resource. *Id.*

Evaluation of Positions

JP02 contends that ULS FPS eligibility needs to be expanded to encourage non-Federal resource development. JP02 Br., BP-12-B-JP02-01, at 11; JP02 Br. Ex., BP-12-R-JP02, at 7. JP02 also states that the eligibility should be expanded to address policies that restrict a customer’s ability to replace non-Federal specified resources that become unable to serve load. JP02 Br., BP-12-B-JP02-01, at 11; JP02 Br. Ex., BP-12-R-JP02, at 9-10 JP02 contends that without the expanded eligibility, customers would face Unauthorized Increase Charges. JP02 Br., BP-12-B-JP02-01, at 11; JP02 Br. Ex., BP-12-R-JP02, at 9. JP02 also contends that contractual deadlines will prevent them from adding a new specified resource and purchasing Resource Support Services, as this must be done by October 31 of a rate case year. Stratman *et al.*, BP-12-E-JP02-04, at 10. This deadline would leave the customer with no contractual ability to replace its specified resource and leave the customer to face a punitive Unauthorized Increase charge. *Id.*

BPA Staff does not agree with the reasoning provided by JP02 for the expansion of ULS FPS eligibility for new Specified Resources. Burbank *et al.*, BP-12-E-BPA-40, at 9. However, Staff proposed expanding ULS FPS eligibility to temporarily replace new Specified Resources that are 10 aMW or less and either experience permanent failure during the rate period or fail to come online in recognition of the time required to request a contractual change associated with the customer’s non-Federal resource. *Id.* Section 5(b)(1) of the Northwest Power Act allows a customer to request a change in its 5(b)(1) non-Federal resources used to serve its load, and BPA may grant consent to do so. *Id.* Such a change could be accomplished by the customer requesting an exception and amendment to its CHWM contract Exhibit A. *Id.* Staff’s proposal to expand ULS FPS eligibility is designed to allow customers time to request the change to their Exhibit A if needed. *Id.*

JP02 supports BPA’s position that the Northwest Power Act does not prevent BPA from providing ULS. JP02 Br. Ex., BP-12-R-JP02-01, at 9.

Snohomish contends that BPA should not offer ULS to Load Following customers for the failure of a new Specified Resource during the rate period or if the resource fails to come online. Snohomish Br., BP-12-B-SN-01, at 10. Snohomish states that the Northwest Power Act requires BPA to treat the resource as one that is serving load until BPA grants the customer resource removal rights. *Id.* Snohomish states that until resource removal has been granted, this is not load that is subject to section 10.1 of the Tiered Rate Methodology, which provides for service to unanticipated load that BPA is obligated under the Northwest Power Act to serve. *Id.* at 11. Snohomish states that a utility has several other options for serving load resulting from the loss of a resource, including securing replacement power from the short-term market or a different resource, or purchasing business interruption insurance. *Id.*

Snohomish's concerns regarding resource removal are misplaced. While the Northwest Power Act does state how BPA will handle resource removal, it does not indicate that BPA cannot provide a temporary service to customers while they engage in the process. As proposed, ULS does not relieve customers of their load service obligation but provides a temporary service while the customer pursues alternative load service. The TRM indicates that the terms and conditions of a rate for unanticipated load will be established in an applicable 7(i) process. TRM-12S-A-03, section 10.1. The TRM may define unanticipated loads as those BPA is obligated to serve under the Northwest Power Act, but it does not limit what BPA may offer as eligible load within the ULS GRSP. BPA may enter into contracts for service under section 9(i) of the Northwest Power Act. BPA may also enter into contracts under section 5(f). While it is true that customers do have other options for replacing a resource, as indicated by Snohomish, that fact does not prevent BPA from offering a backstop service to customers that are trying to engage in resource development.

One of the underlying objectives of the Regional Dialogue and tiered rates is to encourage resource development. With smaller utilities, which may lack experience in resource development, the knowledge that BPA will provide a temporary backstop for resource delays and failures will encourage rather than discourage resource development. This backstop will not relieve the utility of its contractual obligation but rather is intended to encourage the utility to engage in resource development when it might otherwise elect not to because of the downside risk.

Decision

BPA will offer temporary ULS for the permanent failure of a new non-Federal specified resource intended to serve a utility's Above-High Water Mark Load.

Issue 2.6.7.2

Whether BPA should offer ULS for a new Specified Resource intended to serve a utility's Above-Rate Period High Water Mark Load that is delayed in coming online.

Parties' Positions

Snohomish states that ULS is not necessary for the delay in a Specified Resource reaching commercial operation. Snohomish Br., BP-12-B-SN-01, at 11. Snohomish states that a utility has other options for replacing this resource, which include short-term market purchases, procuring a different resource, or acquiring business interruption insurance. *Id.* at 12. Snohomish states that BPA is not obligated to serve this load under the Northwest Power Act, leaving utilities ineligible for ULS. *Id.*

JP02 states that ULS should be available under the FPS rate schedule to customers that experience a delay in the online date of a new Specified Resource and ULS availability in the situations BPA has described in the final GRSPs, BP-12-A-02B. JP02 Br., BP-12-B-JP02-01, at 12 and JP02 Br. Ex., BP-12-R-JP02-01, at 7.

BPA Staff's Position

BPA Staff proposed ULS FPS availability for a customer's new Specified Resource for Above-RHWM service that is delayed in coming online. Burbank *et al.*, BP-12-E-BPA-21, at 18.

Evaluation of Positions

While the types of load being discussed in this issue are different, the argument is essentially identical to that included in Issue 2.6.7.1 above.

When stating BPA should not offer ULS for the delay of a new Specified Resource coming online, Snohomish relies on many of the same reasons it used when stating that BPA should not provide ULS FPS for new Specified Resources that experience a permanent failure or failure to come online (see Issue 2.6.7.1). Snohomish's primary argument is that BPA should not offer this service because BPA is not obligated to serve this load under the Northwest Power Act. Snohomish Br., BP-12-B-SN-01, at 12. Snohomish seems to believe that absent a statutory obligation to serve, BPA should not provide the service. Snohomish indicates that customers have other resource replacement options available to them and that BPA should not be dedicating limited resources to managing ULS. *Id.* Snohomish also contends that customers have other options for replacing a resource that is delayed in coming online. *Id.*

JP02 contends that ULS FPS must be available to new Specified Resources that are delayed in coming online to serve Above-RHWM load to address certain shortcomings in the CHWM contracts. JP02 Br., BP-12-B-JP02-01, at 15. JP02 contends that contractual deadlines in the CHWM contracts will prevent a customer from having the time to replace its resource and not face a high Unauthorized Increase charge. Stratman *et al.*, BP-12-E-JP02-04, at 8.

Pursuant to TRM section 10.1, Staff proposed the availability of ULS FPS to new Specified Resources that are delayed in coming online to serve Above-RHWM load. Burbank *et al.*, BP-12-E-BPA-21, at 18. The need for a backstop to encourage non-Federal resource development is the goal of section 10.1 of the TRM. TRM-12S-A-03, section 10.1.

Snohomish argues that BPA has no obligation to provide this service. Snohomish Br., BP-12-B-SN-01, at 12. While this may or may not be true depending on the specific circumstances of each request, the lack of an obligation does not prohibit BPA from offering its customers a service. ULS is constructed such that BPA's cost of providing this service is at least covered and could be more than covered. *See* Issue 2.6.7.6 below. Thus, Snohomish and other customers will not be adversely affected by BPA offering this service. The only harm that Snohomish identifies is that offering this service might divert Staff from other work. *Id.* This claimed harm is miniscule compared to the benefit gained from an additional service that helps meet regional generation development goals.

As stated above, the TRM does not limit what BPA may offer in the terms and conditions of the ULS GRSP. BPA may enter into contracts for service under section 9(i) of the Northwest Power Act. BPA may also enter into contracts under section 5(f). While it is true that customers do have other options for replacing a resource, as indicated by Snohomish, that fact does not prevent BPA from offering a backstop service to customers that are trying to engage in resource development.

Decision

BPA will offer ULS for a new Specified Resource intended to serve a utility's Above-Rate Period High Water Mark Load that is delayed in coming online.

Issue 2.6.7.3

Whether an expanded availability for ULS would discourage the development of non-Federal resources to serve Above-High Water Mark load.

Parties' Positions

Snohomish states that if a customer chooses to meet its load growth with non-Federal resources, then BPA is not responsible for mitigating the risks associated with that decision. Snohomish Br., BP-12-B-SN-01, at 13. Snohomish contends that such customers have a contractual commitment to serve their load growth. *Id.* Snohomish notes that encouraging the development of non-Federal resources is a goal of the TRM and Regional Dialogue and claims that the ULS undermines this goal. *Id.*

JP02 states that expanded ULS FPS eligibility is necessary to promote the goals of the Regional Dialogue and TRM. JP02 Br., BP-12-B-JP02-01, at 11; JP02 Br. Ex., BP-12-R-JP02-01, at 10. JP02 indicates that some aspects of the contracts and other BPA policies restrict a customer's ability to replace a non-Federal resource. *Id.* JP02 claims that without the expansion of ULS FPS availability, customers would be faced with punitive Unauthorized Increase charges. *Id.*

BPA Staff's Position

BPA Staff did not directly address in testimony how ULS eligibility impacts the goals of the Long-Term Regional Dialogue Policy or the TRM. BPA Staff did indicate that policies and

deadlines of the Regional Dialogue contracts were “negotiated, reviewed, and established and were known by the customers when they made their power purchase commitments.” Burbank *et al.*, BP-12-E-BPA-40, at 6.

Evaluation of Positions

Snohomish contends that once a customer has elected to serve its load growth with a non-Federal resource, BPA is not responsible for helping to mitigate any potential delivery risks. Snohomish Br., BP-12-B-SN-01, at 13. Snohomish also states that mitigating the risks a customer may face when serving its load growth would undermine the goal of non-Federal resource development embedded in the Regional Dialogue Policy and TRM. *Id.*

JP02 states that shortcomings in the Regional Dialogue contracts and policies make it necessary for BPA to provide a backstop as customers pursue non-Federal resources. JP02 Br., BP-12-B-JP02-01, at 15. JP02 claims that having this backstop will further the goal of non-Federal resource development. *Id.*

The ULS as proposed will promote the goal of non-Federal resource development. Throughout development of the Long-Term Regional Dialogue Policy, contracts, and the TRM, a common goal was to encourage non-Federal resource development. A provision was included in the TRM (section 10.1) to address the delays that customers may potentially experience when engaging in non-Federal resource development. This language states that “BPA will develop rates in the applicable 7(i) Process for service to unanticipated load (*e.g.*, due to delay in the start-up of a specified new Non-Federal Resource).” TRM-12S-A-03, section 10.1. Parties that helped craft the TRM recognized that problems could arise with resource development and there needed to be some mechanism with which BPA could provide some support in the event the resource development did not go as planned. Rather than discouraging resource development, the ULS encourages utilities that might otherwise shy away from such an endeavor.

Staff has proposed reasonable bounds and limits around the ULS, including limitations on the duration a customer may take ULS and pricing methods to ensure cost shifts do not occur, which will ensure that it serves the intended purpose and does not become a permanent replacement for problematic resource projects.

Decision

An expanded availability for ULS would not discourage the development of non-Federal resources to serve Above-High Water Mark load.

Issue 2.6.7.4

Whether it is reasonable to limit ULS eligibility to customers that purchase Load Following but not Slice/Block.

Parties' Positions

In its brief on exceptions, Snohomish amplifies its initial argument that focused on eligibility for ULS as between Transfer customers (Load Following and Slice/Block) by arguing that ULS should be generally available for all preference customers. Snohomish Br. Ex., BP-12-R-SN-01, at 2. In its initial brief, Snohomish contended that BPA should not limit ULS eligibility to a specific subset of customers. Snohomish Br., BP-12-B-SN-01, at 13; Snohomish Br. Ex., BP-12-R-SN-01, at 2.

In its brief on exceptions. Snohomish argues that since the ULS is discretionary and available on a temporary basis to replace new non-Federal specified resources and does not relieve the customer of its contractual obligation, the Administrator's reasoning equally applies to both Load Following and Slice/Block customers. Snohomish Br. Ex., BP-12-R-SN-01, at 2. Snohomish adds that BPA has interpreted section 5.1 under the Slice/Block contract as barring BPA from offering ULS to Slice/Block customers and that "[t]he Administrator's broad interpretation of Section 5.1 inadvertently limits BPA's business dealings for the sale of power to customers with the Slice/Block product." *Id.* at 3. Snohomish argues that "equitability" requires BPA to offer the same service to both its Load Following customers and its Slice/Block customers. *Id.* at 3.

JP02 agrees with BPA's position that there are fundamental differences between the Load Following and Slice/Block contracts. JP02 Br. Ex., BP-12-R-JP02-01, at 11-12. JP02 states that BPA is responsible to meet the remainder of a Load Following customer's load and is not similarly responsible under the Slice/Block contract; JP02 concludes that "[i]t is, therefore, reasonable, for BPA to offer ULS to Load Following but not Slice/Block customers." *Id.* at 12.

BPA Staff's Position

In the Draft ROD, Staff responded to and agreed with JP02's direct testimony that suggested BPA expand eligibility for the ULS rate to Load Following Transfer customers that cannot secure firm transmission and are expected to face high TCMS charges. Burbank *et al.*, BP-12-E-BPA-40, at 7. Limiting ULS to Load Following customers would be based upon the terms of their CHWM contracts and would not relate to the fact that a customer takes deliveries under a Transfer service arrangement. Draft ROD, BPA-12-A-01, at 154.

Evaluation of Positions

Snohomish's brief on exceptions broadens its prior argument regarding ULS eligibility as between Transfer customers (Load Following and Slice/Block) by arguing the ULS should be generally available for all preference customers. Snohomish Br. Ex., BP-12-R-SN-01, at 2. Snohomish contends that it is inequitable for BPA to provide ULS to only a subset of Transfer customers. Snohomish Br., BP-12-B-SN-01, at 13. Snohomish indicates that all Transfer customers face the same transmission difficulties and that BPA should not use the product selected as a criterion to determine which customers are eligible. *Id.* at 14.

As between BPA's preference customers, the proposed ULS service is available only to Load Following customers, and customers that signed Slice/Block contracts will not be eligible for

ULS regardless of whether they are Transfer customers. Draft ROD, BPA-12-A-01, at 154. In BPA’s rebuttal testimony staff agreed with a suggestion by JP02 to expand ULS eligibility to Load Following customers that are served under a Transfer service arrangement. Burbank *et al.*, BP-12-E-BPA-40, at 7. Staff proposed offering ULS to only Load Following customers because only these customers are contractually eligible to take ULS service. Burbank *et al.*, BP-12-E-BPA-21, at 18-19. ULS, in this circumstance, is intended to be available for these customers for only the time period they wait for Firm NT to become available. Burbank *et al.*, BP-12-E-BPA-40, at 8. ULS is intended to be a temporary service. *Id.* If the customer is receiving ULS from BPA, the customer will be required to continue to pursue Firm NT, pursuant to the requirements of TCMS. *Id.*

Snohomish contends that BPA’s reasoning for providing ULS as a temporary service while customers pursue alternative load service equally applies to Load Following and Slice/Block customers. Snohomish Br. Ex., BP-12-R-SN-01 at 2.

Snohomish contends that the Administrator interprets section 5.1 of the Slice/Block contract as “barring” BPA from offering ULS to Slice/Block customers. Snohomish Br. Ex., BP-12-R-SN-01 at 3. Snohomish interprets it to mean that it relieves BPA of the *obligation* to serve in the event the Slice product does not fully meet the needs of the customer due to the variable nature of Slice output as compared to the customer’s load profile; not that it prohibits the sale of discretionary firm power products, like ULS for the Slice/Block product. *Id.* BPA should not interpret this section as barring the Administrator from offering Slice/Block customer’s service through other products or rates. *Id.*

Snohomish concludes that the Administrator’s interpretation of section 5.1 inadvertently limits BPA’s business dealings for the sale of power to customers with the Slice/Block product, precluding BPA from selling additional power or products at any rate to a Slice/Block customer, even if it is in BPA’s best interests to do so. Snohomish Br. Ex., BP-12-R-SN-01 at 3.

Unlike the Slice and Block contract, section 3.1 of the Load Following contract provides that BPA is obligated to meet the remainder of the customer’s load when a resource is not available:

From October 1, 2011, and continuing through September 30, 2028, BPA shall sell and make available, and «Customer Name» shall purchase, Firm Requirements Power in hourly amounts equal to «Customer Name»’s hourly Total Retail Load minus the hourly firm energy from each of «Customer Name»’s Dedicated Resources as listed in Exhibit A.

Conformed Load Following Contract Template dated October 26, 2010 (BPA Web site under Power—Regional Dialogue Policy Implementation—Documents/Publications—20-year Regional Dialogue Contracts).

In contrast, section 5.1 of the Slice/Block contract the customer, not BPA, is obligated to meet its hourly, daily, weekly, monthly, and annual consumer loads:

BPA does not guarantee that the amount of Slice Output Energy made available under the Slice Product, combined with Firm Requirements Power made available

under the Block Product, will be sufficient to meet «Customer Name»’s regional consumer load, on an hourly, daily, weekly, monthly, or annual basis. «Customer Name» agrees that it has the obligation to supply nonfederal power to meet its Total Retail Load not met by its purchase of Slice Output and power from the Block Product.

Conformed Slice/Block Contract Template dated October 26, 2010 (BPA Web site under Power—Regional Dialogue Policy Implementation—Documents/Publications—20-year Regional Dialogue Contracts)

The customer’s contractual election on their type of power service dictates whether a customer is eligible to take ULS service. BPA left to each customer the choice of what type of power sales contract and service it would choose. There is a big difference between the long-term power products offered by BPA to its customers, which Snohomish must undoubtedly recognize since it has purchased its power supply from BPA under the Subscription Slice and Block contract over the past 10 years and will continue to purchase Slice and Block under the Regional Dialogue CHWM contract through 2028. The difference is detailed in BPA’s Long Term Regional Dialogue Contract Policy Record of Decision, October 2008, page 11. It states, “[w]e note that inherent in a customer’s decision to purchase Slice is an agreement that they will receive power shaped to the output of the Federal system, which at times will be insufficient to meet its loads. If a customer wants power shaped to its specific net requirement shape, it should consider BPA’s Load Following product.” BPA Web site under Publications—Records of Decision—2008.

Eligibility to receive ULS is based on the fundamental distinction, discussed above, in the type of power service the customer has elected to take under its CHWM contract—Slice/Block or Load Following. BPA does not interpret section 5.1 as “barring” it from providing ULS to Slice/Block customers. BPA is making a policy decision that ULS will be available to Load Following customers given BPA’s contractual obligation to meet their metered load. BPA does not have the same obligation to Slice/Block customers. The decision to limit ULS availability to Load Following customers does not prevent BPA from making future sales to Slice/Block customers of additional firm power consistent with the terms of the CHWM contract, such as an election by such customers to have BPA serve above high water mark load at the Tier 2 rate, or the ability of such customers to purchase surplus power from BPA.

Snohomish also argues that BPA’s interpretation of section 5.1 of their Slice/Block contract “inadvertently limits BPA’s business dealings for the sale of power to customer with the Slice/Block contract.” Snohomish Br. Ex., BP-12-R-SN-01, at 3. As stated above, section 5.1 of the Slice/Block contract addresses the parties’ obligation regarding service to the retail load of the customer. BPA did not intend or state that this provision prohibits sales of power under other contracts and Snohomish’s argument is misplaced and unpersuasive.

As Snohomish correctly points out, power supplied under the ULS rate is discretionary. However, BPA has no contractual obligation to provide service to replace a Slice/Block customer’s non-Federal resource during a rate period. The Slice/Block customer has an obligation to replace its non-Federal resources. Slice/Block customers have this obligation because Slice is a planned sale of Federal power and does not vary based on a change in the

customer's non-Federal resources. Slice/Block customers bear the obligation to meet the variation between both their loads and their resources, not BPA. Because the service of federal power for a Load Following customer is different from a Slice/Block customer, there is no issue of equitability in offering the ULS service to only Load Following customers as a matter of policy.

Decision

Because BPA is obligated under its Load Following contract to meet the remainder of the customer's load when a resource is not available, and BPA has no such obligation under the Slice and Block contract, it is reasonable to limit ULS eligibility to customers that take service under Load Following contracts.

Issue 2.6.7.5

Whether it is appropriate to limit the availability of ULS to new non-Federal resources of 10 aMW or less.

Parties' Positions

Snohomish states that BPA must provide rationale for the 10 aMW cap on ULS FPS availability to new Specified Resources that experience permanent failure during the rate period or fail to come online. Snohomish Br., BP-12-B-SN-01, at 14.

JP02 states that BPA has provided sufficient justification for the 10 aMW cap. JP02 Br. Ex., BP-12-R-JP02-01, at 10. JP02 states “[t]his is one of the provisions that BPA has included to avoid cost exposure to other customers. For [that] reason ..., JP02 supports the Administrator’s decision” JP02 Br. Ex., BP-12-R-JP02-01, at 11.

BPA Staff's Position

BPA Staff proposed a 10 aMW cap on new non-Federal specified resources for ULS eligibility, but did not address this issue in testimony; Snohomish raises the issue for the first time in its brief. Burbank *et al.*, BP-12-E-BPA-40, at 9.

Evaluation of Positions

Snohomish contends that BPA must provide rationale or analysis for capping ULS FPS eligibility to new Specified Resources to 10 aMW. Snohomish Br., BP-12-B-SN-01, at 14. However, Snohomish has provided no explanation as to why the 10 aMW should not be adopted. Snohomish fails to provide an explanation whether the 10 aMW value should be bigger, smaller, or removed altogether. As JP04 notes, “... Snohomish has failed to provide an argument [why] 10 MW is *not* a reasonable limit.” JP04 Br. Ex., BP-12-R-JP04-01, at 10 (emphasis in original).

The goal of ULS is not to shelter customers from high resource costs or high resource replacement costs, as implied by NRU. Rather, the goal of ULS is to provide a rate to reflect the

costs associated with serving loads that BPA offers to serve under the Northwest Power Act but for which BPA did not receive adequate notice. The ULS is designed to be used as a service to backstop for failed or delayed resource development to further encourage customers to pursue resource development (particularly customers with limited access to the market). JP04 also rightly notes that BPA intends the 10 MW limit to ULS "... to avoid cost exposure to other customers." *Id.* at 11.

Given that one of the goals of the ULS is to backstop customers with added challenges of replacing failed or delayed resources with market purchases, the inclusion of a size threshold is reasonable. Under Subscription, resources less than 3 MW in nameplate were determined small enough to ignore, while resources between 3 MW and 15 MW were determined small enough to guarantee a Full Service product with the addition of Generation Management Service. Customers with resources larger than 15 MW nameplate were not guaranteed a Full Service product. Under Regional Dialogue, new thresholds are set, one of which is included in the small resource exception of the Diurnal Flattening Service and Forced Outage Reserves Service section of the Load Following Contract Template. Section 2.3.2.3 of the Load Following Contract Template provides a small resource exception, where a small resource is defined as one that is 10 MW or less in nameplate capacity. Section 2.4.4.2 provides criteria for exceptions in requesting FORS and includes a criterion of a nameplate capability of less than 10 MW. Conformed Load Following Contract Template dated October 26, 2010 (BPA Web site under Power—Regional Dialogue Policy Implementation—Documents/Publications—20-year Regional Dialogue Contracts).

Given these examples, the 10 aMW is a reasonable number, as it provides some consistency between BPA's power rates and contracts.

Decision

It is appropriate for BPA to limit the availability of ULS to new non-Federal resources of 10 aMW or less.

Issue 2.6.7.6

Whether BPA has properly designed the ULS to avoid cost shifts.

Parties' Positions

Snohomish contends that if BPA adopts the ULS FPS availability as proposed, BPA must revise the GRSP to ensure there are no cost shifts as a result of providing this service. Snohomish Br., BP-12-B-SN-01, at 15. Snohomish points out that BPA has reserved the right to make adjustments to ULS pricing, but only if ULS is requested for more than one year. *Id.* at 16. Snohomish states that the GRSP needs to be revised to indicate that BPA will update the listed price when a utility first requests ULS, including the actual purchase price, and again when BPA makes any additional purchases to serve the load. *Id.*

JP02 states that BPA Staff's proposal isolates the costs of ULS and adheres to the TRM principles of cost causation. JP02 Br., BP-12-B-JP02-01, at 15; JP02 Br. Ex., BP-12-R-JP02-01, at 11.

BPA Staff's Position

BPA Staff proposed that BPA will have the option to adjust the rate during the rate period should there be large fluctuations in the market price or in the case that BPA does not immediately make the entire market purchase to serve the ULS obligation. Burbank *et al.*, BP-12-E-BPA-40, at 9-10. The ability to modify the rate during the rate period will help ensure there are no cost shifts among customers. *Id.*

Evaluation of Positions

Snohomish contends that BPA must adequately price ULS to avoid cost shifts and ensure that customers requesting ULS are paying the full cost BPA incurs. Snohomish Br., BP-12-B-SN-01, at 15. Snohomish also contends that to avoid cost shifts, BPA must revise the GRSPs to adjust the list price two or possibly more times during the rate period, "(1) at the time each contract for ULS is entered into, allowing BPA to include the actual purchase price if BPA has made all or part of the purchase at the outset; and (2) at the time BPA makes additional purchases to provide ULS service under any particular contract." *Id.* at 16.

JP02 contends that ULS FPS rate design strictly limits costs associated with the service. JP02 Br., BP-12-B-JP02-01, at 15. JP02 also points out that BPA reserves the right to adjust the ULS price each fiscal year and that all costs associated with providing ULS are allocated to the requesting customer. *Id.* JP02 adds that "Snohomish's concerns are unfounded as the proposed ULS rate design proposed by BPA strictly limits the costs associated with ULS service to the customer taking ULS service." JP02 Br. Ex., BP-12-R-JP02-01, at 11.

Staff proposes that BPA have the option to update the rate if a customer requests ULS for more than one year of the rate period. Burbank *et al.*, BP-12-E-BPA-40, at 9-10. It is necessary to have the option to update the price in case there are large fluctuations in market prices or BPA does not make the entire market purchase at the time ULS is requested. *Id.* Reserving the right to update the rate will avoid any potential cost shifts. *Id.* Staff proposes updates to the GRSP language to state the rate may be adjusted each fiscal year. *Id.* at Attachment 3, page 3-2.

There does not appear to be a material distinction between Staff's proposal and Snohomish's. As proposed by Staff, BPA would calculate the cost of ULS at the time the customer makes a request. Burbank *et al.*, BP-12-E-BPA-21, at 19. The price would be the higher of current market price or listed price for ULS in the rate schedule. *Id.* Should the customer request ULS for longer than one year of the rate period, BPA would reserve the right to update the pricing to reflect any changes in market prices or in the situation in which BPA has not made the full resource purchase needed to serve the load. Burbank *et al.*, BP-12-E-BPA-40, at 9-10. Each of these steps appears to be consistent with Snohomish's proposal. JP02 concurs. JP02 Br. Ex., BP-12-R-JP02-01, at 11.

The ULS pricing methodology limits price risk in two substantial ways. First, the rate would be subject to a floor and would be calculated based on the current market price at the time the service is requested. This pricing approach not only ensures the rate is equal to the current market price but that it could be higher than the current market price if the floor rates are higher than the current market price. Secondly, if ULS is taken for more than a year, BPA would have the option to adjust the rate in the second year. In addition to mitigation of price risk, the quantity of this service also would be limited. ULS as proposed is limited to the rate period and is available only to Load Following customers that have new Specified Resources that are 10 aMW or less. The combination of price mitigation and limited eligibility is substantial and reduces the risk of cost shifts.

Decision

BPA has properly designed the ULS to avoid cost shifts.

Issue 2.6.7.7

Whether the ULS GRSP language should be rewritten to address potential stranded costs when customers switch from Transmission Curtailment Management Service to ULS.

Parties' Positions

Snohomish states that BPA needs to revise the GRSP to address the potential that ULS service may create stranded costs resulting from TCMS purchases. Snohomish Br., BP-12-B-SN-01, at 16. Snohomish is concerned that BPA may make a purchase to serve the customer's TCMS needs and then the customer may decide to switch to ULS, leaving BPA with stranded costs for any purchases made for the TCMS. *Id.*

BPA Staff's Position

Staff does not specifically address TCMS charges but testifies that customers will be charged Resource Support Services costs if any are incurred. Burbank *et al.*, BP-12-E-BPA-40, at 11.

Evaluation of Positions

Snohomish contends that BPA must revise the ULS GRSP to include language that ensures there will be no stranded costs from TCMS if a customer chooses ULS to avoid excessive TCMS charges that result from a transmission access issues. Snohomish Br., BP-12-B-SN-01, at 16. Snohomish states that BPA "hinted at the possibility of stranded costs when it stated that it '...believes there would still be limited cost risk to BPA and other customers if the eligibility is expanded.'" *Id.* at 16-17.

No stranded costs will result if a customer elects ULS service instead of TCMS. Snohomish's concern is based on an assumption that BPA will purchase resources to serve TCMS well in advance of need and then will need to recover those purchase costs if a customer switches to

ULS service before the end of the purchases made for the TCMS service. Snohomish's assumption regarding the timing of the TCMS purchases is incorrect.

When a customer purchases TCMS as part of its Transmission Scheduling Service (TSS), BPA will take on scheduling obligations for the customer and provide either replacement power or transmission to a customer that experiences a qualifying transmission event pursuant to conditions specified in Exhibit F of the CHWM contract. Power Rate Schedules, BP-12-A-02, GRSP II.P.4. The rate will be the Powerdex Mid-C hourly index price for the hour the event occurred. *Id.* ULS must be requested three months in advance of the start of the service. GRSP II.U.1. In the coming rate period, BPA will not be making long-term purchases for TCMS. That fact, combined with the three-month required notification for taking ULS, leaves no possibility for stranded TCMS costs. There is no need to add GRSP language to address the possibility of stranded TCMS costs.

To bolster its claim of stranded costs, Snohomish cites a BPA Staff statement that Staff "...believes there would still be limited cost risk to BPA and other customers if the eligibility [of ULS] is expanded." Snohomish Br, BP-12-B-SN-01, at 16-17, *citing* Burbank *et al.*, BP-12-E-BPA-40, at 9. Snohomish has quoted that statement out of context: when BPA Staff testified there would still be a limited cost risk, Staff was stating why they were proposing to reserve the right to update the ULS rate when the service is taken for more than one year of the rate period. Burbank *et al.*, BP-12-E-BPA-40, at 9. That quote is not applicable or relevant to Snohomish's claim about stranded costs.

Decision

The ULS GRSP language does not need to be rewritten to address potential stranded costs when customers switch from TCMS to ULS, because the possibility of such stranded costs does not exist.

2.6.8 Metering Usage Data Estimation Provision

The metering section of the CHWM contract for customers that elected to purchase the Load Following product states in section 15.1:

If the metering equipment associated with the meters listed in Exhibit E fails to properly measure or record the interval readings, then BPA shall apply the procedure set out in the Meter Usage Data Estimations provision of the Wholesale Power Rate Schedules and GRSPs to determine the appropriate billing adjustment.

The GRSPs must align with this contract provision; however, it is not BPA's intent to include the Meter Usage Data Estimations provision in its entirety in the GRSPs. Staff proposes to add the following section to the GRSPs, to become GRSP I.F:

F. Metering Usage Data Estimation Provision

Pursuant to section 15.1 of the CHWM Contract for the Load Following product, BPA shall apply the Meter Usage Data Estimations procedures posted on the BPA Metering website.

Burbank *et al.*, BP-12-E-BPA-40, at 12. The Meter Usage Data Estimations procedures will be posted on the BPA Metering Web site no later than October 1, 2011. *Id.*

2.6.9 Residential Exchange Program-Related Issues

As discussed in section 1.2.3, BPA has adopted the 2012 Residential Exchange Program (REP) Settlement Agreement (2012 REP Settlement), which resolves long-standing and contentious litigation over BPA's implementation of the Residential Exchange Program established by section 5(c) of the Northwest Power Act. 16 U.S.C. § 839c(c). The 2012 REP Settlement is evaluated in a separate section 7(i) proceeding, the REP-12 proceeding, wherein BPA presents its analysis on the legal, factual, and policy merits of the 2012 REP Settlement. All issues pertaining to the REP were required to be raised in the REP-12 proceeding. *See* 75 Fed. Reg. 70744, at 70747. As such, no issues related to the REP, such as the implementation of the section 7(b)(2) rate test, the impositions of surcharges under section 7(b)(3), and issues regarding whether BPA should or should not adopt the 2012 REP Settlement, are dealt with in this proceeding. Instead, these matters are addressed in the REP-12 proceeding. The basis for BPA's decision to accept the 2012 REP Settlement is set forth in the REP-12 Administrator's Final Record of Decision, REP-12-A-02. Parties interested in these topics are directed to the REP-12 Final ROD for a full discussion of the issues and findings for all issues related to the REP.

The BP-12 rates have been determined consistent with the terms of the 2012 REP Settlement. The REP-12 Final ROD, and the material presented in the REP-12 proceeding, have been incorporated by reference into the BP-12 record to ensure that all material BPA has relied on to set rates is available in the record of this case.

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3.0 GENERATION INPUTS AND THE ANCILLARY AND CONTROL AREA SERVICES RATE SCHEDULE

3.1 Introduction

The purpose of the generation inputs portion of the rate proceeding is to assign certain power costs from Power Services to Transmission Services consistent with BPA’s statutory authorities. Many products and services that Transmission Services provides to its customers require generation to supply both power and capacity. This generation is referred to as generation inputs, and these inputs are necessary for most of the ancillary and control area services that Transmission Services provides under its Open Access Transmission Tariff (OATT). In general, the cost methodology for generation inputs involves (1) a forecast of the necessary amount of generation inputs, energy and/or capacity, (2) an assignment of embedded costs associated with the generation system that is used to provide the generation inputs, (3) an assignment of any other applicable costs such as variable and direct costs, and (4) assignment of these costs to Transmission Services as an input for the transmission rate design. Transmission Services collects these costs through Ancillary and Control Area Services (ACS) rates.

Cost assignments for generation inputs are developed for the specific services that Transmission Services offers to its customers and for other identifiable generation inputs that Transmission Services needs to maintain system reliability. Generation inputs include Regulating Reserve, Variable Energy Resource Balancing Service (VERBS), Dispatchable Energy Resource Balancing Service (DERBS), Operating Reserve, Synchronous Condensing, Generation Dropping, Energy and Generation Imbalance, Redispatch, and Station Service. The inter-business line assignment of costs also includes the segmentation of Corps of Engineers and Bureau of Reclamation transmission facilities. These segmentation costs are not a generation input, but it is a cost in the generation revenue requirement that is assigned to Transmission Services.

The rate design for recovering the generation inputs costs associated with providing balancing reserve capacity services during the FY 2012–2013 rate period has been revised and expanded significantly from the current design. BPA is adopting new rates to recover the costs of balancing services from generators other than wind generators and to address specific circumstances that BPA may face during the rate period:

- The FY 2012–2013 ACS rate schedule includes a new VERBS rate that applies to variable energy resources (VERs) in the BPA balancing authority area during the rate period. VERBS replaces the FY 2010–2011 Wind Balancing Service for wind generators and is a new service for solar generators.
- The VERBS rate schedule includes a “Supplemental Service” option under which a customer can request the use of non-Federal capacity resources to provide a higher quality of balancing service than BPA provides under the standard VERBS rate.
- The “Provisional Balancing Service” in the VERBS rate schedule is a new service that applies to customers that elect to self-supply during the rate period but become unable to do so or that have failed to elect to take VERBS or otherwise procure balancing reserve

services and choose to interconnect and operate in the BPA balancing authority area during the rate period.

- The Formula Rates in the VERBS rates schedule are designed to recover the costs associated with acquiring non-Federal balancing reserve capacity to replace Federal balancing reserve capacity that becomes unavailable during the rate period or to increase the balancing reserve capacity for the imbalance component of VERBS.
- DERBS is a new balancing service that applies to non-Federal thermal generators in the BPA balancing authority area during the rate period.

BPA is establishing two pilot programs for the rate period to address the balancing reserve capacity associated with providing balancing services. The Committed Intra-Hour Scheduling Pilot is a program under which wind generators that commit to submit schedules every 30 minutes and meet scheduling accuracy metrics are eligible for a reduced VERBS rate. The *dec* Acquisition Pilot is a separate program under which BPA will purchase *dec* balancing reserves from third parties to replace some of the *dec* balancing reserves provided by the FCRPS. BPA is conducting these pilot programs in the hope that they will help address challenges that BPA could face in integrating large amounts of VERs during the rate period.

Almost all inter-business line cost assignments identified in the Initial Proposal are revised for the Final Proposal to reflect the updated balancing reserve capacity quantity forecast, updated revenue requirement, and updated market price forecast. Specific policy issues, methodologies for forecasting and pricing generation inputs, and rate design matters are addressed in the sections below.

3.2 Generation Inputs Policy

3.2.1 Introduction

Staff's proposal for assigning costs to generation inputs and setting Ancillary and Control Area Services rates has not changed significantly from the methodology and rate design used for the FY 2010–2011 rate period. This Generation Inputs Policy section addresses overarching policy issues in section 3.2.2 and then focuses on more specific policy issues including pricing, operations, risk issues, the Federal Energy Regulatory Commission's variable energy resource Integration Notice of Proposed Rulemaking (NOPR), VERBS formula rates, Operating Reserves, Committed Intra-Hour Pilot, and VERBS Supplemental Service.

3.2.2 General Policy Issues

Issue 3.2.2.1

Whether BPA's reciprocity safe harbor open access transmission tariff status is an issue in this rate proceeding.

Parties' Positions

Iberdrola discusses the fact that BPA currently does not have a Commission-approved reciprocity safe harbor OATT and expresses concern over the resulting uncertainty for VER owners and other transmission customers. Iberdrola Br., BP-12-B-IR-01, at 11-12. Iberdrola states that because Staff's direction in this rate proceeding regarding VERBS is significantly different from the direction of the Commission's VER Integration NOPR, BPA should refrain from taking any action in this rate proceeding that would prevent BPA from offering service under a reciprocity OATT, including the ability to follow the Commission's VER Integration policies. *Id.* at 15.

NWG mentions that BPA's reciprocity status has the potential to have a negative discriminatory effect on wind energy producers, but acknowledges that BPA's reciprocity status is not a rate case issue. NWG Br., BP-12-B-NG-01, at 9-10.

PPC states that there is no reasonable basis presented in the record for BPA to anticipate the outcome of the VER Integration NOPR process in this rate proceeding. PPC Br., BP-12-B-PP-01, at 5-7.

BPA Staff's Position

Staff does not address the issue of BPA's reciprocity status because it is not a rate case issue and there is another public process in which reciprocity tariff issues are being addressed. However, Staff does evaluate the various operational and rate assumptions proposed by Iberdrola and NWG that are part of the Commission's VER Integration NOPR. Mainzer *et al.*, BP-12-E-BPA-42, at 12-16; *see also Integration of Variable Energy Resources*, 133 FERC ¶ 61,149, (2010). Staff's analysis indicates that the proposed reforms would be difficult to implement during the FY 2012–2013 rate period and that the assumed benefits of the proposed reforms are not necessarily sound. *Id.* Staff concludes:

Given the uncertainty about the ultimate outcome of the FERC NOPR, serious concerns on the part of BPA and other parties about certain aspects of the proposal, and the technical hurdles associated with a transition to 15-minute scheduling in a timeframe consistent with the upcoming rate period, we have not changed our approach to this rate case as a result of the NOPR.

Id. at 15-16.

Evaluation of Positions

As NWG recognizes, BPA's reciprocity status is not a rate case issue, and there is a separate ongoing BPA process in which BPA's approach to reciprocity status is being addressed. *See* ROD section 1.2.5. Iberdrola makes a valid point: that decisions made in this rate proceeding should not pre-decide the outcome of other processes. Iberdrola Br., BP-12-B-IR-01, at 15. However, Iberdrola is primarily arguing that BPA should align the decisions in this rate proceeding with the Commission's proposed rule in the VER Integration NOPR. *Id.* Iberdrola anticipates that the proposed rule will become a final rule during the FY 2012–2013 rate period, and BPA's VERBS rate would not be consistent with these anticipated Commission policies. *Id.*

PPC states that there is no reasonable basis for BPA to anticipate the outcome of the VER Integration NOPR. PPC Br., BP-12-B-PP-01, at 5-7. Staff points out that the Commission's VER Integration NOPR is not a final rule and entities around the country, including BPA, filed comments that opposed various aspects of the VER Integration NOPR. Mainzer *et al.*, BP-12-E-BPA-42, at 12-13. The particular issues associated with the VER Integration NOPR are discussed in detail in ROD section 3.2.6.

As BPA has stated, BPA is not bound by Commission policy, though it does take it into account where appropriate. WP-10 ROD, WP-10-A-02, at 478. Since the VER Integration NOPR is not a final rule, it could change significantly before it becomes a final rule. In addition, Staff describes the technical hurdles to implementing some aspects of the proposed rule during the FY 2012–2013 rate period. Mainzer *et al.*, BP-12-E-BPA-42, at 12-16. Thus, the record does not support Iberdrola's suggestion to design the FY 2012–2013 rate proposal around an anticipated outcome.

BPA's reciprocity process is considering potential deviations from the Commission's *pro forma* OATT. If new Commission policy conflicts with decisions made in this rate proceeding and BPA chooses to file a reciprocity OATT, BPA can decide whether additional deviations are necessary or whether the conflicts can be resolved in a future rate proceeding.

Decision

BPA's reciprocity status is not a rate case issue.

Issue 3.2.2.2

Whether BPA's treatment of VERs is inconsistent with national energy policy.

Parties' Positions

Iberdrola provides examples of statements from the Obama Administration regarding the importance of developing renewable energy resources and acknowledges that BPA has spent a great deal of time and effort on issues related to wind integration. Iberdrola Br., BP-12-B-IR-01, at 3-5. Iberdrola takes issue with BPA's proposed solutions as short-sighted, resulting in significant costs for VER developers and severely damaging the value of wind power in the market. *Id.* at 5. Iberdrola lists the various components of the VERBS rate, other rates that apply to generators interconnected to BPA's transmission system, and operational restrictions of DSO 216 to assert that Staff's proposal is not consistent with national energy policy to encourage the development of renewable resources. *Id.* at 15-19. Iberdrola concludes that BPA's treatment of VERs is clearly inconsistent with the direction provided by the Obama Administration, the Department of Energy, and national energy regulatory policies. *Id.* at 19.

BPA Staff's Position

Staff describes BPA's multiple programs developed to encourage the development of wind in the BPA balancing authority area and the significant increase in wind interconnected to BPA's system in the last few years. Mainzer *et al.*, BP-12-E-BPA-23, at 4-9. In rebuttal testimony, Staff explains:

As the operator of the Federal hydroelectric system and a 10,500 MW peak load balancing authority, BPA has the responsibility to maintain reliability, including ensuring that there is sufficient capacity and other mechanisms available to maintain the reliability of its system and to handle extreme tail events. BPA has developed and facilitated significant innovations, including its Network Open Season transmission subscription process, customer-supplied generation imbalance, intra-hour scheduling, and new forecasting tools, to enable a massive increase of wind generation on its system while preserving reliability, honoring our statutory obligation and non-power operating constraints, and acting consistent with cost causation principles. The fact that wind generation has increased by a factor of six over the past four years and is set to double again over the next two to three years is clear evidence that our rates and policies, if anything, are a stimulus to further wind development across our footprint.

Mainzer *et al.*, BP-12-E-BPA-42, at 9-10.

Staff goes on to assert that these successes show:

Our rates, including our Initial Proposal in this proceeding, have clearly supported, rather than prevented, a continued increase of wind generation, as evidenced by the thousands of megawatts of wind generation that continue to line up in our transmission and interconnection queues. In addition to a considerable amount of renewable energy that is exported to California, a significant fraction of the renewable resources required to meet state Renewable Portfolio Standards (RPS) requirements in the states of Washington and Oregon is interconnected to the BPA system. To date, the region's utilities have been able to meet their RPS requirements in a timely fashion. Finally, BPA's focus on improved wind forecasting and intra-hour scheduling has been a significant driver of emerging Federal policies to support renewable resources.

Id. at 10-11.

Staff also describes the burdens that this significant amount of wind generation puts on the balancing authority and the need for DSO 216 to protect the reliability of the system. *Id.* at 19. Staff addresses each of the components of the VERBS rate and the other rates and penalties that apply to wind generators and explains in detail how each of these is reasonable and consistent with cost causation principles. *Id.* at 42-44.

Evaluation of Positions

Iberdrola's assertions that BPA policy and rate proposals are inconsistent with national policy are made in the larger context of Iberdrola advocating that BPA should adopt the Commission's proposals in the VER Integration NOPR, pursue the development of a regional balancing market, and file a reciprocity OATT. Iberdrola Br., BP-12-B-IR-01. Staff explains the effects of integrating a significant amount of wind generation into the BPA system and the need for operational tools to maintain reliability and provides justification for the various rates and penalties that affect VERs interconnected to the BPA system. Mainzer *et al.*, BP-12-E-BPA-42, at 19, 42-44.

National and regional energy policy is focused on inducing the development of VERs to replace thermal generation and reduce greenhouse gas emissions. However, this policy cannot be carried out without consideration for maintaining the reliability of the existing electric grid and the costs imposed on existing users of the system.

BPA has been successful at integrating wind generation, as evidenced by the facts that over 3,500 MW of wind generation is currently interconnected and over 5,700 MW is projected to be interconnected by the end of the FY 2012–2013 rate period. Generation Inputs Study Documentation (Documentation), BP-12-FS-BPA-05A, Table 2.1. As described in the Commission's VER Integration NOPR, the significant increase in the amount of VERs is raising issues that may lead to dramatic changes to the electrical industry. *Integration of Variable Energy Resources*, 133 FERC ¶ 61,149, P 13-18 (2010). BPA must meet many responsibilities, and its VER policies and rate proposals must take these responsibilities and the changing energy industry landscape into account. BPA's policies cannot remain static, and as the makeup of the system continues to change, BPA must continue to adjust to meet its many responsibilities. Many of the positions advocated by Iberdrola will most likely be part of this continuing transition.

For purposes of setting rates for the FY 2012–2013 rate period, BPA's policies and rates are consistent with the national policy of encouraging the continued development of VERs. For example, in this rate proceeding, BPA is initiating a new VERBS Supplemental Service and a Committed Intra-Hour pilot program as new options for VERs to manage risk and cost exposure. Specific issues on DSO 216 are described in section 3.2.4 of this ROD.

Decision

BPA's wind integration policies, including the proposed rates in this proceeding are consistent with national energy policy.

Issue 3.2.2.3

Whether BPA's treatment of VERs is consistent with Congress's directive that BPA encourage the development of renewable resources in the Pacific Northwest.

Parties' Positions

Iberdrola claims that Staff's proposed rates, penalties, and use of DSO 216 demonstrate that BPA is not acting consistently with its statutory directive in the Northwest Power Act to encourage, through the unique opportunity provided by the FCRPS, the development of renewable resources within the Pacific Northwest. Iberdrola Br., BP-12-B-IR-01, at 18-19.

NWG recognizes that BPA has done several things to encourage the development of wind in the Northwest. NWG Br., BP-12-B-NG-01, at 8. However, NWG also takes issue with specific aspects of Staff's VERBS proposal. *Id.* at 8-9. NWG states Staff's VERBS proposal and other related activities raise serious questions about BPA's intention to meet the obligations under the Northwest Power Act to encourage the development of renewable resources. *Id.* at 9-10.

BPA Staff's Position

Staff does not directly address the issue of whether BPA's rate proposals are consistent with the Northwest Power Act, because this is a legal issue and many of the related issues raised by the Parties are not rate case issues. Staff does describe system and policy enhancements that have allowed a significant amount of wind generation to interconnect to BPA's system and provided significant justification for the VERBS rate proposal and other aspects of the rate proposal that will apply to wind generators.

Evaluation of Positions

The provision in the Northwest Power Act that both Iberdrola and NWG refer to is one of several purposes listed at the beginning of the Act, "to encourage through the unique opportunity provided by the Federal Columbia River Power System ... the development of renewable resources within the Pacific Northwest." 16 U.S.C. § 839(1), (1)(B). The other listed purposes include:

- 839(1)(A).** conservation and efficiency in the use of electric power; ...
- 839(2).** to assure the Pacific Northwest of an adequate, efficient, economical, and reliable power supply;
- 839(3).** to provide for participation and consultation of the Pacific Northwest States, local governments, consumers, customers, users of the Columbia River System (including Federal and State fish and wildlife agencies and appropriate Indian tribes), and the public at large within the region in—
 - 839(3)(A).** the development of regional plans and programs related to energy conservation, renewable resources, other resources, and protecting, mitigating, and enhancing fish and wildlife resources.
 - 839(3)(B).** facilitating the orderly planning of the region's power system, and
 - 839(3)(C).** providing environmental quality.

16 U.S.C. §§ 839(1)(A)–(3)(C).

This list of purposes is prefaced with the statement that “[t]he purposes of this chapter, together with the provisions of other laws applicable to the Federal Columbia River Power System, are all intended to be construed in a consistent manner.” 16 U.S.C. § 839. As such, BPA gives substantive effect to these purposes by acting consistent with the multiple provisions of law that apply to BPA in its marketing and transmitting of power and establishment of rates. BPA must balance these purposes with its other statutory directives that govern the setting of rates and direct BPA to recover costs for transmission and other services.

NWG and Iberdrola appear to give great weight to the statutory language pertaining to the encouragement of the development of renewable resources without considering BPA’s other statutory provisions. Contrary to the assertions of Iberdrola and NWG, BPA’s policies and rate decisions are not solely driven by the purpose of encouraging through the unique opportunity provided by the Federal Columbia River Power System the development of renewable resources within the Pacific Northwest. BPA’s policies and decisions in this rate proceeding must balance the multiple purposes of the Northwest Power Act and other laws applicable to the FCRPS, which include assuring the Pacific Northwest of an adequate, efficient, economical, and reliable power supply.

In balancing the above purpose to encourage the development of renewable resources, BPA must also look to the specific directives in the Northwest Power Act regarding renewable resources and BPA. Specifically, the Northwest Power Act provisions pertaining to renewable resources are aimed at BPA’s acquisition of such resources and consumers’ application of renewable resources. *See generally* 16 U.S.C. §§ 839b(d)(2), 839b(e)(1)-(2), 839d(a). Such directives do not speak to a requirement that BPA encourage commercial marketers, developers, and owners of VERs to integrate their resources to BPA’s transmission system at the risk or expense of BPA’s existing power system. *Id.*

In addition, the Northwest Power Act directs the Northwest Power and Conservation Council to establish a regional conservation and electric power plan, which first affords a priority to cost effective conservation, and then renewable resources *for reducing or meeting the Administrator’s obligations*. 16 U.S.C. § 839b(e)(1)-(2). A further directive is stated in section 6 of the Northwest Power Act regarding the Administrator’s obligation to “...acquire such renewable resources which are installed by a residential or small commercial consumer to reduce load, as the Administrator determines are consistent with the plan” 16 U.S.C. § 839d(a)(1). These directives govern BPA acquisition of renewable resources; they do not prohibit BPA from assigning costs to commercial marketers and operators of renewable resources that use the BPA transmission system for commercial sales. To the contrary, the Northwest Power Act directs BPA to establish and revise rates to recover the costs associated with the transmission of electric power, among other purposes. Consequently, assigning balancing service costs to the commercial operators of renewable resources that use such services to transmit electric power is wholly consistent with the directives in the Northwest Power Act.

As described in Staff testimony and discussed in Issue 3.2.2.2 above, BPA continues to invest significant resources to promote the development of wind in the Pacific Northwest and has gone to great lengths to integrate wind resources into the BPA system. The continued growth of wind

generation development in BPA's balancing authority area is *prima facie* evidence that BPA's efforts to encourage the growth of renewable resources have been successful. The development of BPA's policies and rate proposals involves the careful consideration of all of the multiple purposes that BPA is statutorily instructed to meet, including the promotion of renewable resource development, maintaining system reliability, and cost recovery. As a result, BPA continues to satisfy the many objectives stated in the Northwest Power Act.

Decision

BPA's treatment of VERs is consistent with the purposes of the Northwest Power Act, including encouraging the development of renewable resources in the Pacific Northwest through the unique opportunity provided by the FCRPS.

Issue 3.2.2.4

Whether BPA's utilization of several forums to develop wind policy is inappropriate.

Parties' Positions

Iberdrola states that "Bonneville has attempted to disaggregate the many forums for addressing wind penalties and restrictions, making it difficult, if not impossible, for VERs to ever fully address the collective impact of the numerous punitive policies Bonneville is implementing and proposing, but the impact of these policies is very real and evident in the market." Iberdrola Br., BP-12-B-IR-01, at 18.

BPA Staff's Position

This is not rate case issue.

Evaluation of Positions

As described in ROD section 1.2.5, BPA is addressing policy and operations that affect VERs in several processes outside the rate proceeding. These other processes include the Environmental Redispatch Policy, the process for determining e-Tagging requirements and the Northwest Power Pool (NWPP) deliberation over the use of contingency reserves during extreme wind deviation events, the Wind Integration Team (WIT) initiatives, and to some extent the OATT reciprocity process. Each of these other forums involves operational implementation or policy decisions that are beyond the scope of this rate proceeding. BPA's 7(i) process is limited to rates issues in order to make it a manageable process through which BPA can meet its statutory obligation to set rates for various services and products.

Iberdrola's suggestion that BPA policies are punitive in nature is unsubstantiated and unsupported in the record. Utilizing different forums to address VER policy is necessary and appropriate to address the issues that are beyond the scope of the rate process. In fact, many of the public processes that Iberdrola now criticizes were developed largely in response to customer requests and suggestions.

In addition, the fact that BPA has multiple ongoing processes to address non-rate issues and a rate process focused on rate issues is not unique to VERs. Because of the nature of BPA's business, all of BPA's customers work with BPA through multiple processes that affect particular aspects of the customers' services and contracts. These other processes are necessary to address the multiple non-rate operational and policy issues. BPA considers the interaction of these various processes with the rate decisions, and as is demonstrated by Iberdrola's initial brief, parties are provided the opportunity to evaluate and express opinions regarding this interaction in the rate proceeding. BPA finds no legal or policy basis to consolidate all public forums into one proceeding.

Decision

The utilization of different forums by BPA to develop wind policy is necessary and appropriate for issues that are not appropriately addressed in the rate process.

Issue 3.2.2.5

Whether BPA should initiate a reexamination of wind rates, terms, and conditions in association with other ongoing processes, such as Environmental Redispatch and other transmission processes.

Parties' Positions

MSR suggests that the best way to appropriately allocate costs would be to initiate a reexamination of the rate, terms, and conditions for wind integration in conjunction with a reexamination of the environmental redispatch protocols, the 2011 NOS process, and conclusion of the MOD 29 and 30 efforts. MSR Br., BP-12-B-MS-01, at 4. MSR states that this approach would allow a better understanding of the operational attributes of the system and how best to manage integration of resources and maximization of transmission. *Id.*

BPA Staff's Position

Staff does not address the relationship between these other processes and Ancillary and Control Area Services rates.

Evaluation of Positions

MSR appears to suggest that assigning costs to ACS rates and establishing terms and conditions for ACS is somehow directly interlinked and affected by the decisions in the other processes MSR has referred to in its brief.

The Environmental Redispatch protocols are an operational mechanism designed to protect system reliability and meet Clean Water Act requirements during high water events. There is one rate issue raised by MSR related to Environmental Redispatch, which is addressed in this ROD as Issue 3.2.3.1, but there is no other intrinsic relationship between rates and Environmental Redispatch. The 2011 NOS process is strictly limited to assigning transmission

rights and determining the level of interest in future transmission rights so that BPA can plan future transmission infrastructure development. Nothing in that process should have any impact on the establishment of ACS rates or revenue forecasts from ACS rates in the FY 2012–2013 rate period. Similarly, there is no relationship between the rate process and conclusion of the MOD 29 and 30 efforts, which are related to implementation of BPA’s methodology for determining available transmission capacity. The processes described by MSR do not have a material relationship to the assignment of costs for establishing ACS rates, and decisions made in this rate proceeding would not be impacted by a reexamination of these other processes. Therefore, it is not clear that a “reexamination” as MSR recommends would provide any insights to issues related to setting ACS rates.

Decision

BPA will not initiate a reexamination of wind rates, terms, and conditions in association with other ongoing process, such as Environmental Redispatch and other transmission processes.

Issue 3.2.2.6

Whether the BP-12 Record of Decision should expressly state that the rate assumptions about the operational or commercial characteristics of VERBS Supplemental Service should not prejudice the outcome of BPA’s policy regarding the appropriate e-Tagging protocol for wind resources or the outcome of BPA’s business process to determine the commercial and operational terms for VERBS Supplemental Service.

Parties’ Positions

SCE describes Staff’s position regarding the decision on firm and firm-contingent e-Tagging as being outside the scope of the rate proceeding but states that Staff needed to make some assumptions regarding the outcome of this issue. SCE Br., BP-12-B-SC-01, at 6-7. To support the conclusion that the decision regarding firm and firm-contingent e-Tagging is outside the scope of the rate proceeding SCE cites to an order of the Hearing Officer striking testimony on the issue. *Id.*, citing BP-12-HOO-40, at 3.

SCE also characterizes Staff as contradicting its own testimony in regard to Staff stating that the operational or commercial characteristics of VERBS Supplemental Service are outside the scope of the rate case and then providing detailed testimony describing and limiting VERBS Supplemental Service. *Id.* at 7. SCE concludes that the Final ROD should expressly state that assumptions by Staff, Staff testimony about the operational or commercial characteristics of VERBS Supplemental Service, and any approval of rates based on such assumptions and testimony shall not in any way prejudice the outcome of whether firm or firm contingent e-Tags should apply to wind power or the outcome of BPA’s business practice process to determine the operational or commercial characteristics of VERBS Supplemental Service. *Id.*

BPA Staff's Position

Staff explains that the e-Tagging requirements for wind generation are outside the scope of the rate case, but Staff needs to make an assumption regarding the outcome of this issue in order to forecast the amount of Operating Reserves BPA will be providing during the rate period. Mainzer *et al.*, BP-12-E-BPA-23, at 43. Staff recognizes that the e-Tagging issue was still under external and internal deliberation, and Staff's assumption in the Initial Proposal is based on the best information at the time. Staff states that BPA will base its Operating Reserve forecast for the Final Proposal on the best information available at the time. *Id.*

Staff states that for VERBS Supplemental Service, the primary issue in the rate case is recovery of costs associated with the service. Kitchen *et al.*, BP-12-E-BPA-45, at 3. In regard to the operational or commercial characteristics of VERBS Supplemental Service, Staff explains that these issues will be addressed outside of the rate case in a participant agreement and business practice, which will be posted for public comment in order to solicit the best ideas in the region for procuring supplemental reserves. *Id.* In response to testimony submitted by SCE, Staff discusses methods for quantifying the amount of VERBS Supplemental Service needed to avoid DSO 216, SCE's suggested use of the CSGI pilot program as a proxy for VERBS Supplemental Service, and the use of the Balancing Authority percentiles to address individual wind facility needs for VERBS Supplemental Service. *Id.* at 5-7.

Evaluation of Positions

The issues pertaining to e-Tag requirements are expressly excluded from the scope of this rate proceeding:

Pursuant to § 1010.3(f) of BPA's Procedures, the Administrator directs the Hearing Officer to exclude from the record all argument, testimony, or other evidence that seeks in any way to revisit the appropriateness or reasonableness of any other issues related to the generation inputs or Ancillary and Control Area Services. This exclusion includes, but is not limited to, issues regarding reliability of the transmission system, any existing or proposed Transmission Services dispatcher standing orders, *e-Tag requirements*, and business practices.

75 Fed. Reg. 70744, 70746 (2010) (emphasis added).

SCE acknowledges that the decision regarding the appropriate e-Tag for wind generation is outside the scope of the rate proceeding. SCE Br., BP-12-B-SC-01, at 6-7. The fact that this issue is outside the scope of the proceeding is also pointed out by Staff on more than one occasion during the proceeding. Mainzer *et al.*, BP-12-E-BPA-23, at 3, 43; Kitchen *et al.*, BP-12-E-BPA-45, at 4. Staff's testimony, however, explains the basis for an assumption that is needed to forecast the amount of Operating Reserves BPA believes it will need to provide during the rate period and does not seek to influence the outcome of the e-Tagging issue. Mainzer *et al.*, BP-12-E-BPA-23, at 43.

As is discussed in more detail in Issue 3.2.8.1, for the Final Study, BPA Staff is relying on the most up-to-date information regarding the potential outcome of the e-Tagging issue and is not

assuming that there will be a reduction in the amount of Operating Reserves provided due to a firm-contingent tagging requirement. The e-Tagging issue was discussed at a public meeting held on June 10, 2011. Since BPA has been consistent throughout the rate proceeding in keeping the e-Tagging issue outside the scope of the rate proceeding, and that decision process is moving forward independent of the BP-12 rate process, there is no need for an express statement in the Record of Decision regarding prejudicing the outcome of this other decision process.

SCE requests that the express statement also apply to the business process BPA will be using to determine the operational or commercial characteristics of VERBS Supplemental Service. SCE Br., BP-12-B-SC-01, at 7. Staff introduces VERBS Supplemental Service as a concept in the Initial Proposal, providing a general description and a set of principles for the development of an actual rate proposal. Mainzer *et al.*, BP-12-E-BPA-23, at 38-42. The concept was further developed through a rate case workshop discussion held on January 13, 2011. Parties made proposals for VERBS Supplemental Service in their direct testimony. Nelson, BP-12-E-SC-01, at 2-21. In rebuttal testimony, Staff proposes VERBS Supplemental Service, including the details that need to be determined in this rate proceeding. Kitchen *et al.*, BP-12-E-BPA-45. Staff also requested a modification to the procedural schedule to allow parties an opportunity to submit surrebuttal testimony on VERBS Supplemental Service and other issues that were new or changed significantly in BPA's rebuttal testimony. BP-12-M-BPA-15.

In rebuttal testimony, Staff states that the primary issue in the rate case is recovery of costs associated with the VERBS Supplemental Service and discusses the general parameters of the service. Kitchen *et al.*, BP-12-E-BPA-45, at 2-3. Staff also states that a business practice process and participant agreement would be used outside of the rate case to address issues of a commercial and operational nature. *Id.* at 3. The Staff testimony that SCE characterizes as a contradiction is responding to SCE's direct testimony regarding the methodologies for quantifying the amount of VERBS Supplemental Service parties would need to purchase. *Id.* at 5-7. Staff goes on to describe Staff's position regarding several other aspects of VERBS Supplemental Service. *Id.* at 7-16.

While it is true that the commercial and operational details will be finalized in a business practice and participant agreement process, it is important for Staff to discuss some of the details of the Supplemental Service in rebuttal testimony. Staff does so to inform BPA's decision regarding the appropriate rate design for such service, and to help parties understand how Staff believed the VERBS Supplemental Service will work so parties could fully understand what Staff is proposing and respond in surrebuttal testimony. These details do not need to be decided in the rate case, but they may be referred to as a starting point for the business practice and participant agreement process.

As mentioned above, Staff originally proposes principles for the VERBS Supplemental Service in the Initial Proposal. If, as SCE requests, BPA were to include an express statement that Staff's testimony should not in any way prejudice the outcome of the business practice process regarding the commercial and operational details, that express statement could preclude consideration of the principles Staff articulates for the service, as well as details in Staff's rebuttal testimony from consideration in the development of the business practice. It is

important that decisions made in the rate proceeding and the logic related to those decisions, while not determinative, are factored into the business practice process.

Decision

It is unnecessary for BPA to make the express statement proposed by SCE because the firm-contingent e-Tagging issue is moving forward without any influence from the testimony in this rate proceeding and the VERBS Supplemental Service business practice process should be an open process that factors in the ideas that were presented by parties and Staff during the rate proceeding.

Issue 3.2.2.7

Whether BPA misinterprets the Commission's jurisdiction over BPA.

Parties' Position

Iberdrola takes issue with BPA's statement in section 1.2.5 of the Draft ROD that BPA is not subject to Commission jurisdiction under the Federal Power Act. Iberdrola argues that "the Commission also has the jurisdictional authority to issue an order directing Bonneville to provide comparable, not unduly discriminatory or preferential transmission services, and to do so at rates that are comparable to the rates Bonneville charges itself." Iberdrola Br. Ex., BP-12-R-IR-01, at 9. Iberdrola states that Bonneville's description of the Commission's jurisdiction, however, "focuses exclusively on the Commission's review of Bonneville's regional power and transmission rates under the Northwest Power Act, which is limited to determining whether Bonneville's proposed rates meet the three specific requirements of the Northwest Power Act Section 7(a)(2)." *Id.*

BPA Staff's Position

This is a legal issue and Staff has not addressed it.

Evaluation of Positions

Before turning to the factual premises of Iberdrola's legal arguments, it is important to set forth the legal standards that apply to the review of BPA's rates.

As stated in section 1.2 of this ROD, the legal standards that govern BPA ratemaking derive from the Flood Control Act and from BPA's organic statutes. Commission review of BPA's rates is limited to the three criteria specified in section 7(a)(2) of the Northwest Power Act. 16 U.S.C. § 839e(a)(2); *see also* section 1.1.3 of this ROD. Although BPA has voluntarily filed a reciprocity tariff with the Commission and adheres to open access principles in its sale of transmission, the Commission's proposed Notice of Proposed Rulemaking pertaining to the Integration of Variable Energy Resources, Order No. 890, and related open access principles are not legally binding on BPA and do not form part of either the Commission or Ninth Circuit review of BPA's rates. In addition, BPA's adherence to reciprocity principles is not an issue in

this proceeding and is not relevant to the approval of BPA's rates. Finally, the statutes that govern BPA ratemaking do not include an undue discrimination or comparability standard (as discussed below, FPA section 212(i), which includes an undue discrimination standard, and FPA section 211A, which includes a comparability standard, are irrelevant to this proceeding). The Commission's authority under sections 210, 211, 211A, and 212 of the Federal Power Act is not at issue in this rate proceeding, and such authority has no bearing on the confirmation of BPA's rates under the Northwest Power Act.

Iberdrola takes issue with BPA's statement in the ROD that "As a Federal power marketing administration, BPA is not subject to Federal Energy Regulatory Commission jurisdiction or to the standards that apply to 'public utilities' under the Federal Power Act." Iberdrola Br. Ex., BP-12-R-IR-01, at 7; Draft ROD, BP-12-A-01, at 11. Iberdrola argues that the Commission has the authority to order BPA to provide interconnection and transmission services under sections 210, 211, and 212 of the FPA, and to ensure that the rates for such service are not unjust, unreasonable, unduly discriminatory or preferential, as determined by the Commission. Iberdrola Br. Ex., BP-12 R-IR-01, at 7.

Iberdrola misrepresents BPA's statement regarding the Commission's jurisdiction. BPA's statement in section 1.2.5.2 of this ROD is under the heading entitled "Reciprocity" and is directly related to the discussion about transmission service under the Commission's reciprocity safe harbor open access transmission tariff model. The statement, when taken in context, does not represent an attempt by BPA to disclaim the Commission's authority under sections 210 through 212 of the Federal Power Act.

In addition, Iberdrola misreads both BPA's position regarding Commission jurisdiction and sections 210 through 212 of the Federal Power Act. If the Commission were to exercise its limited jurisdiction over BPA transmission service under sections 210, 211, 211A, and 212 of the Federal Power Act, only then might the Commission review BPA transmission rates for the service at issue to determine compliance with the applicable statutory standards. That is, the Commission does not have the discretion to deny approval of BPA's rates under the Northwest Power Act because they are inconsistent with those provisions of the Federal Power Act, but not inconsistent with the standards for Commission review under section 7(a)(2) of the Northwest Power Act.

Iberdrola states that BPA has acknowledged the Commission's jurisdiction in the 2002 rate case, in which BPA stated that it must satisfy section 212(i) of the Federal Power Act, 16 U.S.C. § 824k(i). *Id.* In addition, Iberdrola states that it has repeatedly urged BPA to be mindful of the section 211A standards when developing transmission rates, terms and conditions, and that it is error for BPA to state that BPA is not subject to Commission jurisdiction or the standards that apply to public utilities under the FPA. *Id.* at 9. As described above and in section 1.1.3 of this ROD, sections 210, 211, 211A, and 212 of the Federal Power Act are irrelevant to the Commission's confirmation of BPA's rates in this rate proceeding. Nonetheless, BPA is certainly mindful of the standards when it establishes its rates, since it is not BPA's purpose to invite controversy.

Section 212(i) of the Federal Power Act provides that under sections 210, 211, 212, and 213 of the Federal Power Act, the Commission has the authority to order BPA to provide transmission service, and that “[i]n applying such sections” to BPA the Commission shall ensure that

The rates for the transmission of electric power on the [FCRTS] are governed only by ... otherwise applicable provisions of law ... except that no rate for the transmission of power on the [FCRTS] shall be unjust, unreasonable, or unduly discriminatory or preferential, as determined by the Commission.

16 U.S.C. § 824k(i)(1)(B)(ii).

As the statute makes clear, the rate standard in section 212(i) applies only when the Commission is applying to BPA the referred sections of the Federal Power Act: that is, when the Commission orders BPA to provide transmission or interconnection services in accordance with the applicable provisions of the Federal Power Act. Section 212(i) does not apply to the Commission’s review of BPA’s rate filings under the Northwest Power Act. Iberdrola’s reliance on the Commission’s review of BPA’s 2002 rates for a contrary conclusion mischaracterizes the Commission’s holding.

When BPA filed its 2002 rates, in addition to seeking approval of the rates under the Northwest Power Act, BPA asked the Commission to find that the rates were consistent with section 212(i) of the Federal Power Act. At times BPA has requested such a finding for assurance that the rates it has established for general applicability also satisfy the standard for Commission-ordered transmission. In response to BPA’s request, the Commission stated that, although the Federal Power Act does not require it to make such a finding, the act also does not deny the Commission the discretion to do so. *United States Dep’t of Energy – Bonneville Power Admin.*, 95 FERC ¶ 62,094, 64,135 (2001). The Commission found that the rates were consistent with the standards of section 212(i). *Id.*

The Commission did not say that it had the discretion to condition approval of BPA’s transmission rates under the Northwest Power Act on their consistency with section 212(i) of the Federal Power Act. Instead, it asserted the authority to make a finding not relevant to the case before it, at least when so requested.

Indeed, the Commission recognized the limited reach of section 212(i) in its review of BPA’s 1993 rate filing. *United States Dep’t of Energy – Bonneville Power Admin.*, 67 FERC ¶ 61,351, 62,218 (1994); *order on reh’g, United States Dep’t of Energy – Bonneville Power Admin.*, 68 FERC ¶ 61,344, 62,389 (1994). Powerex argued that the Commission must review BPA’s Northern Intertie rate under section 212(i). BPA and several other parties replied that, because the Commission had not ordered BPA to provide transmission service under section 211, section 212(i) did not apply. The Commission agreed, noting that “since [BPA’s] application does not involve transmission services ordered by the Commission under section 211, the review standards under 211 are totally inapplicable.” *Id.*

The Commission’s logic regarding section 212(i) is easily applied to section 211A. The pertinent language in section 211A states:

Subject to section 824k (h) of this title, the Commission may, *by rule or order*, require an unregulated transmitting utility to provide transmission services at rates that are comparable to those that the unregulated transmitting utility charges itself; and on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides transmission services to itself and that are not unduly discriminatory or preferential.

16 U.S.C. § 824j-1(b). Under the plain meaning of the statute, section 211A applies only when the Commission requires the provision of transmission service at comparable rates by rule or order. Nothing in this rate proceeding involves such an order by the Commission; hence, section 211A is inapplicable to this proceeding.

Notably, Iberdrola does not argue that BPA's transmission rates are inconsistent with the Commission's comparability standard. This is because BPA's Ancillary and Control Area Service rates clearly satisfy that standard, which generally requires that a transmission provider charge itself the same rates as it charges its customers. *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036, 31,761 (1996). This is demonstrated by the methodology used in BPA's balancing reserve capacity forecast and cost allocation methodology, which quantify the reserve needs for all uses of the system and assign cost to all uses, including load following for load served with Federal power. See Pulyeart *et al.*, BP-12-E-BPA-24; Klippstein *et al.*, BP-12-E-BPA-25. With regard to the VERBS rate, for example, BPA purchases wind output from a few wind generators and the cost of the VERBS rate is passed back to BPA through these long-term power purchase agreements.

In conclusion, sections 210 through 212(i) of the Federal Power Act do not govern the decisions in this rate proceeding. In any case, as discussed here and elsewhere in this ROD, the rate case record demonstrates that BPA's rates are comparable and not unduly discriminatory or preferential.

Decision

Federal Power Act sections 210, 211, 211A, and 212 do not govern Commission confirmation of BPA rates. Nevertheless, BPA's ancillary and control area service rates are not unduly discriminatory or preferential. Such rates are also comparable to the rates BPA charges itself.

3.2.3 Policy Pricing Issues

Staff's proposal for pricing is generally consistent with the FY 2010–2011 methodology. Staff does propose the inclusion of certain directly assigned costs for the VERBS rate and some modifications to the variable component of the rates to better capture the shift of water between super peak and graveyard periods. These specific issues are addressed in ROD section 3.4 on cost allocation methodology. A wide variety of pricing policy issues are addressed in this section.

Issue 3.2.3.1

Whether the VERBS rate should be discounted when BPA is unable to provide the full amount of reserves due to system constraints such as high water events.

Parties' Positions

MSR states that BPA should consider the extent to which it is charging VERBS customers for reserves that simply are not available on an operating basis, because BPA's high water discussion paper discloses that during certain conditions BPA does not have the reserves sufficient to meet its current commitment to VERBS customers. MSR Br., BP-12-B-MS-01, at 9. MSR argues that under the current proposal VERBS customers are charged for reserves that are not available on an operating basis and likely will not be available in the future during certain operating conditions. *Id.* at 10. MSR claims that VERBS customers are charged for a firm product, but they are receiving only an opportunity to use surplus reserves (after load and thermal needs) if and when they are available, and this is inappropriate. *Id.* MSR appreciates BPA's willingness to consider a credit for VERBS when reserves are simply unavailable and suggests that BPA should work with parties to understand the interaction between water availability and the availability of balancing reserves to support wind generation and system operations. MSR Br. Ex., BP-12-R-MS-01, at 6-7. MSR points out that the focus has been on extreme conditions without regard to the frequency of those conditions. *Id.* at 7.

PPC counters MSR's suggestion that VERBS customers should receive a discount for curtailments during future Environmental Redispatch events. PPC Br., BP-12-B-PP-01, at 9. PPC points out that MSR's proposal is not supported by substantial evidence in regard to the feasibility or amount of such a discount. *Id.* PPC points out that the record does demonstrate that the number and value of reserve reductions and curtailments cannot be forecast with accuracy, and a discount could lead to cost shifts in some years. *Id.*

BPA Staff's Position

Staff responds to MSR's proposal that VERBS customers should receive a credit or a discounted rate during high water events:

We do not agree that VERBS customers should receive a credit or reduced rate under the conditions mentioned in MSR's testimony. VERBS is an Ancillary and Control Area Service, and like other transmission services it is not always available due to reliability impacts. Transmission customers do not receive a credit when transmission is curtailed, and we do not believe a credit is appropriate for VERBS at this time. Lowering the VERBS rate due to the possibility of reductions from high water and high wind events would impose a cost shift risk to other customers, because in years that there is not a high water event BPA would be providing more balancing reserve capacity than we would have forecast in the rate proceeding.

Mainzer *et al.*, BP-12-E-BPA-42, at 38-39.

Staff distinguishes VERBS from a sale of capacity and explained that the balancing reserve capacity for VERBS is available for specific uses, given specific assumptions about the nature of that use and the ability of the FCRPS to provide that balancing reserve capacity. Mainzer *et al.*, BP-12-E-BPA-23, at 23. Staff also describes the potential for operational conditions that may lead to a reduction of the amount of balancing reserve capacity available to provide VERBS to VER customers:

The amount of balancing reserve capacity that BPA can supply from the FCRPS to provide VERBS and DERBS is limited by a number of factors. The FCRPS is a series of hydroelectric projects that share an interconnected fuel supply. BPA must manage that fuel supply to meet a number of non-power constraints, provide reliable load service to customers, supply other generation inputs for the BPA Balancing Authority Area that are required for system reliability, and honor generation restrictions due to transmission system limitations. These fundamental requirements define a base operation that can be modified where possible to provide available generating capacity that can be loaded for *incs* or unloaded for *decs*, while continuing to serve those other obligations.

Balancing reserve capacity capability is also defined by issues related to balancing reserve capacity deployment. Deployment must be consistent with safe and reliable project operations as defined by the U.S. Army Corps of Engineers and the U.S. Bureau of Reclamation, which own and operate the individual hydroelectric facilities. In addition, the operational uncertainty associated with deployment, when added to existing uncertainties, must not put BPA in the position of potentially violating non-power obligations or failing to meet firm load obligations. These amounts will vary based on water conditions, generation status, non-power requirements, and load patterns.

These factors combine to imply different overall limits to FCRPS balancing reserve capacity under different weather and seasonal conditions and constraints. On a planning basis, BPA offers an amount of balancing reserve capacity that is relatively certain to be available on an annualized basis. However, BPA must occasionally under some conditions limit the availability of balancing reserve capacity for short periods. Beyond the FCRPS balancing reserve capacity levels proposed in this Initial Proposal, BPA anticipates the need for non-FCRPS sources of balancing reserve capacity.

Id. at 25-26.

Evaluation of Positions

Staff makes several valid points regarding the nature of VERBS as a service that is subject to reductions for reliability purposes that result from relying on an interconnected hydro system to provide the balancing reserve capacity for the service. Mainzer *et al.*, BP-12-E-BPA-42, at 38-39; Mainzer *et al.*, BP-12-E-BPA-23, at 23-26. Also, PPC is correct that any reduction in the VERBS rate or credit to VERBS customers would mean the costs are borne by other customers, and on a prospective basis forecasting the amount of rate reduction or credit could be difficult. PPC Br., BP-12-B-PP-01, at 9. In addition, MSR overstates its case by contending that

VERBS customers are paying for firm service. MSR Br., BP-12-B-MS-01, at 10. As is described in more detail in the evaluation of Issue 3.2.3.9, if BPA were providing VERBS as a firm product, not subject to any limitation, it would cost more and less capacity could be provided from the FCRPS.

Notwithstanding Staff and PPC positions, it appears that MSR's proposal for some kind of a rate reduction or credit may have merit. In a normal water year there may be no reductions or only a few hours when hydro conditions or excessive usage of balancing reserve capacity could cause BPA to limit the amount of *inc* or *dec* reserve used to provide VERBS. In those years a VERBS credit mechanism would not appear to be rational. However, in years with extreme water conditions, such as the current extremely high water runoff season, BPA can be forced to reduce the amount of *inc* or *dec* reserves for an extended period of time to help reduce the hours that BPA must resort to Environmental Redispatch orders to mitigate total dissolved gas (TDG) problems. Administrator's Final Record of Decision on BPA's Interim Environmental Redispatch and Negative Pricing Policies (May 2011), available at BPA's Web site under Publications—Records of Decision—2011. Under these types of conditions, the idea of providing a credit to VERBS customers to reflect the limitations to the service may be justified.

Because there is currently nothing in BPA's rate schedules pertaining to a credit for VERBS customers, BPA cannot legally provide a credit to VERBS customers during the FY 2010–2011 rate period. PPC is correct that there is nothing in the record of this proceeding to support the details needed to decide on the structure or the merits of a VERBS credit. PPC Br., BP-12-B-PP-01, at 9. BPA will not adopt a VERBS rate reduction or credit in this proceeding, but BPA will commit to hold a technical workshop shortly after the close of this proceeding to discuss the issue of providing a credit to VERBS customers when *inc* or *dec* reserves are reduced due to extreme hydro system conditions. MSR is supportive of the idea of holding a workshop to work with parties to understand the interaction between water availability and the availability of balancing reserves to support wind generation and system operations. MSR Br. Ex., BP-12-R-MS-01, at 6-7. The potential outcomes of the technical workshop could be: (1) operational proposals for how *inc* and *dec* reserve amounts should be treated in the next high water event; (2) the beginning of a dialogue for proposals that could be made in the FY 2014–2015 rate proceeding, which could include inclusion of variable rate mechanisms that could make these credits less of an issue; or (3) depending on the issues raised by participants in the workshop, BPA may be open to initiating an expedited section 7(i) process limited in scope specifically to developing a VERBS rate credit mechanism that could be in place prior to the runoff season next spring.

Decision

VERBS is a service that is subject to reductions from time to time due to hydro system limitations. The record in this proceeding is not adequate to support the establishment of a credit for VERBS customers when reserves are reduced. BPA proposes to hold a technical workshop shortly after the close of this proceeding to discuss the possibility of establishing such a credit as a proposal in the next rate proceeding or possibly through an expedited section 7(i) process prior to the next rate proceeding.

Issue 3.2.3.2

Whether BPA should identify the forecast amount of reserves available from the FCRPS during Heavy Load Hour (HLH) and Light Load Hour (LLH) periods during different times of the year and then price wind balancing reserves based on whether reserves are scarce.

Parties' Positions

MSR suggests that BPA change the overall approach to pricing balancing reserve capacity used to provide Ancillary and Control Area Services. MSR Br., BP-12-B-MS-01, at 10-11. MSR proposes that rather than basing the reserve quantity forecast on the reserve need of load and generation, BPA should forecast the capability of the FCRPS for HLH and LLH in each month of the rate period and then price the balancing reserve capacity based on its availability. *Id.* MSR claims that this analysis needs to recognize system capability on an operating and NERC reliability basis, not a planning basis. *Id.* MSR claims that this approach will provide greater granularity, fewer lost secondary sales, a more efficient and reliable transmission system, and a more equitable pricing and provision of reserves to VERs customers. *Id.*

BPA Staff's Position

Staff's methodology starts with forecasting the reserve needs of load and generators based on an assumed level of service for VERs that is linked to triggering DSO 216. Pulyeart *et al.*, BP-12-E-BPA-24, at 2-5. This approach allows BPA to set aside a known amount of reserves that adjusts as more VERs interconnect to the system, which can be used for the purposes of planning and setting up the hydro operations. *Id.* Having a set amount of reserves allows BPA to employ DSO 216 when the reserves are exhausted. *Id.* at 3; Mainzer *et al.*, BP-12-E-BPA-42, at 25-26. This method also allows BPA to determine a unit price and assignment of costs for the various types of reserves, which is then used to establish the various Ancillary and Control Area Services rates. Mainzer *et al.*, BP-12-E-BPA-42, at 25.

Evaluation of Positions

MSR proposes to forecast the amount of balancing reserve capacity available from the FCRPS for each diurnal period on a monthly basis during the rate period. MSR Br., BP-12-B-MS-01, at 10-11. It appears that MSR is suggesting that BPA would then price the VERBS with a variable rate that depends on the amount of balancing reserve capacity that is available during any given period. MSR also suggests that BPA make all available system capacity available to VERBS in periods when system capability is robust. *Id.* at 10. MSR asserts that its proposed approach would provide greater granularity, fewer lost secondary sales, a more efficient and reliable transmission system, and a more equitable pricing and provision of reserves to VERs customers. *Id.* at 11.

MSR's proposal would require a completely different approach to pricing balancing reserve capacity. BPA, however, finds no basis in the rate case record to support MSR's proposal. MSR's claim of greater granularity is questionable, because the ability of the FCRPS to provide balancing reserves depends on water conditions, non-power constraints, and existing commitments. Forecasting the amount of balancing reserve capacity available during a given

timeframe more than two years in advance would be difficult and result in a highly uncertain level of accuracy. MSR's claim regarding fewer lost secondary sales is unsupported, because BPA's ability to make secondary sales is directly affected by the amount of balancing reserve capacity BPA must hold to provide VERBS. Klippstein *et al.*, BP-12-E-BPA-25, at 24-53. MSR's proposal is to not restrict the provision of reserves when system capability is robust; MSR would have BPA use its capability to provide balancing reserve capacity rather than make secondary sales. The basis for MSR's assertion that its proposal would provide a more efficient and reliable transmission system is unclear. It is also unclear in the context of this rate proceeding and forecasting the balancing reserve capacity for VERBS what is intended by MSR's distinction between analysis that recognizes system capability on an operating and NERC reliability basis rather than a planning basis. In addition to not being supported by the record, MSR's proposal lacks the detail and clarity necessary to fully evaluate it.

Decision

There is no basis in the rate case record to support an alternative to BPA's approach for quantifying and pricing balancing reserve capacity used to supply VERBS based on pricing forecast scarcity.

Issue 3.2.3.3

Whether BPA should allocate the incremental cost of procuring more balancing reserve capacity to only those new VER customers causing the need to purchase the additional capacity.

Parties' Positions

In testimony, MSR suggests that existing interconnected customers should receive their VERBS service from the FCRPS, and incremental costs associated with obtaining non-Federal balancing reserve capacity should be charged to new VERs that are causing these additional costs to be incurred. Arthur and Mayson, BP-12-E-MS-01, at 19-20. MSR argues that providing existing VERBS customers service from the FCRPS and assigning incremental costs to new wind developers follows cost causation principles, protects existing customers from higher costs, and would send a clear price signal to new wind developers that the Federal Base System (FBS) no longer has the ability to meet the balancing needs for new VERs. MSR Br. Ex., BP-12-R-MS-01, at 7. MSR urges BPA to commit to investigating this issue further and concludes that BPA has the highest VER penetration rate in the country and it serves no useful purpose to exceed the limits of feasible penetration to the detriment of all parties. *Id.*

JP01 (Cowlitz and EWEB) supports MSR's proposal, stating that spreading the incremental costs to all VERBS customers will fail to send a price signal to new wind developers and could contribute to over building wind resources for export out of the region. JP01 Br., BP-12-B-JP01-01, at 28-29. JP01 states that allocating the cost of incremental capacity to the projects that require BPA to obtain new capacity is consistent with BPA's treatment of transmission upgrades and BPA's Large Generator Interconnection Agreement (LGIA) policy, and sends the correct

price signal to new wind projects. *Id.* at 29. JP01 states that allocating such costs to all VERBS through the formula rates is only a second-best solution. *Id.*

SCE and NWG argue that BPA should reject MSR's proposal, because it fundamentally misinterprets the cost causation principle. SCE Br., BP-12-B-SC-01, at 8-9; NWG Br., BP-12-B-NG-01, at 56. SCE and NWG point out that BPA serves all users of balancing reserve capacity from the same pool, and MSR's proposal would be difficult to implement, require multiple classes of balancing services, and be inconsistent with BPA's actual use of balancing reserve capacity. *Id.*

BPA Staff's Position

In response to MSR's proposal, Staff states that its proposal to apply the VERBS rate equally to all wind projects as a class is consistent with cost causation, irrespective of whether such projects are incremental to existing wind facilities. Mainzer *et al.*, BP-12-E-BPA-42, at 33-34. However, Staff also agrees that pricing VERBS for incremental projects at marginal cost would be consistent with cost causation, although doing so would be at a more granular level than BPA established in its generation inputs rates policy. *Id.* at 33. Staff points out that BPA must balance pricing of its balancing reserve capacity with its objective of facilitating renewable resource development, and thus Staff's proposal is to have all VERBS customers pay the same rate as a class. *Id.* at 33-34.

Evaluation of Positions

Arguably MSR's proposal is consistent with the Commission's direction regarding balancing authorities acquiring additional balancing reserve capacity to serve newly interconnecting customers. *Preventing Undue Discrimination and Preference in Transmission Service*, 121 FERC ¶ 61,297, P 289-290 (2007) (Order 890-A). The Commission appeared to indicate that transmission providers should allocate the cost of incremental purchases to newly interconnecting customers. *Id.* However, this approach would be inconsistent with BPA's approach of providing Ancillary and Control Area Services on the same terms and conditions and price to all members of the class of customers taking a particular service.

SCE and NWG are correct that BPA provides balancing reserve capacity for all users from the same pool, because it is more efficient to serve all loads and resources from the same pool of balancing resources. SCE and NWG also make good points that MSR's proposal would be difficult to implement and require multiple classes of balancing services. SCE Br., BP-12-B-SC-01, at 8-9; NWG Br., BP-12-B-NG-01, at 56.

MSR disagrees with SCE and NWG's assertions that this approach would be difficult to implement, because MSR's proposed approach mirrors BPA's proposed VERBS Supplemental Service. MSR Br. Ex., BP-12-R-MS-01, at 7. MSR's comparison to VERBS Supplemental Service is overstated, because VERBS Supplemental Service will only provide a higher level of service and protection against some amount of DSO 216 curtailments at an incremental price for any VERBS customer that purchases the additional service. Kitchen *et al.*, BP-12-E-BPA-45, at 1-2. MSR's proposal would assign all incremental costs of balancing reserve capacity to new

VERBS customers for provision of the base VERBS. Arthur and Mayson, BP-12-E-MS-01, at 19-20; MSR Br. Ex., BP-12-R-MS-01, at 7.

Staff proposes to assign the cost of incremental balancing reserve capacity purchases to the VERBS customers as a class based on the rationale that the need to obtain additional reserves would not arise if it were not for the growth of wind generation interconnecting to the BPA system. Mainzer *et al.*, BP-12-E-BPA-42, at 33-34. JP01's and MSR's argument that MSR's proposal would send an accurate price signal to new wind developers and could mitigate the problem of overbuilding wind resources for export out of the region must be balanced against the objective of facilitating renewable resource development. The cost of incremental capacity purchases for *inc* reserves may be substantially higher than the cost of providing these reserves from the FCRPS. While MSR is correct that its proposed approach would protect existing customers from higher VERBS rates, a rate design that results in a significantly higher rate for new wind developers would discourage new development and would conflict with the objective of facilitating renewable resource development.

In addition, the rate design proposed by MSR would insinuate that the existing users of the VERBS somehow have a vested interest in that capacity. Since VERBS is a service and not a sale of capacity, wind generators currently taking the service do not have a vested interest in the underlying capacity. JP01's assertion that MSR's proposal would be consistent with BPA's treatment of transmission upgrades and Generator Interconnection policy is inaccurate and unpersuasive. Any direct assignments of costs under the LGIA policy are strictly for facilities that must be constructed solely to support the generator interconnection. While network upgrades may require up-front payments, those payments are credited back to the transmission customer and the costs of the upgrades are eventually rolled into transmission rates.

While MSR's proposal would send a significant price signal to new wind developers, it does not fit with BPA's past practices and could essentially discourage future wind development. Staff's proposal to allocate the costs of incremental capacity purchases to the VERBS rate as a class is sufficient to send a price signal that BPA is reaching the limits of the FCRPS's capability to meet the needs of a larger wind fleet and that the costs associated with wind integration are likely to increase.

MSR asserts that BPA has the highest VER penetration rate in the country and it serves no useful purpose to exceed the limits of feasible penetration to the detriment of all parties. MSR Br. Ex., BP-12-R-MS-01, at 7. BPA does have one of the highest penetration rates of VERs in the country when installed capacity of wind generation is compared to peak load in the balancing authority area. However, Staff anticipates that with the forecast amount of self-supply the FCRPS should be able to provide the balancing reserve capacity to meet the 99.5 percent level of service on a planning basis, and if additional capacity is needed BPA has the VERBS Formula rates in place to pass through the costs of purchasing additional balancing reserve capacity. Mainzer *et al.*, BP-12-E-BPA-23, at 26; Mainzer *et al.*, BP-12-E-BPA-42, at 30. There is no evidence in the record to suggest that there are not additional non-Federal resources in the region from which BPA can purchase additional balancing reserve capacity to support VERBS if the FCRPS is not adequate to meet the needs of VERBS customers during the FY 2012–2013 rate

period. BPA will need to evaluate this approach for the FY 2014–2015 rate process, but for purposes of setting rates in this proceeding, BPA will assign incremental balancing reserve capacity costs to VERBS customers as a class.

Decision

Based on the record of this rate case, BPA will not allocate the incremental cost of procuring more balancing reserve capacity to only those new VER customers causing the need for the additional capacity.

Issue 3.2.3.4

Whether BPA’s proposed rates for VERBS, DERBS, and Load Following are high compared to other regions of the country, and whether BPA should consider prices from organized markets in other parts of the country as a benchmark in this rate proceeding.

Parties’ Positions

NWG claims that one benchmark for evaluating the level of BPA’s rates for ancillary services is the price of comparable ancillary services from other regional markets. NWG Br., BP-12-B-NG-01, at 10. NWG’s testimony compares Staff’s proposed rates to the annual average prices for regulation, spinning reserve, non-spinning reserve and /or supplemental operating reserve from CAISO, ERCOT, NY ISO, and MISO. Kirby and Castille, BP-12-E-NG-02, Section 2; Kirby and Castille, BP-12-E-NG-02-AT01, at 1-2. NWG acknowledges that no two regional markets are identical but states there is still value in the comparison. NWG Br., BP-12-B-NG-01, at 10. NWG claims that the Following and Imbalance components of BPA’s proposed rates for VERBS, DERBS, and Load Following are high as compared to other regions of the country with established markets for capacity products. *Id.* at 10-12.

PPC disagrees with NWG’s assertions, stating that the products sold in these organized markets are materially different from the balancing reserve capacity BPA provides. PPC Br., BP-12-B-PP-01, at 8. PPC adds that since there is not an organized market for capacity products in the Northwest, BPA must use its current tools to price balancing reserve capacity products. *Id.* PPC also points out that the prices presented by NWG are only hourly costs of regulation, spinning, non-spinning, and supplemental reserves. These prices do not include export fees, which these markets charge to supply reserves to other balancing areas, and the critical need for capacity payments that are used to ensure that generating resources are constructed and available to supply hourly markets with reserves. PPC concludes that NWG’s price quotes are not comparable or relevant to BPA’s rates. *Id.* at 8-9.

BPA Staff’s Position

Staff explains that BPA operates in the Pacific Northwest, where there is not a centralized energy or capacity market similar to the markets operated by ERCOT, MISO, NYISO, CAISO, PJM, and ISO-NE, and BPA must price capacity products and services based on the current tools and markets available in the region. Mainzer *et al.*, BP-12-E-BPA-42, at 34.

Staff goes on to explain why NWG's comparison does not capture all the appropriate costs:

NWG looks at only the hourly costs for regulation, spinning reserve, non-spinning reserve, and supplemental operating reserve. Their testimony does not discuss the export fees these markets charge to supply reserves for schedules to other balancing areas, which is similar to many of the costs BPA must recover in the VERBS rate. NWG also does not consider the critical need for capacity payments to ensure that resources are constructed and available to supply the hourly markets for regulation, spinning reserve, non-spinning reserve, and supplemental operating reserve.

Id. at 34-35.

Evaluation of Positions

After acknowledging that no two regional markets are identical, NWG states that the price comparison provides a basis for determining whether BPA provides balancing services in an efficient manner at just and reasonable cost and offers an opportunity to learn from other regions and develop cost effective operations to minimize the costs of integration. NWG Br., BP-12-B-NG-01, at 10.

There is value in understanding how organized markets are providing and pricing balancing reserve capacity, but any comparison must provide all the relevant facts. As Staff and PPC explain, NWG does not quantify the cost of ancillary and control area service costs associated with exports or capacity payments to ensure resource construction that are used in these organized markets. Mainzer *et al.*, BP-12-E-BPA-42, at 34-35; PPC Br., BP-12-B-PP-01, at 8-9. The cost of Ancillary and Control Area Services for exports would be of particular interest, since a significant amount of the wind generation in BPA's balancing area is exported to other balancing areas in and out of the region. Mainzer *et al.*, BP-12-E-BPA-23, at 4.

Another aspect of NWG's analysis that is not apparent is whether significant amounts of wind generation are being exported from the organized markets that were analyzed. If there are not significant exports, is the load in these organized markets absorbing some of the costs associated with the variability of the resources? Staff's proposed VERBS rate is the same for wind generators whether they are exporting or sinking in the BPA balancing area, so in essence export fees are spread across all users of VERBS. It is not clear from the record how capacity payments work in the organized markets analyzed by NWG, but to some extent these payments may be comparable to BPA's embedded cost, which assign a share of BPA's system costs to the VERBS rate, since the balancing reserve capacity used for the service is provided from that portion of the FCRPS. Klippstein *et al.*, BP-12-E-BPA-25, at 3-16.

Without a capacity market in the Northwest, BPA must price capacity products based on the tools that are available for providing these services. Mainzer *et al.*, BP-12-E-BPA-42, at 34; PPC Br., BP-12-B-PP-01, at 8-9. It is not clear from NWG's analysis whether the generators that bid into these organized markets to establish the average prices NWG quotes are required to provide the balancing reserve capacity products on a continuous basis or whether these

generators move in and out of these markets based on economic and operational considerations. Staff's proposed VERBS rate is based on providing the balancing reserve capacity from the same resources on a continuous basis, with the only exception being certain system conditions that cause BPA to reduce the amount of balancing reserve capacity it is able to maintain.

During oral argument, in response to a question about comparing BPA prices with the organized market prices from generators that do not have a 24/7/365 obligation, NWG provides some clarification on this point, stating that:

one point to make is that all of those balancing authorities, they also have balancing obligations and that shows the costs they paid to procure that. The individual providers of ancillary services, an individual generator, may or may not have the obligation, but the balancing authority, California ISO, Midwest ISO, they have the same obligation that BPA has. I wouldn't agree that it's apples and oranges, but I think it's fair to say that it's maybe peaches and nectarines.

Hall, Oral Tr. at 213-214.

NWG supports its assertion that Staff's proposed VERBS rate is high by comparing the unit prices for the following and imbalance components of the rate to similar products in the organized markets. NWG Br., BP-12-B-NG-01, at 11. Interestingly, NWG's analysis also shows the annual average price for regulation in these organized markets. Kirby and Castille, BP-12-E-NG-02-AT01, at 1-2. In these organized markets, regulation service is significantly more costly than following and imbalance reserve. *Id.* VERBS is a combined service that includes regulation, following, and imbalance components. Mainzer *et al.*, BP-12-E-BPA-23, at 14. NWG does not provide analysis of what a combined service such as VERBS would cost in the organized markets. NWG does take issue with Staff's methodology for pricing the different components of the VERBS rate. NWG Br., BP-12-B-NG-01, at 12-14. This issue is addressed in Issue 3.4.2.2.

BPA is interested in understanding how balancing reserve capacity is provided and priced in organized markets, but regardless of whether NWG's pricing comparison of BPA's rates to organized markets is an apples to oranges or peaches to nectarines comparison, it does not include all relevant costs or considerations. In future rate proceedings, some of the tools available in organized markets may be available to BPA, and understanding how these products are made available and priced in other markets could become a relevant factor for BPA to consider in pricing the services it provides.

Decision

BPA's pricing of Ancillary and Control Area Services must be based on the tools that are available for providing these services. While interesting, comparisons to prices in organized markets provided in this proceeding are not based on the same factors and should not be used to benchmark BPA's rates.

Issue 3.2.3.5

Whether BPA collected excess revenues of approximately \$4 million from its Wind Balancing Service rate in FY 2010.

Parties' Positions

NWG states that under-collection of revenues has not historically been a problem with BPA's Wind Balancing Service rate, and then claims that during FY 2010, BPA collected excess revenues of approximately \$4 million from the Wind Balancing Service rate. NWG Br., BP-12-B-NG-01, at 28.

BPA Staff's Position

Staff explains that the \$4 million NWG referred to in testimony was not excess revenues or an over-recovery. Rather, it resulted from the fact that more wind generators interconnected to the BPA system during FY 2010 than BPA had forecast in the FY 2010–2011 rate proceeding. The amount of balancing reserve capacity that BPA provides for the Wind Balancing Service (VERBS under the current proposal) is determined by the amount of wind installed, so BPA provided more balancing reserve capacity to the wind generation fleet during FY 2010 than was forecast in the FY 2010–2011 rate proceeding and recovered revenues based on the amount of balancing reserve capacity it provided. Mainzer *et al.*, BP-12-E-BPA-42, at 37. Staff states that “BPA forecast in the 2010 rate proceeding that 2,515 MW of wind generation would be interconnected in June 2010, and the actual amount was 2,830 MW” and provides a graph that shows that prior to July 2010, the actual amount of wind interconnected was greater than the forecast, but that after July 2010, the forecast surpassed the actual amount of wind interconnected. *Id.* at 37, Attachment 3.

Evaluation of Positions

BPA's revenues from providing Wind Balancing Service during the FY 2010–2011 rate period are dependent on how soon new wind projects interconnect. The revenue forecasts in this rate proceeding are based on forecasting the timing of wind and solar project interconnections, but the art of forecasting will, by its nature, involve some level of imprecision. During the rate period, BPA will collect revenues based on the actual timing of the interconnection dates of wind and solar projects rather than the forecast date.

NWG mischaracterizes BPA's collection of \$4 million in revenues as an over-recovery under the Wind Balancing Service rate, NWG Br., BP-12-B-NG-01, at 28, when in actuality, BPA merely recovered its costs associated with providing a \$4 million equivalent amount of balancing reserve capacity for balancing services based on the actual balancing requirements of the wind fleet at the time. Since variable energy resources may come online faster than BPA's forecast interconnection date for those resources, BPA will provide balancing reserve capacity for VERBS faster than it forecast for those wind projects, up to the quantity of balancing reserve capacity established in the rate proceeding. However, if wind and solar projects come online later than expected, the corresponding amount of balancing reserve capacity for VERBS and associated revenues would come in below BPA's forecast, which has been the case since

August 2010. Mainzer *et al.*, BP-12-E-BPA-42, Attachment 3. Thus, there is no merit in NWG's assertion that BPA over-collected revenues from the Wind Balancing Service rate.

Decision

BPA did not over-collect \$4 million in revenues under the wind balancing service rate. BPA recovered its costs as a result of more wind generators interconnecting to the BPA system during FY 2010 than were forecast in the FY 2010–2011 rate proceeding, and BPA provided an associated amount of balancing reserve capacity to support the balancing service requirements of those wind generators.

Issue 3.2.3.6

Whether BPA should consider rate design methodologies that include a mechanism to recover costs associated with depressed market prices due to a surplus of regional generation or one that would pass through the cost of negative prices BPA incurs during over-generation events.

Parties' Positions

In response to JP02's testimony suggesting that BPA's rate proposal does not capture the effect of variable generation on market prices, Carr *et al.*, BP-12-E-JP02-01, at 21-23, NWG states that JP02 did not have a specific proposal, and the concept of redesigning "the VERBS rate to charge a financial penalty to wind generators because wholesale market prices are 'too low' not only is beyond the scope of this proceeding, but would also set a dangerous precedent." NWG Br., BP-12-B-NG-01, at 92-93. NWG surmises that JP02's suggestion that BPA take strong action with regard to negative pricing is referring to Environmental Redispatch. *Id.* at 93. NWG argues that decisions regarding BPA's Environmental Redispatch program are outside the scope of this proceeding. *Id.*

JP02 did not raise this issue in its brief.

WPAG recommends that BPA directly allocate to the VERBS rate the costs BPA incurs due to high wind/high water events. WPAG Br., BP-12-B-WG-01, at 11. In particular, WPAG advocates that the costs resulting from differential treatment of VERs so they can retain the economic benefits of Production Tax Credits (PTCs) and Renewable Energy Credits (RECs) should be allocated to the VERBS rate. *Id.* WPAG points out that BPA Staff declined to allocate these cost to the VERBS rate because BPA intends to handle such events through the proposed Environmental Redispatch protocol, and BPA did not plan to pay negative prices or otherwise compensate wind generators for the costs of curtailment of wind generation. *Id.* WPAG points out that the ER ROD expires on its own terms on March 30, 2012. WPAG Br. Ex., BP-12-R-WG-01, at 16.

WPAG is concerned that without the Environmental Redispatch protocol in place, BPA's preference customers will end up absorbing the cost associated with BPA paying negative prices to wind generators during high wind/high water events, which WPAG argues is contrary to cost

causation principles and section 7(g) of the Northwest Power Act direction that costs be equitably allocated. WPAG Br., BP-12-B-WG-01, at 12-13; WPAG Br. Ex., BP-12-R-WG-01, at 17. WPAG strongly recommends that BPA either (1) include a VERBS rate adjustment mechanism that will permit BPA to collect from customers receiving service under the rate the costs of over-generation events once those costs are known; or (2) include an acknowledgement in the Record of Decision that costs incurred by BPA to permit VERs to continue generating in order to receive the value of PTCs and RECs during over-generation events must be borne by VERs, and commit to a public process after the close of this proceeding to develop a mechanism for allocating such costs to the VERBS rate in the next rate period. WPAG Br., BP-12-B-WG-01, at 13.

WPAG claims that assuming that the potential costs associated with the Environmental Redispatch Policy do not need to be addressed as long as the Environmental Redispatch Policy is in place is erroneous, because under the Environmental Redispatch Policy, BPA displaces wind only after it has exhausted all practicable mitigating measures, and costs associated with this policy should be allocated to wind generators. WPAG Br. Ex., BP-12-R-WG-01, at 17. WPAG states that even if the Environmental Redispatch Policy is extended beyond March 30, 2012, allocation of these costs would be an issue in the next rate case. *Id.*

WPAG argues that in the event BPA decides not to renew or replace the Environmental Redispatch Policy, BPA should initiate an expedited section 7(i) process during the rate period to develop a mechanism to allocate over-generation costs, including the costs of paying negative market prices, to VERBS customers. *Id.* at 17-18.

BPA Staff's Position

Staff states that it agrees “with JP02 that to the extent that BPA’s VERBS rate does not recover the full cost of the service that preference customers bear the consequences.” Mainzer *et al.*, BP-12-E-BPA-42, at 38. Staff believes the proposed VERBS rate recovers the costs of integrating variable generation in the BPA balancing authority area. *Id.*

BPA’s intention with respect to high wind/high water events is to implement the Environmental Redispatch protocol. *Id.* at 39. “Under this protocol, after all reasonable actions to avoid excess spill during an over-generation event have been exhausted, BPA proposes to displace wind generation with free, zero-emission FCRPS generation as a last resort to comply with the Endangered Species Act and the Clean Water Act. *Id.* BPA does not plan to pay negative prices or otherwise compensate wind generators for their costs of curtailment.” *Id.* Therefore, Staff does not intend to address such costs through the VERBS rate. *Id.*

Evaluation of Positions

NWG states that the concept of including in the VERBS rate a penalty to wind generators because market prices are too low is outside the scope of this proceeding and would set dangerous precedent. NWG Br., BP-12-B-NG-01, at 92-93. This issue is not fully developed in the record in this proceeding. As it stands, the record does not include sufficient evidence to support applying a charge in the VERBS rate to account for low market prices. It is evident that

there is a significant amount of generation coming onto the system, which will likely affect market prices. However, many other factors may also impact market prices, and without further analysis, there is currently no basis to attribute low market prices to wind or include a charge in the VERBS rate to account for low market prices.

Furthermore, BPA agrees with NWG that the Environmental Redispatch policy is outside the scope of this BP-12 rate proceeding. As part of a separate process, BPA has elected to put the Environmental Redispatch policy in place until March 30, 2012, while it seeks to develop other solutions. Administrator's Final Record of Decision on BPA's Interim Environmental Redispatch and Negative Pricing Policies (May 2011), available at BPA's Web site under Publications—Records of Decision—2011, at 17. WPAG is correct that BPA has not made a decision on the Environmental Redispatch policy beyond the first six months of the upcoming rate period. WPAG Br. Ex., BP-12-R-WG-01, at 16.

WPAG recommends that BPA include either: (1) an adjustment mechanism for the VERBS rate to assign the costs of over-generation events to that rate, or (2) an acknowledgment in the Record of Decision for the BP-12 rate proceeding that costs incurred by BPA to permit variable energy resources to continue generating in order to receive the value of PTCs and REC's during over-generation events must be borne by VERs, and WPAG also asks that BPA commit to conducting a public process to design a mechanism to allocate the costs of over-generation to the VERBS rate for the following rate period. WPAG Br., BP-12-B-WG-01, at 13.

BPA has committed in the Environmental Redispatch ROD to develop an on-going regional forum to address over-generation issues. Administrator's Final Record of Decision on BPA's Interim Environmental Redispatch and Negative Pricing Policies (May 2011), at 80. Once it is determined whether or not the Environmental Redispatch policy will continue, BPA can address the treatment of the costs of over-generation events that BPA would face in the event an Environmental Redispatch policy is not in place. There will be time to address this issue in workshops prior to the next rate case.

WPAG claims that assuming that the potential costs associated Environmental Redispatch Policy do not need to be addressed as long as the Environmental Redispatch Policy is in place is erroneous, because under the Environmental Redispatch Policy, BPA only displaces wind after it has exhausted all practicable mitigating measures. WPAG Br. Ex., BP-12-R-WG-01, at 17. WPAG argues that all practical mitigating measures includes reducing generation at CGS, offering to sell power at a price of zero, deferring maintenance activities, and operating hydro projects inefficiently. *Id.* WPAG asserts that since the costs associated with these measures is not allocated to any other rate, power customers are paying these costs, and WPAG argues that to the extent such costs are incurred to ensure that wind generators are the last resource on the system, recovering PTCs and REC's, those costs should be allocated to the wind generators. *Id.* WPAG states that even if the Environmental Redispatch Policy is extended beyond March 30, 2012, allocation of these costs would be an issue in the next rate case. *Id.*

While WPAG may be correct that the costs associated with measures BPA takes to mitigate the amount of Environmental Redispatch it is forced to implement during a high water event may be

an issue in the next rate proceeding, there is nothing in the record to quantify or support the inclusion of such costs in the VERBS rate for the FY 2012–2013 rate period. WPAG asserts that BPA’s assumption that the potential costs associated Environmental Redispatch Policy do not need to be addressed as long as the Environmental Redispatch Policy is in place is erroneous. *Id.* WPAG’s assertion is speculative and not supported by evidence. The mitigating measures described by WPAG include reducing generation at CGS, offering to sell power at a price of zero, deferring maintenance activities, and operating hydro projects inefficiently. These measures are taken during an extreme high water event to mitigate over-generation and to protect endangered species, not to preserve wind generators’ PTCs and RECs. *See Administrator’s Final Record of Decision on BPA’s Interim Environmental Redispatch and Negative Pricing Policies (May 2011).* These things are done prior to ordering thermal generators and wind generators to shut down and serving those generators’ loads with FCRPS power, but that does not necessarily mean, and there is no record evidence in this proceeding to indicate, that costs associated with these measures could have been avoided during the high water event.

WPAG argues that in the event BPA decides not to renew or replace the Environmental Redispatch Policy, BPA should initiate an expedited section 7(i) process during the rate period to develop a mechanism to allocate over-generation costs, including the costs of paying negative market prices, to VERBS customers. WPAG Br. Ex., BP-12-R-WG-01, at 17-18. WPAG suggests that BPA could conduct the expedited 7(i) at the same time as the process discussed in Issue 3.2.3.1 for developing a VERBS credit mechanism to reflect reductions in the level of reserves during high water events. *Id.* at 18.

BPA has not yet attempted to identify specific costs that BPA would incur if an Environmental Redispatch policy is not in place after March 2012, and the outcome of the current Environmental Redispatch complaint pending before the Commission and the ongoing regional discussion are unknown. Thus, it is premature to commit to an expedited 7(i) process.

Decision

The rate case record does not support a mechanism to recover costs arising from depressed market prices or from over-generation events related to high water conditions. With the Environmental Redispatch Policy there are too many unknowns at this time to commit to an additional 7(i) process. Depending on the outcome of the current complaint pending before the Commission and the ongoing regional discussion, BPA may choose to have an expedited 7(i) process to determine the appropriateness of assigning costs associated with high water events.

Issue 3.2.3.7

Whether provision of balancing reserve capacity from a regional imbalance market would be a better solution for meeting the balancing reserve capacity needs of the VERs in the Pacific Northwest, and whether BPA should pursue such a regional solution as an alternative to the current VERBS service.

Parties' Positions

Iberdrola states that before discussing the allocation of costs associated with purchases of incremental balancing capacity, the fundamental issue of how BPA acquires incremental balancing reserve capacity must be addressed. Iberdrola Br., BP-12-B-IR-01, at 32. Iberdrola states that it does not believe that it is efficient or cost-effective for BPA to procure incremental balancing reserve capacity under the current market structure, in which few incremental balancing reserve capacity acquisitions options exist given the absence of a market in the Northwest. *Id.* Iberdrola is concerned that BPA will over-procure and overpay for incremental balancing reserve capacity, but there are multiple initiatives underway that may provide BPA with access to flexible generation at a much lower cost. *Id.* at 32-33. Iberdrola describes the Energy Imbalance Market (EIM) as a regional economic dispatch tool that supplies imbalance energy using the lowest cost generation in the market and explains that EIM could be in place in two to four years in the West. *Id.* at 33-34. Iberdrola also acknowledged that numerous attempts to create an organized market in the West have failed, but Iberdrola claims that EIM has several important differences from an organized market, and EIM would be an extremely beneficial improvement over the current situation. *Id.* Iberdrola states that BPA's active support and participation in an EIM initiative is critical. *Id.* at 34.

BPA Staff's Position

Staff does not address the issue of procuring incremental balancing reserves from an EIM type market. Staff does describe BPA's current third-party supply program for procuring incremental balancing reserve capacity:

In 2008, BPA proposed an additional WIT pilot program to test the availability and effectiveness of non-Federal sources of generation inputs to provide balancing services for variable energy resources. Based on customer feedback regarding the WIT's priorities, however, BPA decided to temporarily defer implementation of this pilot program. After making significant progress on the other initiatives, BPA decided to implement a pilot program for third-party supply of *dec* balancing reserve capacity. Under this pilot program, BPA purchased 75 MW of *dec* balancing reserve capacity for September through November 2010 from a Calpine Corporation natural gas-fired generator located in BPA's Balancing Authority Area.

Mainzer *et al.*, BP-12-E-BPA-23, at 7-8.

Staff explains that it is also proposing a *Dec* Acquisition Pilot Project:

BPA is proposing to develop a pilot project for FY 2012–2013 that provides for the acquisition of *dec* balancing reserve capacity to replace the provision of *dec* balancing reserve capacity from the FCRPS. BPA has completed one contract during FY 2010 under which BPA purchased *dec* balancing reserve capacity from a non-Federal resource. Although BPA is still evaluating the impacts of this

contract, Staff believes that it provides the foundation for expanding those purchases during the FY 2012–2013 rate period.

Id. at 48.

In addition, Staff proposes VERBS Supplemental Service that would allow individual wind generators to either provide an additional on-demand capacity product to cover extreme wind tail events or to request that BPA procure this type of capacity product on their behalf. Kitchen *et al.*, BP-12-E-BPA-45.

Evaluation of Positions

BPA has been participating in the investigation of establishing an EIM-type market in the West. However, Iberdrola acknowledges that an EIM type market for the Northwest is two to four years away from coming into existence. Iberdrola Br., BP-12-B-IR-01, at 34. Iberdrola also acknowledges that numerous attempts to create an organized market in the West have failed. *Id.* at 33.

During the FY 2012–2013 rate period, if BPA has to procure incremental balancing reserve capacity to support the growing wind fleet, BPA will have to find the most cost-effective means of procuring incremental balancing reserve capacity from the current bilateral marketplace. BPA’s third-party supply team, the proposed *Dec* Acquisition Pilot Project, and VERBS Supplemental Service should provide ample opportunity to develop BPA’s systems and technical knowledge needed to add incremental balancing reserve capacity to the system. BPA has been engaged in the regional EIM scoping process and plans to continue to participate in these efforts.

Decision

BPA will continue to participate in regional efforts to establish an EIM type of market in the West. For the FY 2012–2013 rate period, however, such market tools are not forecast to be available.

Issue 3.2.3.8

Whether BPA should declare a “moratorium on rates” and adopt no rate change for the wind balancing rate.

Parties’ Positions

MSR recommends that BPA declare a moratorium on rates, allowing a zero rate increase for wind integration services. MSR Br., BP-12-B-MS-01, at 4. MSR reasons that a zero rate increase is consistent with the treatment of other transmission and ancillary service rates, and with the increase of new wind being integrated on BPA’s system, this still represents a significant revenue stream. *Id.*

BPA Staff's Position

Staff provides a comprehensive record to support the Ancillary and Control Area Services rates based on the principle of cost causation. Mainzer *et al.*, BP-12-E-BPA-23, at 21.

Evaluation of Positions

MSR broadly states the need for more granularity in BPA's rate methodology and operations and takes issue with some aspects of BPA's reserve forecast study and cost allocation methodology. MSR Br., BP-12-B-MS-01, at 4-5, 8-9. Thus, MSR states that BPA should "declare a moratorium on rates" and adopt a zero percent increase for all Ancillary and Control Area Services rates, which, according to MSR, would be consistent with BPA's treatment of other transmission rates. *Id.* at 4.

BPA finds no basis in the rate case record to support MSR's proposal. MSR is correct that BPA is adopting a zero percent rate increase for transmission rates and the two required ancillary services based on the settlement of the transmission portion of this proceeding. *See* section 4.1 of this ROD. However, those rates do not recover the costs associated with balancing reserve capacity for balancing services, and therefore, involve a different, and arguably, less complicated, set of issues.

For Ancillary and Control Area Services, Staff provides a detailed study of the amount of balancing reserve capacity needed for each Ancillary and Control Area Service, and assigns costs to those rates based on a cost allocation methodology that includes an embedded cost methodology that accounts for all capacity uses of the FCRPS and a variable cost methodology based on the operational effects BPA incurs from providing balancing reserve capacity for Ancillary and Control Area Services. Generation Inputs Study, BP-12-FS-BPA-05; Pulyeart *et al.*, BP-12-E-BPA-24; Pulyeart *et al.*, BP-12-E-BPA-43; Klippstein *et al.*, BP-12-E-BPA-25; Klippstein *et al.*, BP-12-E-BPA-44; Chen *et al.*, BP-12-E-BPA-26. MSR's proposal would require BPA to ignore the substantial evidence in the rate case record and forgo its recovery of costs associated with providing ancillary and control area services from the users that created those costs. That approach, however, could also result in a shift of costs associated with Ancillary and Control Area Services to BPA's power rates. MSR provides no evidence to support such an inequitable allocation of costs. As Staff explains:

The principle of cost causation is important for fair and non-discriminatory power and transmission rates because, by aligning costs and benefits, it is possible to prevent cost shifts between different customers, send clear price signals for the value of different products, support the equitable allocation of risk, and alleviate concerns that could otherwise limit long-term resource development.

Mainzer *et al.*, BP-12-E-BPA-23, at 21.

It appears that MSR's rate moratorium proposal is designed to reduce the costs associated specifically with the VERBS rate. The irony of MSR's proposal is that a rate moratorium would actually result in a higher VERBS rate. The VERBS rate increase proposed by Staff in the Initial Proposal was only a \$.03 rate increase over the existing Wind Balancing Service rate. *See*

Generation Inputs Study, BP-12-E-BPA-05, Table 5. However, several inputs to the VERBS rate have changed since the Initial Proposal, and the Final Proposal is that the VERBS rate is lower than the current Wind Balancing Service rate of \$1.29 per kilowatt per month.

Decision

The rate case record does not support a zero percent increase for the VERBS rates.

Issue 3.2.3.9

Whether VERBS constitutes a purchase of firm balancing reserve capacity from the FCRPS.

Parties' Positions

In the context of arguing that customers should not be charged for VERBS when reserve levels are reduced due to system conditions, MSR asserts that under Staff's proposal VERBS customers are being charged for a firm product and getting at best, an opportunity to use surplus reserves (after load and thermal needs) if and when they are available. MSR Br., BP-12-B-MS-01, at 10. MSR goes on to state that as VERBS is currently envisioned, VERBS customers pay the full price to purchase reserves and then are prevented from using them, and that charging VERBS customers for a product that they cannot receive is inappropriate. *Id.*

MSR argues that all costs should not be assigned solely to VERBS customers when thermal generators and loads are also using balancing reserves. MSR Br. Ex., BP-12-R-MS-01, at 7. MSR concludes that there is nothing in the record to support assessing VERBS for all or substantially all of these costs unless VERBS receives a first call on the balancing reserves they have paid for. *Id.* at 8.

BPA Staff's Position

Staff explains that VERBS and DERBS are not a purchase of firm capacity from the FCRPS. Mainzer *et al.*, BP-12-E-BPA-23, at 23. Staff goes on to explain:

They are not comparable to purchase of a put or call option. VERBS and DERBS are services in which BPA commits to making a specific amount of balancing reserve capacity available for specific uses, given specific assumptions about the nature of that use and the ability of the FCRPS to provide that balancing reserve capacity. These amounts are calculated assuming multiple uses of a pool of balancing reserve capacity. The diversity of the multiple uses lowers the total amount of balancing reserve capacity BPA needs to make available based on each individual use and lowers the cost for all users.

Id. at 23-24.

Staff explains that:

Specifically, VERBS is designed to provide an amount of flexibility to cover unavoidable schedule errors associated with the short-term unpredictability of variable energy resource output. VERBS is a Control Area Service, and like other transmission services there are times when the service may be limited or may not be available. For wind resources, VERBS provides an amount of flexibility assuming that schedule errors (the difference between the scheduled amount and actual generation) are generally consistent with the use that would occur with 30-minute persistence-based hourly scheduling.

Id. at 24.

Staff also explains why the distinction between a service and a firm capacity commitment is important:

The key distinction is that VERBS and DERBS are for limited use and are not general put and call options. The increased risks associated with the additional uncertainty and potential for energy accumulation associated with a put or call would reduce the capability of the FCRPS to provide balancing reserve capacity and increase the frequency of balancing reserve capacity reductions. If these services are used for purposes other than to balance unavoidable schedule errors, it would become difficult to determine the quantity of service required. BPA would have to plan operations to allow for full deployment of *incs* or *decs* at any time, for long periods of time, and would have to assume that market-driven motivations would lead to increased correlation in use of the service. Currently, BPA plans operations based on an expected distribution of deployments associated with unpredictable schedule errors, which are expected to be random, unbiased, and net to zero over relatively short periods of time. Under a set of planning parameters that offered a firm capacity commitment, the FCRPS would have much less available capacity, and the amounts of balancing reserve capacity needed for any individual use would need to be increased.

Id. at 24-25.

Staff describes the limitations on BPA's ability to supply balancing reserve capacity to support VERBS:

The amount of balancing reserve capacity that BPA can supply from the FCRPS to provide VERBS and DERBS is limited by a number of factors. The FCRPS is a series of hydroelectric projects that share an interconnected fuel supply. BPA must manage that fuel supply to meet a number of non-power constraints, provide reliable load service to customers, supply other generation inputs for the BPA Balancing Authority Area that are required for system reliability, and honor generation restrictions due to transmission system limitations. These fundamental requirements define a base operation that can be modified where possible to provide available generating capacity that can be loaded for *incs* or unloaded for *decs*, while continuing to serve those other obligations.

Balancing reserve capacity capability is also defined by issues related to balancing reserve capacity deployment. Deployment must be consistent with safe and reliable project operations as defined by the U.S. Army Corps of Engineers and the U.S. Bureau of Reclamation, which own and operate the individual hydroelectric facilities. In addition, the operational uncertainty associated with deployment, when added to existing uncertainties, must not put BPA in the position of potentially violating non-power obligations or failing to meet firm load obligations. These amounts will vary based on water conditions, generation status, non-power requirements, and load patterns.

These factors combine to imply different overall limits to FCRPS balancing reserve capacity under different weather and seasonal conditions and constraints. On a planning basis, BPA offers an amount of balancing reserve capacity that is relatively certain to be available on an annualized basis. However, BPA must occasionally under some conditions limit the availability of balancing reserve capacity for short periods. Beyond the FCRPS balancing reserve capacity levels proposed in this Initial Proposal, BPA anticipates the need for non-FCRPS sources of balancing reserve capacity.

Id. at 25-26.

Staff also explains that the amount of balancing reserve capacity BPA uses to determine the DSO 216 limitations on service is based on the forecast determined in the rate proceeding to ensure that BPA's deployment of balancing reserve capacity does not exceed the planned amount of service. *Id.* at 6, 31. In addition, Staff describes conditions that might cause BPA to reduce the trigger level for DSO 216:

BPA may reduce the trigger level for DSO 216 in response to unplanned risk of violating non-power constraints, to ensure that it can provide reliable load service to customers, to ensure it can supply other generation inputs for the BPA Balancing Authority Area that are required for system reliability, to respond to generation restrictions due to transmission system limitations or other transmission requirements, or to limit excessive energy accumulations or withdrawals. BPA plans transmission system and hydro system operations to avoid and manage these risks, but there can be occasions where operations encounters unforeseen circumstances and BPA must be able to limit the amount of balancing reserve capacity in these situations.

Id. at 31-32.

Evaluation of Positions

MSR's primary argument is that VERBS customers should not pay for VERBS service when the full amounts of forecast *incs* and *decs* are not available. MSR Br., BP-12-B-MS-01, at 10. This issue is addressed in Issue 3.2.3.1. In the course of asserting this argument, MSR claims that VERBS should be a firm product, but that the possibility of a reduction in the reserve levels due to hydro system conditions and the fact that wind generators are subject to DSO 216 makes VERBS comparable to an opportunity to use surplus reserves. *Id.*

Staff explains in detail that VERBS is a service rather than a firm sale of capacity. Mainzer *et al.*, BP-12-E-BPA-23, at 23-26. Because the balancing reserve capacity BPA uses to provide VERBS is produced by the FCRPS, there will occasionally be operating constraints that force BPA to limit the amount of balancing reserve capacity that is maintained for VERBS below the level that was forecast in the rate proceeding. *Id.* at 25-26. The FCRPS must be operated to meet multiple obligations, including load service, reliability support for the FCRTS, and other non-power obligations. If BPA did not reserve the right to occasionally limit the amount of balancing reserve capacity it is providing, the amount of balancing reserve capacity BPA could commit to providing from the FCRPS would be reduced significantly. *Id.* at 25.

Even with this limitation, MSR's description of VERBS service as being provided from surplus reserves is a mischaracterization. The potential limitations described by Staff are relatively rare other than under high water conditions, and most hours the full amount of *inc* and *dec* reserves are available for VERBS and the other ACS capacity-based services. For example, in FY 2010 the amount of balancing reserve capacity that BPA was maintaining for these services was reduced on less than .05 percent of the 8760 hours of the year. *See* Columbia River High-Water Operations, June 1-14, 2010, at 9 (Sept. 2010), available at BPA's Web site under Publications—Columbia River high-water operations June 1-14, 2010—Final Report. During these limitation events, wind generators are only impacted by the lower level of reserves if the use of reserves exceeds the set amount of reserves, triggering a DSO 216 event, and the individual generator's actual generation is off its schedule in the same direction as the DSO 216 event far enough to receive a curtailment or generation reduction order.

VERBS is a service, and the amount that BPA can provide is based on assumptions about how that service will be used. That is, VERBS is designed to provide an amount of flexibility to cover unavoidable schedule errors associated with the short-term unpredictability of VER output that is not based on market-driven motivations. These same assumptions underlie the pricing methodology used to set the VERBS rate. Thus, contrary to MSR's assertion that VERBS customers are being charged for a firm product, VERBS is priced as a service that is intended to be used for a limited purpose.

MSR also appears to assert that since wind generators are subject to DSO 216, VERBS is a lower quality of service that should not be charged for the full cost of balancing reserve capacity. The use of DSO 216 is addressed in Issue 3.2.4.2. In the context of MSR's argument regarding VERBS as a firm product, Staff explains that the VERBS balancing reserve capacity is calculated assuming multiple uses of a pool capacity and the diversity of the multiple uses lowers the total amount of balancing reserve capacity BPA needs to make available based on each individual use and lowers the cost for all users. Mainzer *et al.*, BP-12-E-BPA-23, at 23-24. VERBS customers are one of the beneficiaries of this diversity, but it is only the wind generators that are subject to DSO 216 when reserve limits are reached. The logic behind applying DSO 216 only to wind generators is that it is wind generators that are causing the deployment of the majority of the balancing reserve capacity that may lead to a DSO 216 event. Significant scheduling error associated with wind ramps should not lead to curtailment of loads or thermal

generators that generally are contributing only a small amount to the use of balancing reserve capacity.

MSR argues that all costs should not be assigned solely to VERBS customers when thermal generators and loads are also using balancing reserves. MSR Br. Ex., BP-12-R-MS-01, at 7. MSR claims that because thermal generators and loads often call on the balancing reserve leaving no reserves available to wind and resulting in increased DSO 216 events, wind pays the cost for everyone and gets nothing. *Id.* at 7-8. MSR concludes that there is nothing in the record to support assessing VERBS for all or substantially all of these costs unless VERBS receives a first call on the balancing reserves they have paid for. *Id.* at 8.

MSR's assertion that all balancing reserve capacity costs are assigned solely to VERBS customers is mistaken. Thermal generators are charged for the balancing reserve capacity they use under the DERBS rate, and loads are allocated a share of balancing reserve capacity costs for Load Following through both the embedded cost and variable cost methodologies. Documentation, BP-12-FS-BPA-05A, Table 3.6, lines 4 and 6, and Table 3.12, lines 4 and 5.

MSR's claim that thermal generators and loads often call on the balancing reserves, leaving no reserves available to wind and increasing DSO 216 events, is not supported by the record. All balancing reserve capacity is pooled to lower costs to all users. Wind generators, thermal generators, and loads all use the amount of balancing reserve capacity set aside on a planning basis. Mainzer *et al.*, BP-12-E-BPA-23, at 19. Because of the pooling of reserves and the fact that BPA's AGC system responds to the net signal of all uses of balancing reserve capacity, wind generators benefit when thermal generators or load is deviating less than the amount that is held for thermal generators and load or if these non-wind generator uses are deviating in the opposite direction from the deviation of the wind fleet. Generation Inputs Study, BP-12-FS-BPA-05, at 4-5. Wind generation uses significantly more balancing reserve capacity than thermal generators and load; thus MSR's claim that thermal generators and loads often leave no reserves available for wind generators is a misstatement of the facts. The record does not support MSR's conclusion that VERBS is assessed substantially all of the costs of balancing reserve capacity or that VERBS customers should get the first call on balancing reserves they have paid for.

The distinction between VERBS as the firm product MSR describes and VERBS as a service is important to understanding how VERBS is intended to be used, how VERBS is priced, and how VERBS customers are treated with respect to DSO 216.

Decision

VERBS is not a purchase of firm capacity from the FCRPS, but rather a service provided to maintain the balance between scheduled and actual generation. VERBS is a service, and as such is subject to reductions to account for system conditions.

3.2.4 Policy Operations Issues

BPA policy regarding operations associated with providing balancing reserve capacity to support the growing wind fleet was a major issue addressed in the parties' briefs. Most of the issues involve BPA's reliance on DSO 216 to limit the amount of reserves that are provided. Some parties are very concerned about the effect this policy is having on wind generation in the market. Many of the operational issues are outside the scope of the rate proceeding, but there is an interrelationship between these operational issues and the level of VERBS service BPA assumes in the rate proceeding.

Issue 3.2.4.1

Whether BPA should take on additional balancing reserve obligations if there are times during certain operating conditions when BPA cannot provide the forecast amount of balancing reserve capacity.

Parties' Positions

MSR states that BPA should not take on additional reliability obligations until it can meet the current obligations. MSR Br., BP-12-B-MS-01, at 9-10. MSR references BPA's High Water discussion paper as evidence that under certain conditions BPA does not have sufficient reserves to meet its current commitment to VERs customers. *Id.*

MSR argues that it is critically important to understand and examine limitations in system capability and transmission availability to integrate both current and potentially future wind development, and destroying existing projects to facilitate new development is not good policy. MSR Br. Ex., BP-12-R-MS-01, at 5. MSR states that it is important to examine whether wind balancing reserves can realistically be acquired from third parties, because if they are not available, commitments will have been made that cannot be met. *Id.* MSR reiterates its arguments regarding assigning additional costs to new market entrants. *Id.* at 6.

BPA Staff's Position

The issue of limiting VER interconnections is beyond the scope of the rate proceeding, and thus BPA Staff does not provide testimony on it. However, Staff explains that VERBS is a service that is provided from the FCRPS and is subject to the limitations imposed by certain system conditions. Mainzer *et al.*, BP-12-E-BPA-23, at 31-32. Staff infers that based on the current forecast of wind integration, the ability of the FCRPS to provide balancing reserve capacity will be reaching its limit by the end of the FY 2012–2013 rate period. *Id.* at 26; Mainzer *et al.*, BP-12-E-BPA-42, at 17. Staff's proposal includes two formula rate mechanisms that can be used to roll the cost of non-Federal balancing reserve capacity into the VERBS rate if BPA has to make incremental purchases during the rate period to provide balancing services. Jackson *et al.*, BP-12-E-BPA-29, at 38-40.

Evaluation of Positions

MSR argues that “BPA should consider the extent to which it is charging VERBS customers for reserves that simply are not available on an operating basis.” MSR Br., BP-12-B-MS-01, at 9. MSR appears to be seeking a balancing service that is comparable to a firm capacity product or a put and call option. VERBS is a service in which BPA commits to making a specific amount of balancing reserve capacity available, to the extent feasible given other constraints, for specific uses. Mainzer *et al.*, BP-12-E-BPA-23, at 23, 31-32. The amount of balancing reserve capacity to be made available for VERBS is calculated assuming multiple uses of a pool of balancing reserve capacity. *Id.*

Normally, the agreed-upon amount of FCRPS balancing reserve capacity is available. However, there are times when VERBS may be limited or may not be available. *Id.* at 24. MSR is correct that operating conditions will affect the amount of balancing reserve capacity available under different weather and seasonal conditions and constraints. These conditions and constraints will result in a need to occasionally limit the availability of balancing service for short periods. *Id.* at 25-26. Even under limitations, BPA will be able to continue to meet its reliability obligations. If BPA were to provide balancing service as a firm capacity commitment, greater amounts of capacity would be required and the cost of the service would increase significantly to ensure VERBS availability at all times. *Id.* at 23-26. Offering a balancing service (rather than a firm capacity commitment) allows BPA to integrate a larger number of wind plants using only currently available FCRPS balancing reserve capacity without purchasing non-Federal balancing reserve capacity.

MSR counters that it is critically important to understand and examine limitations in system capability and transmission availability to integrate both current and potential future wind development, and destroying existing projects to facilitate new development is not good policy. MSR Br. Ex., BP-12-R-MS-01, at 5. Staff has forecast that balancing reserve capacity from the FCRPS should be sufficient to provide VERBS at the 99.5 percent level of service, discussed in Issue 3.2.4.4, during the FY 2012–2013 rate period. Mainzer *et al.*, BP-12-E-BPA-23, at 26-27. The availability of transmission is not a rate issue and is handled through BPA’s OATT queue and Available Transfer Capability (ATC) process. MSR’s assertion that BPA’s policy is destroying existing projects to facilitate new development is not supported by the record and is simply not true. Requiring existing wind generators to pay for the balancing reserve capacity that they use and exposing them to occasional curtailments under DSO 216 if the generators are significantly deviating from schedule has not destroyed any existing projects in the FY 2010–2011 rate period, and BPA’s VERBS rate and DSO 216 policy are not changing significantly for the FY 2012–2013 rate period. If anything, the availability of intra-hour scheduling, VERBS Supplemental Service (discussed in ROD section 3.2.10), and Committed Intra-Hour Pilot (discussed in ROD section 3.2.9) will provide more flexibility to all wind generators during the FY 2012–2013 rate period to manage their usage of balancing reserve capacity and control their exposure to operational limitation.

BPA will acquire non-Federal reserves when such acquisitions become necessary to provide VERBS; BPA currently anticipates it will need to do so for the FY 2014–2015 rate period. MSR states that it is important to examine whether wind balancing reserves can realistically be

acquired from third parties, because if they are not available, commitments will have been made that cannot be met. MSR Br. Ex., BP-12-R-MS-01, at 5. BPA shares MSR's concern regarding the availability of balancing reserve capacity from third parties. VERBS will be provided primarily from the FCRPS during the FY 2012–2013 rate period, but BPA will be building on the experience it gained integrating dec reserves from a non-Federal resource during the FY 2010–2011 rate period by expanding the Dec Acquisition Pilot and purchasing inc reserves through the VERBS Supplemental Service. See Klippstein *et al.*, BP-12-E-BPA-25, at 19-20; Kitchen *et al.*, BP-12-E-BPA-45. Through these initiatives BPA will develop the technical expertise needed to integrate balancing reserve capacity from third parties and will gain an understanding of what is available in the market prior to the FY 2014–2015 rate period, when BPA may need to rely on balancing reserve capacity from third parties more broadly.

Purchasing incremental balancing reserve capacity to back up the FCRPS during the few times that non-power constraints might cause BPA to reduce the amount of balancing reserve capacity it holds for providing VERBS could add significant costs to the VERBS rate. However, BPA recognizes that it may need to acquire non-Federal balancing reserve capacity for use during the rate period and would use the VERBS Formula Rates to pass through the cost of such reserves. Mainzer *et al.*, BP-12-E-BPA-23, at 27-28. BPA does not plan to incur costs to acquire reserves until it is necessary to do so.

MSR claims that adding additional wind will further tax the FBS, require additional investment by BPA, and may impede BPA's ability to meet its statutory obligations to serve load. MSR Br. Ex., BP-12-R-MS-01, at 6. As discussed above, Staff is confident that the FCRPS can provide VERBS at the 99.5 percent level of service on a planning basis for the existing wind projects and the new wind generation that is forecast to interconnect during the FY 2012–2013 rate period. Mainzer *et al.*, BP-12-E-BPA-23, at 26-27. BPA is making additional investments to expand its ability to integrate VERs and this is consistent with the national policy to encourage the development of VERs. See Issue 3.2.2.2. Finally, BPA has developed reliability tools such as DSO 216 and rate mechanisms such as the VERBS formula rates to ensure that integrating additional wind does not impede BPA's ability to meet its statutory obligations to serve load.

MSR states that the real question is what BPA can do now to support the integration of wind at a reasonable cost and under reasonable operating conditions without jeopardizing the existing wind projects and customers. MSR Br. Ex., BP-12-R-MS-01, at 6. BPA believes that the decisions it has made in this rate proceeding support integration of wind at reasonable cost and under reasonable operating conditions, and none of these decisions will jeopardize existing wind projects or customers. The rate for VERBS is decreasing as compared to the Wind Balancing Service rate for FY 2010–2011. Through intra-hour scheduling, VERBS Supplemental Service, and the Committed Intra-Hour Pilot BPA is offering wind generators more options and flexibility, and there is no evidence in the record to suggest existing wind generators are jeopardized.

MSR argues that socializing costs across all wind customers, both old and new, provides incentive to new entrants to overbuild at the expense of existing projects and could lead to stranded costs. *Id.* The issue of socializing costs across all wind customers is addressed in detail

in Issue 3.2.3.3. There is no evidence in the record to support MSR's assertion that socializing costs could lead to stranded costs. MSR's arguments suggest that BPA should be trying to discourage the development of new VERs. BPA's policy regarding the development of new VERs is a balance between ensuring the reliability of the system while protecting its load customers from additional costs and at the same time following national and regional policy regarding encouraging the development of VERs. BPA believes that the rates and operational policy for wind generation integrating in the BPA system are consistent with this balancing of objectives.

Decision

The decision to allow additional wind resources to interconnect to BPA's transmission system is not a rate case issue. The fact that VERBS is a service that may be limited from time to time and the formula rate mechanism BPA is proposing in this rate proceeding mitigate the concerns raised by MSR.

Issue 3.2.4.2

Whether BPA should continue to rely on DSO 216 during the FY 2012–2013 rate period.

Parties' Positions

NWG states that with respect to *dec* reserves, BPA should continue to rely on the efficient use of DSO 216 feathering events during extreme ramps to reduce the need to hold *dec* reserves for such events during all hours of the year, and should not obtain incremental *dec* reserves beyond the base level of service for VERBS without customer input. NWG Br., BP-12-B-NG-01, at 23. NWG also states that BPA should offer a within-hour balancing service that allows wind energy to be scheduled as firm energy, but concludes that based on the information provided by BPA regarding the costs associated with additional *inc* reserves and BPA's practice of holding balancing reserves on 24/7/365 basis, BPA should continue to use DSO 216 as an operational tool to limit the amount of *inc* reserves covered by the VERBS rate. *Id.* at 72.

Iberdrola states that DSO 216 applies to only wind generation and describes DSO 216 as an operational penalty. Iberdrola Br., BP-12-B-IR-01, at 16. Iberdrola states that BPA's reliance on DSO 216 as a reliability tool is both misguided and misplaced. *Id.* Iberdrola states that it is troubled by the impact DSO 216 and BPA's other wind-related penalties are having on VERs in the market place. *Id.* at 17. Iberdrola also notes that any representation made by Iberdrola with regard to its willingness to accept anticipated curtailments resulting from DSO 216 applied to only the FY 2010–2011 rate period. *Id.* at 16 n.40.

In its brief on exceptions, Iberdrola claims that a DSO 216 order can occur when other imbalance reserves are available and in the absence of a reliability issue. Iberdrola Br. Ex., BP-12-R-IR-01, at 10. Iberdrola argues that BPA has contractual rights to curtail for reliability reasons, but the fact that BPA does not want to use these curtailment rights because it would shift the risk of wind schedule inaccuracies to all transmission customers demonstrates the patent undue

discrimination of DSO 216. *Id.* Iberdrola concludes that BPA cannot substitute its own judgment as to what is socially preferable with regard to curtailments or the costs associated with VER balancing, when such decisions are inconsistent with BPA’s contracts and Commission policy on non-discriminatory transmission access. *Id.* at 12. Iberdrola asserts that by agreeing to integrate and transmit the wind generation, BPA committed to treat it like all other firm generation on the system, and to curtail in accordance with contracts, and Iberdrola claims that BPA cannot go back after the fact and single out a specific type of generation for punitive treatment. *Id.* Iberdrola argues that this is the definition of undue discrimination, and it is unlawful. *Id.*

BPA Staff’s Position

Staff explains that DSO 216 is a necessary reliability and operational tool for establishing and enforcing a limit on the quantity of balancing reserve capacity provided for VERBS, because BPA cannot provide an unlimited service. Mainzer *et al.*, BP-12-E-BPA-23, at 31. In addition, the price for VERBS is directly related to the amount of balancing reserve capacity BPA must set aside for a forecast level of installed variable generation at a forecast quality of service. The amount of capacity BPA sets aside is used to set the limits for directing changes in variable resource plant operation under DSO 216. *Id.* at 22.

In addition, Staff proposes VERBS Supplemental Service to provide VERBS customers an option for obtaining additional balancing reserve capacity that will significantly reduce the effects of DSO 216 curtailments. *Id.* at 2-3; Kitchen *et al.*, BP-12-E-BPA-45. Staff’s proposal for VERBS Supplemental Service would allow VER customers to obtain additional balancing reserve capacity that can be called upon during a DSO 216 *inc* event to avoid a schedule reduction to the extent that the VERBS Supplemental Service is sufficient to cover the difference between output and schedule at the customer’s project. Kitchen *et al.*, BP-12-E-BPA-45, at 1. In addition, Staff documents the expected quantity of DSO 216 events based on various levels of service. Puyleart *et al.*, BP-12-E-BPA-43, Attachments 3 and 4.

Evaluation of Positions

NWG takes issue with some aspects of BPA’s VERBS proposal, but appears to accept the need for DSO 216 as a means for BPA to provide a set level of service without incurring significantly higher costs for additional balancing reserve capacity to meet the needs of the wind fleet during extreme ramp events. NWG Br., BP-12-B-NG-01, at 23, 72. NWG explains:

Although NWG continues to believe that BPA should offer a within-hour balancing service that allows wind energy to be scheduled on a non-discriminatory basis as firm energy, based upon the information provided by BPA, *the cost of providing a within-hour balancing service that significantly reduces inc-related DSO 216 events is cost-prohibitive.*

Id. at 72 (emphasis added).

In contrast, Iberdrola criticizes the purpose and BPA’s continued use of DSO 216. Iberdrola claims that DSO 216 is not required for reliability and that it simply functions as an easy, albeit

improper and discriminatory, way for BPA to avoid the pro rata curtailment procedures required by the OATT and LGIA. Iberdrola Br., BP-12-B-IR-01, at 16-17.

BPA strongly disagrees with Iberdrola's characterization of DSO 216. DSO 216 is clearly necessary to maintain system reliability:

Maintaining reliability in the balancing authority area requires a clear understanding of the amount of balancing reserve capacity available. Any balancing authority must be able to clearly define and understand the limits of its obligation to provide services. The FCRPS is a complicated interconnected system of hydro resources that requires extensive operational planning to ensure that service obligations are met and non-power operating constraints are not violated. Because VERs can have highly unpredictable demands for balancing service, and because providing a service that covers all wind tail events would require a significant amount of balancing reserve capacity, *system reliability cannot be maintained without a mechanism such as DSO 216 that ensures risk is managed when demands for balancing reserve capacity exceed the level of service that is planned and defined on a forecast basis.*

Mainzer *et al.*, BP-12-E-BPA-42, at 19 (emphasis added).

Iberdrola's claim that DSO 216 is unnecessary as a reliability tool also ignores the fact that during extreme wind ramp events, the entire amount of balancing reserve capacity BPA is holding can be used up within 10 minutes. Load and non-VER generators do not impose these extreme movements on the BPA system. Without an operational and reliability tool such as DSO 216, when wind generators have extreme scheduling errors, those errors could exhaust the entire amount of balancing reserve capacity that BPA makes available for variable energy resources, load, and dispatchable energy resources. Such circumstances would leave little room for BPA to maintain the delicate balance between load and generation within the BPA balancing authority area.

Iberdrola claims that a DSO 216 order can occur when other imbalance reserves are available and in the absence of a reliability issue. Iberdrola Br. Ex., BP-12-R-IR-01, at 10. While there are times when BPA may have the ability to provide more reserves and a DSO 216 event is activated, it is not accurate that there is an absence of a reliability issue. Dispatch orders are sent under DSO 216 when 90 percent of the total balancing reserve capacity held for load, dispatchable energy resources, and wind generators has been deployed. A balancing authority must be able to clearly define and understand the limits of its obligations to provide service. The FCRPS is a complicated interconnected system of hydro resources that requires extensive operational planning to ensure that service obligations are met and non-power operating constraints are not violated. Mainzer *et al.*, BP-12-E-BPA-42, at 19. BPA relies on the forecast amount of balancing reserve capacity established in the rate proceeding for load, dispatchable energy resources, and wind generators to set up the integrated hydro system, and any provision of additional balancing reserve capacity during an hour will degrade the ability of the FCRPS to provide balancing reserve capacity and meet other load service and non-power requirements in the following hours. Mainzer *et al.*, BP-12-E-BPA-23, at 31-32. Thus, any time that BPA has

deployed 90 percent of its planned balancing reserve capacity, it is facing a reliability issue, even if the system could produce more balancing reserve capacity at that particular point in time. Providing additional balancing reserve capacity will change the deployment of the hydro system and compromise system reliability by depleting the flexibility of the system and altering the plan for moving water through the interconnected hydro system. Because VERs can have highly unpredictable demands for balancing service, and because providing a service that covers all wind tail events would require a significant amount of balancing reserve capacity, system reliability cannot be maintained without a mechanism such as DSO 216 that ensures risk is managed when demands for balancing reserve capacity exceed the level of service that is planned and defined on a forecast basis. Mainzer *et al.*, BP-12-E-BPA-42, at 19.

Iberdrola states, however, that BPA should drop DSO 216 immediately and rely on the pro rata curtailment provisions of the LGIA and the tariff to maintain reliability when BPA's balancing reserve capacity is exhausted. Skidmore, Oral Tr. at 145-147. Although BPA has the authority to take any actions necessary to maintain system reliability, BPA strongly disagrees with Iberdrola's suggestion to rely upon the curtailment provisions of the OATT and LGIA in lieu of DSO 216.

Iberdrola argues that BPA has contractual rights to curtail for reliability reasons, but the fact that BPA does not want to use these curtailment rights because it would shift the risk of wind schedule inaccuracies to all transmission customers demonstrates the patent undue discrimination of DSO 216. Iberdrola Br. Ex., BP-12-R-IR-01, at 10. First, Iberdrola disregards the fact that the reliability situation that leads to a DSO 216 event is driven by the schedule error of wind generators that are interconnected to BPA's system. During a DSO 216 event, wind generators are curtailed or ordered to reduce generation based on how far the individual generator is deviating from its schedule. Those that are the furthest from their schedules face the most impact from DSO 216, and those that are close to their schedule may see no curtailment or directive to limit generation. While Iberdrola is correct that BPA could use the OATT provision for curtailments and choose to treat extreme wind ramps that exhaust BPA's balancing reserve capacity the same as a transmission reliability event, such an approach would impact many transmission customers that are not responsible for the problem.

Curtailments under the tariff affect all transmission schedules on a non-firm versus firm and pro rata basis. In an extreme wind ramp event, pro rata curtailments of all transmission schedules would require significantly more curtailments than DSO 216. Such an approach would potentially unfairly impact transmission schedules for loads and generators (both thermal and wind) that are not contributing to the balancing reserve capacity depletion problem. BPA finds no basis in the rate case record to shift the risks and costs associated with the schedule inaccuracies of wind generators to all transmission customers.

Second, relying on the curtailment provisions of BPA's Tariff and LGIA instead of DSO 216 would serve to incent wind generators to adopt poor scheduling practices. As explained above, without DSO 216, when wind generators exhaust the total amount of available balancing reserve capacity in BPA's balancing authority, BPA would need to curtail all non-firm customers and then all firm transmission customers on a pro-rata basis. This would have the effect of spreading

the curtailment risk across all customers instead of targeting the customers that created the reliability event. However, if the risks associated with schedule inaccuracies are spread across all transmission customers, wind generators may be less inclined to manage their schedule error. In contrast, under DSO 216, any risks that are borne by the wind generators are the risks imposed upon the system by wind generators. This is a fair and equitable result, since the wind generators are better situated to manage that risk than BPA or BPA's other customers.

Iberdrola argues that by stating that Iberdrola is correct that BPA could use the curtailment provisions in the LGIA and OATT, BPA acknowledges that DSO 216 is inconsistent with the terms of its contracts, but that BPA appears to believe it can take such actions whenever it wants. Iberdrola Br. Ex., BP-12-R-IR-01, at 11. To the contrary, BPA has not acknowledged that DSO 216 is inconsistent with the terms of its contracts. The LGIA provides for the Transmission Provider to establish such operating protocols and procedures as are necessary to maintain system reliability. *See* LGIA section 9.3. Moreover, DSO 216 is designed to curtail only those wind generators that are causing the depletion of reserves and to move those generators down closer to their schedule or curtail their schedules closer to the actual level of their generation. This is the most effective way to relieve the overuse of balancing reserve capacity and it is consistent with section 13.6 of the OATT.

Iberdrola asserts that BPA has represented that penalties and operational restrictions are needed to provide economic incentives for accurate scheduling and to maintain reliability, but the electric utility industry is moving toward cost-based as opposed to penalty-based approaches to provide incentives for accurate VER scheduling. Iberdrola Br., BP-12-B-IR-01, at 16.

DSO 216 is a reliability and operational protocol that enables BPA to limit its obligation to provide balancing reserve capacity to a defined quantity, and is not an operational penalty. *See* Mainzer *et al.*, BP-12-E-BPA-42, at 19. Because the DSO 216 limits are established in the rate case process, and there is a direct relationship between these limits and the rate established for the service, it could be described as cost-based incentive for better scheduling. Indeed, the pricing of VERBS is directly related to the use of DSO 216 to limit the deployment of balancing reserve capacity for VERBS:

The price for VERBS is directly related to the amount of balancing reserve capacity BPA must set aside for a forecast level of installed variable generation at a forecast quality of service. The amount of capacity BPA sets aside is used to set the limits for directing changes in variable resource plant operation under DSO 216. When BPA exhausts the *inc* balancing reserve capacity it has set aside for all balancing purposes, including load balancing, BPA directs the variable energy resources that are scheduling more power than their actual generation to curtail the amount of their schedules to reflect their actual generation levels. Similarly, when BPA exhausts the *dec* balancing reserve capacity it has set aside for all balancing purposes, BPA directs the variable energy resources that are scheduling less power than their actual generation to reduce (feather) their generation to reflect their actual schedule.

Mainzer *et al.*, BP-12-E-BPA-23, at 22.

In addition, in the FY 2010–2011 rate proceeding, BPA clarified that setting the amount of balancing reserve capacity for the Wind Balancing Service rate and thus the trigger level for DSO 216 was a risk-cost trade-off, and part of the risk and cost trade-off was the potential response of other entities to DSO 216 curtailments and the fact that market prices for wind subject to DSO 216 would reflect the fact that there may be occasional curtailments. Mainzer *et al.*, BP-12-E-BPA-42, at 20. In this rate proceeding, Staff further explains how DSO 216 *inc* curtailments relate to the value of wind generation:

When a party on the receiving end of a wind generation schedule understands that the schedule may be curtailed in certain circumstances, it understands that it is subject to risk. When the schedule is curtailed, the recipient must procure substitute energy in some way to ensure that the load is served and reliability is maintained. That additional energy might be purchased as energy imbalance from the sink balancing authority or provided in some other way. With DSO 216, the cost of carrying the balancing reserve capacity in the source balancing authority is reduced because the source balancing authority is not standing ready at all times with balancing reserve capacity to cover infrequent occurrences. However, there is an incremental cost of providing energy to serve the load when the schedule is curtailed. Since the receiving entity bears that cost, it is reasonable that the receiving entity's willingness to pay for the wind product is reduced as a consequence. From BPA's perspective, the capacity required for VERBS is reduced and the rate is lower. From the wind generator's perspective, it has a lower VERBS cost to recover in its energy sale price. From the perspective of the entity purchasing the wind generation output, it is bearing increased risk and should therefore pay a lower price. From the sink balancing authority's perspective, load must be served when the schedule is curtailed, and the load serving entity should pay for that energy. DSO 216 moves risk and costs among entities but does not make them disappear. Presumably parties in the Northwest energy markets understand this.

Id. at 21-22.

In its brief on exceptions, Iberdrola quotes a portion of this section from Staff's testimony and claims that the impropriety and undue discrimination inherent in BPA's "implementation of DSO 216 are evident in BPA's description of the nature and 'need' for the protocol." Iberdrola Br. Ex., BP-12-R-IR-01, at 11. This section of Staff's testimony does not describe the nature or need; rather it explains the perspective of various entities regarding DSO 216 *inc* schedule curtailments. The nature and need for DSO 216 is based on BPA's reliability requirements and need to limit the amount of balancing reserve capacity it deploys to meet the extreme deviation of wind generation from its schedules. Mainzer *et al.*, BP-12-E-BPA-23, at 31-32.

BPA's decision to adopt VERBS at a level of 99.5 percent represents a quality of service versus a lower rate tradeoff for VERBS customers. *See* Issue 3.2.4.4 below. Accordingly, the risk of operational measures needed to preserve system reliability under a 99.5 percent quality level of service for VERBS is a risk that is properly allocated to the wind fleet and one that the wind fleet apparently is willing to accept. NWG Br., BP-12-B-NG-01, at 72.

Nevertheless, BPA finds no fault in the fact that DSO 216 may incentivize wind generators to improve their scheduling accuracy. Such an incentive, however, is not the primary purpose of DSO 216. As described above, DSO 216 is based on the potential for variation in wind generation to exhaust BPA's total balancing reserve capacity.

BPA is committed to offering customers choices regarding their balancing service options. In this ROD, in addition to a base level of VERBS at a 99.5 percent quality level of service, BPA is offering VERBS Supplemental Service to those customers seeking to mitigate the impacts of DSO 216. Mainzer *et al.*, BP-12-E-BPA-42, at 2-3; Kitchen *et al.*, BP-12-E-BPA-45, at 1-2. Moreover, customers such as Iberdrola that choose to participate in the CSGI pilot have more control over their exposure to DSO 216, because they control the imbalance component of their service, which is the primary trigger for DSO 216. The risks of DSO 216 are known, and wind generators can take actions to mitigate the DSO 216 risk. Staff includes estimates of the potential frequency of DSO 216 associated with various levels of service. Puyleart *et al.*, BP-12-E-BPA-43, Attachments 3 and 4. Indeed, Iberdrola acknowledges that it has already taken actions that mitigate exposure to DSO 216 risk, such as making significant infrastructure investments in its forecasting capabilities and development and participation in the Customer Supplied Generation Imbalance (CSGI) pilot. Iberdrola Br., BP-12-B-IR-01, at 2.

Finally, Iberdrola asserts that other regions integrate wind and maintain system reliability without discriminatory curtailment protocols like DSO 216, and BPA can as well. *Id.* at 17. This argument is also unpersuasive. Staff addresses Iberdrola's concern that BPA's actions and policies are having a profoundly harmful and discriminatory impact on VERs in the marketplace. DSO 216 moves risk and costs among entities but does not make them disappear. Mainzer *et al.*, BP-12-E-BPA-42, at 20-22. It is not BPA's obligation as the balancing authority to ensure the value of wind generation; rather, BPA's obligation is to help ensure transparency in the products and services that it provides and that all affected parties are aware of the risks that they face with respect to schedule curtailments initiated by BPA through DSO 216. *Id.* at 22. As discussed above, Staff's proposal includes options for wind generators to mitigate their DSO 216 risk. These options can be used to influence the value of VERs in the marketplace.

In its brief on exceptions, Iberdrola concludes that BPA cannot substitute its own judgment as to what is socially preferable with regard to curtailments or the costs associated with VER balancing, when such decisions are inconsistent with BPA's contracts and Commission policy on non-discriminatory transmission access. Iberdrola Br. Ex., BP-12-R-IR-01, at 12. As discussed above, DSO 216 is not inconsistent with BPA's contracts or the Commission's policy on non-discriminatory access. BPA is not substituting its judgment as to what is socially preferable with regard to curtailment. Rather BPA is implementing a reliability protocol that is necessary to operate a reliable transmission system and meet its other statutory obligations, while meeting the socially preferred integration of a significant amount of unpredictable variable generation.

Iberdrola asserts that by agreeing to integrate and transmit the wind generation, BPA committed to treat it like all other firm generation on the system, and to curtail in accordance with contracts. Iberdrola claims that BPA cannot go back after the fact and single out a specific type of

generation for punitive treatment, and Iberdrola argues that this is the definition of undue discrimination, and it is unlawful. *Id.* Iberdrola’s assertion misrepresents the facts, including the history of BPA’s VER integration policy and the development of DSO 216. First, because of the variable nature of wind generation it is not the same as all other firm generation and BPA did not commit to treat wind generators the same without regard to maintaining the reliability of the transmission system or meeting the other obligation of the FCRPS.

Second, BPA did not “go back after the fact and single out a specific type of generation for punitive curtailment treatment.” BPA began to see a significant increase in the amount of wind generation interconnecting to its transmission system in 2007 and 2008. Recognizing that the increasing amount of wind generation was beginning to use a significant amount of balancing reserve capacity, BPA initiated the WI-09 7(i) process to set a rate for providing this balancing reserve capacity. The WI-09 rate process resulted in a settlement implementing the first rate specifically for wind generators and the creation of the WIT. BPA soon realized that extensive increases in wind interconnection would exhaust the ability of the FCRPS to meet the deviation between wind schedules and actual generation, and toward the end of 2008 BPA initiated a public process to design a reliability tool that would limit the amount of balancing reserve capacity. This public process resulted in the establishment of DSO 216, a final BPA action, which became effective in October 2009. Iberdrola and other wind generation entities participated in the public process that led up to the implementation of DSO 216. In October 2009, roughly half of the wind generation that is now interconnected to BPA’s transmission system was not yet interconnected. In addition, the balancing reserve capacity forecast that is used to establish the DSO 216 limits was the primary issue in the FY 2010–2011 rate proceeding. Iberdrola and other wind generation parties agreed on the record that they were willing to accept the operational risks of DSO 216 in order to pay a lower Wind Balancing Service rate. Hall and Skidmore, WP-10 Oral Tr., WP-10-TA-BPA-02, at 32-33, 64.

Third, DSO 216 does not amount to undue discrimination and it is not unlawful. Wind generators are able to operate like any other generator on the system except when schedule deviations cause BPA to deploy 90 percent of the pooled reserves it is holding for dispatchable generators, loads, and wind generators. Puyleart et al., BP-12- E-BPA-24, at 3. At that point, DSO 216 orders will instruct wind generators to reduce generation down to a set amount above their schedule in a *dec* event, or the wind generators’ schedules will be curtailed to within a set amount above actual generation in an *inc* event. *Id.* In both cases wind generators that are not deviating by more than their set amount are unaffected by the DSO 216 order, unless the problem persists and BPA reaches 100 percent deployment of reserves. *Id.* When this occurs, all wind generators are ordered to match their generation to their schedule in a *dec* event or curtail their schedule to match actual generation in an *inc* event. *Id.* It is true that DSO 216 orders are only given to wind generators, but it is wind generators that are driving the excessive use of balancing reserve capacity. Undue discrimination requires that the Transmission Provider is unreasonably applying different terms and conditions to customers that are similarly situated. *El Paso Natural Gas Co.*, 104 FERC ¶ 61,045, P 115 (2003). In the case of application of DSO 216, the wind generators are not similarly situated to load and dispatchable generators, because the depletion of BPA’s balancing reserve capacity is driven by the variability of the wind generators that are affected by the DSO 216 orders.

Ultimately, the fact that BPA relies on the FCRPS for balancing reserve capacity to support VERBS and other ACS capacity-based services requires that BPA have a clear understanding of the limitations on the services it will provide in order to set up the hydro system and maintain a reliable system. *Id.* at 19. The continued use of DSO 216 is a primary assumption of BPA's wind integration strategy and VERBS rate design. The cost of providing unlimited balancing services to VERs is prohibitive on a balancing area wide basis, but Staff's proposal provides options to customers through CSGI and VERBS Supplemental Service that will allow customers to weigh the cost of additional services against the cost of exposure to potential DSO 216 curtailments.

Decision

DSO 216 will continue to be one of the primary reliability and operational tools for BPA during the FY 2012–2013 rate period.

Issue 3.2.4.3

Whether BPA should assume that it can rely on contingency reserves from the NWPP to provide an additional amount of reserves during extreme wind events.

Parties' Positions

Iberdrola asserts that BPA should support approval at the NWPP of an eligible contingency event for extreme wind conditions. Iberdrola Br., BP-12-B-IR-01, at 34. Iberdrola claims that if BPA has the ability to access reserves from the pool during extreme wind events, the amount of reserves held for wind can be reduced. *Id.*

NWG states that one step BPA can take to firm up the quality of VERBS service without materially increasing costs is through the use of NWPP contingency reserves to manage extreme ramp events and BPA should work with the NWPP to develop an appropriate level of use of those contingency reserves to provide additional balancing reserves to manage extreme wind ramp events. NWG Br., BP-12-B-NG-01, at 22-23. NWG suggests that relying on the use of NWPP contingency reserves could reduce the amount of balancing reserve capacity that BPA holds for VERBS. *Id.* at 23. NWG asserts that reducing the combined reserve obligation while maintaining appropriate reliability standards would reduce costs and benefit BPA and its customers. *Id.* NWG concludes that to the extent such contingency reserves are available, assumptions regarding access to such reserves should be incorporated into the Final Proposal for the FY 2012–21013 rate period. *Id.*

BPA Staff's Position

The debate at the NWPP over the use of contingency reserves for extreme ramp events is an operational issue that is outside of the scope of the rate proceeding. Mainzer *et al.*, BP-12-E-BPA-42, at 4-5. The timing of the outcome of the NWPP process is such that rate case decisions may need to be made prior to resolution of the contingency reserve issue. *Id.* The outcome of the NWPP process is beyond BPA's control and is uncertain based on the facts at hand. *Id.*

Evaluation of Positions

Although the NWPP definition of qualifying contingency events is beyond the scope of this rate proceeding, it is worth noting that the debate at the NWPP over the use of contingency reserve for wind ramping events is not yet resolved. The proposal that was being discussed at the NWPP during this rate proceeding would have allowed for some very limited use of contingency reserves for the most extreme ramp events, with deployment occurring no more than 10 times per year. Staff has forecasts that curtailments due to DSO 216 events are expected to occur over 100 times per year. Puyleart *et al.*, BP-12-E-BPA-43, Section 4.1 and Attachment 3. The NWPP proposal contained rules regarding deployment of contingency reserves that do not align with DSO 216 events. There is a disconnect between Iberdrola's and NWG's assertion that relying on contingency reserves from the NWPP will result in a lower reserve level for VERBS, with corresponding cost savings, and the structure of the NWPP proposal, which is inconsistent with any possibility that NWPP contingency reserves will replace or lower the amount of balancing reserve capacity that Staff proposes for the base level VERBS service.

NWG states that reducing the combined reserve obligation while maintaining appropriate reliability standards would reduce costs and benefit BPA and its customers. NWG Br., BP-12-B-NG-01, at 23. However, BPA is concerned that, because of the extreme growth of the wind fleet, significant reliance on contingency reserves to mitigate extreme wind events could potentially compromise reliability. Staff states its position on the issue of relying on contingency reserves for extreme wind events:

We believe that it is extremely important to preserve the operational integrity and financial value of the NWPP reserves sharing pool. We also believe that fundamentally, the variability of wind and other Variable Energy Resources (VERs) should be dealt with through the carrying and deployment of balancing reserve capacity, as opposed to contingency reserves. As a result, we are open to treating an *extremely limited* number of extreme wind under-generation events as contingencies, but this number is sufficiently small that it is insufficient to cover the number of DSO 216 curtailment events associated with a 99.5 percent quality of service.

Mainzer *et al.*, BP-12-E-BPA-42, at 4.

Rather than make assumptions about the outcome of the NWPP process, BPA is offering wind generators options to increase the quality of service through the CSGI pilot and VERBS Supplemental Service. If the NWPP process determines that some level of contingency events associated with extreme wind events are qualifying events, this may factor into customers' decisions regarding purchases of VERBS Supplemental Service.

Decision

BPA is not including in this ROD any assumptions regarding the use of contingency reserves from the NWPP as a means to mitigate extreme wind ramps. BPA will continue to be involved

with regional discussions regarding the use of contingency reserves from the NWPP during extreme wind ramp events.

Issue 3.2.4.4

Whether BPA should use the 99.5 percent level of service or some higher level of service to establish the VERBS rate.

Parties' Positions

NWG recommends that BPA offer within-hour balancing services at the proposed 99.5 percent quality level of service. NWG Br., BP-12-B-NG-01, at 72. NWG states that it continues to believe that BPA should offer a within-hour balancing service that allows wind energy to be scheduled on a non-discriminatory basis as firm energy; however, based on the information from BPA, the cost of providing a within-hour balancing service that significantly reduces *inc*-related DSO 216 events is cost-prohibitive. *Id.* NWG states that its primary interest in BPA providing more *inc* reserves is to reduce the number of DSO 216 schedule cuts and avoiding firm contingent e-Tagging. *Id.*

NWG states that, based on the information provided by Staff that reducing DSO 216 *inc* events to 4-12 events annually that could be managed with contingency reserves would require approximately 75 to 115 percent additional reserves, it appears that raising the level of service would be cost prohibitive under Staff's proposed operating protocols. *Id.* Based on the options available, NWG recommends that BPA not increase *inc* or *dec* reserves beyond the amount forecast for the 99.5 percent level of service for VERBS in the FY 2012–2013 rate period. *Id.*

Although Iberdrola took issue with BPA's use of DSO 216, no other party addressed the base level of service issue directly.

BPA Staff's Position

Staff proposes a VERBS rate using a level of service that provided a forecast level of balancing reserve capacity to meet 99.5 percent of the over-generation and under-generation events associated with VER operation, subject to limitation on the provision of balancing reserve capacity from the FCRPS. Mainzer *et al.*, BP-12-E-BPA-23, section 4; Mainzer *et al.*, BP-12-E-BPA-42, at 17-18.

Staff also documents the reserve levels and associated costs needed to meet 99.7 percent of the over-generation and under-generation events associated with VER operation and scenarios for both 99.5 percent and 99.7 percent with different assumptions regarding self-supply of VERBS. Puyleart *et al.*, BP12-E-BPA-24; Klippstein *et al.*, BP-12-E-BPA-25; Mainzer *et al.*, BP-12-E-BPA-42, at 18. Staff explains that even with 99.5 percent level of service with self-supply the FCRPS will be reaching the limits of its ability to provide balancing reserve capacity for ACS by the end of the FY 2012–2013 rate period. Mainzer *et al.*, BP-12-E-BPA-42, at 17.

Evaluation of Positions

NWG continues to believe that BPA should offer a within-hour balancing service that allows wind energy to be scheduled on a non-discriminatory basis as firm energy, however, based on the information provided by Staff, NWG states that the cost of providing a within-hour balancing service that significantly reduces *inc*-related DSO 216 events is cost-prohibitive. NWG Br., BP-12-B-BPA-01, at 72.

NWG states that, based on information Staff provided, it appears that approximately 75 and 115 percent of additional balancing reserve capacity would be required to cover the 4-12 events that Staff suggests could be managed with contingency reserves. *Id.* Thus, NWG recommends, BPA should not increase *inc* or *dec* balancing reserves above its proposed 99.5 percent level for purposes of establishing the level of VERBS service for FY 2012–2013. *Id.*

BPA agrees with NWG that the VERBS quality level of service should be consistent with a 99.5 percent standard. Under the facts in this case, a 99.5 percent standard for VERBS is reasonable when considering the significant quantities of balancing reserve capacity that would be required to manage every imbalance of the VERs in BPA’s balancing authority area. Mainzer *et al.*, BP-12-E-BPA-42, at 23 (“Firming wind generation to a level comparable with dispatchable generation requires substantial amounts of balancing reserve capacity.”).

However, as NWG notes, there is a tradeoff between quality of service and price for VERBS. BPA has an “obligation ... to help ensure transparency in the products and services that it provides and that all affected parties are aware of the risks that they face with respect to schedule curtailments initiated by BPA through DSO 216.” *Id.* at 22. As Staff explains:

[T]he level of DSO 216 risk is established in association with the risk and cost tradeoff when the level of balancing reserve capacity requirement is decided in the rate proceeding. That risk and cost tradeoff is made in advance by the BPA Administrator, based on the comments by the industry as a whole. Once the balancing reserve capacity requirement is operationalized, the reserve levels become a binding planning variable and a driver of other day-to-day and hourly operational decisions that impact reliable system operations....

The balancing authority area cannot call on more balancing reserve capacity than the source of such capacity has agreed to provide. Under current conditions, a mechanism to limit balancing reserve capacity use is necessary. DSO 216 transfers the *inc* reserve obligation not provided by the source balancing authority to the sink balancing authority. Any damage to the value of wind generation that occurs is associated with the fact that some party in the receiving balancing authority must then pay for some of *inc* reserve at the time the schedule is curtailed.

Id. at 20-21.

Since a higher quality of service requires a higher quantity of balancing reserve capacity, the costs associated with that quantity of balancing reserve capacity will also be higher. *Id.* at 17.

The benefit of a higher quality of service, however, is that the risk of DSO 216 curtailments is reduced. *Id.* Conversely, if the quality of service is lower, BPA will stand ready with less balancing reserve capacity, but the rate for VERBS will also be lower. *Id.* However, a lower quality of service will have a higher risk of DSO 216 curtailments. *Id.*

Accordingly, from BPA's perspective, a 99.5 percent standard will produce a lower VERBS cost for BPA to recover in rates than would a higher standard for VERBS. *Id.* From the perspective of the entity purchasing the variable energy resource's output, however, that entity will bear any increased risk of DSO 216 curtailments associated with a 99.5 percent standard and may choose to pay a lower price for the variable energy resource's energy. *Id.* at 22. From the sink balancing authority's perspective, since load must be served when a DSO 216 curtailment occurs, the load-serving entity will be responsible to pay for the energy needed to serve its load. *See id.* at 21-22. In summary, DSO 216 moves risk and costs among entities but does not make them disappear. *Id.* at 22. BPA presumes that the parties in the Northwest energy markets understand the inherent quality of service and price tradeoff associated with a 99.5 percent standard for VERBS. *Id.*

BPA recognizes that a 99.5 percent standard of service for VERBS may not be sufficient to meet the business needs of all VERBS customers and that it is important to provide customers with a business choice between an acceptable level of quality of balancing services and price. Mainzer *et al.*, BP-12-E-BPA-23, at 2-3. Therefore, as explained in ROD section 3.2.10, in addition to this base level of service for VERBS, BPA is providing customers the option to purchase VERBS Supplemental Service. This will ensure that customers are provided with choices regarding costs and exposure to DSO 216 curtailments.

Although BPA's decision is to adopt a 99.5 percent standard for VERBS, system conditions and non-power requirements may affect BPA's ability to provide balancing reserve capacity from the FCRPS. Mainzer *et al.*, BP-12-E-BPA-42, at 17. BPA expects that the FCRPS should be able to provide sufficient balancing reserve capacity to meet the 99.5 percent level of service for the rate period. However, to the extent forecast Federal balancing reserve capacity becomes unavailable during the rate period, BPA will rely upon the formula cost recovery mechanism under the VERBS rate to recover the costs of any incremental balancing reserve capacity purchases that are necessary to continue to provide VERBS during the rate period. *Id.*; *see also* Issue 3.2.7.5.

Finally, to ensure that BPA can continue to meet the balancing service requirements of its customers, the Administrator, at his discretion, is retaining the ability to increase the quality level of service for VERBS if one or more participants in the Pacific Northwest utility industry asks the Administrator to increase the amount of balancing reserve capacity provided for VERBS, or if BPA is prevented from implementing DSO 216 or is required to amend it materially due to a legal challenge. Jackson *et al.*, BP-12-E-BPA-47, Attachment 1, at 1-13.

BPA notes that Iberdrola takes issue with BPA's use of DSO 216 to manage the use of balancing reserve capacity under VERBS. BPA addresses that issue in Issue 3.2.4.2 above.

Decision

BPA will provide VERBS at a quality of service level that is consistent with a 99.5 percent standard.

Issue 3.2.4.5

Whether BPA should investigate the use of Banks Lake to provide additional inc and dec reserves.

Parties' Positions

NWG asserts that BPA should investigate the use of pumping load from Banks Lake as a potential source of a substantial amount of *inc* and *dec* reserves. NWG Br., BP-12-B-NG-01, at 23-25. NWG claims that the pumping load at Bank Lake is an under-utilized resource that could provide up to 600 MW of *dec* reserves, and the ability to return water to Grand Coulee during HLH would result in the provision of up to 300 MW of *inc* reserves. *Id.* at 23-24. NWG recognizes that there may be some limitations on the operation of the pump load but states that coordinating this operation could reduce the VERBS rate and make more reserves available to the system. *Id.* at 24. NWG concedes that there may be some costs associated with the use of Banks Lake pumping, but believes this is another source of reserves that could help BPA run the system more efficiently. *Id.* at 25.

BPA Staff's Position

Staff explains that BPA is already using the increased generation at Grand Coulee associated with the pump load when it is available to contribute to the system's ability to provide *dec* balancing reserve capacity. Puyleart *et al.*, BP-12-E-BPA-43, at 8-9. Operation of the Banks Lake pumping load is modeled as part of the BPA system for purposes of determining how to provide balancing reserve capacity. *Id.* Increased *dec* capability is available due to that operation and is modeled in the HYDSIM and GARD studies. *Id.* However, the pump load is subject to strict schedules and operating protocols associated with Bureau irrigation schedules and other restrictions, and low availability due to aging equipment, so it is not as flexible as NWG assumes in its analysis. Specifically, the pump generators cannot be used for within-hour balancing because they are too inflexible with their very discrete operating points. *Id.* In addition, they are not armed for AGC response and need hours of advance notice to cycle on. *Id.*

Evaluation of Positions

BPA's rate studies incorporate the generation used to support the pumping load at Banks Lake when it is available to contribute to the provision of *dec* balancing reserve capacity. *Id.* In their current state, Banks Lake generators cannot be used for within-hour balancing. *Id.* However, in the future, BPA may be able to rely on Banks Lake pumping load for a greater amount of balancing reserve capacity: the Northwest Power and Conservation Council's Sixth Power Plan, issued in 2010, calls for research into the cost-effectiveness of pumped storage and other energy storage alternatives. BPA is preparing a detailed analysis to see what benefits pumped storage at

Grand Coulee might provide and what it would cost. *See* BPA Quarterly Business Review, May 3, 2011, at 42-56, available at BPA’s Web site under Finance & Rates—Financial Overview—Quarterly—May 2011 Quarterly Business Review. If the analysis shows a proposal that is potentially cost-effective, BPA will work with Reclamation and Columbia Basin irrigation districts in preparing further evaluation.

Decision

BPA will continue to use the additional generation associated with Banks Lake pump load, subject to its strict schedules, operating protocols associated with irrigation schedules, equipment condition, and other restrictions, to contribute to the system’s ability to provide balancing reserve capacity. BPA is currently analyzing whether upgrades at Banks Lake would allow for additional, and cost-effective, balancing reserve capacity.

Issue 3.2.4.6

Whether BPA should issue a Request For Information regarding proposals for a balancing reserve capacity product that could be used to manage wind-related tail events but that would not necessarily be available at all hours of all days.

Parties’ Positions

NWG suggests that BPA should work with its customers to identify balancing reserve capacity resources that address the unique balancing needs of wind-related tail events. NWG Br., BP-12-B-NG-01, at 25. NWG reasons that since the frequency of DSO 216 events is well understood and BPA’s iCRS system provides awareness of impending DSO 216 events, it should be possible to tailor a product that addresses wind related tail events that does not need to be held and charged for on a 24/7/365 basis. *Id.* NWG states that BPA should issue a Request for Information or similar process to ascertain the availability of such a source for providing a wind tail event service. *Id.* NWG offers an example of an interruptible export contract structured to provide BPA an option to cut the energy schedule any time the FCRPS reserves have been depleted, enabling BPA to keep the energy in the balancing area to meet the need for additional *inc* reserves. *Id.*

BPA Staff’s Position

Staff does not submit testimony directly on this issue; however, Staff is proposing the VERBS Supplemental Service option that will allow the wind generator customers to bring their own resource or have BPA obtain the additional resources specifically to cover the wind tail events associated with DSO 216 events. Kitchen *et al.*, BP-12-E-BPA-45. Staff explains that balancing reserve capacity for VERBS Supplemental Service will be obtained by soliciting offers from third parties to supply incremental balancing reserves consistent with criteria established in participant agreements. *Id.* at 13-14.

Evaluation of Positions

It appears that NWG may be assuming that there are resources available that can be incorporated into BPA's AGC system with little or no notice. Assuming that capability allows NWG to posit a circumstance in which BPA would need to buy these resources only on the hours needed. NWG does not provide any testimony on the amount of time needed to arrange and incorporate these reserves or the consequence of the lack of availability if the reserves were not offered.

The only resource suggested by NWG was a sale of energy on a recallable basis. NWG Br., BP-12-B-NG-01, at 25. While BPA agrees there are conditions in which sales of energy on a recallable basis could provide a reserve, the most likely reserve would be a contingency reserve and not a balancing reserve. Since this resource would be highly dependent on market conditions, it is not the type of reserve that could be used for any purpose other than displacement of another resource used for reserves or a reserves market where the resource owner did not have an obligation to provide the reserves.

Even if a means were found to incorporate energy sales on a recallable basis into the AGC system on short notice, there is a cost to providing reserves in this manner. NWG provides no testimony on how the costs of providing reserves in this manner would be recovered. NWG objects to BPA's use of a formula rate to include the cost of purchases of non-Federal resources in the VERBS rate. *Id.* at 43-44. NWG suggests no means to recover the cost of these reserve purchases other than holding a section 7(i) hearing. *Id.* at 44. The time necessary to hold that hearing prior to making the purchase would eliminate the benefits of buying reserves only when needed. *See also* Issue 3.5.3.3.

NWG states that BPA should work with its customers to identify balancing reserve capacity resources that address the unique balancing needs of wind-related tail events. NWG Br., BP-12-B-NG-01, at 25. The primary purpose of Staff's VERBS Supplemental Service proposal is to work with individual wind generators to find additional balancing resources to address wind-related tail events for the individual VERs. The resources that are contemplated for the VERBS Supplemental Service are not the same as the balancing reserve capacity used for the base VERBS that can be called to move several times during an operating hour. The VERBS Supplemental Service resources are contemplated to be on-demand resources, which are rights to an amount of power that can be activated only once during an hour. BPA would expect to use the on-demand VERBS Supplemental Service reserves only when it is approaching a DSO 216 event. Kitchen *et al.*, BP-12-E-BPA-45, at 14-15. These resources will still have to be available all the time, because of the unpredictability of wind generation, the uncertainty of wind schedules compared to wind forecasts, and the time necessary to incorporate resources into BPA's systems for managing reserves.

Decision

BPA will not issue an RFI for a product that can manage wind-related tail events for the entire wind fleet; rather, customers will be able to use VERBS Supplemental Service options that will allow the customers to bring their own resource or have BPA obtain the additional resources specifically to cover the wind tail events associated with DSO 216 inc curtailments.

Issue 3.2.4.7

Whether BPA has announced an effective moratorium on new wind interconnections in its balancing authority area.

Parties' Positions

In support of its argument that BPA's policy and practices discriminate against wind generators, Iberdrola states that as recently as April 2011 BPA announced an effective moratorium on new wind interconnections within the BPA balancing authority area. Iberdrola Br., BP-12-B-IR-01, at 3.

NWG refers to BPA's "intention to slow the pace of interconnection of wind projects and to indefinitely delay the 2011 [Network Open Season (NOS)] process." NWG Br., BP-12-B-NG-01, at 9.

BPA Staff's Position

Staff does not address this issue in testimony.

Evaluation of Positions

Iberdrola and NWG allege that BPA's actions outside the rate case have negative and discriminatory effects on wind energy producers. NWG refers to the delay of BPA's next NOS and claims that BPA intends to slow the pace of new wind project interconnections. NWG Br., BP-12-B-NG-01, at 9. Iberdrola alleges generally that BPA has an "effective moratorium" on new wind interconnections. Iberdrola Br., BP-12-B-IR-01, at 3.

The issues raised by Iberdrola and NWG are beyond the scope of this proceeding, but it is important that BPA clear up any misconceptions. The claims about an effective moratorium on interconnection of new wind facilities are incorrect. BPA is continuing to process NOS 2010 requests for new interconnections, sign interconnection agreements, and construct new interconnection facilities.

BPA has delayed the next NOS process to allow time to address certain NOS policy issues and to allow time for regional discussions regarding the next phase of wind integration in the Pacific Northwest. The delay of NOS applies to all customers seeking transmission service through NOS, not only those with wind generators. The claims of discrimination are misplaced under these circumstances. As a result of the 2008 NOS, BPA announced the intention to construct or conduct environmental review for over \$700 million of new transmission facilities. BPA recently announced that it would move forward with environmental review of approximately an additional \$200 million in new transmission infrastructure in response to requests in the 2010 NOS. To the extent that Iberdrola or NWG suggest it is inappropriate for BPA to take time to thoughtfully consider the policies supporting the regional investment in hundreds of millions of dollars' worth of new transmission infrastructure, BPA disagrees.

Decision

BPA has not announced an effective moratorium on the interconnection of new wind facilities in its balancing authority area.

Issue 3.2.4.8

Whether BPA could manage its reserve use more efficiently by not holding a fixed amount of reserves throughout the rate period.

Parties' Positions

NWG takes issue with the predictions of Staff, PPC, and JP01 that BPA is approaching the limits of the capacity-related services that can be reliably supplied from the FCRPS. NWG Br., BP-12-B-NG-01, at 21-22. NWG claims BPA has not yet taken adequate steps to implement reforms that would enable it to manage its existing resources more efficiently. *Id.* at 22. NWG states that one example of these steps is efficiency that could be gained by not holding a fixed amount of reserves during the rate period and using a different method to calculate the within-hour reserve requirement. *Id.* NWG states that BPA does not currently use a VER power production forecast for its unit commitment, dispatch, and reliability assessment process. *Id.* at 16-17. NWG admits that wind generation is more variable than some generating resource types but states that wind is forecast for every hour, and the amount of reserves held should be a function of the forecast. *Id.* at 17. NWG reasons that BPA uses load variability in its operations, and it is only reasonable to expect BPA to do the same for wind generators. *Id.* NWG claims that meteorological data can be used to inform expected project operations and the potential magnitude of schedule error. *Id.*

Citing to the VER Integration NOPR, NWG states that failing to consider VER power production forecasts in the hour-ahead, intra-day, day-ahead, and monthly time frames may result in an over-procurement of reserves, leading to rates that may be unjust, unreasonable, and unduly discriminatory. *Id.* at 17-18. NWG responds to Staff rebuttal testimony, which asserts that use of VER generation forecasts would be impractical for improving situational awareness and minimizing its current practice of holding balancing reserves during all hours of the year, by claiming that Staff's position is contrary to the overwhelming acknowledgement of the value of system-wide VER forecasts noted by the Commission in the VER Integration NOPR. *Id.* at 18. NWG also points out that other organized markets use VER power production forecast every day and has asked the Administrator to take official notice of the NREL report, *Status of Centralized Wind Power Forecasting in North America*. *Id.* at 18 n.37; NWG Br., BP-12-B-NG-01-AT01.

PPC cites to Staff's rebuttal testimony to assert that although BPA currently uses power production forecasts for hydro scheduling and system dispatch, changing the amount of balancing reserves based on power production forecasts would simply increase the risk of DSO 216 curtailments. PPC Br., BP-12-B-PP-01, at 6.

BPA Staff's Position

In response to NWG's assertion that value can be derived from a more sophisticated system for deploying reserves, Staff explains that:

BPA is a strong advocate of improved wind forecasting, and we believe that systematic improvements in forecasting combined with alignment between forecasts and wind generator schedules can reduce total balancing reserve capacity requirements over time, all else equal. However, due to requirements of hydro operations planning, decisions to stand ready to provide balancing reserve capacity must be made sufficiently far enough in advance that it is the assumed level of forecasting *accuracy*, rather than short-term wind forecasts, that is the driver of balancing reserve *capacity* requirements in the BPA balancing authority. By the time a forecast would indicate that balancing reserve capacity might not be needed, most of the cost of standing ready has already been incurred. Water moves through the hydro system in a coordinated fashion, with hours between dams, and the system must be set up in a way that provides both *inc* and *dec* reserves while meeting load obligations and accounting for non-power constraints.

Mainzer *et al.*, BP-12-E-BPA-42, at 14.

In response to NWG's suggestion that BPA should manage its reserves using a wind power production forecast and NWG's assertion that, because BPA does not adjust the amount of reserve based on a power production forecast, BPA is inefficient and has overstated the balancing reserve capacity needs, Staff states:

BPA Staff currently produces a VER power production forecast, and we also purchase forecasts from two vendors. BPA uses information from those forecasts to inform hydro schedulers and dispatchers of wind conditions. If BPA reduces the amount of balancing reserve capacity provided for VERBS, for any reason, there must be some associated adjustment in DSO 216 risk to ensure that balancing service use stays within the limits provided. In the context of its rate cases, BPA must establish a charge for service, and this becomes difficult without defining a specific level of service. If, for example, BPA adjusts the level of service provided on a day-to-day basis, based on wind forecasts, VERs would face a more uncertain amount of DSO 216 risk, and DSO 216 limits would need to be adjusted frequently. We do not agree that the amount of balancing reserve capacity should be adjusted on an hourly or daily basis, based on a VER power production forecast, because of the associated increased risk of triggering DSO 216.

Id. at 25.

Evaluation of Positions

NWG states that BPA could significantly reduce the amount of balancing reserve capacity needed to support VERBS by adjusting the reserve quantity based on VER power production

forecasts. According to NWG, there are times when the variability of the wind fleet is reduced, and the NREL report, *Status of Centralized Wind Power Forecasting in North America*, serves as evidence that other system operators are using VER power production forecasting to limit the amount of reserves they hold. NWG Br., BP-12-B-NG-01-AT01. At oral argument, NWG stated that “staff and customers may be talking past each other on [forecasting], customers asking for one thing and staff saying that’s not how it works.” Hall, Oral Tr. at 215-216. NWG states that the Commission thinks it works and that the California ISO looks at the forecast each day for what the expected variable energy resources generation is going to be, and based on that, they go out and procure resources or make operation decisions that day to try to optimize to that. *Id.* at 216. NWG concludes that the major point on forecasting is that if BPA were to take that forecasting and integrate it into its day-to-day operations, it would not have to hold the worst case scenario quantity of balancing reserves in all hours and all days. *Id.* at 217.

Although BPA does not disagree with NWG’s findings regarding other system operators, it is important to note the distinctions between the operation of an interconnected hydro system and the thermal systems cited by NWG. On a thermal system, if a VER power production forecast is used to plan the unit dispatch and it comes up short, there are likely to be other units that can be deployed. In contrast, if the hydro system is planned and committed to serve a lower level of reserves based on a VER power production forecast, water is moved and there may not be any way to increase the amount of reserves available from the system. Mainzer *et al.*, BP-12-E-BPA-42, at 14-15. This distinction is emphasized by the description of the California ISO’s use of VER power production forecasts provided by NWG at oral argument, explaining that the ISO uses the forecast to “go out and procure resources.” Hall, Oral Tr. at 216. For the FY 2012–2013 rate period, BPA is assuming that most all the balancing reserve capacity needed to supply Ancillary and Control Area Services will come from the FCRPS. BPA does not have the ability at this time to assume a lower level of reserves from the FCRPS and then procure additional reserves from an organized market on a day-ahead or real-time basis because such markets do not exist in the Pacific Northwest.

Hydro system operations must be planned in advance to ensure that the system can provide balancing reserve capacity and meet load obligations while complying with non-power constraints. Mainzer *et al.*, BP-12-E-BPA-42, at 14-15. As described in the NREL report, centralized VER power production forecasts are primarily used in the hour-ahead and day-ahead timeframes. NWG Br., BP-12-B-NG-01-AT01, at 18-20. BPA must plan its hydro operations several days or weeks in advance, and understanding the amount of balancing reserve capacity that will be required is a necessary part of that planning. Wind volatility becomes more unpredictable the further the forecast is from the hour of generation, and there is no specific time of year that shows significantly less volatility. BPA’s experience to date has been that there are a number of DSO 216 events every month, so every month there are at least a few times in which the full amount of balancing reserve capacity is being deployed. *See* Puylear *et al.*, BP-12-E-BPA-43, Attachment 3.

Even if the volatility of the VER fleet output can be predicted in advance for a certain time period, there is no way of guaranteeing wind generation schedulers will be scheduling accurately during those particular hours:

We assume, but cannot be certain, that parties will schedule according to the best available forecast available at 30 minutes prior to the delivery hour or scheduling interval. Because some parties may instead decide to schedule several hours ahead, based on the forecast available at that time in combination with operator judgment and marketing decisions, we cannot assume that the use of *inc* and *dec* reserves will relate directly to the uncertainty around a centralized forecast at a specific point in time. Therefore, we cannot make any assumptions in this rate proceeding about reduced costs based on adjusting the amount of *inc* and *dec* reserves due to wind forecasts.

Mainzer *et al.*, BP-12-E-BPA-42, at 15.

Unless there is some assurance that the wind generation schedulers are following the same forecast that the centralized forecast is based on and no unexpected deviation in scheduling occur, BPA's ability to hold less reserves and still maintain a known level of service is compromised. With the current scheduling protocols, any lowering of the amount of reserves would lead to a higher risk of DSO 216 and wind parties would have to be willing to accept that risk. *Id.* at 14-15, 25. NWG, other VER customers, and the balancing authorities that receive exports from wind generators located in BPA's balancing authority area have not indicated that they are willing to accept this higher level of DSO 216 risk. Quite to the contrary, most wind parties have argued in this rate proceeding for less exposure to DSO 216.

In addition to having no indication that affected parties are willing to accept more risk, BPA has no way to know how often or how much BPA could reduce reserves based on the VER centralized forecast and the timing of planning hydro system operations. This fact would make it very difficult to forecast a rate reduction:

As the balancing authority with the responsibility for maintaining system reliability, BPA has the obligation to ensure that sufficient balancing reserve capacity is available to meet the level of service that is determined in the rate proceeding, while recognizing that there may be short-term limitations in the ability of the FCRPS to provide balancing reserve capacity. Cost savings associated with adjustments in the quantity of balancing reserve capacity standing ready would require accuracy in longer-term wind forecasts. Due to the complexity of planning hydro system operations, the timeframe for adjusting the stand-ready amounts would be sufficiently long and far enough in advance of accurate centralized forecasts that forecast accuracy could not contribute to refinements. Savings could be obtained with sustainable improvements in wind forecasting accuracy coupled with a commitment to use such forecasts as the basis for wind generation schedules. Potential gains associated with reducing stand-ready reserve quantities would need to be associated with commitments to better scheduling accuracy and greater certainty about the types of variability or error that are included in the schedule.

Id. at 25-26.

Also, VERBS and the other ACS products are capacity-based services, so the full extent of the machine flexibility must be available when wind and loads are volatile. Capacity pricing is generally based on peak usage rather than actual use. For example, transmission pricing is based on the full amount of capacity that is reserved. The fact that this is a capacity service would justify assigning the embedded cost of the system to these services based on peak usage. NWG has argued that BPA's method for holding reserves is inefficient and leads to an unreasonable VERBS rate, but NWG has provided no suggestion as to how BPA could quantify or forecast the savings that would come from centralized VER forecasting. Modifying the reserve amounts on a daily or hourly basis based on a VER power production forecast would require a completely different kind of rate design from anything that has been proposed in this proceeding. The examples of other entities that use VER power production forecasts cited by NWG are ISOs with organized markets, which do not face the same rate structure as BPA. There is nothing in the record in this case that could be used to justify a rate reduction associated with using VER power production forecasts to adjust the amount of reserves BPA is providing for VERBS.

Although BPA does not see a way to incorporate VER power production forecasting into the rate design or the assumed operations for the FY 2012–2013 rate period, that does not mean that BPA does not support the concept of using VER power production forecasting or that BPA does not believe there is potential for significant savings that can be obtained if this tool is developed in the future. Consistent with BPA's VER Integration NOPR comments, BPA believes that VER power production forecasting used in conjunction with mandatory intra-hour scheduling requirements and an agreed upon source for individual wind generator forecasts that is consistent with the information that is informing the centralized forecast could lead to a significant reduction in reserve requirements, provided that wind schedulers are not deviating from the agreed upon forecast. *Integration of Variable Energy Resources*, FERC Docket No. RM10-11, Comments of the Bonneville Power Administration at 4, 28-30 (Mar. 2, 2011). This is why BPA believes the Committed Intra-Hour pilot is a step in the right direction. The Committed Intra-Hour pilot will provide a discount to VERBS customers that agree to schedule every half-hour based on a pre-determined forecast. The Committed Intra-Hour pilot is described in detail in ROD section 3.2.9.

Decision

Changing the operational assumptions for this rate period are not supported by the record, but BPA will investigate improvements such as the Committed Intra-Hour pilot to determine if VER power production forecasts and operational changes can be incorporated into future rate proceeding.

Issue 3.2.4.9

Whether BPA can take steps to firm up the quality of its wind balancing service without materially increasing the cost of providing such service.

Parties' Positions

NWG asserts that there are additional steps that BPA can and should take to firm up the quality of its wind balancing service without materially increasing the cost of providing such service. NWG Br., BP-12-B-NG-01, at 22. NWG contends that operational changes discussed in the issues above (basing the amount on reserves held on daily and hourly forecasts, relying on contingency reserves from the NWPP, changes in the operating of Banks Lake pump load, and tail management products) will allow BPA to use the FCRPS more efficiently and provide a higher level of VERBS without adding expensive incremental balancing reserve capacity to the system. *Id.* at 22-25.

BPA Staff's Position

Staff analyzes NWG's proposals to base the amount of reserves held on hourly or daily forecast, relying on contingency reserves, and changes in the operating of Banks Lake pump load and points out the misperceptions and problems with NWG's suggestions. Mainzer *et al.*, BP-12-E-BPA-42, at 14-15, 25-28; Puyleart *et al.*, BP-12-E-BPA-43, at 8-9.

Evaluation of Positions

Each of NWG's suggested operational changes are fully discussed in the evaluations of the Issues 3.2.4.3, 3.2.4.5, 3.2.4.6, and 3.2.4.8 above. NWG's assertion that BPA can operate the system more efficiently and provide more balancing service at lower cost during the FY 2012–2013 rate period is not supported by the record in this proceeding. Some of NWG's suggestions, including widespread use of intra-hour scheduling based on agreed upon forecasts, investment in additional pump storage, and the use of VER power production forecast may lead to significant reductions in the future, and BPA will continue to explore ways to provide more balancing reserve capacity service at lower cost.

Decision

The operational changes that NWG suggests are either not feasible in the FY 2012–2013 rate period or they will not provide the benefits NWG assumes. BPA will continue to investigate options for providing more balancing reserve capacity at lower cost.

3.2.5 Policy Risk Issues

Introduction

BPA's risk analysis focuses on possible events that can affect BPA's financial objectives, particularly the objective of having sufficient cash and liquidity to make all of BPA's payments to the Treasury. Lovell *et al.*, BP-12-E-BPA-15, at 5. BPA's 10-Year Financial Plan, adopted in 1993 and updated in 2008, calls for rates to be set high enough to achieve a 95 percent probability of making all scheduled payments to the Treasury on time. Power Risk and Market Price Study, BP-12-E-BPA-04, at 2. The fundamental protection against the risk of insufficient liquidity to pay the Treasury on time is financial reserves available for risk. *Id.* at 66. The main objectives of the PS risk mitigation package are to meet BPA's 95 percent TPP standard, to not

let financial reserves levels build up to unnecessarily high levels, and to allocate costs and risks of products to the rates for those products to the fullest extent possible. *Id.* at 5-6. The main tools in the PS risk mitigation package are:

- Planned Net Revenue for Risk (PNRR): this is a line item in the PS revenue requirement that serves to increase PS rate levels to generate additional revenue, thus bolstering financial reserves and TPP. *Id.* at 3.
- The Cost Recovery Adjustment Clause (CRAC): the CRAC is an upward rate adjustment mechanism that can increase certain rates if PS accumulated net revenue falls below the threshold set in the rate case. Like PNRR, the CRAC serves to generate additional reserves for making payments to the Treasury. *Id.* at 4.
- The Dividend Distribution Clause (DDC): the DDC is a downward rate adjustment mechanism that in effect returns financial reserves to customers that pay rates that are subject to PNRR and the CRAC if PS accumulated net revenue exceeds a threshold set in the rate case. *Id.* at 4.
- The NMFS FCRPS Biological Opinion Adjustment (NFB Adjustment): this measure will raise the limit on the amount of additional revenue that can be collected under the CRAC if one of five kinds of events related to litigation over the FCRPS BiOp occurs. *Id.* at 77-79.
- The Emergency NMFS FCRPS Biological Opinion Surcharge (Emergency NFB Surcharge): this measure is triggered by the same kinds of events that could trigger the NFB Adjustment, but if the within-year TPP is below 80 percent, the Emergency NFB Surcharge will raise rates within the year to generate additional financial reserves very rapidly instead of waiting for the CRAC for the next year. *Id.*

One significant change that Staff proposes is the application of the CRAC, NFB Adjustment, Emergency NFB Surcharge, PNRR, and DDC (risk mitigation tools) to balancing reserve capacity-based ACS rates. The application of risk mitigation tools to ACS rates was raised in the FY 2010–2011 rate proceeding, and at that time it was decided that the CRAC, NFB Adjustment, Emergency NFB Surcharge, PNRR, and DDC would not be applied to ACS rates. WP-10 ROD, WP-10-A-02, at 309, 311. Staff provides justification for re-opening this issue. Parties respond on both sides of the issue with wind parties opposing and preference customers supporting Staff's proposal.

Issue 3.2.5.1

Whether BPA staff's proposal to apply the CRAC, NFB Adjustment, Emergency NFB Surcharge, PNRR, and DDC to VERBS and other ACS rates is appropriate.

Parties' Positions

PPC states that applying the CRAC, PNRR, and Emergency NFB Adjustments to the VERBS and other ACS rates is appropriate because Staff is using average water to calculate the ACS rates. PPC Br., BP-12-B-PP-01, at 15. PPC rationalizes that ACS customers are receiving the

benefit of lower rates because BPA is using average water as opposed to critical water, and thus it is fair that if BPA experiences a below average water year, ACS customers should bear a portion of the risk that a shortfall in revenues will need to be made up before the subsequent rate period. *Id.* PPC claims that NWG's objections to BPA's proposal are unpersuasive, and NWG's argument that water variability is only one of the risks associated with BPA's operations misses the key point, because water variability is particularly associated with the Big 10 facilities used to set the balancing reserve capacity rates. *Id.* at 15-16. PPC states that the per-unit power costs associated with these facilities vary considerably by water year, and it is appropriate to apply these charges to balancing reserve capacity rates. *Id.* at 16.

WPAG argues that it would be appropriate to use critical water to calculate the ACS rates, but if BPA decides to continue to use average water, then the application of CRAC and PNRR is fully warranted. WPAG Br., BP-12-B-WG-01, at 14-15. WPAG characterizes the application of CRAC to the ACS rate as a correction of a past discriminatory practice that favored VERBS customers. *Id.* at 15. WPAG concludes that these are risk mitigation tools employed to deal with the financial risks associated with using an average water assumption, and those that share in the benefits of the Federal system must bear the cost of the system, including the risks associated with using an average water assumption. *Id.* at 16.

NWG states that the concept of applying CRAC, PNRR, and Emergency NFB Adjustments to the VERBS and other ACS rates is flawed for many reasons, including that Staff's proposal would reopen a previously settled issue, shifting power costs related to secondary revenues to non-Federal transmission customers is inequitable because non-Federal transmission customers do not benefit from secondary revenues, and the proposal violates section 7(g) of the Northwest Power Act. NWG Br., BP-12-B-NG-01, at 26. NWG argues that risk mitigation for power rates should be collected from power rates, and VERBS and other ACS rates are transmission rates. *Id.* NWG asserts that BPA's risk mitigation mechanisms are designed to recover power-related costs, the largest risk to power rates is the variability of secondary sales, and the Administrator has held that the VERBS will not receive credit for secondary revenues. *Id.* at 26-27. NWG states that cost causation principles and the Administrator's prior decisions on this issue make it clear that benefits follow responsibilities; since power rates enjoy the benefits of secondary revenues, it is fair that such rates pay BPA power costs when revenues are less than forecast. *Id.* at 27.

NWG argues that because VERBS is a capacity-based rate that does not present the risk in revenue fluctuation that other energy-based rates present, VERBS does not require additional risk mitigation components. *Id.* NWG argues that the VERBS rate is subject to other risk mitigating aspects, such as election period requirements, provisional balancing service, and DSO 216, and Staff has not made the case that even more risk mitigation is required for the VERBS rate. *Id.* NWG claims that Staff acknowledges that although ACS rates use of the system may create new risk, they may not impose all of the same risks that load service imposes. *Id.* at 28. NWG states that Staff acknowledges that it does not have a methodology for determining the responsibility for bearing the burden of risk mitigation on a product-by-product basis. *Id.* NWG claims that while Staff provides a long list of risks that it models, Staff provides no evidence quantifying these risks. *Id.*

NWG argues that Staff's apparent suggestion that its proposal is better than nothing cannot be the basis for adopting the proposal. *Id.* NWG states that if adopted, Staff's proposal would represent a major shift in agency policy, imposing significant costs on non-Federal transmission customers. *Id.* NWG asserts that it is Staff's responsibility to demonstrate the need and basis for this proposal with its own substantial evidence, not by the absence of a customer proposal. *Id.* NWG claims that by Staff's own test for whether the CRAC should apply to ACS rates, the facts are not supportive. *Id.* at 29.

NWG argues that it is inequitable to apply the CRAC to VERBS and other ACS rates, because these rates should not subsidize power rates for revenue shortfalls without receiving benefits from secondary revenues. *Id.* at 30-31. NWG explains that in the BPA-10 rate proceeding it argued that the Wind Balancing Service rate should be credited for a portion of secondary sales, but the Administrator rejected this argument based on Northwest Power Act section 7(g) specifically requiring that secondary sales revenues be equitably allocated to power rates. *Id.* at 30. NWG points out that in the BPA-10 proceeding Staff noted that the power rates risk mitigation costs are primarily driven by the uncertainty associated with secondary sales. *Id.* at 30-31. NWG rationalizes that since BPA's power customers have the right to the credit for secondary revenues and the responsibility to pay power costs, it would be inconsistent with such rights and responsibilities for the Administrator to assign responsibility for such power cost to a non-power rate, such as the VERBS rate, and to do so would be a classic example of a cost shift. *Id.* at 31. Additionally, NWG argues that with the addition of replenishing the transmission financial reserves that Power Services may rely on to support Treasury payments as a purpose of the CRAC, there is no evidence in the record showing that ACS ratepayers benefit from this arrangement. *Id.* at 32.

NWG states that Staff's proposal to apply the CRAC to the ACS rates rests on the conclusion that ACS rates benefit from basing the calculation of the cost of generation inputs on average water conditions. *Id.* NWG asserts that this justification is a major departure from the original purpose of the CRAC, which was to allow BPA's power customers to benefit from lower base rates while guaranteeing cost recovery for BPA. *Id.* at 32-33. NWG explains that in the WP-10 proceeding the Administrator decided to change the assumption in Staff's generation inputs embedded cost methodology from critical to average water and that the Administrator specifically decided to not apply CRAC to ACS rate, because using average water is not the same as providing a credit for the secondary power sales. *Id.* at 33-35. NWG asserts that in the BP-12 proceeding Staff is not proposing to credit ACS rates with secondary revenues and there are no new facts or basis in the record to cause the Administrator to revisit his earlier decision. *Id.* at 35. NWG claims that Staff and other parties have erroneously conflated use of average water to calculate the ACS rates with credit for secondary revenues, and the Administrator should reject these arguments because the issue was already decided in the last rate proceeding. *Id.* at 35-36.

NWG also asserts that Staff's proposed risk mitigation policy is contrary to the Commission's direction on separation of functions and is an impermissible cross-subsidization. *Id.* at 37. NWG argues that Staff's proposal is not consistent with cost causation, because the use of

average water is not a justification for subjecting ACS rates to the CRAC that may be triggered due to low secondary sales or to pay back a loan to transmission financial reserves. *Id.* NWG claims that ACS ratepayers do not receive any benefits from secondary revenues or the use of transmission financial reserves to support power revenues. *Id.* at 37-38.

NWG concludes by arguing that application of PNRR, CRAC and the Emergency NFB surcharge to ACS rates violates section 7(g) of the Northwest Power Act, because ACS rates are not power rates, and section 7(g) states that unless certain costs and benefits are otherwise allocated under other applicable provisions they should be allocated to power rates. *Id.* at 39. NWG states that such costs include fish and wildlife measures and the sale or inability to sell excess power. *Id.* NWG asserts that the Emergency NFB Adjustments results from changes in BPA's fish and wildlife program, and therefore Staff's proposal to assign these costs to ACS rates would violate the rate directive of section 7(g). *Id.* NWG applies the same rationale to PNRR as the CRAC based on the assertion that the primary driver for these risk mitigation tools is the risk associated with secondary power sales, and section 7(g) applies to both the benefits of secondary revenue and the costs associated with such revenue. *Id.* at 40-41.

In its brief on exceptions, NWG argues that BPA's logic of applying the CRAC to the VERBS rate is flawed, because the CRAC can trigger whether BPA experiences average water or not, and BPA has proposed no modifications to its CRAC to isolate average water risk from other risks that are not associated with VERBS. NWG Br Ex., BP-12-R-NG-01, at 5-6. NWG states that if BPA seeks to allocate the risk of average water to VERBS, BPA must design a risk mitigation tool that specifically allocates risk for average water and does not improperly shift costs by allocating risks for secondary revenues, which are not associated with VERBS. *Id.* at 6.

NWG claims that BPA acknowledges that at this time it does not have a methodology for determining the responsibility for bearing the burden of risk mitigation on a product-by-product, risk-by-risk basis and that in the absence of such a methodology BPA would be basing its decision on speculation rather than substantial evidence. *Id.* at 7.

NWG claims that in a below-average water situation BPA could be at risk of not being able to provide balancing reserves to VERBS at the level forecast in the rate case, and BPA is proposing two formula rates to recover costs through the VERBS rate if BPA must make incremental purchases of non-Federal balancing reserves to either maintain or increase the level of balancing reserves. *Id.* at 7-8. NWG argues that other than the risk of not being able to provide the forecast level of balancing reserves it is not evident what other risks are associated with average water, and since this risk is mitigated by the formula rates there is an overlap and it would not be equitable for BPA to apply both cost-recovery mechanisms to the VERBS rate. *Id.* at 8.

NWG concludes that because the record lacks substantial evidence quantifying and allocating the risk of average water to VERBS, BPA should either withdraw the current risk mitigation proposal for VERBS and develop a methodology to allocate average water risk for the FY 2014-2015 rate period or allocate a proportionate share of the associated secondary revenues to the VERBS rate. *Id.* at 12.

JP06 argues that BPA recognizes that the basis for applying the risk mitigation tools to ACS rates has not been adequately explored or explained and has not adequately demonstrated the relationship between the costs of risk attendant to the ACS rates and the risk mitigation tools so as to justify the proposed application to the ACS rates. JP06 Br. Ex., BP-12-R-JP06-01, at 2. JP06 claims that the application of the risk mitigation tools to ACS rates is not supported by a full and complete justification or substantial evidence in the record. *Id.* JP06 states that regardless of whether BPA applies the risk mitigation tools to ACS rates, it is important that BPA work with parties to investigate whether and what type of risk mitigation tools may be appropriate to apply to ACS rates. *Id.* at 3.

JP06 argues that the risk mitigation tools BPA proposes to apply to the VERBS rate are not limited to the power-based risk mitigation tools, because BPA has also imposed the VERBS Formula Rates I and II. *Id.* at 3-4. JP06 concludes that the record does not support BPA's proposal to apply the risk mitigation tools to ACS rates and this is particularly true for VERBS because of the additional risk mitigation tools of Formula Rates I and II. *Id.* at 5.

BPA Staff's Position

Staff supports applying risk mitigation tools to the balancing reserve capacity-based ACS rates. In the Initial Proposal Staff explained the rationale for applying the CRAC to ACS rates:

[T]hese ACS rates benefit from basing the calculation of the cost of generation inputs on average water conditions, and there is considerable risk in any given year that the actual volume of water will fall short of the average amount. This risk is one of the two largest risks that we treat with the Power risk mitigation package, and it is reasonable that customers that benefit from the rate case anticipation of average water, including those that pay these ACS rates, help shoulder the treatments of hydro volume risk.

Lovell *et al.*, BP-12-E-BPA-15, at 57.

Staff also explains the procedural history of this issue in the WP-10 rate proceeding:

In the WP-10 rate case BPA Staff proposed not to apply risk mitigation tools to the Wind Balancing Rate or any balancing reserve capacity-based Ancillary and Control Area Services. The WP-10 Initial Proposal based this election on the use of critical water as a basis for establishing the uses of FCRPS capacity. This use of critical water as a basis for the embedded cost calculation did not account for secondary sales as a system use and, therefore, Staff reasoned that it was not appropriate to apply BPA's risk mitigation tools, which are associated with the uncertainty of secondary sales. Klippstein *et al.*, WP-10-E-BPA-24 at 3. In the Draft Record of Decision (ROD), the draft decision was to use average water as the basis for establishing the uses of the capacity of the FCRPS. The reasoning was that basing the cost allocation on average water instead of critical water could require application of risk mitigation tools such as PNR, CRAC, and DDC, but concluded such change was not necessary, because the Wind Balancing Rate did not receive an allocation of any secondary sales revenue. WP-10 Draft ROD,

WP-10-A-01, at 267. The final decision of the Administrator did not change. WP-10 Final ROD, WP-10-A-02, at 309 and 311.

Mainzer *et al.*, BP-12-E-BPA-23, at 56-57.

Staff describes new information that led Staff to revisit the decision of whether to apply risk mitigation tools to balancing reserve capacity based ACS rates:

Previously BPA Staff did not consider the impact of water conditions on the amount of variable costs caused by the provision of balancing reserve capacity-based Ancillary and Control Area Services. When BPA Staff analyzed the level of variable costs based on critical water and not the average of 70 water conditions, the amount of variable costs attributable to balancing reserve capacity-based Ancillary and Control Area Services increased to \$39.9 million. This amount is significantly more than the \$25.2 million expected on average across all water conditions. Klippstein *et al.*, BP-12-E-BPA-25, section 5.3. In addition, staff reviewed the decision from the 2010 rate proposal. Given the use of the average water assumption for allocating embedded costs, it appears to staff upon further review that the users of these capacity reserve-based rates realize a benefit (*i.e.*, a lower rate) from this assumption of additional capacity. This additional capacity allows for the sale of secondary energy. Thus, BPA Staff proposes to apply BPA's risk mitigation tools to balancing reserve capacity-based Ancillary and Control Area Services in this rate proceeding.

Id. at 57.

Staff describes the policy rationale behind the proposal to apply risk mitigation tools to the balancing reserve capacity-based ACS rates:

The rationale is that basing the costs of balancing reserve capacity-based Ancillary and Control Area Services rates on average water instead of critical water yields lower rates, that is, customers purchasing these services realize a benefit from the use of average water as part of the cost basis. There is considerable risk that actual water volume will be below average in any one year. This risk represents a large fraction of the total risk that Power's risk mitigation measures are designed to treat. It is reasonable for ACS customers who benefit from the assumption of average water in the calculation of rates based on Power system operations contribute to mitigating that risk by paying a share of PNRR, when Power rates include it, and by being subject to the CRAC, the DDC, and the Emergency NFB Surcharge.

Id. at 57-58.

In rebuttal testimony, Staff explains that its risk mitigation methodology aggregates all risks and it does not have a methodology for determining the responsibility for bearing the burden of risk mitigation on a product-by-product, risk-by-risk basis. Lovell and Mandell, BP-12-E-BPA-37, at 31. Staff postulates that such a methodology would consider at least two factors:

(1) Does the provision of a product or service directly create financial risk for BPA? For example, is the volume of ACS sales uncertain, with the result that BPA's net revenue may be higher or lower than anticipated in the rate case due to the uncertainty in ACS sales? (2) Does the estimation of the cost of providing a product or service depend on assumptions that cannot be known with certainty, the ultimate resolution of which could affect BPA's financial results? For example, does the assumption of average hydro volume in the calculations of the cost of supporting ACS sales create financial uncertainty for BPA because the actual costs depend in part on the uncertain hydro conditions, or does uncertainty in market prices affect the financial impact of the constraint on BPA's ability to optimize its secondary marketing activities due to holding reserves for ACS support? If the answers to questions 1 and 2 are generally "no," then we might conclude that including no risk mitigation in the ACS rates would be more fair than including the whole package BPA has proposed.

Id. at 32-33.

In response to NWG's argument that applying CRAC to the VERBS rate based on the use of average water in the embedded cost methodology is not consistent with cost causation, Staff states that while it agrees that Ancillary and Control Area Service rates and use of the system to support them may not impose all of the same risks that load service imposes, they create some new risks. Mainzer *et al.*, BP-12-E-BPA-42, at 41. The risks imposed by providing Ancillary and Control Area Service are sufficient to warrant their participation in risk mitigation. *Id.*

Staff lists all the risks that are quantified in RiskMod and the Non-Operating Risk Model:

RiskMod includes these risks: market price for electricity (based in turn on natural gas variability and basis risks; hydro uncertainty in the Pacific Northwest, California, and British Columbia; wind generation shape and uncertainty; transmission availability; and regional thermal plant output uncertainty), BPA load risk, Columbia Generating Station (CGS) output risk, uncertainty in wind generation under contract to PS, risk in PS expenses for transmission and ancillary services, system augmentation expense, and Federal hydro generation. The Non-Operating Risk Model (NORM) includes risks in these factors: CGS O&M, Corps of Engineers O&M, Bureau of Reclamation O&M, Residential Exchange Program (REP) Exchangeable Load, Conservation expense, settlements for the Colville and Spokane tribes, PS internal expenses, Fish and Wildlife (BPA Direct program, U.S. Fish and Wildlife Lower Snake River Hatchery expense, Bureau of Reclamation Leavenworth Complex O&M, FCRPS Biological Opinion (BiOp) Performance Standard uncertainty), CGS Condenser Replacement Outage, and ACS Sales Volume uncertainty.

Lovell and Mandell, BP-12-E-BPA-37, at 33.

Staff then explains:

Many of these risks are related to the costing or support of ACS sales. ACS provision depends on the Federal hydro system; uncertainty in the cost or capability of that system then seems related to ACS—O&M uncertainty, and expense or capability uncertainty due to uncertainty in the area of fish mitigation. The impact on system operations of setting aside reserves for resource integration seems to be clearly linked to hydro volumes and the uncertainty around those volumes. The financial impact of deoptimizing secondary marketing due to setting aside reserves—that is, the variable cost of integrating resources—depends on the market price of power, so uncertainty in market prices creates uncertainty in the cost of resource integration. BPA Staff believes that it is more fair to apply BPA’s rate case risk mitigation, the CRAC and PNR, to ACS rates than not to apply them.

Id. at 33-34.

Evaluation of Positions

This section evaluates the primary arguments raised by parties, and additional parts of NWG’s argument are evaluated in nine sub-issues that follow this evaluation section.

Many of NWG’s arguments are based on an assumption that application of the CRAC to non-Federal transmission customers is unfair or illegal. However, most of BPA’s customers for power, transmission, and ancillary and control area services are non-Federal entities. The fundamental issues are clearer when discussed in terms of the rates to which the CRAC is to be applied. The main issue is whether the balancing reserve capacity-based ACS *rates* ought to be subject to the CRAC. ACS is not a rate for the purchase of transmission; but it is a rate for services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the transmission system. These services are produced by the power system.

NWG and JP06 provide several arguments against the application of the risk mitigation tools to the ACS rates, and PPC and WPAG clearly support the application of risk mitigation tools to ACS rates. The decision regarding the application of the risk mitigation tools to ACS rates turns on whether there are significant aspects of the balancing reserve capacity-based ACS rate design that lead to financial risks, such as, financial risks attributable to resources BPA must maintain or actions BPA must take to support the provision of the services.

NWG argues that risk mitigation for power rates should be collected from power rates and VERBS and other ACS rates are transmission rates. NWG Br., BP-12-B-NG-01, at 26. This is a foundational theme for several of NWG’s arguments that are addressed in various sub-issues below. It is important to recognize that balancing reserve capacity-based ACS rates are generation input costs because these services are provided from the generation capacity provided from the FCRPS to balance the movement of generation and load interconnected in BPA’s balancing authority area. Mainzer *et al.*, BP-12-E-BPA-23, at 13-15. The ACS rates are designed to recover a portion of the embedded system cost of the FCRPS projects that are used

to provide this balancing reserve capacity and the variable cost BPA incurs from setting up the system to maintain and deploy this balancing reserve capacity. Thus the balancing reserve capacity-based ACS rates are directly linked to the assumptions Staff makes regarding the forecast performance of the FCRPS and its ability to provide balancing reserve capacity, including the assumptions about water conditions. Using average water conditions as an assumption in the embedded cost allocation means that more water (compared to critical water conditions) is available to create capacity, and rates that are based on this assumption will be lower. Klippstein *et al.*, BP-12-E-BPA-25, at 11. A critical water assumption would mean that relatively less water is available (than under average water), and rates based on this assumption will be higher.

For example, in the FY 2010–2011 rate proceeding Staff’s initial proposal used critical water to calculate the Wind Balancing Service rate. Generation Inputs Study and Study Documentation, WP-10-E-BPA-08, section 3.3. In the final studies average water was used, resulting in a much lower Wind Balancing Service rate. Generation Inputs Final Study, WP-10-FS-BPA-08, section 3.3. Some of this change in the rate was due to other factors, but a significant portion of the difference is a direct result of changing from critical to average water in the embedded cost methodology.

NWG is correct that the ACS rates are transmission rates; however, NWG’s conclusion that the risk mitigation tools, such as CRAC, are a risk mitigation tool only for power rates and thus should not be applied to the ACS rates is based on a false premise. The purpose of the risk analysis and the risk mitigation tools is to ensure that BPA will have at least a 95 percent probability of recovering enough revenue to make both of its Treasury payments in the rate period. Power Risk and Market Price Study, BP-12-E-BPA-04, at 1-2. NWG describes the original purposes of the CRAC and other risk mitigation tools as twin objectives of allowing BPA’s power customers to benefit from lower base rates while guaranteeing cost recovery for BPA. NWG Br., BP-12-B-NG-01, at 33. The authority cited for the purpose of “lower base rates” needs to be put in context. The fundamental reason that CRACs (and PNRR) have been employed is to provide risk mitigation, specifically mitigation of the risk of not generating enough net revenue for making BPA’s Treasury payments. This same logic holds true for the ACS rates. Using average water results in significantly lower balancing reserve capacity-based ACS rates, thus generating less revenue for making BPA’s Treasury payments. If BPA experiences below-average water, the cost of providing ACS increases and BPA’s net revenue decreases. BPA needs a means to increase the assurance of cost recovery, which is a statutory obligation of both power and transmission. *See, e.g.*, 16 U.S.C. § 839e(a)(1). The fact that ACS rates are transmission rates does not resolve the issue of whether or not the risk mitigation tools should apply to the ACS rates.

NWG explains that BPA’s decision to revise its embedded cost methodology by using average water rather than critical water late in the FY 2010–2011 rate proceeding was based on Cowlitz’s argument that using critical water in the methodology did not account for any non-firm use and the Big 10 generation projects produce a substantial amount of secondary energy and that BPA concluded that using average water was a better representation of the peaking capability of the hydro system than critical water for purposes of allocating costs to generation inputs. NWG Br.,

BP-12-B-NG-01, at 34, *citing* WP-10 ROD, WP-10-A-02, at 306, 310. This rationale still makes sense, and BPA continues to use average water in the embedded cost methodology in this proceeding. However, it does not make sense that the risk associated with the average water assumption should go unmitigated. The argument raised by NWG regarding the reopening of a previously settled issue and evaluation of the decision in the WP-10 ROD to not apply the risk mitigation tools to ACS rates is discussed in Sub-Issue 3.2.5.1.8 below.

In regard to whether the ACS rates create risk that needs to be mitigated, Staff concludes that ACS rates and use of the system to support them may not impose all of the same risks that load service imposes, but that they do create some new risks. Staff believes that on balance the risks imposed by providing Ancillary and Control Area Service are sufficient to warrant their participation in risk mitigation. Mainzer *et al.*, BP-12-E-BPA-42, at 41. NWG takes issue with this conclusion on the basis that Staff acknowledges that it does not have a methodology for determining the responsibility for bearing the burden of risk mitigation on a product-by-product basis. NWG Br., BP-12-B-NG-01, at 28.

NWG claims that BPA acknowledges that at this time it does not have a methodology for determining the responsibility for bearing the burden of risk mitigation on a product-by-product, risk-by-risk basis and that in the absence of such a methodology BPA would be basing its decision on speculation rather than substantial evidence. NWG Br. Ex., BP-12-R-NG-01, at 7. JP06 argues that BPA recognizes that the basis for applying the risk mitigation tools to ACS rates has not been adequately explored or explained and has not adequately demonstrated the relationship between the costs of risk attendant to the ACS rates and the risk mitigation tools so as to justify the proposed application to the ACS rates. JP06 Br. Ex., BP-12-R-JP06-01, at 2. Staff has demonstrated that using average water to calculate the ACS rates imposes a substantive financial risk on BPA. Mainzer *et al.*, BP-12-E-BPA-23, at 57; Lovell *et al.*, BP-12-E-BPA-15, at 57. NWG and JP06 miss the point that the risk methodology is designed to aggregate all risks in order to quantify the amount of financial protection that BPA will need to ensure a 95 percent probability of making all scheduled payments to Treasury on time. Demonstrating the specific risks associated with specific products does not inform the overall risk BPA faces in regard to ensuring it can make its Treasury payments. BPA is allocating only a small portion of the risk mitigation costs to ACS rates based on the revenue requirement associated with these rates as compared to other rates to which the risk mitigation tools apply. NWG seeks to dictate a fundamental change in BPA's financial risk mitigation approach, asserting that risk mitigation that does not quantify each and every risk—and the relationship between each risk and each rate—is fatally flawed. BPA rejects this unsubstantiated assertion.

NWG also argues that Staff provides a long list of risks that it models, but Staff provides no evidence quantifying these risks. *Id.* NWG states that this is not a satisfactory analysis. *Id.* Contrary to NWG's assertion that Staff provides no evidence quantifying these risks, Staff does explain how the risks that are modeled relate to the ACS rates. Lovell and Mandell, BP-12-E-BPA-37, at 33-34. Staff explains that many of these risks are related to the costing or support of ACS sales. ACS provision depends on the Federal hydro system; uncertainty in the cost or capability of that system then seems related to ACS—O&M uncertainty, and expense or capability uncertainty due to uncertainty in the area of fish mitigation. The impact on system

operations of setting aside reserves for resource integration seems to be clearly linked to hydro volumes and the uncertainty around those volumes. The financial impact of deoptimizing secondary marketing due to setting aside reserves—that is, the variable cost of integrating resources—depends on the market price of power, so uncertainty in market prices creates uncertainty in the cost of resource integration. *Id.*

As NWG points out, Staff's risk mitigation methodology aggregates all risks and does not have a methodology for determining the responsibility for bearing the burden of risk mitigation on a product-by-product basis. *Id.* at 31. However, it is important to recognize that aggregating all the risks results in a lower overall cost than if BPA were to account for each risk and assess the need for risk mitigation tools based on the cumulative impact of adding all the risks together. NWG asserts that Staff's apparent suggestion that its proposal is better than nothing cannot be the basis for adopting the proposal. NWG Br., BP-12-B-NG-01, at 28. Staff does not state that applying the proposed risk mitigation tools to the ACS rates is better than nothing. Staff does recognize that not all of the risks that are analyzed for the power rates apply to the ACS rates, but the ACS rates are directly tied to the risk that in any given year the actual volume of water will fall short of the average amount, and that this risk is one of the two largest risks that is treated with the power risk mitigation package. Lovell *et al.*, BP-12-E-BPA-15, at 57. Since the use of average water in determining the balancing reserve capacity-based ACS rates does impose a risk on BPA, it makes sense to mitigate the risk with the possibility of raising the ACS rates if the assumptions on which the rate is based turn out to be erroneous and BPA's financial reserves are threatened. The fact that the proposed suite of risk mitigation tools is not perfectly tailored to the risks associated with the ACS rates and Staff has not broken out the individual risk by product does not mean that application of the proposed risk mitigation tools is unreasonable or inconsistent with the principle of cost causation. As mentioned above, adding up the cost of individual risks would result in higher costs than Staff's aggregation methodology. In addition, the complexity of the analysis NWG claims is necessary (quantitatively assessing the relationship between each risk and each rate) would create additional costs that would be borne by all power and generation inputs customers.

JP06 states that regardless of whether BPA applies the risk mitigation tools to ACS rates, it is important that BPA work with parties to investigate whether and what type of risk mitigation tools may be appropriate to apply to ACS rates. JP06 Br. Ex., BP-12-R-JP06-01, at 3. It may be that there is a better way to allocate risk to the ACS rates. BPA and its customers can investigate different approaches prior to the next rate proceeding, but for the FY 2012–2013 rate period BPA's risk mitigation tools are CRAC, PNRR, NFB Adjustment, Emergency NFB Surcharge, and DDC.

NWG asserts that Staff's proposal would represent a major shift in agency policy, imposing significant costs on non-Federal transmission customers. NWG Br., BP-12-B-NG-01, at 28. Staff's proposal will impact non-Federal transmission customers if any of the rate mitigation tools is triggered during the rate period, but it is not necessarily a major shift in agency policy. Prior to the last rate proceeding, BPA used critical water to calculate the embedded cost of the generation inputs used to provide the ACS, so there was no reason to evaluate the risk associated with using average water in the methodology. BPA's ratemaking policy has consistently

attempted to ensure that customers receiving benefits from the FCRPS should bear an appropriate share of the costs of the system, including the costs of risk mitigation. With the dramatic increase of wind generation interconnecting to the BPA system in the last few years, the use of balancing reserve capacity and the risks associated with setting ACS rates has become much more prominent. As the provision of balancing reserve capacity for ACS has increased to become significant, it has become more important that BPA ensure that customers using this balancing reserve capacity bear an appropriate share of the costs and risks.

JP06 claims that the application of the risk mitigation tools to ACS rates is not supported by a full and complete justification or substantial evidence in the record. JP06 Br. Ex., BP-12-R-JP06-01, at 2. NWG suggests that it is Staff's responsibility to demonstrate the need and basis for this proposal with its own substantial evidence, not by the absence of a customer proposal. NWG Br., BP-12-B-NG-01, at 28. Staff does demonstrate that the use of average water in the embedded cost methodology results in risks that need to be mitigated, and Staff describes how many of the risks in the risk model are directly related to the forecast of water available to the FCRPS. Lovell *et al.*, BP-12-E-BPA-15, at 57; Lovell and Mandell, BP-12-E-BPA-37, at 33-34; Mainzer *et al.*, BP-12-E-BPA-23, at 57.

NWG argues that Staff's proposal is flawed because it is not consistent with cost causation because the use of average water is not a justification for subjecting ACS rates to the CRAC that may be triggered due to low secondary sales or to pay back a loan to transmission financial reserves, and ACS ratepayers do not receive any benefit from secondary revenues or the use of transmission financial reserves to support power revenues. NWG Br., BP-12-B-NG-01, at 37. The specific discussion of the interaction of the CRAC with low secondary sales and paying back a loan to transmission financial reserves is addressed in the evaluation of Sub-Issues 3.2.5.1.4 and 3.2.5.1.6.

As to whether Staff's proposal is consistent with cost causation, PPC and WPAG base their support for Staff's proposal on the facts that there are risks associated with using average water in the embedded cost methodology, and the ACS customers benefit from the lower ACS rates that result from using average water in the methodology. PPC Br., BP-12-B-PP-01, at 15-16; WPAG Br., BP-12-B-WG-01, at 15-16. NWG states that in its "view, 'cost causation' means that costs should be allocated to the rates and the customers that benefit from such cost." NWG Br., BP-12-B-NG-01, at 38. NWG makes this statement in the context of arguing that CRAC should not apply to ACS rates because the CRAC trigger is affected by low secondary sales and paying back a loan to transmission financial reserves; however, the CRAC trigger is affected by many risks, including, for example, the risk that installed wind capacity on the system will be lower than forecast, thus generating less VERBS revenue that TS receives and passes to PS. NWG's understanding of cost causation does not appear to conflict with PPC's and WPAG's rationale for supporting Staff's proposal.

In addition, NWG's argument appears to ignore that use of average water initially protects ACS rates to some degree from higher cost attendant to use of critical water. Fewer secondary sales revenues would be a consequence of below-average water, such that ACS and other rates should be revised. Similarly, replenishing transmission financial reserves would be necessary only if

risks, such as low water, have occurred and necessitated consumption of financial reserves to cover costs. As indicated, ACS rates should not be shielded from that cost recovery responsibility.

NWG claims that in a below-average water situation BPA could be at risk of not being able to provide balancing reserves to VERBS at the level forecast in the rate case, and BPA is proposing two formula rates to recover costs through the VERBS rate if BPA must make incremental purchases of non-Federal balancing reserves to either maintain or increase the level of balancing reserves. NWG Br. Ex., BP-12-R-NG-01, at 7-8. NWG argues that other than the risk of not being able to provide the forecast level of balancing reserves, it is not evident what other risks are associated with average water, and since this risk is mitigated by the formula rates there is an overlap, and it would not be equitable for BPA to apply both cost-recovery mechanisms to the VERBS rate. *Id.* at 8. Likewise, JP06 argues that the risk mitigation tools BPA proposes to apply to the VERBS rate are not limited to the power-based risk mitigation tools, because BPA has also imposed the VERBS Formula Rates I and II. JP06 Br. Ex., BP-12-R-JP06-01, at 3-4. JP06 claims that BPA does not analyze the relationship between the cost and risks attendant to VERBS, the power rate mitigation tools, and the VERBS Formula Rates I and II. *Id.* at 4. JP06 concludes that the record does not support BPA's proposal to apply the risk mitigation tools to ACS rates, and this is particularly true for VERBS because of the additional risk mitigation tools of Formula Rates I and II. *Id.* at 5.

The VERBS Formula Rates I and II are discussed in section 3.5.3 of the ROD. VERBS Formula Rate II is designed to trigger only if BPA increases the level of service during the FY 2012–2013 due to circumstances specified in the rate schedule. Generation Inputs Study, BP-12-FS-BPA-05, section 10.5.3. It is simply a pass-through mechanism for the additional costs BPA would incur if the level of service were increased, so VERBS Formula Rate II is not related to any of the financial risks that BPA's risk mitigation tools are designed to address.

VERBS Formula Rate I would be used to assign the net costs of non-Federal capacity purchases to the VERBS rate if BPA is unable to supply the forecast amount of balancing reserve capacity from the FCRPS for an extended period of time during the FY 2012–2013 rate period. *Id.* at section 10.5.2. NWG's claim that other than the risk of not being able to provide the forecast level of balancing reserves, it is not evident what other risks are associated with average water, and that this risk is addressed by the VERBS Formula Rates, ignores Staff's testimony regarding the multiple financial risks associated with assuming average water. Mainzer *et al.*, BP-12-E-BPA-23, at 57; Lovell *et al.*, BP-12-E-BPA-15, at 57. The financial risk of using average water stems from the fact that BPA's costs of providing ACS will be higher than forecast in a below-average water year. BPA's potential determination that the FCRPS is not capable of supplying the forecast amount of balancing reserve capacity to support ACS and implementation of VERBS Formula Rate I during the same year is immaterial to the financial exposure BPA would face due to the increase in costs of providing ACS from the FCRPS.

JP06 postulates an example of the NFB mechanisms reducing revenues and the potential that BPA could mitigate this with Formula Rate I for the VERBS rate. JP06 Br. Ex., BP-12-R-JP06-01, at 4-5. This could happen, but again passing through the net costs of non-Federal

capacity that BPA purchases under VERBS Formula Rate I will not mitigate the additional costs BPA incurs due to the higher costs of producing balancing reserve capacity from the FCRPS. NWG's assertion that there is an overlap between the VERBS Formula Rates and the risk mitigation tools is not supported by the record. Similarly, JP06's claim that BPA has not analyzed the relationship between the risk mitigation tools and the VERBS Formula Rates I and II, and that the record does not support the application of the risk mitigation tools to the ACS rates, is not supportable because the rate mitigation tools and the VERBS Formula Rates operate completely independently. There is no nexus between BPA's financial situation that could trigger the risk mitigation tools and the need to pass through the net costs of acquiring non-Federal capacity to meet the forecast amount of ACS or passing through additional costs of non-Federal capacity associated with raising the level of service for VERBS customers.

NWG argues that BPA's logic of applying the CRAC to the VERBS rate is flawed, because the CRAC can trigger whether BPA experiences average water or not, and BPA has proposed no modifications to its CRAC to isolate average water risk from other risks that are not associated with VERBS. NWG Br Ex., BP-12-R-NG-01, at 5-6. NWG states that if BPA seeks to allocate the risk of average water to VERBS, BPA must design a risk mitigation tool that specifically allocates risk for average water and does not improperly shift costs by allocating risks for secondary revenues, which are not associated with VERBS. *Id.* at 6.

NWG is correct that BPA could trigger a CRAC even if it is not a below-average water year. As is explained above, BPA's risk methodology aggregates all the financial risks in order to lower the overall cost of risk mitigation. Staff has explained that there are several other risks that are applicable to ACS rates, including the volume of ACS sales, increased operation and maintenance costs on the generation projects that provide ACS, and uncertainty in market prices that are used directly in the calculation of the variable cost component of the ACS rates. Lovell and Mandell, BP-12-E-BPA-37, at 33-34. While the use of average water in the ACS cost methodology is the largest risk associated with ACS rate, there are other risks associated with ACS rates that could contribute to financial shortfalls that trigger a CRAC even in an average water year. Thus, BPA does not need to design special risk mitigation tools that trigger only in below-average water years, and BPA can use the existing risk mitigation tools to apply a reasonable share of risk mitigation responsibility to ACS customers.

NWG concludes that because the record lacks substantial evidence quantifying and allocating the risk of average water to VERBS, BPA should either withdraw the current risk mitigation proposal for VERBS and develop a methodology to allocate average water risk for the FY 2014–2015 rate period or allocate a proportionate share of the associated secondary revenues to the VERBS rate. NWG Br Ex., BP-12-R-NG-01, at 12. This conclusion is based on the misperception that all risks in BPA's aggregated risk methodology must align with a product before BPA can assign the risk mitigation tools to the product. There is substantial evidence that the risk of below-average water and several other risks that are analyzed in the risk methodology are applicable to the ACS rates. Lovell and Mandell, BP-12-E-BPA-37, at 33-34. BPA does not need to develop a methodology to allocate average water risk or allocate a proportionate share of the associated secondary revenues to the VERBS rate before it assigns some risk mitigation responsibility to ACS customers.

The focus of NWG arguments is on the risk aspects that are not necessarily applicable to ACS rates, but NWG does not assert that there is no risk associated with using average water in the ACS cost allocation methodology. In addition to the formula rate issue addressed above, NWG does suggest that since VERBS is subject to other risk mitigation aspects it does not require additional risk mitigation. NWG Br., BP-12-B-NG-01, at 27. This argument is evaluated in Sub-Issue 3.2.5.1.7. Since the fact that there is risk associated with the use of average water is not disputed, cost causation dictates that BPA use the tools that it has available to mitigate that risk.

However, parties have raised several issues with the application of the risk mitigation tools to the ACS rates, and there is some level of doubt as to whether the full amount of risk mitigation should be applied to the ACS rates. NWG proposes fundamental changes in BPA's longstanding financial risk mitigation approach that have had little or no discussion among rate case parties. The formula for applying risk mitigation tools to the ACS rates is based on the revenue requirement of the ACS rates as a portion of the overall power revenue requirement, and it results in a ratio that would apply 7.2 percent of an applicable risk mitigation to ACS rates. Based on the record, the use of average water to calculate the ACS rates does impose a risk that needs to be mitigated, but this is the first time BPA has applied the risk mitigation tools to ACS rates, and BPA recognizes that the full application of the risk mitigation tools to the ACS rates needs more discussion among BPA and parties. Thus BPA will reduce the 7.2 percent of an applicable risk mitigation to 3.6 percent. This will ensure that ACS customers pay a share of any risk mitigation, but it will not impose the full burden of the risk mitigation on these customers. As is discussed above, BPA will work with customers to refine its risk mitigation tools for the next rate case to better allocate the level of risk associated with average water to the ACS rates, but for this rate period BPA needs to use the tools that are available.

Decision

BPA will apply the risk mitigation tools to the balancing reserve capacity-based ACS rates, because there are significant risks associated with the ACS rate design, and customers that benefit from the use of the FCRPS should bear the costs of the system, including financial risk mitigation; however, BPA recognizes that the set of risks associated with the provision of Ancillary and Control Area Services may not be identical to the set of risks which have historically been mitigated by the risk mitigation tools, and will therefore reduce the fraction of any CRAC, Emergency NFB Adjustment, or DDC amount to be recovered from ACS rates from 7.2 percent to 3.6 percent for the FY 2012–2013 rate period. In addition, for the next rate period BPA will work with parties to investigate and assess the risks associated with these ACS rates and to determine the appropriate risk mitigation to be borne by ACS rates.

Sub-Issue 3.2.5.1.1

Whether the uncertainty of the volume of ACS sales creates financial risk for BPA.

Parties' Positions

NWG asserts that because the VERBS rate and other ACS rates are based on capacity charges, which means that revenues from ACS services are very predictable, the volume of ACS sales does not create financial risk for BPA. NWG Br., BP-12-B-NG-01, at 29.

NWG asserts that the risk of variation in the amount of installed wind capacity as compared to rate case forecast alone is not sufficient to justify applying the CRAC to VERBS, because less VERBS sales would be offset by BPA using the capacity to make additional secondary sales. NWG Br. Ex., BP-12-R-NG-01, at 9.

BPA Staff's Position

Staff explains that the volume of ACS sales is a risk that is modeled in the Non-Operating Risk Model. Lovell and Mandell, BP-12-E-BPA-37, at 33.

Evaluation of Positions

Staff describes a two-part test for determining whether CRAC should apply to the ACS rate. *Id.* at 32. NWG asserts that the answer to both parts of Staff's test is no, and thus the CRAC should not be applied to the ACS rates. NWG Br., BP-12-B-NG-01, at 29. This sub-issue relates to the first question in the two-part test: Does the provision of a product or service directly create financial risk for BPA? For example, is the volume of ACS sales uncertain, with the result that BPA's net revenue may be higher or lower than anticipated in the rate case due to the uncertainty in ACS sales?

The rate design of the VERBS rate is based on installed wind capacity, which is more stable than the volume risk associated with some rates. However, there are several factors that can impede or accelerate the interconnection of wind generation during the rate period, which creates some risk associated with BPA's forecast, and this risk can result in a financial impact. Lovell and Mandell, BP-12-E-BPA-37, at 33. The Non-Operating Risk Model (NORM) simulates this uncertainty. In NORM, VERBS revenue for FY 2013 can be as much as \$7.5 million below the amount assumed in the base rate calculations.

Other ACS rates are different from the VERBS rate in that they are based on actual usage of the transmission system rather than installed capacity. For example, Operating Reserves, the second highest revenue producer of the ACS rates, is charged based on actual use of the transmission system by generators located in BPA's balancing authority. The forecast for Operating Reserves is based on historical usage and is more susceptible to the volume risk than the VERBS rate. Chen *et al.*, BP-12-E-BPA-26, at 6.

NWG asserts that the risk of variation in the amount of installed wind capacity as compared to rate case forecast alone is not sufficient to justify applying the CRAC to VERBS. NWG Br. Ex., BP-12-R-NG-01, at 9. BPA's decision to apply the risk mitigation tools to ACS rates is not based on the variation of installed wind capacity as compared to forecast alone. This is one risk of many associated with setting all ACS rates that is driving BPA's decision to apply the risk mitigation tools to ACS rates. Lovell and Mandell, BP-12-E-BPA-37, at 33. NWG argues that

the risk of wind interconnecting slower than forecast would be mitigated because less VERBS sales would be offset by BPA using the capacity to make additional secondary sales. NWG Br. Ex., BP-12-R-NG-01, at 9. It is true that there would be some additional secondary sales of energy if less wind is installed than forecast. However, the VERBS rate recovers three categories of costs—the embedded costs of the portions of the FCRPS deemed to support provision of VERBS, some direct assignment costs of enhancing BPA’s capability to analyze and integrate variable-energy resources, and the variable costs derived from the fact that setting reserves aside to provide VERBS deoptimizes secondary marketing operations and causes a reduction in net secondary revenue. As NWG points out, if interconnected wind capacity is below BPA’s forecast, the revenue intended to recover variable costs will be lower, and that decrease will be more or less offset by the enhanced secondary marketing that would result from not having to set aside as much reserves, but the forecast embedded and direct assignment costs would not be recovered.

Decision

ACS revenue is based on volumes of services provided or on volumes of installed wind capacity, both of which are uncertain; thus the ACS rates create financial risk for BPA.

Sub-Issue 3.2.5.1.2

Whether the assumption of average water used to price ACS capacity-based products creates financial risk for BPA.

Parties’ Positions

NWG asserts that assuming average water to price ACS capacity-based products does not create financial risk. NWG Br., BP-12-B-NG-01, at 29-30.

BPA Staff’s Position

Staff argues that the assumption of average water creates financial risk for BPA. Lovell *et al.*, BP-12-E-BPA-15, at 57. Staff explains that the cost of providing ACS increases under low-water conditions, meaning that the amount of cost recovery assumed to occur under average water generally does not occur if low-water conditions eventuate. Lovell and Mandell, BP-12-E-BPA-37, at 33. Staff states that:

ACS provision depends on the Federal hydro system; uncertainty in the cost or capability of that system then seems related to ACS—O&M uncertainty, and expense or capability uncertainty due to uncertainty in the area of fish mitigation. The impact on system operations of setting aside reserves for resource integration seems to be clearly linked to hydro volumes and the uncertainty around those volumes. The financial impact of deoptimizing secondary marketing due to setting aside reserves—that is, the variable cost of integrating resources—depends

on the market price of power, so uncertainty in market prices creates uncertainty in the cost of resource integration.

Id. at 33-34.

Evaluation of Positions

This sub-issue is related to the second question in the two-part test posed by Staff:

Does the estimation of the cost of providing a product or service depend on assumptions that cannot be known with certainty, the ultimate resolution of which could affect BPA's financial results? For example, does the assumption of average hydro volume in the calculations of the cost of supporting ACS sales create financial uncertainty for BPA because the actual costs depend in part on the uncertain hydro conditions, or does uncertainty in market prices affect the financial impact of the constraint on BPA's ability to optimize its secondary marketing activities due to holding reserves for ACS support?

Lovell and Mandell, BP-12-E-BPA-37, at 32-33.

NWG claimed that the answer to this question was no, but NWG does not provide any support for this assertion. NWG Br., BP-12-B-NG-01, at 29-30. NWG does discuss whether average water can be equated to receiving credits for secondary revenues, but NWG does not argue that there is no financial risk associated with BPA using average water to calculate ACS rates.

Staff compares the variable costs attributable to balancing reserve capacity-based Ancillary and Control Area Services under two different water assumptions—critical water, and the average of 70 water years. Mainzer, *et al.*, BP-12-E-BPA-23, at 57. The variable costs were \$39.9 million using a critical water assumption, \$14.7 million higher than using an average assumption. *Id.* The logical implication of this is that if critical water is assumed, ACS rates would be set to generate \$39.9 million for the purpose of recovering the variable costs of providing ACS, and if average water is assumed, \$14.7 million less cost recovery would be required from ACS rates. *Id.* Under average water, that \$14.7 million of cost recovery would instead be assumed to come from the greater volume of power sales that average water supports compared to critical water. Thus, using an average water assumption yields lower ACS rates than critical water because it assumes \$14.7 million of cost recovery from other sources that may not materialize.

These figures demonstrate that the use of average water creates a risk of under-recovery of costs that would not exist if critical water were used: under critical water, ACS rates would yield \$39.9 million of recovery of variable costs (assuming for simplicity that there is no risk in the volume of ACS sales). *Id.* Under average water, the same rates would generate only \$25.2 million of recovery of variable costs and the difference, \$14.7 million, would be assumed to come from the increase in other sales that BPA can make if average water instead of critical water materializes. If average water does materialize, BPA will realize the entire \$39.9 million in recovery combined from variable costs and other sales. If critical water materializes, however, only \$25.2 million in recovery of variable costs will be realized. There is a similar risk for embedded costs, because under critical water conditions the FCRPS will have less flexibility

and the provision of balancing reserve capacity will have a greater impact on the system. This risk contributes to the overall risk of not having enough financial reserves to make BPA's Treasury payments.

Decision

The assumption of average water used to price ACS capacity-based products creates financial risk for BPA that would not exist if critical water were assumed instead.

Sub-Issue 3.2.5.1.3

Whether using average water to calculate the cost associated with the ACS rates is the same as crediting secondary revenues to ASC rates.

Parties' Positions

NWG argues that certain parties, including Staff, continue to erroneously conflate the use of average water to calculate the capacity of the FCRPS with credit for secondary sales. NWG Br., BP-12-B-NG-01, at 35. NWG states that the issue has already been decided in the WP-10 Record of Decision and it is clear that ACS rates do not receive credit from secondary sales. *Id.* at 35-36. NWG argues that the Administrator should reject WPAG's position that VERBS should be subject to CRAC and PNRR since the change from critical to average water had a beneficial effect on the VERBS rate, because the rationale for changing from critical to average water was to capture the use of the Big 10 projects to make secondary sales. *Id.* at 36. NWG argues that this change was necessary to avoid overstating the costs of providing capacity and that use of average water restored the balance of the embedded cost methodology. NWG claims that imposing the CRAC and PNRR on the VERBS rate would destroy the balance established by the Administrator in WP-10. *Id.*

PPC's rebuttal testimony states that VERBS customers get credit for secondary sales through the use of average water to calculate allocations of embedded costs, and if the parties are unwilling to be subject to the CRAC, BPA should forecast reserve availability and allocate costs based on critical water. Baker *et al.*, BP-12-E-PP-04, at 13-14. In its initial brief PPC explained that ACS customers are receiving the benefit of lower rates because BPA is using average water as opposed to critical water, and thus it is fair that if BPA experiences a below-average water year, ASC customers should bear a portion of the risk that a shortfall in revenues will need to be made up before the subsequent rate period. PPC Br., BP-12-B-PP-01, at 15-16.

WPAG characterizes the application of CRAC to the ASC rate as a correction of a past discriminatory practice that favored VERBS customers. WPAG Br., BP-12-B-WG-01, at 15. WPAG concludes that these are risk mitigation tools employed to deal with the financial risks associated with using an average water assumption, and those who share in the benefits of the Federal system must bear the cost of the system, including the risks associated with using an average water assumption. *Id.* at 16.

BPA Staff's Position

In the explanation of the use of average water in the generation inputs embedded cost methodology, Staff states:

The use of an average water assumption to calculate the unit embedded cost of peaking capacity continues the same assumption that was used to develop the current balancing reserve capacity rates. By using average water BPA has taken into account that secondary sales are a use of the FCRPS. Products and services that include a benefit from secondary sales are also subject to risk mitigation tools.

Klippstein *et al.*, BP-12-E-BPA-25, at 11.

Staff explains the rationale for applying the CRAC, PNRR, and Emergency NFB to the ACS rates, stating:

The rationale is that basing the costs of balancing reserve capacity-based Ancillary and Control Area Services rates on average water instead of critical water yields lower rates, that is, customers purchasing these services realize a benefit from the use of average water as part of the cost basis. There is considerable risk that actual water volume will be below average in any one year. This risk represents a large fraction of the total risk that Power's risk mitigation measures are designed to treat.

Mainzer *et al.*, BP-12-E-BPA-23, at 57-58.

Evaluation of Positions

NWG provides a full description of the rationale behind the move from critical to average water that BPA decided in the WP-10 Record of Decision. NWG Br., BP-12-B-NG-01, at 35-36. The decision to use average water was based on arguments raised by Cowlitz that the embedded cost methodology should account for all uses of the Big 10 projects' capacity, and using critical water did not account for the capacity associated with sales of secondary energy. WP-10 ROD, WP-10-A-02, at 309-310. It is clear from the WP-10 Record of Decision and NWG explanation that NWG argued for a secondary revenue credit for the Wind Balancing Service Rate, and BPA decided that such a credit would not be provided. *Id.* at 306; NWG Br., BP-12-B-NG-01, at 33; 35-36. There is a connection between secondary revenues and the use of average water, but using average water is not the same as getting credit for secondary revenues.

NWG's assertion that certain parties, including Staff, continue to erroneously conflate the use of average water to calculate the capacity of the FCRPS with credit for secondary sales appears to arise from Staff's statement that "[p]roducts and services that include a benefit from secondary sales are also subject to risk mitigation tools." Klippstein *et al.*, BP-12-E-BPA-25, at 11. Notably this statement was preceded by, "[b]y using average water BPA has taken into account that secondary sales are a use of the FCRPS," and was followed by reference to Mainzer *et al.*, BP-12-E-BPA-23, section 5.8 where the specifics of the proposal to apply the risk mitigation tools to the ACS rate are found. *Id.* While Staff's statement taken out of context appears to

conflate the use of average water to calculate the capacity of the FCRPS with credit for secondary sales, this testimony is not on point to address the rationale behind the proposal.

Staff does not argue that CRAC, PNRR, and Emergency NFB should be applied to the ACS rates because these rates received credit from secondary sales; rather, Staff proposes to apply the risk mitigation tools to ACS rates because using average water to calculate these rates inflates the risk that BPA will under-recover from these customers when experiencing below-average water conditions. Mainzer *et al.*, BP-12-E-BPA-23, at 57-58.

Similarly, PPC's statement that, "VERBS customers get credit for secondary sales through the use of average water to calculate allocations of embedded costs," could be read as a misstatement. Baker *et al.*, BP-12-E-PP-04, at 13-14. However, this can also be read as simply stating that secondary sales are accounted for as a capacity use of the system when average water is used and the resulting lower ACS rates benefits VERBS customers. Thus, there should be no confusion regarding the relationship between the use of average water and secondary revenue credits. The decision on whether or not to apply risk mitigation tools to ACS rates is not driven by whether or not the VERBS rate receives secondary revenue credits; rather, it is driven by whether there is financial risk associated with the use of average water in the pricing methodology used to set the VERBS rate.

NWG appears to argue that a deal was made in which non-Slice PF rates received the benefit of a credit for secondary sales in return for accepting the CRAC. NWG Br., BP-12-B-NG-01, at 36. This is not the case. PF rates received a credit for anticipated secondary sales since well before 1980, when neither PNRR nor the CRAC was included in rates. In 1979, 1980, 1982, and 1983, BPA was unable to make any of the scheduled amortization payments to Treasury and was not able to pay the full amount of current interest owed. This was recognized inside and outside BPA as a serious problem. Over the next decade, BPA strengthened its risk mitigation. The 10-Year Financial Plan, adopted in 1993, explicitly prescribed the use of PNRR and an Interim Rate Adjustment (essentially the same as the mechanism now termed the CRAC). WP-93 ROD, WP-93-A-02, at 57. The adoption of PNRR and the rate adjustment was not part of a "deal"; it was in order to mitigate the risk of cost under-recovery. Many of the assumptions made in the calculation of anticipated costs and revenues were uncertain, and the risk that costs would be higher than assumed in rates, or that sales revenues would be lower than assumed in rates, was high enough that the risk of cost under-recovery was intolerably high, and additional risk mitigation was needed.

Staff does not argue that using average water in calculating ACS rates is the same as crediting anticipated secondary sales in calculating non-Slice PF rates, but that these two are parallel. In both cases, the assumption of an average future outcome is used instead of using a more conservative assumption in calculating the amount of cost recovery to be expected from a class of rates. Since it is not certain that the future outcome will be as favorable as average, a risk of cost under-recovery is created by the adoption of the assumption of average outcomes. In the case of non-Slice PF rates, the assumption of average net secondary sales results creates risk because it assumes some cost recovery from secondary marketing that will not be realized if net secondary results are below average; this assumption reduces the amount of cost recovery

expected from non-Slice PF rates. One approach to mitigating this risk would be to assume critical water in calculating the credit for secondary sales; in that case, the assumed cost recovery from secondary sales plus that from non-Slice PF rates would be highly likely to occur. Instead, BPA assumes an average outcome, and include PNRR and the CRAC in non-Slice PF rates to mitigate the cost under-recovery risk. In the case of ACS rates, the assumption of average water conditions creates risk because it assumes some cost recovery from some non-ACS products that will not be realized if water conditions are below average; this assumption reduces the amount of cost recovery expected from ACS. One approach to mitigating this risk would be to assume critical water in calculating the ACS rates; in that case, the assumed cost recovery from ACS plus that from other non-ACS sales would be highly likely to occur. Instead, BPA has assumed an average outcome, and included PNRR and the CRAC in ACS rates to mitigate the cost under-recovery risk.

Decision

Using average water to calculate the cost associated with the ACS rates is not the same as crediting secondary revenues to ASC rates, but using average water does create risks that justify assigning risk mitigation to ACS rates.

Sub-Issue 3.2.5.1.4

Whether applying a CRAC that results from the use of financial reserves from transmission services to non-Federal transmission customers is inequitable because non-Federal transmission customers do not benefit from secondary revenues.

Parties' Positions

NWG argues that shifting power costs related to secondary revenues to non-Federal transmission customers is inequitable because non-Federal transmission customers do not benefit from secondary revenues. NWG Br., BP-12-NG-01, at 30. NWG asserts that the largest risk to power rates is the variability of secondary sales and the Administrator has held that the VERBS will not receive credit for secondary revenues. *Id.* at 30-31

JP01 argues that the VERBS rates should not be subject to the CRAC or DDC because VERBS rates do not receive credit for net secondary sales. Skeahan *et al.*, BP-12-E-JP01-02, at 6.

WPAG argues that the VERBS rates as proposed should be subject to PNRR and the CRAC. WPAG Br., BP-12-B-WG-01, at 15.

BPA Staff's Position

Because the ACS rates receive a benefit from a methodology that assumes average water, which may not be realized, it is reasonable to assign some risk mitigation responsibility for mitigating the risk of cost under-recovery to the ACS rates. Lovell *et al.*, BP-12-E-BPA-15, at 57.

Evaluation of Positions

As argued above, NWG's implication that the CRAC is applied to non-Slice PF rates as a trade for receiving a credit for anticipated secondary sales is incorrect. The CRAC is applied to non-Slice PF rates because an assumption favorable to non-Slice PF rates was made that is not sure to hold, and if net secondary sales conditions for BPA turn out to be worse than assumed in rates, cost under-recovery could result. Similarly, an assumption favorable to ACS rates was made in calculating those rates, and if water conditions turn out to be worse than assumed in rates, cost under-recovery could result. BPA agrees with WPAG's that with the benefits of average water, comes the financial burdens of average water. WPAG Br., BP-12-B-WG-01, at 15.

NWG argues that because variability of net secondary sales is the largest risk in the set of risks that BPA mitigates through application of the CRAC, it follows that BPA applies the CRAC *because* of net secondary sales variability. *See* NWG Br., BP-12-NG-01, at 30-31. BPA actually applies the CRAC to mitigate the risk of cost under-recovery; net secondary sales variability is one of the risks mitigated by the CRAC, but it is not the purpose of the CRAC.

It is not the case that BPA applies the CRAC to non-Slice PF rates because those rates receive a benefit from net secondary sales, and likewise it is not the case that because ACS rates do not receive an explicit credit for net secondary sales, ACS rates should not be subject to the CRAC. Both non-Slice PF rates and ACS rates receive a benefit from optimistic assumptions in the calculation of the rates, and applying the CRAC to these rates to mitigate the cost under-recovery risk created by the optimistic assumptions is reasonable. Whether ACS rates receive a credit for secondary sales is not the appropriate basis for determining whether ACS rates should be subject to the CRAC.

Decision

It is equitable to apply the CRAC to ACS rates because ACS rates benefit from an assumption in rate design that may not hold, and this assumption creates a risk of cost under-recovery. The lack of a credit in ACS rate calculations for net secondary sales is not relevant to the issue of equity.

Sub-Issue 3.2.5.1.5

Whether section 7(g) of the Northwest Power Act dictates that PNRR, CRAC, and Emergency NFB surcharge adjustments cannot be assigned to ACS rates.

Parties' Positions

NWG argues that application of CRAC, PNRR, and Emergency NFB surcharge to the VERBS and other ACS rate violates the rate directives of section 7(g) of the Northwest Power Act, because section 7(g) provides that certain costs are to be allocated specifically to power rates. NWG Br., BP-12-B-NG-01, at 39. NWG asserts that section 7(g) requires all costs and benefits not otherwise allocated under other applicable provisions of law, including fish and wildlife

measures and the sale of and inability to sell excess electric power, be allocated to power rates. *Id.* NWG asserts that VERBS and other ACS rates are not power rates and cites to the WP-10 ROD for support. *Id.* NWG rationalizes that the Emergency NFB surcharge is directly related to fish and wildlife costs, because it is driven by changes to the fish and wildlife programs or change in river operations that results in a forecast loss of net revenues and therefore since VERBS and other ACS rates are not power rates allocation of fish and wildlife costs through the Emergency NFB surcharge would violate the rate directive of section 7(g). *Id.*

NWG then asserts that applying CRAC to VERBS and other ACS rates is also prohibited by section 7(g), because the primary use of CRAC is to mitigate the risk of fluctuations in secondary revenues associated with the sale of excess power. *Id.* at 40. NWG states that PNRR has no corresponding cash use and that it improves BPA's ability to make Treasury payments; however, NWG equates the use of PNRR to CRAC and states that applying it to the VERBS and ACS rates violates cost causation principles for the same reasons as application of the CRAC. *Id.* NWG claims that the level of secondary revenues BPA receives is directly related to the amount of excess electric power available to BPA, the price at which BPA can sell such power, and the extent to which BPA is unable to sell such power, and the Administrator held in the WP-10 Record of Decision that credit for secondary revenues is allocated under section 7(g). *Id.* NWG concludes that if section 7(g) allocates the benefits of secondary revenues to power rates, it also mandates that the costs associated with such revenues be allocated to power rates. *Id.* at 40-41.

In its brief on exceptions, NWG argues that BPA's conclusion that the Transmission System Act precludes application of section 7(g) is erroneous as a matter of law, because the Transmission System Act does not govern the allocation of costs and benefits. NWG Br. Ex., BP-12-R-NG-01, at 11. NWG claims that the Transmission System Act does not require the Administrator to use any particular method of allocating the costs and benefits of producing and transmitting electrical power, and it deals with cost recovery, not allocation of costs and benefits. *Id.* at 12. NWG asserts that BPA does not cite any provisions of the Transmission System Act that requires allocation of costs and benefits, much less a provision that conflicts with the express directives of section 7(g). *Id.* NWG concludes by claiming that BPA's conclusion that the Transmission System Act precludes application of section 7(g) would mean that section 7(g) was a nullity at the time that Congress enacted it. *Id.*

BPA Staff's Position

This is a legal issue, and Staff does not address this issue in testimony.

Evaluation of Positions

Section 7(g) of the Northwest Power Act states:

Except to the extent that the allocation of costs and benefits is governed by provisions of law in effect on December 5, 1980, or by other provisions of this section, the Administrator shall equitably allocate to power rates, in accordance with generally acceptable ratemaking principles and the provisions of this chapter, all costs and benefits not otherwise allocated under this section, including, but not

limited to, conservation, fish and wildlife measures, uncontrollable events, reserves, the excess costs of experimental resources acquired under [16 U.S.C. § 839d], the cost of credits granted pursuant to [16 U.S.C. § 839d], operating services, and the sale of or inability to sell excess electric power.

16 U.S.C. § 839e(g).

NWG's argument regarding the application of the Emergency NFB surcharge to ACS rates turns on two factors: (1) whether or not the application of the Emergency NFB surcharge to ACS rates is governed by provisions of law in effect on December 5, 1980, and (2) whether the fish and wildlife measures referred to in the Northwest Power Act are the same as the changes to fish and wildlife programs or river operations for which the Emergency NFB surcharge would trigger. The issue of whether Northwest Power Act section 7(g) prohibits the assignment of fish and wildlife costs to the ACS rates is discussed in detail in Issue 3.4.2.4.

As to whether or not the application of the Emergency NFB surcharge is governed by provisions of law that were in place on December 5, 1980, the date the Northwest Power Act was passed, the 1974 Transmission System Act must be examined. Section 4 of the Transmission System Act instructs “[t]he Secretary of Energy, acting by and through the Administrator, shall operate and maintain the Federal transmission system within the Pacific Northwest and shall construct improvements, betterments, and additions to and replacements of such system within the Pacific Northwest as he determines are appropriate and required to: (a). integrate and transmit the electric power from existing or additional Federal or non-Federal generating units; ... (d). maintain the electrical stability and electrical reliability of the Federal system....” 16 U.S.C. § 838b. The purpose of the balancing reserve capacity-based ACS is to maintain load resource balance. Mainzer *et al.*, BP-12-E-BPA-23, at 10-15. Maintaining load resource balance is the quintessential component of maintaining electric stability and electric reliability of the transmission system.

Section 9 of the Transmission system Act states, in pertinent part:

Schedules of rates and charges for the sale, including dispositions to Federal agencies, of all electric power made available to the Administrator pursuant to section 838f of this title or otherwise acquired, and for the transmission of non-Federal electric power over the Federal transmission system, shall become effective upon confirmation and approval thereof by the Secretary of Energy. Such rate schedules may be modified from time to time by the Secretary of Energy, acting by and through the Administrator, subject to confirmation and approval by the Secretary of Energy, and shall be fixed and established 1) with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles, (2) *having regard to the recovery (upon the basis of the application of such rate schedules to the capacity of the electric facilities of the projects) of the cost of producing and transmitting such electric power*, including the amortization of the

capital investment allocated to power over a reasonable period of years and payments provided for in section 838i(b)(9) of this title.

16 U.S.C. § 838g (emphasis added).

Thus, the Transmission System Act instructs the Administrator to maintain the stability and reliability of the transmission system and to establish rates to recover the costs of producing and transmitting such electric power. At the time the Northwest Power Act and the Transmission System Act were passed, 1980 and 1974, respectively, rates were not unbundled with separately identified rates for ACS and Congress did not contemplate whether the cost of the balancing reserve capacity needed to maintain stability and reliability would be recovered in power or transmission rates. *See* Hall, Oral Tr. at 194. But there is no doubt that the Transmission System Act instructs the Administrator to establish rates to recover these costs, and the Transmission System Act was a provision of law that was in effect on December 5, 1980 requiring transmission rates to recover the costs of that service. The Transmission System Act therefore directs (one meaning of “govern”) that the Administrator determine what costs are appropriately allocated to power and transmission, respectively.

In its brief on exceptions, NWG argues that BPA’s conclusion that the Transmission System Act precludes application of section 7(g) is erroneous as a matter of law, because the Transmission System Act does not govern the allocation of costs and benefits. NWG Br. Ex., BP-12-R-NG-01, at 11. NWG claims that the Transmission System Act does not require the Administrator to use any particular method of allocating the costs and benefits of producing and transmitting electrical power, and it deals with cost recovery, not allocation of costs and benefits. *Id.* at 12. NWG asserts that the BPA does not cite any provisions of the Transmission System Act that requires allocation of costs and benefits, much less a provision that conflicts with the express directives of section 7(g). *Id.*

The Transmission System Act does not contain the same level of detail regarding cost allocation as the Northwest Power Act, but section 9 does direct allocation of costs between power and transmission, and section 10 does direct that “recovery of the cost of the Federal transmission system shall be equitably allocated between Federal and non-Federal power utilizing such system.” 16 U.S.C. § 838h. It is well established, and NWG has not disputed, that there is a nexus between fish and wildlife costs that arise from the operation of the FCRPS projects and the balancing reserve capacity provided from these projects that are used to provide ACS.

Staff has explained in previous rate proceedings how fish and wildlife costs are directly related to the operation of the Big 10 projects that produce the balancing reserve capacity used for ACS.

BPA’s fish and wildlife costs result directly from production of real power at the FCRPS hydro facilities that provide regulating reserve to meet BPA Control Area obligations. Fish and wildlife programs are necessary to protect, mitigate, and enhance fish and wildlife affected by the development and operation of the FCRPS hydro projects. This approach is consistent with other utilities’ FERC filings, where environmental compliance costs have been included in the

embedded cost of regulating reserves. The “Big 10” share based on capacity (89 percent) is allocated to the cost of providing regulation service.

Declerck *et al.*, WP-02-E-BPA-26, at 13; Bermejo *et al.*, WP-07-E-BPA-20, at 19.

Assigning costs associated with the Emergency NFB Surcharge to ACS rates is consistent with the equitable allocation of the costs of the Federal transmission system directed by section 10 of the Transmission System Act. 16 U.S.C. § 838h.

In its brief on exceptions NWG concludes by claiming that BPA’s conclusion that the Transmission System Act precludes application of section 7(g) would mean that section 7(g) was a nullity at the time that Congress enacted it. NWG Br. Ex., BP-12-R-NG-01, at 12. This is not the case; BPA is not claiming that the Transmission System Act precludes section 7(g) of the Northwest Power Act. BPA is interpreting the exception in section 7(g) (“Except to the extent that the allocation of costs and benefits is governed by provisions of law in effect on December 5, 1980”) and assessing the directives of the Transmission System Act that apply to the costs of providing transmission service. Section 7(g) of the Northwest Power Act does not speak to the functionalization of costs between the power and transmission functions. 16 U.S.C. § 839e(g). It speaks only to the allocation of costs under power rates. Including fish and wildlife costs and related surcharges that are clearly a cost of the projects that produce the balancing reserve capacity used to provide ACS in ACS rates is consistent with the functionalization of costs to transmission rates under section 10 of the Transmission System Act. Section 7(g) is applicable to any fish and wildlife measures that are not functionalized to the transmission function. In a nutshell, BPA is respecting the exception in section 7(g): with the exception of fish and wildlife costs allocated to transmission, the balance of fish and wildlife costs will be equitably allocated pursuant to section 7(g) of the Northwest Power Act.

As to whether the “fish and wildlife measures” referred to in the Northwest Power Act are the same as the changes to fish and wildlife programs or river operations for which the Emergency NFB surcharge would trigger, it does not matter if the answer to the issue regarding whether provisions of law were in place at the time the Northwest Power Act was passed is affirmative. However, there is some question as to whether the “fish and wildlife measures” referred to in Northwest Power Act section 7(g) are the same as mandated changes in BPA’s fish and wildlife programs or river operations that may result in financial impacts that arise from circumstances related to the litigation over the FCRPS Biological Opinion. Lovell *et al.*, BP-12-E-BPA-15. Since one of the risks associated with any Biological Opinion litigation is that certain river operations could be mandated that would reduce the flexibility of the FCRPS operations and thus impact the ability of the FCRPS to serve loads and provide balancing reserve capacity for ACS, it is reasonable that the ACS rate should be exposed to the Emergency NFB surcharge. Section 7(g) preserves and does not preclude BPA’s authority to apply risk mitigation tools to ACS rates to mitigate mandated changes to river operations that could significantly change BPA’s operations and the costs of providing balancing reserve capacity.

NWG’s 7(g) argument is extended to PNRR, because NWG equates PNRR with CRAC, and argues that PNRR has no corresponding cash use and that it improves BPA’s ability to make Treasury payments and therefore should not be applied to ACS rates. NWG Br., BP-12-B-

NG-01, at 40. This argument is unpersuasive. PNRR is designed to ensure there are enough financial reserves to make Treasury payments, and there is nothing to suggest that customers that receive capacity-based services from the FCRPS should not pay a fair share of such costs. 16 U.S.C. § 839e(a)(1) (...such rates shall be established and, as appropriate, revised to recover...the cost associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the Federal Columbia River Power System...); *see also* 16 U.S.C. § 838g.

NWG's 7(g) argument with regard to CRAC turns on the premise that BPA's need for risk mitigation is primarily driven by BPA's sale of excess electric power. NWG Br., BP-12-B-NG-01, at 39-40. This argument was evaluated in Sub-Issues 3.2.5.1.3 and 3.2.5.1.4. To support its premise, NWG states that the need for risk mitigation tools is primarily driven by BPA's sale of excess electric power, *i.e.*, secondary sales. *Id.* at 40. For support NWG quotes a passage from the WP-10 ROD:

No costs of risk mitigation have been included in the generation inputs embedded cost allocation, and the rate adjustment mechanisms for risk mitigation would not apply to these Transmission Services rates, because the risks that contribute to power rates risk mitigation costs and adjustment mechanisms are primarily driven by the uncertainty of secondary sales.

Id., quoting WP-10 ROD, WP-10-A-02, at 307.

The quote that NWG relies on to support its position is taken from the description of Staff's position in regard to the issue of whether BPA should use critical or average water in the generation inputs embedded cost methodology. Staff's position was stated in the WP-10 Initial Proposal in regard to whether the embedded cost should include PNRR, and Staff concluded that PNRR should not be included in ACS rates, because Staff was using critical water, which did not account for non-firm uses of the FCRPS, such as secondary sales. Klippstein *et al.*, WP-10-E-BPA-24, at 3-4. NWG's use of Staff's position associated with critical water and not applying risk mitigation tools to ACS rates to argue that secondary sales risk drives the need for risk mitigation, without acknowledging the distinction between critical and average water, creates an interesting juxtaposition.

In the WP-10 case, BPA did summarily conclude that since Wind Balancing Service is not a power rate, there was no need for BPA to revisit the issue of crediting Wind Balancing Service with secondary sales revenues. The evaluation did not consider the factual and statutory arguments and factors that have now been more fully and, BPA believes, correctly addressed in this case and Record of Decision in connection with risk measures and fish and wildlife costs. While BPA believes the WP-10 conclusion not to credit the rates with secondary sales revenues was appropriate, given the context of basing Wind Balancing Service rates on average water, BPA does not believe it is appropriate to rely on section 7(g) as an absolute bar, given the appropriate facts, to assigning some portion of the listed costs to ACS rates. The decisions that were made in the WP-10 rate proceeding regarding the applicability of risk mitigation tools are evaluated further below in Sub-Issue 3.2.5.1.8.

As Staff explains, there are multiple risks that are evaluated to determine the need for BPA’s risk mitigation tools, and it is not based solely on risk associated with secondary revenues. Lovell and Mandell, BP-12-E-BPA-37, at 33-34. Many of the risks BPA faces concern the hydro system and the availability of water in any given year. *Id.* The balancing reserve capacity-based ACS are all services provided from the flexibility of the FCRPS. In low-water years this flexibility is reduced. Lovell *et al.*, BP-12-E-BPA-15, at 57. The CRAC is intended to provide a lower rate for BPA customers while ensuring that BPA can recover its costs and make its Treasury payments. Because the CRAC is used to ensure that BPA can adjust its rates to make its Treasury payments, and given there are multiple risks evaluated to determine the applicability of the CRAC, NWG’s argument that Northwest Power Act section 7(g) requires the cost of associated secondary revenues to be assigned to power rates is not persuasive.

Decision

Section 7(g) of the Northwest Power Act does not dictate that the risk mitigation tools cannot be assigned to ACS rates.

Sub-Issue 3.2.5.1.6

Whether the inclusion of replenishing transmission financial reserves that Power Services may rely on to support Treasury payments as a purpose of the CRAC provides any benefit to ACS customers.

Parties’ Positions

NWG states that Staff proposes to add the replenishing of the transmission financial reserves that PS may rely on to support Treasury payments as a purpose of the CRAC. NWG Br., BP-12-E-NG-01, at 32. NWG argues that there is no evidence in the record showing that ACS rate payers benefit from this arrangement. *Id.*

BPA Staff’s Position

Staff explains that the CRAC is applied to rates, not customers, and that Staff is proposing to apply the CRAC to ACS rates because those rates are supported by assets of the power system, not the transmission system. Lovell and Mandell, BP-12-E-BPA-37, at 34. Staff explains that:

[W]e believe it is appropriate for ACS customers to participate in mitigating power system risks. If Staff had not proposed the risk mitigation allowance by PS on reserves attributed to TS in the Initial Proposal, PNRR would have been required for PS rates to meet BPA’s TPP standard, and the PNRR would have caused ACS rates to be higher than in the Initial Proposal. We believe the reserves sharing arrangement has decreased the ACS rates and is compatible with all of the “reasonable bas[e]s” applicable in this rate proceeding, including the principles of cost causation.

Id. at 34-35.

Evaluation of Positions

NWG argues that “[r]educing BPA’s power rates does not directly benefit non-Federal transmission customers.” NWG Br., BP-12-E-NG-01, at 32. The addition of the liquidity replenishment function of the CRAC does not represent a direct *benefit* to customers; to the contrary, it is a *responsibility* of the customers whose rates benefit from the availability of non-cash liquidity to contribute to replenishing that liquidity if it is drawn upon.

Staff does not propose adding a liquidity-replenishing function to the CRAC because customers would receive a direct benefit from that function of the CRAC. Staff proposes adding the liquidity-replenishing function to the CRAC in order to prudently restore liquidity in the event the liquidity is actually drawn upon to manage cost under-recovery events. This is necessary in order to make the liquidity available again in a timely manner to mitigate other risks. Lovell *et al.*, BP-12-E-BPA-15, at 53-54.

The complete picture is more complicated than NWG’s simple claim that non-Federal transmission customers should not help pay to reduce power rates. As argued above, it is reasonable to apply risk mitigation measures to rates that benefit from optimistic assumptions which lead to cost under-recovery risk. Both non-Slice PF rates and ACS rates benefit from optimistic assumptions, the assumption of average net secondary revenues in the case of PF rates, and the assumption of average water in the case of ACS rates.

Financial reserves are BPA’s primary financial risk mitigation tool. Power Risk and Market Price Study, BP-12-FS-BPA-04, section 1.2.2.2. When reserves are insufficient to meet BPA’s financial risk tolerance standard, the 95 percent TPP standard, PNRR may need to be added to the revenue requirement to generate additional reserves. *Id.* PNRR is part of the revenue requirement for both non-Slice PF rates and ACS rates. Essentially, PNRR serves as a means for replenishing the liquidity provided by financial reserves if the reserves have been drawn upon to pay financial obligations during times when revenue under-recovery actually occurs. BPA has secured a Treasury facility that provides significant liquidity to BPA, *id.*, section 3.2.1.2, and BPA’s reliance on this liquidity reduces the need for financial reserves. In addition, BPA is relying on \$150 million of financial reserves attributed to TS that were above the needs for reserves identified in the TS revenue requirement study, further reducing the PS reliance on financial reserves for risk mitigation. Lovell *et al.*, BP-12-E-BPA-15, at 48-51. The reduced reliance on PS financial reserves reduces the need for PNRR to replenish reserves. The reduced need for PNRR relieves the potential rate pressure from PNRR for rates responsible for generating PNRR, which include both non-Slice PF rates and the capacity reserves-based ACS rates.

The two sources of non-reserves liquidity—the Treasury Facility and reserves attributed to TS—need to be replenished if tapped. Thus, adding the liquidity replenishment function of the CRAC that is applicable to non-Slice PF rates and to balancing reserve capacity-based ACS rates is a responsibility, not a benefit, for non-Slice PF and ACS rates that accompanies the use of additional sources of liquidity that serves to reduce the cost of risk mitigation for those rates.

Decision

The inclusion of a liquidity replenishment function to the CRAC is an appropriate responsibility of purchasers of balancing reserve capacity-based ACS rates, even considering that those purchasers may also be non-Federal purchasers of transmission services.

Sub-Issue 3.2.5.1.7

Whether various aspects of VERBS provide adequate risk mitigation.

Parties' Positions

NWG asserts that Staff has not made the case that additional risk mitigation is required for the VERBS rate. NWG Br., BP-12-B-NG-01, at 27. NWG claims that the VERBS rate is subject to risk mitigating aspects that power rates are generally not exposed to, including election period requirements, onerous provisional balancing service terms, and DSO 216. *Id.* NWG states that Staff has made no attempt to quantify or reconcile these risk mitigating aspects of the VERBS rate with those of the CRAC and PNRR. *Id.*

In its brief on exceptions, NWG provides a list of differences between VERBS and BPA's power rates subject to the CRAC. NWG Br. Ex., BP-12-R-NG-01, at 9. NWG argues that the record does not have sufficient evidence to evaluate these factors and there is not substantial evidence to support allocation of a portion of BPA's cost recovery risk to VERBS on the basis of the limited risk that the VERBS rate represents to BPA's revenues. *Id.* at 9-10.

BPA Staff's Position

Staff does not address NWG's assertion that the terms and conditions of the VERBS subject the VERBS rate to risk mitigating aspects that do not apply to power rates. This assertion is first raised by NWG in its brief.

Evaluation of Positions

NWG makes an assertion that the terms and conditions for VERBS contain risk mitigating aspects that generally don't apply to power rates. NWG Br., BP-12-B-NG-01, at 27. The aspects of this service referred to by NWG include the requirements that customers using VERBS notify BPA that they intend to take the service during a rate period, that customers that do not provide such notice receive a different control area service called Provisional Balancing Service, and that provision of VERBS is limited on any hour by DSO 216 to the amount of reserves BPA planned to provide. *Id.*

Notice that a customer intends to take a service is a basic requirement for operating a wholesale power system. Absent election provisions and other notice provisions, such as schedules, there would be no basis to plan the operation of the wholesale power system. This type of provision is a basic reliability tool.

Defining service terms when a customer takes unauthorized services is another means of managing operational risks. Provisional Balancing Service defines a diminished quality of service that BPA provides when a customer has not provided proper notice of service. These types of terms and conditions limit the need to direct certain generators or loads to cease operation for reliability purposes to those hours where their operation must be limited to protect the system's integrity. Mainzer *et al.*, BP-12-E-BPA-23, at 34-35; Jackson *et al.*, BP-12-E-BPA-29, section 7.1.

Placing limits on the service provided is another basic reliability tool for operating the wholesale power system. DSO 216 was put in place to allow BPA to continue integrating additional wind generation in the BPA balancing authority. DSO 216 limits the amount of balancing reserve capacity BPA will provide to the amount BPA has forecast in the previous rate proceeding and thus protects system reliability. Mainzer *et al.*, BP-12-E-BPA-23, at 31-32.

NWG provides no analysis of the terms and conditions for BPA's power sales contracts and whether they address the same issues as the terms and conditions of VERBS. BPA's Regional Dialogue Power Sales contracts require customers to notify BPA several years prior to the date they expect to take service. For example, customers must notify BPA by September 30, 2011, if they want to purchase additional power to meet their load growth for the period from October 1, 2014, until September 30, 2019. *See* Regional Dialogue contract, section 3.5. Clearly, power sales customers must provide notice of their election to purchase power. Power customers are limited to contractually defined amounts of power and pay higher or lower rates depending on the terms of their power sales contract. If a customer takes more power than its power sales contract authorizes, the customer faces an unauthorized increase charge penalty that is similar to but higher than the Persistent Deviation penalty faced by users of generation imbalance service. *See* GRSP II.V. Power customers face their own set of terms and conditions providing notice of the service they are taking from BPA, limiting the amounts they are authorized to take, and providing different charges if they take more than the authorized amount. PF power deliveries are limited by customers' Net Requirements. They are not allowed to resell Federal power. They must meet credit requirements. Under the Regional Dialogue contracts, PF customers who own generating resources are required to specify which of their resources will be dedicated to meeting their native load, and they are required to operate accordingly. Both VERBS customers and other BPA customers are subject to some risk-limiting terms and conditions; different classes of service come with different sets of terms and conditions.

These terms and conditions define the service, not the risks that BPA faces in recovering revenue under applicable rates for the services provided. The same conclusion can be drawn for the terms and conditions described by NWG as risk mitigating aspects of VERBS: these terms and conditions define the service and mitigate operational risk, but they do not mitigate BPA's financial risks, which are addressed by the risk mitigation tools.

In its brief on exceptions, NWG provides a list of differences between VERBS and BPA's power rates subject to the CRAC: VERBS is not allocated a credit from secondary revenues; VERBS is considered a service rather than a firm product; VERBS is subject to DSO 216; and VERBS would be subject to two formula rates under BPA's proposal. NWG Br. Ex., BP-12-R-NG-01, at 9. NWG argues that the record does not have sufficient evidence to evaluate these factors and

there is not substantial evidence to support allocation of a portion of BPA's cost recovery risk to VERBS on the basis of the limited risk that the VERBS rate represents to BPA's revenues. *Id.* at 9-10.

The risk mitigation associated with VERBS exposure to DSO 216 is discussed above. DSO 216 mitigates an operational risk and it is comparable to terms that limit the amount of power PF power customers can take. The issue of whether the VERBS rate should not be subject to the risk mitigation tools because it is not allocated a credit from secondary revenues is discussed above in Sub-Issue 3.2.5.1.4. The relationship between the VERBS Formula Rates and the risk mitigation tools is discussed above in the overall evaluation of Issue 3.2.5.1. As to NWG's assertion that VERBS is considered a service rather than a firm product, and that the record does not have sufficient evidence to evaluate these factors and support an assignment of risk mitigation costs to the VERBS rate, the difference between a service and a firm product does not change the financial risk that the risk mitigation tools are intended to mitigate. The fact that the amount of balancing reserve capacity BPA maintains to support VERBS may be reduced for operational reasons occasionally, making it a service rather than a firm product (*see* Issue 3.2.3.9), addresses another operational risk and does not change the impacts of the aggregate financial risks associated with the assumptions BPA has made to establish the VERBS rate. NWG's attempt to distinguish VERBS from other products is not persuasive in regard to application of the risk mitigation tools.

Decision

The terms and conditions described by NWG define the service and place limits on the operational and reliability risks BPA faces in providing the service, but these terms and conditions do not change the financial risks that BPA faces in recovering revenue under applicable rates for the services provided.

Sub-Issue 3.2.5.1.8

Whether the WP-10 ROD rejected the application of the CRAC to ACS rates based on the use of average water and whether the proposal to apply CRAC, PNRR, and Emergency NFB Surcharge to balancing reserve capacity based-ACS rates reopens a previously settled issue.

Parties' Positions

NWG argues that the Administrator rejected the idea of applying CRAC, PNRR, and Emergency NFB Surcharge to ACS rates in the WP-10 rate proceeding, and Staff's proposal would reopen a previously settled issue. NWG Br., BP-12-B-NG-01, at 26. NWG explains that in the WP-10 rate proceeding, NWG argued that the Wind Balancing Service rate should be credited for a portion of secondary sales, but the Administrator rejected this argument based on Northwest Power Act section 7(g), specifically requiring that secondary sales revenues be equitably allocated to power rates. *Id.* at 30. NWG points out that in WP-10, Staff noted that the power rates risk mitigation costs are primarily driven by the uncertainty associated with secondary sales. *Id.* at 30-31. NWG rationalizes that because BPA's power customers have the right to the

credit for secondary revenues and the responsibility to pay power costs, it would be inconsistent with such rights and responsibilities for the Administrator to assign responsibility for such power cost to a non-power rate, such as the VERBS rate, and to do so would be a classic example of a cost shift. *Id.* at 31.

NWG states that Staff's proposal to apply the CRAC to the ACS rates rests on the conclusion that ACS rates benefit from basing the calculation of the cost of generation inputs on average water conditions. *Id.* at 32-33. NWG explains that in the WP-10 proceeding, the Administrator decided to change the assumption in Staff's generation inputs embedded cost methodology from critical to average water and that the Administrator specifically decided to not apply CRAC to the ACS rate. *Id.* at 33-34. For support, NWG quotes the WP-10:

This could be read to suggest that if BPA chooses to use average water instead of critical water, PNRR and the CRAC should be applied to the cost allocation for these reserves. However, BPA does not believe this is necessary, because using average water to establish the 120-hour peaking capability is not the same as providing a credit to a transmission rate for secondary power sales.

Id. at 34, *citing* WP-10 ROD, WP-10-A-02, at 309.

NWG claims that this is the same proposal that Staff is now recommending. *Id.* NWG states that in WP-10, the Administrator decided that because using average water is not the same as providing a credit for the secondary power sales, it was not appropriate to charge ACS rates for risk mitigation associated with secondary power sales. *Id.* NWG further asserts that in the BP-12 proceeding Staff is not proposing to credit ACS rates with secondary revenues, and there are no new facts or basis in the record to cause the Administrator to revisit his earlier decision. *Id.* at 35.

BPA Staff's Position

Staff explains the procedural history of this issue in the WP-10 rate proceeding:

In the WP-10 rate case BPA Staff proposed not to apply risk mitigation tools to the Wind Balancing Rate or any balancing reserve capacity-based Ancillary and Control Area Services. The WP-10 Initial Proposal based this election on the use of critical water as a basis for establishing the uses of FCRPS capacity. This use of critical water as a basis for the embedded cost calculation did not account for secondary sales as a system use and, therefore, Staff reasoned that it was not appropriate to apply BPA's risk mitigation tools, which are associated with the uncertainty of secondary sales. Klippstein *et al.*, WP-10-E-BPA-24 at 3. In the Draft Record of Decision (ROD), the draft decision was to use average water as the basis for establishing the uses of the capacity of the FCRPS. The reasoning was that basing the cost allocation on average water instead of critical water could require application of risk mitigation tools such as PNRR, CRAC, and DDC, but concluded such change was not necessary, because the Wind Balancing Rate did not receive an allocation of any secondary sales revenue. WP-10 Draft ROD,

WP-10-A-01, at 267. The final decision of the Administrator did not change. WP-10 Final ROD, WP-10-A-02, at 309 and 311.

Mainzer *et al.*, BP-12-E-BPA-23, at 56-57.

Staff explains the reason for proposing to change the application of risk mitigation tools to balancing reserve capacity-based ACS rates in its initial proposal:

Previously BPA Staff did not consider the impact of water conditions on the amount of variable costs caused by the provision of balancing reserve capacity-based Ancillary and Control Area Services. When BPA Staff analyzed the level of variable costs based on critical water and not the average of 70 water conditions, the amount of variable costs attributable to balancing reserve capacity-based Ancillary and Control Area Services increased to \$39.9 million. This amount is significantly more than the \$25.2 million expected on average across all water conditions. Klippstein *et al.*, BP-12-E-BPA-25, section 5.3. In addition, staff reviewed the decision from the 2010 rate proposal. Given the use of the average water assumption for allocating embedded costs, it appears to staff upon further review that the users of these capacity reserve-based rates realize a benefit (*i.e.*, a lower rate) from this assumption of additional capacity. This additional capacity allows for the sale of secondary energy. Thus, BPA Staff proposes to apply BPA's risk mitigation tools to balancing reserve capacity-based Ancillary and Control Area Services in this rate proceeding.

Mainzer *et al.*, BP-12-E-BPA-23, at 57.

Staff also examines all the risks that are evaluated in the Power Risk and Market Price Study and determined that many of these risks are applicable to ACS rates because of the assumption of average water in the rate setting methodology. Lovell *et al.*, BP-12-E-BPA-15, at 57; Lovell and Mandell, BP-12-E-BPA-37, at 33-34.

Evaluation of Positions

NWG's description of the procedural history of the decision to use average water for BPA's generation inputs embedded cost methodology is relatively accurate. Staff proposed to use critical water and 120-hour peaking capacity to determine the baseline for assigning embedded costs to capacity uses of the Big 10 FCRPS projects. *See* Klippstein *et al.*, WP-10-E-BPA-24, at 8-9. NWG raised several objections to this methodology and the inputs to the methodology, and argued that the Wind Balancing Service rate should receive a credit for the secondary sales that came from these FCRPS projects. Cowlitz offered a well reasoned alternative in its initial brief, suggesting that it is not appropriate to assign credits from secondary revenues to the ACS rates, but that using average water to determine the 120-hour peaking capacity would account for all capacity uses of the FCRPS. Cowlitz Br., WP-10-B-CO-01, at 14. BPA decided to align the methodology with Cowlitz's proposal. WP-10 ROD, WP-10-A-02, at 306-311.

NWG's description of the procedural history of the WP-10 decision to not apply the risk mitigation tools to the ACS rates misses several key points. Notably, NWG is selective in the

quotes from the WP-10 Final Record of Decision that were included in its initial brief. NWG uses the same quote of Staff's position discussed in Sub-Issue 3.2.5.1.5 above to sustain its argument regarding the decision to not apply the risk mitigation tools. NWG Br., BP-12-B-NG-01, at 31. Again this is taken out of context. Staff's position was stated in the WP-10 Initial Proposal in regard to whether the embedded cost should include PNRR, and Staff concluded that PNRR should not be included in ACS rates, because Staff was using critical water, which did not account for non-firm uses of the FCRPS, such as secondary sales. Klippstein *et al.*, WP-10-E-BPA-24, at 3-4. Interestingly, NWG's quote from the evaluation section of the WP-10 ROD documenting the decision to not apply the risk mitigation tools to the ACS rates did not include this same language.

The Draft ROD concludes by stating that Staff also points out that PNRR and other risk mitigation tools do not apply to the cost allocation for generation inputs, because BPA uses 1937 water to allocate embedded cost to this rate, and the revenues assigned to these reserves do not include a credit for secondary sales. Klippstein et al., WP-10-E-BPA-24, at 3-4. This could be read to suggest that if BPA chooses to use average water instead of critical water, PNRR and the CRAC should be applied to the cost allocation for these reserves. However, BPA does not believe this is necessary, because using average water to establish the 120-hour peaking capability is not the same as providing a credit to a transmission rate for secondary power sales.

WP-10 ROD, WP-10-A-02, at 309 (emphasis added to the language that NWG did not include in its initial brief).

This additional language is important because it demonstrates that the decision to go from critical water to average water was made in the Draft Record of Decision based on Cowlitz's initial brief. Likewise, the decision to not apply the risk mitigation tools was made in the WP-10 Draft ROD based on a rationale associated with the use of critical water. There was no Staff analysis regarding the applicability of the risk mitigation tools associated with the use of average water because the decision to change from critical to average water was made so late in the proceeding. The only thing in the WP-10 record on the issue of applying the risk mitigation tools to the ACS rates is quoted above. This was not addressed as a separate issue or decision, and no parties submitted testimony or briefs on this specific issue. It was simply decided as part of the broader issue of changing from critical to average water.

This version of the procedural history hardly supports NWG's assertion that Staff's proposal is opening a previously settled issue. It is worth noting a few other quotes from this particular evaluation section in the WP-10 ROD.

Using either critical or average water can be justified and supported in this rate proceeding. In future rate proceedings, BPA may want to use critical water for this cost allocation, but for purposes of balancing the interests in this proceeding, average water will be used for determining the 120-hour peaking capability used to allocate cost to generation inputs.

WP-10 ROD, WP-10-A-02, at 309.

As BPA stated in the Draft ROD, the industry is in a transitional period with unprecedented amounts of wind generation interconnecting to the Federal transmission system, and BPA may propose to use critical water or something completely different in future rate cases.

Id. at 311.

These quotes, from the same evaluation section in which the decision was made to not apply the risk mitigation tools to the ACS rates, show that the Wind Balancing Service (now referred to as VERBS) rate is a relatively new endeavor for BPA and that BPA has the discretion to reevaluate decisions that were made in prior rate cases based on the information that is on the record in this rate proceeding.

NWG's claim that Staff has not advanced any new information or arguments that were not before the Administrator during the WP-10 proceeding, and that there are no new facts or basis in the record to cause the Administrator to revisit his earlier decision, is disingenuous. NWG Br., BP-12-B-NG-01, at 35. As described above, there was no analysis of the risks associated with an ACS rate design based on average water on the record in the WP-10 case. The only thing on the WP-10 record was Staff's testimony that under critical water secondary revenues are not taken into account, and thus PNRR should not apply to the ACS rates. Klippstein *et al.*, WP-10-E-BPA-24, at 3-4. Once BPA decided to change from critical to average water, BPA was faced with Staff's testimony that "could be read to suggest that if BPA chooses to use average water instead of critical water, PNRR and the CRAC should be applied to the cost allocation for these reserves." WP-10 ROD, WP-10-A-02, at 309. Since there was no analysis in the WP-10 record, there were no calculations or documentation to describe how the risk mitigation tools could be applied to the ACS rates; thus, if BPA had chosen to apply the risk mitigation tools to the ACS rates at that time, it would have been very difficult to sustain.

In this FY 2012–2013 rate proceeding Staff provides testimony on the risk associated with using average water in the ACS rate methodology and explains how those risks are part of the overall risk assessment. Lovell *et al.*, BP-12-E-BPA-15, at 57; Lovell and Mandell, BP-12-E-BPA-37, at 31-34; Mainzer *et al.*, BP-12-E-BPA-23, at 57. Staff also includes calculations for how the risk mitigation tools can be applied to the balancing reserve capacity-based ACS rates. *See* Proposed ACS Rate Schedules, BP-12-E-BPA-10, GRSP II.H. There is ample evidence in this rate proceeding to support a change to the WP-10 decision to not apply the risk mitigation tools to the ACS rates.

Decision

In the WP-10 Administrator's Final Record of Decision, BPA did decide to change the ACS rate methodology from critical to average water and to not apply the risk mitigation tools to the ACS rates. However, that decision is not a settled issue and must be decided based on the record before BPA in this proceeding.

Sub-Issue 3.2.5.1.9

Whether applying CRAC, Emergency NFB Surcharge, and PNR to ACS rates is contrary to the Commission's policy on separation of functions or an impermissible cross-subsidization.

Parties' Positions

NWG asserts that Staff's risk mitigation proposal would result in a cost shift from power rates to transmission rates that would contravene the Commission's Order 888 and its progeny, which emphasize the importance of separation between merchant and transmission functions. NWG Br., BP-12-B-NG-01, at 37. NWG states that this separation of functions is critical to ensuring non-discriminatory open access transmission service. *Id.* NWG argues that Staff's proposal to apply the CRAC to non-Federal transmission customers blurs the line between BPA's power and transmission functions and is an impermissible cross-subsidization. *Id.*

BPA Staff's Position

This is a legal issue, and Staff does not directly address this issue in testimony. Staff does explain why generation input costs are assigned to transmission rates:

Generation Inputs costs are assigned to transmission rates because the generation inputs are used to provide Ancillary and Control Area Services to transmission customers. Assigning these costs to transmission rates follows the principle of cost causation, which holds that the entity responsible for creating costs should be responsible for paying such costs.

Mainzer *et al.*, BP-12-E-BPA-23, at 10.

Evaluation of Positions

NWG's assertions regarding cost shifts, contravention of separation of functions, and impermissible cross-subsidization all start from the premise that the CRAC and other risk mitigation tools are power costs. As was discussed above, the risk of a low-water year that arises from using average water in the ACS rate methodology is directly related to the ACS transmission services. As Staff has explained, generation inputs costs are based on assigning the cost of the FCRPS generating resources to the ACS uses of the balancing reserve capacity. *See* Mainzer *et al.*, BP-12-E-BPA-23, at 10-15. The risk mitigation tools are designed to address the possibility that assumptions BPA makes in the rate proceeding come up short and result in financial short falls that threaten BPA's ability to make its Treasury payment.

Taking NWG's logic regarding separation of functions and cross-subsidization one step further could lead to questions about the overall assignment of generation input costs to ACS transmission rates. This is an absurd result, and since the passage of Order 888 and the unbundling of the ACS the Commission has consistently approved the assignment of generation costs associated with providing capacity-based ACS to ACS rates. *See, e.g., Am. Elec. Power Service Corp.*, 80 FERC ¶ 63,006 (1997) (affirmed in part and reversed in part by 88 FERC ¶ 61,141 (1999)). Because risk mitigation is intended to protect BPA's ability to make its Treasury payment, it is not simply a power cost, and therefore applying the risk mitigation tools

to ACS rates is not a cost shift, a contravention of separation of functions, or an impermissible cross-subsidization.

Decision

Applying the risk mitigation tools to ACS rates is not contrary to the Commission's policy on separation of functions, nor is it an impermissible cross-subsidization.

Issue 3.2.5.2

Whether applying CRAC, Emergency NFB Surcharge, and PNRR to VERBS is discriminatory and whether it will discourage the development of renewable energy in the Pacific Northwest.

Parties' Positions

As an example of proposed ACS rate changes that NWG claims discriminate against wind energy producers and other non-Federal transmission users, NWG takes issue with the proposal to apply the CRAC, Emergency NFB Surcharge, and PNRR to ACS rates, which NWG describes as a power-related surcharge. NWG Br., BP-12-B-NG-01, at 8-9. NWG claims that in combination with other parts of Staff's proposal, this surcharge will burden renewable energy producers and other non-Federal transmission customers with inappropriate and unreasonable charges and discourage additional clean energy projects from being developed in the Pacific Northwest. *Id.* at 9.

BPA Staff's Position

Staff describes BPA's efforts to integrate wind resources:

BPA has developed and facilitated significant innovations, including its Network Open Season transmission subscription process, customer-supplied generation imbalance, intra-hour scheduling, and new forecasting tools, to enable a massive increase of wind generation on its system while preserving reliability, honoring our statutory obligation and non-power operating constraints, and acting consistent with cost causation principles. The fact that wind generation has increased by a factor of six over the past four years and is set to double again over the next two to three years is clear evidence that our rates and policies, if anything, are a stimulus to further wind development across our footprint.

Mainzer *et al.*, BP-12-E-BPA-42, at 9-10.

Evaluation of Positions

As is discussed above, NWG mischaracterizes the risk mitigation tools as a power-related surcharge. In regard to NWG's claim that Staff's proposal to apply the risk mitigation tools will burden renewable energy producers and other non-Federal transmission customers with inappropriate and unreasonable charges and discourage additional clean energy projects from being developed in the Pacific Northwest, it is important to understand the potential impact of

Staff's proposal on the VERBS rate. Under Staff's proposal the risk mitigation tools would trigger only if the level of BPA's financial reserves puts BPA in jeopardy of not being able to meet its 95 percent TPP standard. Power Risk and Market Price Study, BP-12-E-BPA-04, at 1-2. In the event that a CRAC were to trigger, less than four percent of the CRAC costs would be assigned to ACS rates and less than two percent would flow to the VERBS rate. PF customers are exposed to the balance of any costs associated with CRAC. Also worth noting, Staff's Initial Proposal called for a three cent increase in the VERBS rate, but based on adjustments to some of the components of the rate calculation, VERBS customers will see a rate decrease. With the trends BPA has seen in wind interconnections and BPA's efforts to encourage wind integration, it does not appear likely that Staff's proposal to apply the risk mitigation tools to ACS rates will discourage VER development in the region.

Decision

Applying the risk mitigation tools to VERBS is not discriminatory; the impact of applying the risk mitigation tools to VERBS is modest if any and therefore is unlikely to discourage the development of renewable energy in the Pacific Northwest.

3.2.6 VER Integration NOPR Policy Issues

During the rate proceeding, the Commission issued a Notice of Proposed Rulemaking on VER Integration (NOPR). The Commission proposes significant changes to the operational requirements for jurisdictional utilities that interconnect VERs and new policies regarding rates for the capacity used to support generation. The NOPR includes specific proposals related to: (1) implementation of intra-hour scheduling on 15-minute intervals; (2) use of VER power production forecasts; and (3) recovery of capacity charges associated with generator imbalance service. Certain parties maintain that VERBS and the associated rate are inconsistent with the proposals in the NOPR and advocate that BPA incorporate the operational changes proposed in the NOPR and use those changes as a basis for assumptions in setting the VERBS rate.

Issue 3.2.6.1

Whether as a balancing authority BPA is subject to FERC orders applicable to jurisdictional utilities regarding the provision of balancing reserves.

Parties' Positions

NWG and Iberdrola maintain that BPA's proposal for VERBS is not consistent with the proposals in the NOPR. Iberdrola Br., BP-12-B-IR-01, at 8-10; NWG Br., BP-12-B-NG-01, at 15-21. NWG goes on to suggest that BPA should implement the Commission's proposals in setting rates and that, according to the NOPR, failure to do so would result in rates that are unjust, unreasonable, and unduly discriminatory. NWG Br., BP-12-B-NG-01, at 15-18. Both Iberdrola and NWG suggest that BPA take Commission policy into account when establishing the VERBS rate. Iberdrola Br., BP-12-B-IR-01, at 8; NWG Br., BP-12-B-NG-01, at 20-21.

In the context of discussing the appropriateness of Staff’s VERBS formula rate proposal, PPC states that as a balancing authority, BPA has an obligation by regulation to meet control performance standards established by NERC and approved by the Commission. However, PPC disagrees with Iberdrola’s assertion that BPA has any obligation under Commission orders applicable to jurisdictional utilities to provide balancing services. PPC Br., BP-12-B-PP-01, at 21. PPC states that even if BPA were subject to the Commission’s jurisdiction in this regard, BPA’s organic statutes must be read consistent with any statute providing the authority for the Commission regulations, and these statutes must be read to give effect to each to the maximum extent possible. *Id.*

BPA Staff’s Position

For purposes of explaining how Staff believes BPA should react to the Commission’s VER NOPR proposal, and addressing the WP-10 ROD quote raised by NWG, Staff states:

BPA will continue to take Commission policy into account where appropriate. However, as BPA explained in its NOPR comment, there are several aspects of the NOPR with which BPA disagrees. In particular, the proposal to delay establishment of a rate to recover the cost of balancing reserve capacity provided to VERs would violate the core ratemaking principle of cost causation.

Mainzer *et al.*, BP-12-E-BPA-42, at 13.

Evaluation of Positions

Both NWG and Iberdrola quote the statement from BPA’s WP-10 ROD that BPA “is not bound by Commission policy, although it does take it into account where appropriate.” Iberdrola Br., BP-12-B-IR-01, at 8 n.13; NWG Br., BP-12-B-NG-01, at 20-21, *quoting* WP-10-A-02 at 478. Iberdrola states that while BPA “is not a ‘public utility’ under the Federal Power Act, and therefore not necessarily required to follow Commission policy, as a federal agency, it is appropriate for Bonneville to take Commission policy into account in developing the VERBS rate.” Iberdrola Br., BP-12-B-IR-01, at 8. Iberdrola also points out that BPA could be subject to a Commission order issued under section 210, 211, 211A, or 212 of the Federal Power Act. Iberdrola Br. Ex., BP-12-R-IR-01, at 7-9. BPA addresses Iberdrola’s arguments about these sections of the Federal Power Act in section 3.2.2.7 of this ROD.

In the ratemaking context, BPA’s authority is governed specifically by statute. BPA is setting rates in this proceeding and is not bound by FERC orders.

In the context of providing transmission service, the applicability of a Commission order on the NOPR issues regarding the provision of balancing reserves will depend on whether BPA seeks reciprocity status for its transmission tariff. Issue 3.2.2.1 addresses Iberdrola’s concerns about reciprocity. If FERC issues final rules regarding VER integration, BPA will consider those rules in developing its tariff if BPA decides to seek reciprocity status in the future.

Decision

BPA is not required to follow Commission decisions regarding provision of balancing services.

Issue 3.2.6.2

Whether BPA should align the VERBS and VERBS rate with the NOPR as a matter of policy.

Parties' Positions

NWG argues that BPA's proposed VERBS rate is inconsistent with the Commission's proposed rules regarding: (1) 15-minute intra-hour scheduling; (2) use of VER power production forecasts; and (3) recovery of capacity charges associated with generator imbalance service. NWG Br., BP-12-B-NG-01, at 15. NWG claims that if BPA were a jurisdictional utility, the Commission would find that the VERBS rate proposal unjust and unreasonable. *Id.* at 19-20. NWG also points out that when the Commission's rule becomes final, jurisdictional utilities in the region will be subject to the requirements, and suggests that BPA align its policies with regional public utility transmission providers to avoid seams issues. *Id.* at 20.

Iberdrola raises similar issues to NWG. Iberdrola Br., BP-12-B-IR-01, at 6-8. Iberdrola states that while BPA is not necessarily required to follow Commission policy, it is appropriate for a Federal agency such as BPA to take Commission policy into account in developing the VERBS rate. *Id.* at 8. Iberdrola states that the Commission's transmission and interconnection policies establish the national standard for open access transmission service, and BPA's VER integration rate policies should not substantially depart from the Commission's policies for legal, policy, and operational reasons. *Id.* Iberdrola also argues that BPA has not considered the potential costs associated with establishing rates and policies that may have to be revised to conform with Commission rules. Iberdrola Br. Ex., BP-12-R-IR-01 at 16.

PPC asserts that the proposals to align BPA's VERBS rate proposal with the proposals in the NOPR are unreasonable, because the NOPR is not a final rule, and BPA cannot base rate assumptions on proposed rules or what reforms, if any, BPA may choose to adopt. PPC Br., BP-12-B-PP-01, at 5-7. PPC agrees with Staff that the NOPR reforms might not produce savings, would violate the principle of cost causation, and create additional risk of DSO 216 curtailments. *Id.* at 6. PPC states that NWG and Iberdrola have not demonstrated that reforms or the benefits from the reforms are feasible during the FY 2012–2013 rate period. *Id.* at 7. PPC concludes that there is nothing in the record on which BPA could base assumptions regarding the reforms in the VER NOPR or any benefits in the form of lower reserve amounts associated with those reforms. *Id.*

BPA Staff's Position

The NOPR is a proposed rule to which BPA and many parties across the country have responded in the form of comments. Mainzer *et al.*, BP-12-E-BPA-42, at 12-13. There is no certainty as to what the final rule will contain or the timing of the issuance of the final rule. *Id.* at 13. Staff

addresses the specific reforms of the VER NOPR and explained how these reforms may not result in the benefits asserted by Iberdrola and NWG. *Id.*

Evaluation of Positions

NWG and Iberdrola suggest that BPA adopt a number of new operating practices and reflect those new practices in rate assumptions. Operational issues are beyond the scope of this proceeding and will not be resolved in this ROD. Issues 3.2.6.3–3.2.6.6 address the consistency of BPA’s VERBS proposals with the specific proposals in the NOPR regarding intra-hour scheduling, VER power production forecasting, and recovery of capacity costs.

The suggestion that BPA should adopt the specific reforms proposed by FERC for purposes of making operational decisions as well as setting rates in this proceeding is curious. Setting aside BPA’s non-jurisdictional status, the benefit to BPA or its customers of investing in operational changes and adopting rates on the basis of rules that FERC has not yet adopted is questionable. For example, the costs and complexities of implementing 15-minute intra-hour scheduling alone would likely be significant, and it is unclear why BPA should begin investing resources in modifying operations to implement rules that FERC might not adopt. Such actions could lead to incurring unnecessary costs to the detriment of customers, and it is unproven at this point if certain proposed reforms will lead to substantial savings in VER integration costs. Mainzer *et al.*, BP-12-E-BPA-42, at 12-13; PPC Br., BP-12-B-PP-01, at 5-7. Moreover, immediately devoting resources to implementing the reforms as proposed may divert resources from other initiatives, such as the Committed Intra-Hour Scheduling pilot, which most parties seem to agree will benefit customers.

BPA does not agree with the suggestion to use the proposals in the NOPR as a basis for ratemaking. Setting aside that the proposals would not bind BPA even if FERC does issue final rules, the resolution of the Commission’s proposals is simply too speculative to rely upon for ratemaking purposes. BPA faced similar uncertainty in the WP-10 proceeding in the context of the proposed changes to rules governing Operating Reserves, and BPA adopted reasonable measures to account for those changes during the rate period. WP-10 ROD, WP-10-A-02, at 332. The proposals in this proceeding to immediately account for the NOPR proposals do not even suggest a more conservative approach such as this. BPA does not believe that using the operational changes proposed by FERC for its assumptions in this proceeding is the correct approach as a matter of ratemaking policy. In any event, the record in this proceeding does not support that assumption. The record lacks evidence to provide confidence in the substance of any final rules or the timing when final rules might be adopted.

Iberdrola maintains that BPA has not considered the potential costs of establishing rates and policies that may have to be revised during the rate period if the Commission issues a final order in the VER integration NOPR. Iberdrola Br. Ex., BP-12-R-IR-01, at 16. This argument suggests that BPA should assume, for ratemaking purposes, that it will be bound to implement any order regarding the VER integration NOPR. As described in Issue 3.2.6.1, that assumption is incorrect. Iberdrola maintains that the Commission could require BPA to provide “non-discriminatory transmission access” upon request. Iberdrola Br. Ex., BP-12-R-IR-01, at 7-9, 15. BPA disagrees that its decisions in this proceeding are discriminatory. BPA also disagrees that it

is necessary for BPA to base its rates on the speculative “what ifs” underlying the suggestion to incorporate the NOPR proposals in the VERBS rate.

Finally, the suggestions regarding the NOPR do not seem to account for the fact that BPA (and some other Northwest transmission providers) did not support certain aspects of the proposed rules. NWG expresses concerns that BPA’s departure from the proposed rules could create “seams issues” in the Northwest, but BPA’s implementation plans for items such as 30-minute intra-hour scheduling are consistent with regional initiatives. NWG Br., BP-12-B-NG-01, at 20. Immediate implementation of 15-minute scheduling at this point actually would run counter to regional intra-hour scheduling efforts.

The argument that BPA’s operational procedures and rate proposals are inconsistent with FERC’s proposed rules does not seem to reflect the circumstances in the region or the reality that BPA faces in setting rates. BPA will continue to participate in FERC’s rulemaking and will assess how any final rules affect BPA’s VERBS and VERBS rate. BPA is moving forward with reforms, such as intra-hour scheduling, that are in line with the direction indicated by the Commission in the VER Integration NOPR, and BPA will continue to evaluate the value of other reforms in future rate proceedings.

Decision

BPA will not revise its VERBS proposals to align with the Commission’s proposed rules. BPA will continue to participate in the FERC proceeding and will assess the impact of any final rules when they are adopted by FERC.

Issue 3.2.6.3

Whether the fact that BPA is not following the VER NOPR and using VER power production forecasts in operations as a means to reduce its forecast of balancing reserve capacity requirements for ratemaking purposes results in a rate that is unjust, unreasonable, and unduly discriminatory.

Parties’ Positions

NWG asserts that BPA’s current VER power production forecasting system does not meet the standards proposed by the Commission under the VER NOPR, because BPA does not currently use a VER power production forecast for its unit commitment, dispatch, and reliability assessment process. NWG Br., BP-12-B-NG-01, at 16-17. NWG admits that wind generation is more variable than some generating resource types, but maintains that wind is forecast for every hour, and the amount of reserves held should be a function of the forecast. BPA uses load variability in its operations, and it is only reasonable to expect BPA to do the same for wind generators. NWG claims that meteorological data can be used to inform expected project operations and the potential magnitude of schedule error. *Id.* at 17. Citing to the VER Integration NOPR, NWG states that failing to consider VER power production forecasts in the hour-ahead, intra-day, day-ahead, and monthly time frames may result in an over-procurement of

reserves, leading to rates that may be unjust, unreasonable, and unduly discriminatory. *Id.* at 17-18. NWG responds to Staff's rebuttal testimony, which asserted use of VER generation forecasts would be impractical for improving situational awareness and minimizing its current practice of holding balancing reserves during all hours of the year, by claiming that Staff's position is contrary to the overwhelming acknowledgement of the value of system wide VER forecasts noted by the Commission in the VER Integration NOPR. NWG also points out that other organized markets use VER power production forecast every day and has asked the Administrator to take official notice of the NREL report, *Status of Centralized Wind Power Forecasting in North America*. *Id.* at 18.

PPC cites to Staff's rebuttal testimony to assert that although BPA currently uses power production forecasts for hydro scheduling and system dispatch, changing the amount of balancing reserves based on power production forecasts would simply increase the risk of DSO 216 curtailments. PPC Br., BP-12-B-PP-01, at 6.

BPA Staff's Position

Staff explains that planning reliable operations of the hydro system requires that the system commitments to provide balancing reserve capacity must be known well in advance of that which would be provided from VER power production forecasts that become less dependable the further they are from actual operations. Mainzer *et al.*, BP-12-E-BPA-42, at 14-15. BPA must stand ready to provide *inc* and *dec* reserves to cover the full range of schedule error between the wind generation schedule and the actual performance of the generator. So even if BPA were using a system-wide VER power production forecast to reduce the number of reserves held during times when less volatility is forecast, schedule error could cause the depletion of the reserves that are being held. Staff believes that reliance on VER power production forecast to adjust the amount of reserves on an hourly or daily basis would result in more DSO 216 events. *Id.* at 25-26.

With regard to the Commission's proposal in the VER Integration NOPR regarding the use of VER power production, forecast Staff responds:

BPA has commented to FERC in the context of NOPR responses that centralized forecasting becomes more useful if it is combined with clearly defined or mandatory scheduling practices. We assume, but cannot be certain, that parties will schedule according to the best available forecast available at 30 minutes prior to the delivery hour or scheduling interval. Because some parties may instead decide to schedule several hours ahead, based on the forecast available at that time in combination with operator judgment and marketing decisions, we cannot assume that the use of *inc* and *dec* reserves will relate directly to the uncertainty around a centralized forecast at a specific point in time. Therefore, we cannot make any assumptions in this rate proceeding about reduced costs based on adjusting the amount of *inc* and *dec* reserves due to wind forecasts.

Id. at 15.

Evaluation of Positions

The substantive issues of whether BPA should use VER power production forecasts to adjust the amount of balancing reserve capacity it is holding during the rate period and how any reduction in the VERBS rate could be calculated based on such a change are evaluated in Issue 3.2.4.8. As is explained in the evaluation of that issue, under the current operating conditions, where BPA is responsible for providing all balancing reserve capacity from the FCRPS and hydro planning must be done well in advance of the availability of quality VER power production forecasts, it is hard to see how the saving associated with adjusting the amount of reserves BPA maintains would offset the risk of additional DSO 216 events due to forecast error. BPA is not reducing its forecast of the balancing reserve capacity requirements based on the assumption that use of VER power production forecasts would reduce the reserve requirement in the monthly time frame or shorter time frames.

As Staff points out, the VER power production forecasts become more useful if it is combined with mandatory scheduling requirements for wind generators and the uncertainty over the scheduling behavior of individual wind generators is taken out of the mix. NWG bases its assertion that BPA's unwillingness to adjust the amount of reserves based on VER power production forecasts makes BPA's rate unjust, unreasonable, and unduly discriminatory, on the Commission's proposal in the VER Integration NOPR. Since this is a proposed rule, which does not consider the unique character of the FCRPS or the other particular facts associated with BPA providing VERBS to wind generators, it is a stretch to assert that BPA's VERBS rate proposal is unjust, unreasonable, and unduly discriminatory. As is discussed in the evaluation of Issue 3.2.4.8, BPA does believe that VER power production forecast used in combination with other scheduling requirements may lead to significant improvements in the use of balancing reserve capacity in the future, but for the FY 2012–2013 rate period BPA must establish rates consistent with current operating practice.

Decision

The fact that BPA is not using VER power production forecasts to reduce its forecasted reserve requirement and set a lower VERBS rate as described in the VER Integration NOPR does not result in a rate that is unjust, unreasonable, and unduly discriminatory.

Issue 3.2.6.4

Whether implementation of 15-minute scheduling is practical in this rate period and whether it should be considered for purposes of setting rates.

Parties' Positions

NWG extols the benefits of lower reserve needs associated with moving to shorter scheduling intervals. NWG Br., BP-12-B-NG-01, at 60. NWG points out that BPA's current scheduling protocols do not meet the Commission's proposed 15-minute standard and that BPA does not have any plans to introduce 15-minute scheduling. *Id.* at 16. NWG acknowledges that BPA

Staff is proposing a CIH pilot for the FY 2012–2013 rate period that would allow intra-hour scheduling on a 30-minute basis, and NWG is very supportive of this effort. *Id.* at 16, 60.

Iberdrola describes the rationale for 15-minute scheduling contained in the VER Integration NOPR. Iberdrola Br., BP-12-B-IR-01, at 10. Iberdrola explains that it commented on the VER Integration NOPR that the Commission should allow entities to initially schedule at 30 minutes, as a transitional measure to 15-minute scheduling. *Id.* Iberdrola recommends that BPA adopt 30-minute schedules as a transitional measure until it can move to 15-minute schedules. *Id.* at 10-11.

PPC states that Iberdrola and NWG have failed to demonstrate that 15-minute scheduling could be implemented in the FY 2012–2013 rate period or that quantifiable reductions in the amount of balancing reserve capacity BPA maintains could be reasonably forecast as a result. PPC Br., BP-12-B-PP-01, at 6-7. PPC points out that BPA Staff states that 15-minute scheduling would have to be mandatory, rather than voluntary, as proposed in the VER Integration NOPR. *Id.* at 7. PPC concludes that no reasonable basis exists in the record to support a reduction of the balancing reserve capacity forecast based on 15-minute scheduling assumptions. *Id.*

BPA Staff's Position

Staff describes BPA's efforts to make 30-minute scheduling available and anticipates that it should be expanded to allow schedule adjustments for any use by any scheduling entity by the start of the FY 2012–2013 rate period. Mainzer *et al.*, BP-12-E-BPA-23, at 44. Staff points out that 30-minute scheduling will be voluntary, and with voluntary intra-hour scheduling it would be difficult to predict the effect on the amount of balancing reserve capacity needed for VERBS. *Id.*

Staff agrees with the concept that intra-hour scheduling can lower balancing reserve capacity requirements provided there is a firm commitment to adjust schedules at each scheduling interval and to meet or exceed a pre-defined level of scheduling accuracy. Mainzer *et al.*, BP-12-E-BPA-42, at 24. Staff is proposing the Committed Intra-Hour Scheduling pilot for wind generators that are willing to commit to 30-minute scheduling consistent with either a persistent schedule or a verifiable meteorological-based forecast. Simpson *et al.*, BP-12-E-BPA-46, at 2. The pilot estimates a balancing reserve capacity requirement reduction and a VERBS rate reduction for Committed Intra-Hour Scheduling participants. *Id.* at 7.

Staff does not propose to set FY 2012–2013 rates on the possible outcomes of the VER Integration NOPR, which includes 15-minute scheduling. Mainzer *et al.*, BP-12-E-BPA-42, at 13.

Evaluation of Positions

Staff states, and NWG and Iberdrola recognize, that BPA does not plan to go to 15-minute scheduling in the FY 2012–2013 rate period. Iberdrola supports 30-minute intra-hour scheduling as a transition to 15-minute intra-hour scheduling. Iberdrola recommends BPA move to 30-minute intra-hour scheduling. Iberdrola urges BPA to fully implement 30-minute intra-hour

scheduling both in and out of the Bonneville balancing authority area as a transitional measure until the move to shorter scheduling time periods. Skidmore, Oral Tr. at 138. NWG seems to acknowledge in oral argument that 15-minute scheduling might not be in the “art of the possible” for BPA during the rate period and that intra-hour scheduling on 30-minute intervals would be better than hourly scheduling. Hall, Oral Tr. at 215.

The benefits of intra-hour scheduling to reduce the forecast balancing reserve capacity quantity lie in the consistent application of shorter scheduling windows and a quality metric of meeting or beating 30-minute persistence accuracy. NWG and Iberdrola recommend that BPA move toward 15-minute scheduling as described in the VER Integration NOPR with voluntary participation. As PPC points out, intra-hour scheduling would have to be mandatory in order for BPA to reasonably forecast a reduction in the balancing reserve capacity amount. PPC Br., BP-12-B-PP-01, at 7. BPA explained the need for mandatory scheduling and a commitment to schedule consistently with a known forecast in its comments on the VER Integration NOPR. *Integration of Variable Energy Resources*, FERC Docket No. RM10-11, Comments of the Bonneville Power Administration at 4, 28–30 (Mar. 2, 2011).

As a means to gain experience with the concepts of mandatory intra-hour scheduling in combination with a quality metric for the intra-hour schedules, Staff proposes a Committed Intra-Hour Scheduling pilot for the rate period. NWG supports the pilot where participants commit to mandatory intra-hour scheduling with a reduction in their balancing reserve capacity amount and a corresponding reduction in the VERBS rate. The scheduling interval for the pilot is 30 minutes rather than 15 minutes.

The feasibility of 15-minute scheduling and assumptions about lower reserve amounts based on voluntary scheduling are not supported by the record. Without commitments such as will be required in the Committed Intra-Hour Scheduling pilot, the record lacks data to forecast whether intra-hour schedules will be used enough or accurately enough to support an assumption regarding a reduction in the amount of reserves BPA is holding to support VERBS. BPA hopes that the use of voluntary intra-hour scheduling will increase during the FY 2012–2013 rate period and will help develop intra-hour scheduling practices that will be a consideration in the FY 2014–2015 rate proceeding.

Decision

Implementation of 15-minute scheduling is not practical for the FY 2012–2013 rate period. A reduction to the balancing reserve capacity requirement due to an assumption of 15-minute scheduling will not be used in setting the VERBS rates.

Issue 3.2.6.5

Whether BPA should not apply a VERBS rate until the FERC Integration NOPR reforms are in place and BPA has gathered one year worth of data.

Parties' Positions

Iberdrola describes the proposed requirement in the VER Integration NOPR that transmission providers must implement 15-minute scheduling and VER power production forecast and collect at least one year's worth of data to demonstrate the true cost of variability associated with VERs prior to charging a VER balancing service rate. Iberdrola Br., BP-12-B-IR-01, at 8-9. Iberdrola recognizes that BPA will be implementing 30-minute scheduling and recommends that BPA gather at least one year of data with 30-minute scheduling in place to determine the true cost of VER integration with 30-minute scheduling in place, prior to charging a VERBS rate. *Id.* at 11.

PPC describes Iberdrola's suggestion that BPA not recover the cost of providing balancing reserve capacity that BPA incurs on behalf of wind generators as wholly inappropriate. PPC Br., BP-12-B-PP-01 at 6-7. PPC states that not charging a VERBS rate until some indeterminate time when reforms are implemented shifts costs to power customers in violation of established ratemaking principles and would cause BPA not to recover its full costs. *Id.* PPC concludes that Iberdrola's proposal violates the cost causation principle and would be inequitable. *Id.* at 7. PPC states the proposed rule is not final, and BPA should not assume the outcome of the VERs NOPR or what reforms BPA might choose to adopt, if any, based on the outcome of that docket. *Id.* at 5.

NWG says it is appropriate for the Administrator to take the proposed rule into account when evaluating the appropriateness of other proposed upward rate adjustments to the VERBS rate. NWG Br., BP-12-B-NG-01, at 21.

BPA Staff's Position

Staff responds to NWG and Iberdrola's proposal by stating:

We have provided testimony in this rate case regarding the costs of providing VERBS. Klippstein *et al.*, BP-12-E-BPA-25. The quantity of VERs interconnected to the BPA transmission system is already significant and is expected to increase significantly during this rate period. Any delay in charging a rate for VERBS would be inconsistent with the principle of cost causation, because it would impose the costs of balancing service on other ratepayers. It would be inequitable to assign the costs of VERBS to other Pacific Northwest ratepayers, and we do not propose to do so. ... [W]e have not changed our approach to this rate case as a result of the NOPR.

Mainzer *et al.*, BP-12-E-BPA-42, at 15-16.

Evaluation of Positions

BPA has had a wind balancing rate in place for three years. Staff provides a significant amount of evidence regarding the quantity of balancing reserve capacity required for within-hour wind integration and the costs associated with providing balancing reserve capacity. Staff considers historical information for the balancing reserve capacity required to integrate wind and the wind facilities' historical scheduling accuracy in its forecast of balancing reserve capacity for the rate period. In addition to the data presented in this rate proceeding, BPA has held numerous public

workshops to share information and worked collaboratively with wind developers and operators to integrate the growing amount of wind in the balancing authority area.

In response to a question from the Administrator on whether Iberdrola was recommending that BPA adopt the Commission's NOPR proposals for 15-minute scheduling, power production forecasting, and no VER rate until a year's worth of data has been gathered with these other reforms in place, Iberdrola says it would be delighted if BPA adopted these reforms, but realizes it is unlikely. Skidmore, Oral Tr. at 144.

Not charging a VERBS rate until proposed possible reforms are in place and a year's worth of data is collected would cause a significant cost shift to other BPA ratepayers. In this rate case and the previous case, BPA provides evidence of the effect imposed by the increasingly large amount of wind that is interconnecting on the BPA system. The VERBS rate is consistent with cost causation because it is based on the use of balancing reserve capacity by the various users, and corresponding costs are proportioned out accordingly. The VER Integration NOPR is still in process and could change significantly before the final ruling. Once the reforms are in place, they may be very different from those in the VER Integration NOPR. At that time BPA may consider the proven effects of these reforms in the subsequent revisions to the VERBS rate through future rate proceedings.

Decision

BPA will continue to apply a VERBS rate in the FY 2012–2013 rate period for providing balancing reserves to wind facilities in the balancing authority area and will not wait to gather additional data with the VER Integration NOPR proposed reforms in place.

Issue 3.2.6.6

Whether the VERBS rate should contain a volumetric component consistent with the Commission's proposal in the VER Integration NOPR.

Parties' Positions

NWG describes the VER Integration NOPR proposal for a new Schedule 10 rate designed to recover the costs of capacity used by generators that would apply to VERs and all other generating resources. NWG Br., BP-12-B-NG-01, at 19. NWG explains that the rate proposed by the Commission would have two components, a per-unit rate and a volumetric component. *Id.* While BPA's VERBS rate has a per-unit component, it does not have a volumetric component. NWG argues that structuring BPA's VERBS rate consistent with the Commission's proposal, including a volumetric component, would provide transparency and send appropriate price signals that a capacity-based rate, such as the current VERBS rate proposal, cannot. *Id.* NWG concludes that the proposed VERBS rate is not consistent with the VER Integration NOPR due to the lack of a volumetric charge. *Id.*

SCE states that basing the VERBS rate on the nameplate capacity rating is inefficient and does not follow cost causation principles. SCE recommends allocating the total VERBS costs in part based on individual wind facility performance and not just on a nameplate basis. SCE Br., BP-12-B-SC-01, at 7. SCE points to the DERBS rate design in BPA’s rebuttal testimony, Jackson *et al.*, BP-12-E-BPA-47, at 2-3, that contains a base charge plus a per-megawatt charge, as an example. SCE Br., BP-12-B-SC-01, at 8.

BPA Staff’s Position

Staff does not address the use of a volumetric component for the VERBS rate. Staff’s proposal is consistent with rate design used for the FY 2010–2011 Wind Balancing Service rate. Staff does propose a volumetric component for the DERBS rate. Of the two DERBS rate proposals in Staff’s rebuttal testimony, Jackson *et al.*, BP-12-E-BPA-47, at 2-3, one contains both a per-unit component and a volumetric component and the other is strictly based on the volumetric component.

Evaluation of Positions

The substantive issue of including a volumetric component in the VERBS rate design is addressed in Issue 3.5.3.5. The VER NOPR is still in process and could change significantly before the final ruling. BPA is using a volumetric component in a rate for balancing reserve capacity in this rate case for the DERBS rate. BPA will gain experience with using a volumetric component for the DERBS rate during this rate period and will evaluate the possibility of including a volumetric component to the VERBS rate in the next rate case.

Decision

BPA will not include a volumetric component in the VERBS rate in this proceeding. However, BPA will use the experience it will gain with using a volumetric component for the DERBS rate during the FY 2012–2013 rate period and evaluate the possibility of including a volumetric component to the VERBS rate in the next rate case.

3.2.7 Formula Rate Policy Issues

Introduction

Another new aspect of Staff’s proposal is the use of formula rates to adjust the VERBS rate if BPA has to make incremental purchases of balancing reserve capacity during the rate period. The wind parties argue that the costs of incremental purchases should be assigned to all users of balancing reserve capacity and not just to the VERBS rate, while preference customers support Staff’s proposal. This section evaluates the legal issues that the parties raise regarding Staff’s proposal to assign the costs associated with incremental purchases of balancing reserve capacity to the VERBS rate. The parties also raise several rate design issues pertaining to VERBS and the VERBS Formula Rates. Those rate design issues are evaluated in ROD section 3.5.1.2.

Issue 3.2.7.1

Whether BPA should address the issue of preference to balancing reserve capacity from the FCRPS in this proceeding.

Parties' Positions

NWG states that questions regarding preference and priority to within-hour balancing reserves are not properly before the Administrator in this proceeding because no party has asserted that there is a current competing or conflicting request for reserves that would make such a question ripe for decision. NWG Br., BP-12-B-NG-01, at 60. Accordingly, the Administrator need not address the various preference and priority issues at this time. *Id.*

PPC states that Staff's Initial Proposal indicates the FCRPS is near the limits of its ability to produce balancing reserve capacity for all uses of that product. PPC Br., BP-12-B-PP-01, at 19. PPC continues that given the impending shortage, PPC believes that BPA has responded prudently and appropriately by proposing a formula rate mechanism to assign the cost of incremental balancing reserve capacity purchases to the VERBS rate. *Id.* at 20. PPC argues that preference provisions of BPA's organic statutes dictate that when BPA receives competing applications for a product but cannot meet both requests, BPA must give preference and priority to its public body and cooperative customers and either use or preserve that power for their benefit. *Id.*

WPAG states that the Tier 1 system capability is rapidly approaching the limits of its ability to reliably serve preference customers' loads and provide wind integration services, due in no small part to the demand for capacity VERs place on the BPA system. WPAG Br., BP-12-B-WG-01, at 5. WPAG expresses concern that the impending inability of the Tier 1 system to provide reliable load service and integrate the growing non-Federal wind fleet will result in preference utilities bearing the costs of capacity resources to integrate non-Federal wind generation, which are unnecessary to serve preference loads. *Id.* at 6-7. WPAG recognizes Staff's proposal to include a formula rate to assign incremental balancing reserve capacity costs to the VERBS rate as a step in the right direction. *Id.* at 7. WPAG goes on to assert that the Northwest Power Act and related statutes give preference customers priority access to the Federal system capability over non-preference customers. *Id.* WPAG states that when the Federal system reaches its limit, BPA must acquire non-Federal resources to provide balancing reserve capacity to non-preference customers and withdraw Federal system capability from non-preference customers to serve preference customers' loads. *Id.* at 8. WPAG concludes that preference customer rates must be based on the full capability of the Federal system and should not include the cost of acquiring additional capacity, which must be assigned to non-preference customers. *Id.*

JP01 argues that section 7(b)(1) forbids BPA from recovering the cost of non-Federal capacity from preference customers unless and until the capacity available from the Federal Base System is inadequate to meet their needs, including capacity for ancillary service for preference customers. JP01 Br., BP-12-B-JP01-01, at 24-25.

BPA Staff's Position

This is a legal issue, but in the process of explaining how Staff expects BPA to manage competing demands from preference customer loads and VERs for FCRPS balancing reserve capacity Staff explains:

BPA Staff believes that the preference and priority provisions under a number of BPA statutes provide the first right to use the resources of the FCRPS to BPA's public customers for load service and the provision of balancing reserve capacity. As the need to use the FCRPS to provide load service increases under BPA's requirements power sales contracts, BPA will reduce, if necessary, the balancing reserve capacity provided by the FCRPS and replace that balancing reserve capacity with non-Federal sources of balancing reserve capacity.

Mainzer *et al.*, BP-12-E-BPA-23, at 28-29.

Regarding the ability of the FCRPS to provide enough balancing reserve capacity to support the wind fleet and the proposed formula rate approach, Staff explains:

The FCRPS does not have the capability to reliably provide enough balancing reserve capacity to support all foreseeable future increases in the size of the wind fleet in BPA's balancing authority. There are limitations on river operations, capacity needs for other Ancillary and Control Area Services, capacity needs for preference power customers, and other non-power constraints that create significant uncertainty for providing a quality of service for VERBS that is greater than 99.5 percent assuming some level of customer self-supply. We believe there is enough uncertainty about the ability to reliably provide capacity from the FCRPS that BPA needs to establish a rate construct that can enable purchases and cost recovery of additional balancing reserve capacity from non-Federal resources to continue to provide VERBS during the rate period. For the FY 2012–2013 rate period we have developed formula rates for replacing FCRPS capacity if that becomes unavailable during the rate period and that recover costs for augmenting the FCRPS capacity to increase the level of service.

Mainzer *et al.*, BP-12-E-BPA-42, at 17.

Evaluation of Positions

Staff's testimony in the Initial Proposal regarding preference to the capacity of the FCRPS initiated a significant amount of debate. Mainzer *et al.*, BP-12-E-BPA-23, at 28-29. NWG argues that the preference issue is not properly before BPA in this proceeding because no party has asserted that there is a current competing or conflicting request for reserves that would make such a question ripe for decision. NWG Br., BP-12-B-NG-01, at 60. At oral argument, SCE discussed the issue of preference extensively, but concluded that BPA has proposed specific amounts of *inc* and *dec* balancing reserve capacity for VERBS in this rate case and that the record does not indicate preference customers will require those amounts of capacity to meet load requirements. SCE states an issue of preference to capacity from the FCRPS is simply not

ripe, and BPA should not decide anything he does not need to decide in this rate case. Spigal, Oral Tr. at 112, 132.

BPA's preference customers argue that the issues of preference to the FCRPS capacity and the assignment of costs associated with incremental capacity purchases are ripe because the FCRPS is reaching its limits and Staff has proposed two formula rates to address the issue during the FY 2012–2013 rate period. PPC Br., BP-12-B-PP-01, at 19-20; WPAG Br., BP-12-B-WG-01, at 5-7; Murphy, Oral Tr. at 230; Lorenz, Oral Tr. at 260.

Based on the facts in this proceeding, the issue of preference to balancing reserve capacity is currently not ripe for BPA's review. A preference issue arises only when there are competing or conflicting requests between a preference entity and non-preference entity to purchase an amount of Federal power. 16 U.S.C. § 832c(b); 16 U.S.C. § 839c(a). As the U.S. Supreme Court stated regarding section 5(a) of the Northwest Power Act, "...that section preserves the priority and preference provisions that existed under the Project Act. But the preference system merely determines the priority of different customers when the Administrator receives 'conflicting or competing' applications for power that the Administrator is authorized to allocate administratively." *Aluminum Co. of Am. v. Central Lincoln People's Util. Dist.*, 467 U.S. 380, 393 (1984). In essence, preference applies to supply and not to BPA's assignment of costs for service and products to its rates, which are governed by section 7 of the Northwest Power Act and BPA's rate design in the TRM.

While the preference customers are correct that the FCRPS may be nearing its limits to provide balancing reserve capacity, nothing in the record indicates that BPA is currently unable to supply balancing reserve capacity to meet the needs of VERBS customers. In rebuttal testimony, Staff testifies to the possibility that BPA might not be able to provide the full amount of balancing reserve capacity from the FCRPS during the FY 2012–2013 rate period:

We cannot be certain that VERBS can be provided solely from FCRPS resources. There are many uncertain factors, including hydro conditions, the level of customer self-supply and participation in the Committed Intra-hour Scheduling Pilot, and the quantity of wind generation that will interconnect to BPA's system. On a planning basis BPA is assuming that without self-supply it may need to acquire additional *inc* or *dec* balancing reserve capacity.... Through the establishment of a formula rate to recover the cost of additional balancing reserve capacity purchases, we are proposing to ensure that the risk of FCRPS capacity being inadequate is addressed in this rate proceeding.

Mainzer *et al.*, BP-12-E-BPA-42, at 30.

Forecasts, by their very nature, are unpredictable. The potential for a need to purchase incremental reserves to occur, however, does not prove that BPA is currently unable to supply balancing reserve capacity to serve load and satisfy other needs.

Even if the FCRPS is inadequate, BPA expects to have the ability to add balancing reserve capacity from non-Federal sources for VERBS to avoid disruption to supply. Staff proposes two

formula rates in this proceeding that will provide BPA with the ability to recover its costs through the VERBS rate if BPA must make incremental purchases of non-Federal balancing reserve capacity to maintain or increase the level of VERBS service during the rate period. These formula rates are triggered only under limited circumstances that may or may not occur during the rate period. Jackson *et al.*, BP-12-E-BPA-47, at 38. With the formula rate mechanism in place, BPA will have the ability to incur and recover the cost of purchasing non-Federal balancing reserve capacity to provide VERBS and continue to satisfy the requests of VERBS customers. The formula rate mechanism ensures that BPA continues to supply balancing reserve capacity for all requests of the system, therefore eliminating the potential for a competing application for the supply of such capacity. Since an adequate supply is planned both under normal conditions and under unexpected conditions, balancing reserve capacity availability or supply is not the issue. Moreover, there is not and will not be a preference issue because BPA has a plan for acquiring additional balancing reserve capacity to meet the needs of all customers, and all requests for Federal power will be met.

As stated above, preference does not apply to BPA's assignment of costs for services and products to the VERBS rate. Preference customers raise issues of use and allocation of power that are not issues to be addressed by a 7(i) rate proceeding. The rate issue that is appropriate for the 7(i) rate process is the proper assignment of the costs associated with the incremental purchases of balancing reserve capacity. Staff proposes to assign the costs of incremental purchases of balancing reserve capacity to the VERBS rate. Mainzer *et al.*, BP-12-E-BPA-23, at 27-28. Staff's proposal is based on the rationale that BPA's need to purchase additional amounts of capacity from non-Federal generation inputs to supply balancing reserve capacity is based solely on the growing number of variable energy resources interconnecting to the transmission system in the BPA balancing authority area. *Id.* at 21. Staff's proposal to assign these costs to the VERBS rate is fully evaluated in Issue 3.2.7.5 below.

Decision

The issue of preference to competing applications from preference customers for FCRPS balancing reserve capacity is not ripe, is not a rate issue, and it will not be addressed in this proceeding.

Issue 3.2.7.2

Whether BPA is required by section 7(b)(1) of the Northwest Power Act to assign incremental capacity costs from capacity acquisitions to the VERBS rate.

Parties' Positions

JP01 supports BPA's proposal to assign non-Federal capacity costs to the VERBS rate. JP01 Br., BP-12-B-JP01-01, at 24. JP01 argues that section 7(b)(1) forbids BPA from recovering the cost of non-Federal capacity from preference customers unless and until the capacity available from the FBS is inadequate to meet their needs, including capacity for ancillary service for preference customers. *Id.* at 24-25. The following sentence from 7(b)(1) expressly supports this

conclusion: “Such rate or rates shall recover the costs of that portion of the Federal base system resources needed to supply such loads until such sales exceed the Federal base system resources.” *Id.*

WPAG argues that it would be contrary to law for BPA to include the costs of incremental capacity resources in the PF rate, or continue to price non-Federal wind integration service as if it were supported by the Tier 1 system capacity. WPAG Br., BP-12-B-WG-01, at 7. WPAG claims that section 7(b) directs BPA to set rates for service to the general requirements of preference customers based on the entire capability of the Federal system, and BPA is only allowed to use other resources to set rates if the Federal system capability is no longer sufficient to serve preference customer loads. *Id.* WPAG asserts that if the Federal system does not have enough capacity to supply the balancing reserve needs of non-preference customers, “the Federal system capability must be withdrawn from non-preference customer use in order to meet the load service needs of BPA’s preference customers.” *Id.* at 8. WPAG concludes that BPA must base its rates for preference customers on the full capability of the Federal system, and cannot include the acquired capacity resources. Non-preference customers must pay for those costs. *Id.*

NWG argues that 7(b)(1) does not prohibit BPA from allocating the costs of non-Federal capacity for balancing reserves to BPA’s preference customers. NWG Br., BP-12-B-NG-01, at 58-59. NWG argues that in *Golden NW*, the Court determined that BPA is authorized to acquire replacement FBS resources and to include such amounts in calculating its preference rates. *Id.* at 59, citing *Golden Northwest Aluminum v. BPA*, 501 F.3d 1037, 1046-1047. NWG asserts that it is inappropriate to rely on 7(b)(1) as to cost allocation for within-hour balancing reserve costs because “[s]ection 7(b)(1) does not include all costs that may be allocated to power rates.” *Id.* at 59. Section 7(g) lists several categories of costs not included in 7(b)(1). “Section 7(b)(1) governs rates of general application for ‘electric power,’ which is defined to include energy and peaking capacity. Within-hour balancing reserves are neither ‘energy’ nor ‘peaking capacity’ and are therefore not governed by the provision of section 7(b)(1).” *Id.*

SCE argues that Staff’s proposal to recover the costs of non-Federal capacity from the VERBS rate is not required by law. SCE Br., BP-12-B-SC-01, at 12. SCE claims that 16 U.S.C. § 839c(a), which provides that all sales of FCRPS power be subject to the preference and priority provision of the Bonneville Project Act, does not require BPA to give public utility customers the “first right” to use the FCRPS, because providing balancing service from the FCRPS is not a sale of capacity. Rather, it is a use of the FCRPS to operate the FCRTS in a reliable manner, as required by law. *Id.* at 12-13. SCE asserts that 16 U.S.C. § 838b(d) requires BPA to “operate and maintain the Federal transmission system within the Pacific Northwest ... [to] maintain the electrical stability and reliability of the Federal system,” and 16 U.S.C. § 838b(a) “implicitly includes the requirement that BPA maintain the stability and reliability of the FCRTS after integrating non-Federal generating units.” *Id.* at 13.

SCE goes on to argue that 16 U.S.C. § 839c(b)(1) also does not require BPA to give public utility customers the “first right” to use the FCRPS. This provision requires BPA to meet preference customers’ net requirements. BPA is able to meet these customers’ net requirements without reducing the amount of capacity that will be made available for VERBS, DERBS, and

Load Following Reserve. SCE claims that there is nothing in the record to indicate otherwise. *Id.*

SCE asserts that 16 U.S.C. § 839e(e) enables BPA to adopt rates in conformance with its cost causation pricing principle, because this provision states that, “Nothing in this chapter prohibits the Administrator from establishing, in rate schedules of general application, a uniform rate or rates for sale of peaking capacity or from establishing time-of-day, seasonal rates, or other rate forms” and “Nothing in this chapter” includes 7(b)(1). *Id.* at 13. SCE reasons that, if BPA needs to purchase non-Federal capacity to meet all of its obligations to customers, including generation inputs customers, then BPA must recover the costs of purchasing non-Federal capacity resources “in accordance with 16 U.S.C. § 839e(e) by establishing a rate for sale of such purchased capacity for public customer load service that is the same as the rate or charge for use of such capacity to provide VERBS, DERBS and Load Service Reserve.” *Id.* at 13-14. SCE argues that all segments of customers that benefit from the acquisition of non-Federal capacity should share in the costs. *Id.* at 14. SCE states that in *Central Lincoln Peoples’ Util. Dist. v. Johnson*, 735 F.2d 1101 (9th Cir. 1984) (*Central Lincoln II*), the Ninth Circuit has held that 16 U.S.C. § 839e(e) “specifically allows the Administrator wide latitude in choosing rate forms.” *Id.* SCE goes on to explain that the Court also stated that BPA could use rate design to encourage conservation, which is required by the Northwest Power Act. *Id.* SCE reasons that the Northwest Power Act also encourages renewables development, and therefore it is within BPA’s authority under 16 U.S.C. § 839e(e) to establish a rate to cover the costs of non-Federal capacity to be applied to all customers. *Id.* SCE claims that in *Central Lincoln II*, the Court “explicitly rejected the argument that 16 U.S.C. § 839e(e) only allows equalization of rates and charges between customers in a given class, not between classes of customers.” *Id.* SCE concludes that BPA’s principle of cost causation justifies establishment of a uniform rate to cover the costs of non-Federal capacity to be applied to all customers. *Id.*

SCE continues by explaining that in *City of Seattle v. Johnson*, 813 F.2d 1364 (9th Cir. 1987), the Ninth Circuit rejected an argument that the availability charge was not a rate. *Id.* at 15. SCE claims that this shows that 16 U.S.C. § 839e(e) is broad enough to include both the cost of non-Federal capacity sold to public utility customers for load service and charges for use of VERBS, DERBS, and Load Following Reserve. *Id.*

SCE also states that PPC’s argument that preference laws require BPA to make FCRPS power available to preference customers before non-preference customers is incorrect, because “BPA can provide preference customers with priority to FCRPS capacity amounts ... while utilizing 16 U.S.C. § 839e(e) authority to establish a rate for capacity and an identical charge for VERBS, DERBS, and Load Following Reserve based on BPA’s cost of third party capacity purchases.” *Id.*

BPA Staff’s Position

This is a legal issue. In response to JP01’s testimony regarding PF customers’ preference to the use of the FCRPS capacity, Staff states that:

JP01 also suggests that section 7(b)(1) grants PF customers preference to the use of the FCRPS capacity and thereby prohibits BPA from recovering the cost of non-Federal capacity additions in PF rates. *Id.* at 14. JP01's legal interpretation of section 7(b)(1) is a matter that is beyond the scope of this panel's expertise. However, much of this discussion about section 7(b)(1) ignores the facts of the case. When constructing rates pursuant to section 7(b)(1), the Staff proposal does not allocate any costs to the supply of generation inputs. Rather, costs of certain existing FCRPS resources and purchases of non-Federal resources are used in the computation of generation inputs costs. Generation inputs costs are used to develop Ancillary and Control Area Service rates. Revenues from the application of such rates are forecast, and the forecast revenues from use of generation inputs are then credited to offset the costs of the FCRPS resources, as they have been allocated pursuant to sections 7(b)(1) and 7(f). The proposed ratesetting and crediting method avoids any priority of usage issues regarding section 7(b)(1). This is especially appropriate because the resource usage is in terms of capacity, and BPA does not allocate costs to capacity uses, just to energy uses.

Mainzer *et al.*, BP-12-E-BPA-42, at 40-41.

Evaluation of Positions

The parties, and in particular the preference customers, assert a particular interpretation and application of section 7(b)(1), and in certain ways that interpretation overstates the reach and application of that provision. Staff explains that much of the discussion about section 7(b)(1) ignores the fact that Staff's proposal does not allocate any costs to the supply of generation inputs. Rather, costs of certain existing FCRPS resources, specific programs, and purchases of non-Federal resources are used in the computation of generation inputs costs. Generation inputs costs are assigned to TS and are used to develop Ancillary and Control Area Service rates. *Id.*

WPAG argues that section 7(b)(1) limits use of FCRPS capacity and WPAG contends that BPA must recall capacity from other parties if needed to meet their loads. JP01 and WPAG contends that BPA's rate cannot include the cost of incremental resources unless the full capability of the Federal system is allocated to preference customers. A review of section 7(b)(1) shows it contains none of those directives. It states:

The Administrator shall establish a rate or rates for electric power sold to meet the general requirements of public body, cooperative, and Federal agency customers within the Pacific Northwest, and loads of electric utilities under section 5(c). Such rate or rates *shall recover the costs of* that portion of the Federal base system resources needed to supply such loads until such sales exceed the Federal base system resources. Thereafter *such rates shall recover the cost of* additional electric power as needed to supply such loads, first from the electric power acquired by the Administrator under section 5(c) and then from other resources.

16 U.S.C. § 839e(b)(1) (emphasis added).

Contrary to WPAG's' position, this provision does not direct BPA as to the use of FBS resources, or which specific FBS resources may be used. Neither does it prohibit use of any resource for any statutory purpose, nor does it state that any amount of Federal capacity needs to be recalled or withdrawn by BPA from use. Rather, this directive is to establish rates for power sold to meet loads based on the costs of that portion of the Federal system "needed to supply" such loads. Thus the costs of an amount of FBS resources needed to meet the load of preference customers are allocated to, and recovered through, the rate or rates of preference customers. The provision goes on to say that such rate or rates can be allocated the costs of additional electric power, first from section 5(c) exchange resources and then from "other resources." This provision allows BPA to allocate the costs of other resources to its preference customer rates as appropriate when sales exceed FBS resources. This provision assumes the replacement or other resources are in fact serving a power function. Staff's proposal, which includes formula rates to assign non-Federal capacity costs to a non-preference rate, is consistent with this provision.

NWG argues that section 7(b)(1) allows BPA to assign costs of non-Federal generation to its preference customer rates because BPA can purchase or acquire non-Federal resources as FBS replacement resources and include such costs in the preference rate. NWG relies on *Golden NW* as holding that BPA may acquire FBS replacement resources and include a portion of such costs in its 7(b)(1) preference rates. NWG Br., BP-12-B-NG-01, at 58-59, *citing Golden NW*, 501 F.3d at 1046-1047. Alternatively, NWG argues that within-hour balancing reserves costs are not costs to which 7(b)(1) applies because the capacity is not the electric power that is addressed by that provision and instead falls within the costs to be included in other rates under section 7(g). *Id.*

NWG's first argument is correct. The *Golden NW* decision states that once BPA acquires power and designates it as an FBS replacement resource, BPA is not precluded by anything in section 7(b)(1) from considering the costs of such replacements when calculating its preference rates. If a portion of the cost of both the replacement and primary FBS resources are needed to supply preference customer loads, then BPA may include such costs in its preference rates. *Golden NW*, 501 F.3d at 1046, *citing Central Lincoln II*, 735 F.2d at 1125 (rejecting the premise that preference customers were entitled to purchase not just available power but the cheapest available power). To the extent BPA purchases additional capacity from non-Federal resources, and such capacity replaces FBS capacity that may not be available due to system conditions, and the capacity allows BPA to balance its system and load service needs, then section 7(b)(1) does not foreclose BPA from including a portion of those costs in its preference rates. As to NWG's other argument that the within-hour capacity is not the electric peaking energy or electric energy used for firm load service, it is not clear that such a distinction would yield any different result.

SCE argues that BPA should rely on its section 7(e) rate design authority to establish a rate that is identical for all users of capacity—both power and transmission users. SCE also raises arguments that there is no first right or priority of preference customers to use the FCRPS. As discussed above, this section 7(i) rate proceeding is not the forum for resolving differences of opinion over preference.

SCE asserts that if BPA needs to purchase non-Federal capacity to meet all of its obligations to customers, including generation inputs customers, then BPA must recover the costs of purchasing non-Federal capacity resources “in accordance with 16 U.S.C. § 839e(e) by establishing a rate for sale of such purchased capacity for public customer load service that is the same as the rate or charge for use of such capacity to provide VERBS, DERBS, and Load Service Reserve.” SCE Br., BP-12-B-SC-01, at 13-14. SCE argues that all segments of customers that benefit from the acquisition of non-Federal capacity should share in the costs. *Id.* at 14. SCE states that in *Central Lincoln II*, the Ninth Circuit has held that 16 U.S.C. § 839e(e) “specifically allows the Administrator wide latitude in choosing rate forms.” *Id.* citing *Central Lincoln II*, 735 F.2d at 1122. BPA agrees in part and disagrees in part with SCE’s position.

SCE misapprehends the reach of section 7(e), as BPA has long interpreted and applied it. Section 7(e) is a savings clause which clarifies that the rate provisions of the Northwest Power Act should not be construed to prohibit the Administrator from establishing various rate forms or designs: “[n]othing in this chapter prohibits the Administrator from establishing, in rate schedules of general application, a uniform rate or rates for sale of peaking capacity or from establishing time-of-day, seasonal rates, or other rate forms.” 16 U.S.C. § 839e(e). The legislative history of section 7(e) expresses Congress’ recognition that the rate directives expressed in section 7(b)(1) and other sections of the Northwest Power Act:

only govern the amount of money BPA is to collect from each class of customer and not the form of the rate used to collect that sum of money. For example, time-of-day rates, seasonal rates, rate structures designed to give BPA customers particular price signals, and other rate forms would be permissible.

H.R. Rep. No. 96-976, Part II, at 53 (Sept. 16, 1980) (emphasis added). In other words, for example, section 7(b)(1) does govern the amount of costs (money) that can be recovered from preference and other customers subject to it, but not how BPA designs its rates *for that class of customer* to recover that amount of money. Thus, for example, BPA has recently adopted the Tiered Rates Methodology based on its rate design discretion, which is substantial, as SCE observes. See *City of Seattle v. Johnson*, 813 F.2d at 1367; *Central Lincoln II*, 735 F.2d at 1121-1122; see also *Central Electric Power Coop., Inc. v. Southeastern Power Admin.*, 338 F.3d 333, 337 (4th Cir. 2003). The language of section 7(b)(1) demonstrates that the Administrator is authorized to establish more than a single PF rate for the sale of power to meet the general requirements of BPA’s preference customers since Congress specifically used the plural form—”rates”—three separate times within this single subsection. As another example, in the context of section 7(c) and DSI rates, BPA relied on section 7(e) in the mid-1980s to adopt a variable rate design as a means to recover costs required to be recovered from DSI customers. There again, Congress prefaced the section 7(c) rate directive with the phrase “rate or rates” for DSI service. 16 U.S.C. § 839e(c)(1).

Further, section 7(e) can be read to apply across rate classes if the Administrator so determines, not in a cost allocation sense, but in a rate design sense. In other words, if pursuant to sections 7(b)(1), (c) or (f), the Administrator identifies costs to be recovered from the covered customer class(es), the Administrator can use of the authority of section 7(e) to design all of

those rates in a fashion that recovers those costs while at the same time providing an appropriate price signal.

However, as evidenced from the structure of section 7 and the legislative history of section 7(e), underlying the scheme of section 7(e) is a pre-existing allocation or assignment of costs. In other words, you already know and start with the amount of money BPA is to collect from each class of customer. Thus, SCE errs when it argues that section 7(e) governs cost allocation. In that connection, SCE's reading of *Central Lincoln II* for the proposition that the Court countenanced use of section 7(e) to allocate costs is overbroad. The Court simply approved BPA's equalization of demand charges in the context of insignificant cost differences of providing capacity to different classes of customers.

That all leaves open the issue of the basis for, in the first instance, allocating or assigning costs to be recovered through the VERBS, DERBS, and Load Following rates. In that regard, section 7(a)(1) of the Northwest Power Act provides that power and transmission rates shall be established in accordance with the Northwest Power Act, sections 9 and 10 of the Transmission System Act, and section 5 of the Flood Control Act of 1944. 16 U.S.C § 839e(a)(1). Section 7(a)(1) itself expressly states that rates for power and transmission must be established as appropriate to recover, in accordance with sound business principles, the cost associated with, among other things, the generation and transmission of electric power. As related in connection with the issue of the allocation of fish and wildlife costs in Issues 3.2.5.1.5 and 3.4.2.4, section 9 of the Transmission System Act states in part that the Administrator's rates for the sale of power "and transmission of non-federal electric power over the Federal transmission system" shall be established:

(1) with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles, (2) having regard to the recovery (upon the basis of the application of such rate schedules to the capacity of the electric facilities of the projects) of the cost of producing and transmitting such electric power, including the amortization of the capital investment allocated to power over a reasonable period of years and payments provided for in section 838i(b)(9) of this title, and (3) at levels to produce such additional revenues as may be required, in the aggregate with all other revenues of the Administrator, to pay when due the principal of, premiums, discounts, and expenses in connection with the issuance of and interest on all bonds issued and outstanding pursuant to this Act, and amounts required to establish and maintain reserve and other funds and accounts established in connection therewith.

16 U.S.C. § 838(g). This clearly authorizes transmission rates to be set to recover all costs attendant to the transmission of power. While the costs that are to be recovered through power rates should ordinarily be power costs, and through transmission rates should ordinarily be transmission costs, the determination of what is a power and what is a transmission cost is to be informed by the facts and the objectives of Transmission System Act section 9 and Northwest Power Act section 7(a)(1).

In that regard, BPA believes that consideration of cost causation should be one of the primary criteria for determining what is a transmission cost and what is a power cost. That is consistent with recovering costs consistent with sound business principles. If a cost is incurred to meet a transmission need, then ostensibly that cost should be allocated or assigned to transmission. That is not to say that if power directly and substantially benefits from the cost, there might or should not be a recognition of that in the cost allocation or assignment. Oftentimes actions are taken for, or serve, multiple purposes. For present purposes it is sufficient to acknowledge that BPA has a responsibility to maintain the electric stability and reliability of the Federal transmission system. *Cf.*, 16 U.S.C. § 838b. The costs discussed here for allocation purposes were incurred or will be incurred to meet that purpose. In establishing the VERBS rate, BPA follows the cost causation principle and as such has proposed to equitably allocate that portion of costs to the VERBS rate that BPA is incurring to expand its service to integrate non-Federal generation onto the FCRTS.

Decision

While BPA is not required by section 7(b)(1) of the Northwest Power Act to assign incremental capacity costs from capacity acquisitions to the VERBS rate, it has the discretion to do so.

Issue 3.2.7.3

Whether the preference customers have a preference to price for capacity products.

Parties' Positions

NWG agrees with Staff that public power customers do not have preference to price for balancing reserve capacity. NWG Br., BP-12-B-NG-01, at 58. NWG states, “[i]f the FCRPS cannot provide enough balancing reserves to meet total system needs, under principles of cost causation, the cost of supplementing BPA’s portfolio of balancing reserves should be shared by all of the customers that will be using those reserves.” *Id.* at 57-58.

PPC states that “the Northwest Power Act directs that BPA allocate to rates charged to preference customers only the costs of FBS resources to the extent needed to serve their needs.” PPC Br., BP-12-B-PP-01, at 22. PPC believes BPA Staff’s formula rate approach is consistent with preference provisions and rate directives applicable to BPA. *Id.*

In its brief on exceptions, PPC states that BPA’s VERBS formula rate approach is consistent with preference provisions and rate directives applicable to BPA. PPC Br. Ex., BP-12-R-PP-01, at 2. PPC takes issue with BPA’s characterization of PPC’s initial brief arguments as asserting that there is a preference to price. *Id.* PPC argues that only the costs of the FBS needed to supply preference loads should be allocated to preference rates until such sales exceed the FBS resource, and thus, since the FBS resources are sufficient to meet the needs of preference customers, the costs of acquiring non-Federal FBS resources for non-preference customers may not be allocated to preference customers’ power rates. *Id.* at 3.

JP01 states that it is rate directives, not preference or priority rules, that provide price protection to preference customers. JP01 Br., BP-12-B-JP01, at 26. JP01 argues that the Ninth Circuit has explained that the “primary purpose” of the 7(b) rate directives is to “protect BPA’s preference customers.” *Id.*; see *Portland Gen. Elec. Co. v. BPA*, 501 F.3d 1009, 1036 (9th Cir. 2007).

In its brief on exceptions, JP01 argues that operating within ordinary ratemaking rules, not preference or priority rules, preference customers are provided price protection. JP01 Br. Ex., BP-12-R-JP01-01, at 1. JP01 agrees with BPA that the FBS can include FBS replacement resources, but claims that BPA goes too far in asserting that identifying FBS replacement resources is up to the Administrator’s unfettered discretion. *Id.* at 1-2. JP01 concludes that BPA properly proposes to apply the cost causation principle and 7(b)(1) to assign the costs of such capacity to the VERBS rate, and the comments regarding the Administrator’s discretion to characterize resources as FBS replacements are unnecessary and should be removed from the final ROD. *Id.* at 3.

BPA Staff’s Position

This is a legal issue, and Staff did not address this issue in testimony.

Evaluation of Positions

Preference applies to supply, not price. As discussed above, because there is no issue of BPA’s ability to supply, there is no preference issue that needs to be addressed in this rate proceeding. More to the point, a preference issue arises when there are competing or conflicting requests between a preference entity and non-preference entity to purchase an amount of Federal power. 16 U.S.C. § 832c(b); 16 U.S.C. § 839c(a). As the U.S. Supreme Court stated regarding section 5(a) of the Northwest Power Act, “...that section preserves the priority and preference provisions that existed under the Project Act. But the preference system merely determines the priority of different customers when the Administrator receives ‘conflicting or competing’ applications for power that the Administrator is authorized to allocate administratively.” *Aluminum Co. of Am.*, 467 U.S. at 393. Preference does not apply to BPA’s allocation of costs for service and products to its rates, which are governed by section 7 of the Northwest Power Act and BPA’s rate design in the TRM.

Also noted previously, the *Golden NW* decision discusses preference at length. In that decision the Court highlighted the so-called preference provisions in BPA statutes; first, section 4 of the Bonneville Project Act and then section 5(a) of the Northwest Power Act. The Court stated, “[w]e have explained that these provisions ‘protect[] the preference customers’ access to power supply’; they do not speak directly to price.” 501 F.3d at 1046. The Court then cited to *Central Lincoln II*, which rejected the premise that preference customers were entitled to purchase not just available power but the cheapest available power. And finally, as explained above, neither section 7(b)(1), nor any other provision of law governing BPA’s ratemaking, directs BPA as to the use of FBS resources, or which specific resources may be used when allocating costs. Neither does it prohibit use of any resource for any statutory purpose, nor does it state that any amount of Federal capacity needs to be recalled or withdrawn by BPA from use to meet the needs of preference customers.

The *Golden NW* decision states that once FBS replacement resources are acquired, BPA is not precluded by anything in section 7(b)(1) from considering the costs of such replacements when calculating its preference rates. 501 F.3d at 1046. That, of course, assumes that the acquisition is designated by BPA as an FBS replacement, a matter committed to the Administrator's discretion. If a portion of the cost of both the FBS replacement and existing FBS resources are needed to supply preference customer loads, then BPA may include such costs in its preference rates. To the extent that a VERBS formula rate triggers and BPA purchases additional capacity from non-Federal resources, and such capacity replaces FBS capacity that may not be available due to system conditions, and the capacity allows BPA to balance its system and load service needs, then section 7(b)(1) does not foreclose BPA from including a portion of those costs in its preference rates. The cost will have in that situation been incurred to meet multiple needs, power and transmission. However, as discussed above, BPA has the discretion to not allocate the cost of incremental resources to all uses of balancing reserve capacity.

In its brief on exceptions JP01 agrees with BPA that the FBS can include FBS replacement resources, but claims that BPA goes too far in asserting that identifying FBS replacement resource is up to the Administrator's unfettered discretion. JP01 Br. Ex., BP-12-R-JP01-01, at 1-2. JP01 argues that FBS replacement is a ratemaking construct intended to help carry out the congressional goal to provide preference customers such benefits, and BPA should revise the final ROD to remove any implication that the decision to identify a resource as an FBS replacement might be committed to agency discretion by law within the meaning of 5 U.S.C. 701(a)(2). *Id.* at 2. JP01 claims that it would be contrary to law for BPA to violate the cost causation principle and assign the cost of incremental capacity needed to provide VERBS to preference customers by means of deeming such capacity to be FBS replacement. *Id.* JP01 concludes that BPA properly proposes to apply the cost causation principle and 7(b)(1) to assign the costs of such capacity to the VERBS rate, and the comments regarding the Administrator's discretion to characterize resources as FBS replacements are unnecessary and should be removed from the final ROD. *Id.* at 3.

BPA is not proposing any FBS replacement resources in this rate proceeding, and the Administrator's discretion to characterize resources as FBS replacements is not an issue that needs to be decided in this rate proceeding. The statement above regarding the Administrator's discretion to designate a resource as an FBS replacement is actually arguing that the Administrator can use his discretion to not designate a resource as FBS replacement, which is an important point as it relates to the acquisition of incremental balancing reserve capacity. BPA recognizes that JP01 may not agree with this characterization of the Administrator's discretion, but BPA will not remove the language referred to by JP01.

In its brief on exceptions PPC claims that BPA misconstrues PPC's argument and PPC did not contend that there is a preference to price. PPC Br. Ex., BP-12-R-PP-01, at 2. Both PPC and JP01 reiterate that their contention is that it is through the ordinary ratemaking rules that preference customers are protected from the cost of incremental resources until such sales exceed the FBS resource. *Id.* at 3; JP01 Br. Ex., BP-12-R-JP01-01, at 1. BPA did not intend to imply that PPC asserted that preference customers have a preference to price. The issue of preference

to price was framed by NWG, and BPA’s representation of the position taken by PPC is consistent with PPC’s briefs. BPA’s decision to use the VERBS Formula Rates to assign incremental costs of balancing reserve capacity to the VERBS rate is consistent with PPC’s and JP01’s position that these costs should not be allocated to preference rates. PPC Br. Ex., BP-12-R-PP-01, at 2; JP01 Br. Ex., BP-12-R-JP01-01, at 1.

Decision

Preference customers do not have a preference to price for capacity products.

Issue 3.2.7.4

Whether preference applies to within-hour balancing capacity or only to peaking capacity and energy.

Parties’ Positions

NWG argues that within-hour balancing reserves are neither “energy” nor “peaking capacity” and therefore are not governed by 7(b)(1). NWG Br., BP-12-B-NG-01, at 59. NWG states that when the Northwest Power Act was passed in 1980, Congress did not contemplate within-hour balancing capacity, and until recently, balancing reserve capacity was plentiful. *Id.* at 57.

JP01 disagrees with NWG’s assertion that the Northwest Power Act only applies to “electric peaking capacity” and not “within hour balancing capacity.” JP01 Br., BP-12-B-JP01-01, at 26. JP01 argues that although Congress did not specifically call out “within-hour balancing capacity,” Congress’s overriding intent was to preserve the value of the FCRPS for preference customers. *Id.* at 26-27. JP01 asserts that 7(b)(1) is meant to “have teeth” when “sales exceed Federal base system resources.” *Id.* at 26. JP01 argues that 7(e) allows BPA to disaggregate the FBS for rate purposes in ways not contemplated by Congress; however BPA must do so in compliance with the rate directives of 7(b) and allocate non-FBS capacity costs to the PF preference rate only after the FBS has been exhausted as provided in 7(b)(1). *Id.* at 27. Additionally, JP01 argues that when Congress referred to the “portion of the Federal base system resources needed to supply such loads,” Congress was referring to electric power *delivered* to preference customers. *Id.* JP01 concludes, “[a]t the time the Northwest Power Act was passed, ‘electric power’ meant delivered power inasmuch as BPA did not have separate transmission or ancillary service rates for its requirements sales.” *Id.*

PPC states that the “applicable statutes give preference customers preference and priority to the power of the FCRPS not to specific types of capacity or energy, whether or not they were designated as particular capacity or energy products at the time of the statutes enactments.” PPC Br., BP-12-B-PP-01, at 21. PPC argues that, if there is a shortage of balancing reserve capacity, BPA is required to first offer that capacity to preference customers if preference customers have a current or forecast need for it. *Id.*

BPA Staff's Position

This is a legal issue, and Staff does not address this issue in testimony.

Evaluation of Positions

As noted above in Issue 3.2.7.2, the distinction between within-hour capacity and peaking energy or capacity used for general requirement loads of BPA customers may be important in the context of system reliability needs versus meeting utility customer loads. However, in the assignment of costs of additional balancing reserve capacity purchased or acquired, BPA can consider whether the additional balancing reserve capacity is a replacement of FBS capacity and whether a portion of that replacement capacity is needed to supply preference customer loads. Contrary to JP01's argument, courts have held that preference does not speak directly to price. If JP01's reference to preserving "the value of the FCRPS for preference customers" is intended to mean preference customers always get the cheapest price for available power, including capacity, then that argument has been specifically rejected by the Court in *Golden NW*, 501 F.3d at 1046.

As JP01 points out, Congress, in section 7(b)(1), was referring to delivered power, and delivered power at that time meant the use of the BPA transmission system. Capacity from the FCRPS inherently supports maintaining a reliable and efficient transmission system. Even with an allocation or assignment of those capacity costs to transmission, the costs of transmission are to be equitably allocated between power and transmission rates under section 10 of the Transmission System Act. 16 U.S.C. § 838h; *see also* 16 U.S.C. § 839e(a)(2)(C). As BPA has moved to unbundle the costs of providing power and transmission to its customers, the existence of ancillary services has been exposed, as have the costs of providing them. This does not mean that BPA is powerless to allocate costs in light of new facts, especially since the overriding purpose of section 7(a)(1) is to preserve BPA's ability to establish its rates in total to assure total cost recovery and timely repayment to the United States treasury. The House Report accompanying the final Northwest Power Act bill states that the rate directives for particular customer classes are "[s]ubject to the general requirement (contained in section 7(a)) that BPA must continue to set its rates so that its total revenues continue to recover its total costs." H.R. Rep. No. 976, Part II, 96th Cong., 2d. Sess., at 36 (1980). BPA has the ability to refine and delineate the granular components of ancillary services, which meshes well with BPA's authority to allocate costs under the Transmission System Act and Northwest Power Act section 7, including the costs of additional balancing reserve capacity, so as to assure their recovery.

Decision

Whether preference applies to within-hour balancing capacity or only to peaking capacity and energy is not determinative of BPA's cost allocation in this case.

Issue 3.2.7.5

Whether BPA should assign the cost of incremental non-Federal balancing reserve capacity purchases to the VERBS rate through the formula rate.

Parties' Positions

NWG objects to Staff's formula rate proposal to allocate the entire cost of incremental balancing reserve capacity purchases solely to the imbalance component of the VERBS rate. NWG Br., BP-12-B-NG-01, at 41. NWG states that BPA does not segregate its use of balancing reserve capacity between and among different customers, but deploys its balancing reserve capacity in response to a net signal composed of loads and generating resources. *Id.* at 42. NWG argues that any incremental acquisitions of balancing reserve capacity would be used to meet BPA's total system balancing obligations. Thus, NWG argues that BPA should allocate the costs of acquiring additional non-Federal balancing reserve capacity (outside of the VERBS Supplemental Service context) to the revenue requirement for Generation Inputs. *Id.* at 42.

NWG also asserts that BPA's authority to purchase resources to replace reductions in the capacity of the FBS is clear: BPA has the authority to include the cost of such replacement resources in preference power rates. *Id.* at 43. NWG argues that there is no statutory basis for allocating the costs of purchasing non-Federal balancing reserves solely to wind generators under BPA's statutes relating to customer preference because such statutes do not guarantee BPA's preference customers a preference to price. NWG states that it is equitable to allocate a share of such costs to BPA's power rates, which also would use these balancing reserves. *Id.*

In addition, NWG argues that unlike other BPA rate adjustments, Staff's proposed formula rates expose customers to potentially unlimited risks without procedural due process protections and incentives for BPA to manage resources and costs efficiently. *Id.* at 43-44.

Iberdrola argues that BPA should roll in the costs of any incremental balancing reserves procured during the rate period. Iberdrola states that it does not believe that it is efficient or cost-effective for BPA to procure incremental balancing reserve capacity. Iberdrola Br., BP-12-B-IR-01, at 32. Iberdrola asserts that BPA has not traditionally distinguished between Federal and non-Federal balancing reserve capacity amounts, and that approach benefits all users of the system because the full reserve is available to everyone. *Id.* Iberdrola states that it would be inappropriate and inefficient for BPA to procure and charge for two completely separate sets of reserves. *Id.*

Furthermore, Iberdrola asserts that under the current market structure, BPA will likely over-procure and overpay for any incremental balancing reserve capacity. *Id.*

JP01, PPC, and WPAG endorse the adoption of the formula rates for VERBS. JP01 Br., BP-12-B-JP01-01, at 24; PPC Br., BP-12-B-PP-01, at 20; WPAG Br., BP-12-B-WG-01, at 11. While WPAG continues to believe that using the same marginal capacity cost price signal for both VERBS and the PF Tier 1 rate would be the better path, WPAG believes that Staff's approach is a good first step in sending a strong price signal to VERBS customers. WPAG Br., BP-12-B-WG-01, at 10.

BPA Staff's Position

Staff states that the proposed formula rates allow BPA to recover costs consistent with the principle of cost causation in the event of unforeseen changes to operations of the FCRPS.

Jackson *et al.*, BP-12-E-BPA-47, at 33. Staff states that without this ability, BPA would be forced to use financial reserves to fund *inc* and *dec* balancing reserve capacity purchases that are needed to continue to provide VERBS. This would create an inequitable cost shift to the customers that do not take VERBS. *Id.*

Staff also states that they forecast a significant increase in the amount of wind generation integrating into the BPA balancing authority area during the rate period. Mainzer *et al.*, BP-12-E-BPA-42, at 9-10. Staff explains that if BPA did not offer VERBS or integrate variable energy resources, BPA would have sufficient FCRPS balancing reserve capacity available to provide the forecast balancing reserve capacity requirements for forecast loads and other resources in the BPA balancing authority area. Jackson *et al.*, BP-12-E-BPA-47, at 38. In that case, it would be unnecessary to make non-Federal purchases of balancing reserve capacity. *Id.* at 38-39.

Evaluation of Positions

This issue has largely been addressed in connection with Issues 3.2.7.1 through 3.2.7.4 above.

In the Initial Proposal, Staff proposes to assign the costs associated with purchasing balancing reserve capacity from non-Federal sources to the VERBS rate. Under Staff's proposal, if BPA purchases non-Federal balancing reserve capacity to replace FCRPS balancing reserve capacity that becomes unavailable during the rate period, the net costs for that purchase would be assigned to the VERBS rate through Formula Rate I. Mainzer *et al.*, BP-12-E-BPA-23, at 27; Jackson *et al.*, BP-12-E-BPA-29, section 7.2. In addition, if BPA purchased non-Federal balancing reserve capacity to increase the quality of service beyond the level BPA forecast in the rate case, Staff proposes to assign the total cost of that purchase to the VERBS rate through Formula Rate II. *Id.*

Staff forecasts a significant increase in the amount of wind generation integrating into the BPA balancing authority area during the rate period. Documentation, BP-12-FS-BPA-05A, Table 2.1; Jackson *et al.*, BP-12-E-BPA-47, at 38. As a result, Staff explains:

If BPA did not offer VERBS or integrate variable energy resources, BPA would have sufficient FCRPS balancing reserve capacity available to provide the forecast balancing reserve capacity requirements for forecast loads and other resources in the BPA balancing authority area. In that case, it would be unnecessary to make non-Federal purchases of balancing reserve capacity. Accordingly, we believe assigning the costs of non-Federal balancing reserve capacity purchases to provide VERBS during the rate period is consistent with the principle of cost causation and is, therefore, appropriate.

Jackson *et al.*, BP-12-E-BPA-47, at 38-39.

Both JP01 and WPAG endorse Staff's proposal for VERBS Formula Rates. JP01 Br., BP-12-B-JP01-01, at 24; WPAG Br., BP-12-B-WG-01, at 11. While WPAG continues to believe that using the same marginal capacity cost price signal for both VERBS and the PF Tier 1 rate would be the better path, WPAG believes that Staff's approach is a good first step in sending a strong price signal to VERBS customers. WPAG Br., BP-12-B-WG-01, at 10.

Similarly, PPC believes that Staff responds prudently and appropriately by proposing that the VERBS rate schedule include a provision for a Formula Rate adder to capture and recover the costs of purchases of incremental balancing reserve capacity. PPC Br., BP-12-B-PP-01, at 20. PPC notes that the costs of incremental balancing reserve capacity are difficult to forecast at this time, but by recovering these costs through the use of the proposed formula rate approach, BPA ensures that costs are recovered and charged to the appropriate customers in accordance with the cost causation principle. *Id.* at 22.

In contrast, NWG and Iberdrola oppose Formula Rates for VERBS. Their primary argument is that BPA should spread the costs of any incremental balancing reserve capacity purchases to all transmission customers because BPA holds and deploys balancing reserve capacity for the benefit of all transmission customers. NWG Br., BP-12-B-NG-01, at 41-43; Iberdrola Br., BP-12-B-IR-01, at 32. Based on the rate case record, BPA disagrees with this contention for several reasons.

First, NWG and Iberdrola appear to confuse the issue by equating the technical operation of the system with cost allocation. As these parties point out, in operations, BPA does not segregate its use of balancing reserve capacity between and among different customers, but deploys its balancing reserve capacity in response to a net signal composed of loads and generating resources. NWG Br., BP-12-B-NG-01, at 42; Iberdrola Br., BP-12-B-IR-01, at 32. In this rate proceeding, BPA has determined the balancing reserve capacity quantity forecast for wind, load, and dispatchable energy resources within the BPA balancing authority, and assigned the costs of the FCRPS and variable costs according to the balancing reserve capacity requirements of each customer class. Puyleart *et al.*, BP-12-E-BPA-24, section 2. BPA deploys its balancing reserve capacity in response to a net signal composed of loads and generating resources because this is the most cost effective and reliable way to operate the system. However, that does not mean that cost allocation associated with incremental purchases should be spread to all users of balancing reserve capacity, when one class of users is driving the need for the incremental acquisitions.

Second, NWG and Iberdrola disregard the principle of cost causation, which holds that those entities responsible for creating costs should be responsible for paying such costs. Mainzer *et al.*, BP-12-E-BPA-23, at 21. NWG and Iberdrola would prefer that BPA “roll in” any costs of incremental purchases across all transmission customers because any incremental purchases would benefit all users of the system. NWG Br., BP-12-B-NG-01, at 42; Iberdrola Br., BP-12-B-IR-01, at 32. However, any benefits that flow to other users of balancing reserve capacity from the purchase of incremental amounts of balancing reserve capacity to provide VERBS is irrelevant. Any incremental purchases of balancing reserve capacity would simply be unnecessary “but for” the significant balancing reserve capacity requirements of wind generators. Nothing in the record disputes the fact that wind generation is increasing within the BPA balancing authority area as well as the demand for balancing reserve capacity for balancing services.

NWG continues, however, that BPA has the authority to purchase resources to replace reductions in the capacity of the Federal Base System, and that BPA has the authority to include the cost of such replacement resources in preference power rates. NWG Br., BP-12-B-NG-01, at 43. As

described in Issues 3.2.7.1 and 3.2.7.2 above, BPA has the authority to allocate the costs associated with incremental purchases of balancing reserve capacity that are necessary to support the stability and reliability of the Transmission System. *See* 16 U.S.C. § 838h; 16 U.S.C. § 839e(a)(2)(C). While it is true that BPA has discretion to “roll in” costs when the facts, sound business principles, or equity would support BPA’s decision to do so, the record contains no factual or legal basis that would prompt BPA to spread costs of any potential purchases of incremental balancing reserve capacity during the rate period to all users of balancing reserve capacity. In establishing the VERBS rate, BPA will equitably allocate the costs associated with incremental purchases of balancing reserve capacity that are necessary to provide VERBS during the rate period solely to the VERBS rate. As stated above, BPA believes rolling in the cost of incremental balancing reserve capacity purchases that are necessary for BPA to continue to provide VERBS to be inequitable and inconsistent with the ratemaking principle of cost causation.

NWG goes on to argue that if BPA anticipates the need to acquire more than a *de minimis* amount of resources, BPA should initiate another rate case and establish rates for such service under a full section 7(i) proceeding. In oral argument, counsel for NWG clarified that BPA has the discretion to determine what “*de minimis*” should constitute. Hall, Oral Tr. at 210; NWG asserts that any purchases above *de minimis* should be allocated to all transmission customers. NWG Br., BP-12-B-NG-01, at 44. The VERBS Formula Rate process issues are addressed in section 3.4.3 of this ROD.

While BPA agrees that it has discretion to determine and purchase balancing reserve capacity, BPA is not convinced that it should rely upon this discretion in lieu of establishing Formula Rates for VERBS. In Issues 3.2.7.1 and 3.2.7.2 above, BPA explains its legal authority to assign the cost of incremental purchases of non-Federal balancing reserve capacity to the VERBS rate. Consistent with that reasoning, the Formula Rates are necessary to “allow the Administrator to recover costs consistent with the principle of cost causation in the event of unforeseen changes to operations of the FCRPS.” Jackson *et al.*, BP-12-E-BPA-47, at 33. Fundamentally, without Formula Rates for VERBS, BPA would either be required to rely upon its financial reserves to purchase balancing reserve capacity to continue to provide VERBS during the rate period, or degrade the quality of VERBS service until a rate to recover the cost of any incremental purchases of balancing reserve capacity could be established. *Id.* at 35. BPA finds both results to be unacceptable, given that any such purchases would be necessary only to provide VERBS during the rate period and no other service. *See also* Jackson *et al.*, BP-12-E-BPA-47, at 33-34.

NWG suggests that BPA set future rates to recover retroactive costs that may have impacted financial reserves instead of adopting Formula Rates. NWG Br., BP-12-B-NG-01, at 42-44. NWG claims that Staff’s Formula Rate proposal, in effect, “requires VERBS customers to ‘prepay’ for VERBS—a requirement that BPA does not impose on other customers.” *Id.* at 44. In contrast, PPC states that since any incremental balancing reserve capacity purchases “will be used during the FY 2012–2013 rate period ... it is best that these costs be collected during that rate period.” Baker *et al.*, BP-12-E-PP-01, at 20.

BPA agrees with PPC that if balancing reserve capacity is necessary to provide VERBS during the rate period, those costs should be recovered within the rate period if reasonably possible. NWG's suggestion to adjust future rates provides little certainty for BPA's other customers, because there is no way to know the outcome of the future rate proceeding. With regard to NWG's argument that VERBS customers are essentially prepaying for VERBS under the Formula Rates, as explained above, since any incremental balancing reserve capacity purchases during the rate period would be necessary solely to provide VERBS during the rate period, BPA believes it is reasonable to recover the costs of such purchases from VERBS customers. Without Formula Rates, costs associated with incremental balancing reserve capacity purchases would be shifted to other ratepayers or VERBS customers could be subjected to significant reliability and operational restrictions if it were no longer physically feasible for BPA to provide the forecast balancing reserve capacity for VERBS from the FCRPS. Jackson *et al.*, BP-12-E-BPA-47, at 35. Finally, BPA is also adopting a public process for purchases of balancing reserve capacity, which will provide notice and an opportunity for customers to comment on any BPA purchases of non-Federal balancing reserve capacity. Such public oversight should help allay fears that BPA will over procure balancing reserve capacity during the rate period. BPA discusses this public process in more detail in Issue 3.5.3.3.

Decision

BPA has the authority to equitably allocate the costs associated with maintaining the stability and reliability of the transmission system. Assigning the costs of incremental balancing reserve capacity purchases that are necessary to provide VERBS to the VERBS rate is consistent with cost causation and equitable allocation.

3.2.8 Operating Reserves Policy Issues

There are two adjustments to the Operating Reserve forecast that are discussed in this section.

Issue 3.2.8.1

Whether BPA should assume that the uncertainty over the appropriate energy product code for e-Tagging wind will impact the forecast of Operating Reserves, and if so, whether BPA should include an adjustment mechanism in the rate to account for the outcome of the energy product e-Tagging protocol issue.

Parties' Positions

PPC states that it appreciates Staff's willingness to calculate the Operating Reserve forecast both with and without the assumption of a firm-contingent energy product code. PPC Br., BP-12-B-PP-01, at 22. PPC suggests that BPA initially set rates without using the firm-contingent assumption, but retain the express ability in the rate schedule to change the rate to the rate calculated to recover costs with the assumption of firm-contingent energy product codes if that condition should arise during the rate period. *Id.* PPC concludes that providing the ability to

toggle the rate to accommodate BPA's decision on firm-contingent product code for e-Tagging will ensure an equitable rate and recover BPA's cost appropriately. *Id.* at 22-23.

BPA Staff's Position

Staff's Initial Proposal includes an adjustment to the Operating Reserve forecast based on an assumption that wind generation exports that are not self-supplying the imbalance reserve component would be required to e-Tag their generation with a firm-contingent energy product code and would not be purchasing Operating Reserves from BPA. Mainzer *et al.*, BP-12-E-BPA-23, at 43; Generation Inputs Study, BP-12-E-BPA-05, at 68-70. This adjustment is a decrease of 43 MW to the Operating Reserve forecast. Generation Inputs Study, BP-12-E-BPA-05, at 70. Staff includes an Operating Reserve forecast without the assumption regarding firm contingent product codes in its rebuttal testimony, Klippstein *et al.*, BP-12-E-BPA-44, Attachment 7, and states that the decision as to which assumption to use in the final studies would be based on the best available information on the status of the requirement for use of the firm-contingent product code for VERs at the time of the final studies. Mainzer *et al.*, BP-12-E-BPA-42, at 5.

Evaluation of Positions

The firm-contingent product code e-Tagging issue is outside of the scope of the rate proceeding, but assumptions regarding the outcome of the issue need to be made for purposes of forecasting the Operating Reserves. Mainzer *et al.*, BP-12-E-BPA-42, at 4-5; Klippstein *et al.*, BP-12-E-BPA-44, at 25. Since the Initial Proposal, the ongoing discussions at the NWPP have made it evident that any use of contingency reserve for extreme wind events will not align with DSO 216 events. This development means that the firm-contingent product code will probably not be used for wind generation that is sinking within the NWPP. While the firm-contingent product code may be used for other export schedules, it does not appear that this will be the case for all exports, so assuming no adjustment to the Operating Reserve forecast is appropriate.

PPC's suggestion that BPA build in an adjustment mechanism is interesting, but as is discussed in the next issue, implementation of BAL-002-WECC-1 will make the firm-contingent product code adjustment for Operating Reserves a moot point, because the new standard will require balancing authorities to carry Operating Reserves on both load and generation. Chen *et al.*, BP-12-E-BPA-26, at 3. Even if there is some chance of some generators using the firm-contingent product code prior to BAL-STD-002-0 implementation, any adjustment to the Operating Reserve rate would be minimal and would probably also need to be carried through to power rates that are impacted by the revenues recovered through the ACS rates. The possible difference between forecast and actual is not worth inclusion of such an adjustment mechanism.

Decision

BPA will not include an adjustment to the Operating Reserve forecast based on potential changes to e-Tag product code requirements.

Issue 3.2.8.2

Whether BPA should adjust the Operating Reserve forecast to account for the latest assumptions regarding BAL-002-WECC-1.

Parties' Positions

No party addressed this issue in brief.

BPA Staff's Position

Staff states that the Operating Reserve forecast for the final studies would be adjusted based on the best available information at the time. This included both the firm-contingent assumption adjustment, Mainzer *et al.*, BP-12-E-BPA-42, at 5, and the status of BAL-002-WECC-1 standard to change from the current five and seven percent standard, where the generation balancing authority holds the Operating Reserves, to the proposed three and three percent standard, with generation and load balancing authorities each holding Operating Reserves. Chen *et al.*, BP-12-E-BPA-26, at 4.

Evaluation of Positions

The current WECC standard for Operating Reserves (BAL-STD-002-0) establishes the minimum amount of spinning and non-spinning Operating Reserves that a balancing authority area carries. Chen *et al.*, BP-12-E-BPA-26, at 2. The minimum is the greater of (a) the loss of generating capacity due to forced outages of generation or transmission equipment that would result from the most severe single contingency; or (b) the sum of five percent of the balancing authority's load responsibility served by hydro and wind generation and seven percent served by thermal generation. *Id.*

The BAL-002-WECC-1 revised standard sets the minimum operating reserve Requirement at the greater of (1) the sum of three percent of the load (generation minus station service minus net actual interchange) and three percent of net generation (generation minus station service); or (2) the most severe single contingency. *Id.* at 3.

At the time of the Initial Proposal Staff believed that it was unlikely that the Commission would decide to approve and implement the proposed BAL-002-WECC-1 regional reliability standard during the rate period. Uncertainty on the adoption of the new standard was based on the remand by the Commission to NERC on October 21, 2010. *Id.* at 3-4.

The WECC drafting team has made the modifications requested in the Commission's remand of BAL-002-WECC-1. The WECC Operating Committee rejected the standard with the modifications on May 19, 2011 in a very close vote. However, the drafting team plans to reconvene to try to resolve the issues that are brought forward by the negative voters. It is expected that the WECC drafting team will be able to resolve enough issues with the negative voters, and the WECC board should approve the new standard, which will then be sent to the Commission. Approval of the modified BAL-002-WECC-1 by the Commission is expected sometime during FY 2012, with an implementation date 90 days after approval.

Based on the timing of the continuing efforts of the WECC drafting team to address the concerns in the WECC Operating Committee's objections and the time for the approval through the WECC Operating Committee, WECC Board of Directors, and the Commission, BPA believes that the new BAL-002-WECC-1 will become effect halfway through the FY 2011–2012 rate period.

Decision

BPA will use the five and seven percent standard to forecast Operating Reserves for FY 2012 and the three and three percent standard for the FY 2013 forecast.

3.2.9 Committed Intra-Hour Scheduling Pilot Issues

In the Initial Proposal, Staff indicates that it has begun investigating the possibility of a committed intra-hour pilot program during the rate period and that it is interested in the parties' perspectives on such a program. Mainzer *et al.*, BP-12-E-BPA-23, at 45. After holding a workshop on this topic, Staff submitted rebuttal testimony proposing a temporary pilot in which participants with a wind project would commit by contract to submit half-hourly schedules based on a persistence model or a generation forecast known and verified by BPA. Simpson *et al.*, BP-12-E-BPA-46, at 2. In exchange for this commitment, participants would receive a discount on the VERBS rate and would be exempt from persistent deviation penalties. *Id.*

As explained in Issue 3.2.9.1, for purposes of the rate case BPA is assuming that it will conduct a committed intra-hour scheduling pilot during the rate period. The discussion of the details of the pilot in this section distinguishes issues that BPA needs to resolve in the rate case from those that BPA and parties can address in the implementation of the pilot. The issues to resolve in the rate case include the forecast of the reduction in reserve requirements associated with the pilot, the rate treatment for participants, the assumptions used to calculate the generation inputs revenue credit, the proposed cap on participation, and the OPUC's suggestion to allow 15-minute scheduling in the pilot.

No party contests Staff's proposals for the forecast of the reduction in reserve requirements associated with the pilot and the rate treatment for participants, including the exemption from Persistent Deviation penalties. BPA is adopting Staff's proposals on those issues without any further discussion.

NWG and SCE disagree with Staff's assumptions about the pilot start date, the amount of participation (in megawatts), and the proposed cap on participation. BPA addresses those topics in Issues 3.2.9.2, 3.2.9.3, and 3.2.9.4. The OPUC's suggestion about 15-minute scheduling is addressed in Issue 3.2.9.5.

BPA and stakeholders will address the remaining details of the pilot in the implementation phase, which will include development of a business practice in BPA's standard process. *See* OPUC Br., BP-12-B-PU-01, at 4, and Miles *et al.*, BP-12-E-SN-08, at 3 (urging BPA to address

implementation details in a public process). Although most of these implementation details do not require discussion in this Final ROD, BPA believes it is important to share its current thinking on WPAG's proposal that Provisional Balancing Service apply to participants that fail to satisfy the requirements of the pilot. WPAG Br., BP-12-B-WG-01, at 23. BPA addresses WPAG's proposal in Issue 3.2.9.6, and BPA hopes that sharing its perspective will be informative as parties consider participating in the pilot.

Issue 3.2.9.1

Whether, for purposes of setting rates, BPA should assume that it will proceed with the committed intra-hour scheduling pilot.

Parties' Positions

NWG and SCE support the proposal for a committed intra-hour scheduling pilot. NWG Br., BP-12-B-NG-01, at 60-61; SCE Br., BP-12-B-SC-01, at 9.

Snohomish stated in its initial brief that it opposes the proposed pilot, because the pilot would discriminate against customers with contracts for the Block/Slice product, which do not allow intra-hour scheduling. Snohomish Br., BP-12-B-SN-01, at 23. At oral argument, Snohomish indicated that it supports the pilot and would like to explore ways to be able to participate or "gain equivalent value." Kallstrom, Oral Tr. at 10. Snohomish's brief on exceptions states that Snohomish supports having discussions outside of the rate case about ways to participate in committed intra-hour scheduling. Snohomish Br. Ex., BP-12-R-SN-01, at 4.

WPAG generally supports the concept of the pilot, but wants customers with wind generation sinking in BPA's balancing authority area to be able to participate and to receive the rate discount. WPAG Br., BP-12-B-WG-01, at 23-24; WPAG Br. Ex., BP-12-R-WG-01, at 25.

BPA Staff's Position

Staff supports implementation of a committed intra-hour scheduling pilot during the rate period. Simpson *et al.*, BP-12-E-BPA-46, at 2.

Evaluation of Positions

Intra-hour scheduling is one of the Wind Integration Team initiatives that BPA has undertaken in recent years to more efficiently integrate the VERs seeking to interconnect with BPA's system. Mainzer *et al.*, BP-12-E-BPA-23, at 7, 44-45. The expectation is that more-frequent scheduling opportunities will help to reduce overall balancing reserve capacity requirements. *Id.* The details of intra-hour scheduling are being developed separate and apart from the rate case. *Id.* at 44-45. Staff's balancing reserve capacity quantity forecast does not incorporate any assumption about intra-hour scheduling during the rate period, because the limited amount of intra-hour scheduling on BPA's system at this point has provided relatively little data, and the impact of voluntary intra-hour scheduling on balancing reserve capacity requirements is unclear. Puylear *et al.*, BP-12-E-BPA-24, at 29.

Staff proposes a committed intra-hour scheduling pilot in order to help assess the potential benefits in terms of reducing balancing reserve capacity requirements if participants agreed to consistently submit intra-hour schedule changes that meet certain accuracy standards. Simpson *et al.*, BP-12-E-BPA-46, at 2. Conducting a limited committed intra-hour scheduling pilot could have significant value in terms of gaining experience with intra-hour scheduling in an environment in which participants will commit to submit accurate schedules on a consistent basis. *Id.*

Snohomish appears to be the only party that has opposed the committed intra-hour scheduling pilot. Snohomish Br., BP-12-B-SN-01, at 23. Snohomish initially suggested that the pilot is discriminatory because the Slice/Block contracts signed as part of the Regional Dialogue explicitly prohibit schedule changes within the hour, and customers with these contracts would be unable to participate. *Id.* However, Snohomish now appears to be more focused on finding ways to participate in the pilot or gaining “equivalent value” than opposing the pilot altogether. Kallstrom, Oral Tr. at 10. Snohomish supports having discussions outside of the rate proceeding regarding ways to achieve broader participation in committed intra-hour scheduling. Snohomish Br. Ex., BP-12-R-SN-01, at 4.

The emphasis on widespread intra-hour scheduling is a relatively recent phenomenon in the Pacific Northwest. Taking Snohomish’s initial concern to its logical end would suggest that intra-hour scheduling as a whole would be discriminatory, because stakeholders with contracts that do not permit within-hour schedule changes would be unable to submit such schedules until the contracts were revised. BPA does not agree with that conclusion and, in any event, is not addressing the details of power purchase contracts in this proceeding. The concern regarding certain contracts not providing for intra-hour scheduling does not justify abandoning the proposal for a committed intra-hour scheduling pilot for this rate period.

At oral argument, Snohomish stated that its inability to schedule the Block/Slice product or its non-Federal resources on an intra-hour basis would force it to face the market risk of procuring resources to participate in intra-hour scheduling or obtain equivalent value. Kallstrom, Oral Tr. at 11-12. Snohomish states a concern that market risk could outweigh the benefits of participating. *Id.* BPA agrees that there is value associated with participating in the committed intra-hour scheduling pilot, but BPA does not agree that its role is to guarantee that value if customers are unwilling to enter the market to participate.

With respect to Snohomish’s suggestion about discussions outside of the rate case regarding the ability of customers with slice contracts to schedule within the hour, BPA agrees that discussions related to provisions of a power sales contract are not part of the rate case process. The Slice/Block Power Sales Agreement does not provide intra-hour flexibility. BPA’s current priority is the successful completion and implementation of this new Slice contract. BPA acknowledges Snohomish’s concern and is willing to discuss this concern in the future; however, any discussion of potential amendments to the new Slice contract do not seem reasonable until it has been successfully implemented for some period as designed, and there is a better understanding of any prospective intra-hour markets.

Discussions between any potential providers and purchasers of intra-hour generation flexibility should appropriately occur on a bi-lateral basis outside the rate process. BPA's current emphasis is the development of intra-hour markets.

WPAG raises an issue similar to that of Snohomish, arguing that customers with wind generation that sinks in BPA's balancing authority should be able to participate in the pilot and receive the rate discount. WPAG Br. Ex., BP-12-R-WG-01, at 25. BPA is not making any decision in this proceeding that excludes any particular customers from participating in the committed intra-hour pilot. Deciding which customers participate in the committed intra-hour scheduling pilot is not a rate case issue. That issue will be resolved in the implementation phase through discussions with individual customers.

Even though the rate case is not resolving which customers can participate in the pilot, WPAG's concerns about wind generation sinking in BPA's balancing authority area warrant some discussion. Justifying the substantial discount in the VERBS rate under the pilot requires some benefit to BPA in terms of reducing balancing reserve capacity needs. Committed intra-hour scheduling by wind generation sinking within BPA's balancing authority area will not reduce BPA's balancing reserve capacity requirement without some non-Federal resources backing up such wind generation. Customers with wind generation sinking in BPA's balancing authority area should not be able to participate in the pilot (and take the benefit of the rate discount) if those customers intend for BPA to continue to balance wind generation through an Energy Imbalance account. Customers with wind generation facilities sinking within BPA's balancing authority will need to demonstrate that a non-Federal capacity resource is backing up the wind facility to participate in the committed intra-hour scheduling pilot.

WPAG's brief on exceptions suggests that BPA is proposing that wind generation sinking in BPA's balancing authority area would be able to participate in the pilot but would not receive the rate discount. WPAG Br. Ex., BP-12-R-WG-01, at 25. This is incorrect. If a customer does not meet the requirements to participate in the committed intra-hour scheduling pilot, it will not be able to participate and will not receive the rate discount. As described above, for customers with wind generation sinking within BPA's balancing authority area, the requirements to participate in the pilot will include demonstrating that a non-Federal capacity resource is backing up the wind facility.

Decision

For purposes of setting rates, BPA assumes that it will conduct a committed intra-hour scheduling pilot during the rate period. In this Final ROD, BPA is not excluding any customer from eligibility to participate in the pilot, but BPA will require all participants to meet certain basic requirements that will be addressed in the implementation phase. For wind generation sinking within BPA's balancing authority area, customers will need to demonstrate that a non-Federal capacity resource is backing up the wind facility.

Issue 3.2.9.2

Whether BPA should assume a January 2012 start date for the pilot to determine the generation inputs revenue credit.

Parties' Positions

NWG recommends that BPA assume an October 1, 2011, start date. NWG Br., BP-12-B-NG-01, at 63; NWG Br. Ex., BP-12-R-NG-01, at 23.

BPA Staff's Position

Staff recommends assuming a January 1, 2012, start date for purposes of calculating the generation inputs revenue credit. Simpson *et al.*, BP-12-E-BPA-46, at 11.

Evaluation of Positions

The start date for the pilot that BPA uses to calculate the generation inputs revenue credit is a ratemaking assumption. That assumption will not determine when the committed intra-hour scheduling pilot will actually start or when participants could be ready to start submitting schedules in the pilot. *See* Simpson *et al.*, BP-12-E-BPA-46, at 11.

Staff explains that widespread intra-hour scheduling in the Northwest depends on BPA and adjacent transmission providers developing the ability to accept such schedules. *Id.* Although BPA and other Northwest transmission providers are working toward being able to accept all types of intra-hour schedules from generators by October 1, 2011, it is uncertain whether all transmission providers will achieve that goal. In addition, participation in the pilot itself depends on the readiness of participants, negotiation of participant agreements, and establishment of business practices. *Id.* at 10-11.

NWG urges BPA to assume October 1, 2011, as the start date for purposes of calculating the generation inputs revenue credit. NWG Br., BP-12-B-NG-01, at 63. NWG suggests that BPA reach out to potential participants and neighboring balancing authorities and prioritize work on business practices and participant agreements to increase the likelihood that the pilot will start on October 1, 2011. NWG Br., BP-12-B-NG-01, at 63-64. NWG also suggests that BPA take into account the progress it has made on such efforts up to the time BPA issues the Final ROD. NWG Br. Ex., BP-12-R-NG-01, at 23.

BPA is actively working toward making generally applicable intra-hour scheduling available by October 1, 2011, but the uncertainty whether such scheduling opportunities will be in place by that date extends beyond BPA's control. BPA considers intra-hour scheduling to be a very important initiative; however, it is one of many efforts that BPA and neighboring balancing authorities are working on diligently. Assuming a January 1, 2012, start date to determine the generation inputs revenue credit appears more consistent with the current information about the pace of intra-hour scheduling efforts.

Decision

BPA assumes that the committed intra-hour scheduling pilot will start on January 1, 2012, for purposes of determining the generation inputs revenue credit.

Issue 3.2.9.3

Whether BPA should assume 600 MW will participate in the committed intra-hour scheduling pilot to determine the generation inputs revenue credit.

Parties' Positions

NWG states that the assumption of 600 MW of participation is reasonable, assuming that current assumptions about issues such as the amount of self-supply do not change. NWG Br., BP-12-B-NG-01, at 64.

SCE urges BPA to assume that at least 20 percent of the wind fleet, approximately 983 MW, will participate. SCE Br., BP-12-B-SC-01, at 10.

BPA Staff's Position

Staff proposes assuming 600 MW of participation, given the current information about the generators likely to participate. Simpson *et al.*, BP-12-E-BPA-46, at 5, 9.

Evaluation of Positions

Staff's proposal that 600 MW of wind generators would participate in the committed intra-hour scheduling pilot is based on consideration of the generators that would most likely be able to participate without having to revise contracts or acquire new resources, that would benefit the most from the program, and that would schedule into a balancing authority that is ready to accept intra-hour schedules during the rate period. *Id.* SCE's suggestion to assume that 20 percent of the wind fleet will participate is based on an assumption that the economic incentive associated with the pilot will lead more generators to participate. SCE Br., BP-12-B-SC-01, at 10.

The rate discount associated with the pilot provides a significant incentive to participate, but having the incentive to participate is different from having the ability to participate. The ability to participate depends on a number of factors, including having contracts that allow intra-hour scheduling, having the ability to submit schedules every 30 minutes, and having a receiving balancing authority that accepts intra-hour schedules. Simpson *et al.*, BP-12-E-BPA-46, at 5, 10-11. Given these factors that will plainly limit the generators that will be able to participate, Staff's more conservative assumption of 600 MW is more appropriate for ratemaking, a primary purpose of which is the assurance of cost recovery.

Decision

BPA assumes 600 MW of wind generation will participate in the committed intra-hour scheduling pilot for purposes of determining the generation inputs revenue credit.

Issue 3.2.9.4

Whether BPA should establish a cap on the total amount of participation in the committed intra-hour scheduling pilot.

Parties' Positions

NWG recommends that BPA not limit participation in the pilot and is specifically concerned that an initial cap of 1200 MW is too low. NWG Br., BP-12-B-NG-01, at 65-66; NWG Br. Ex., BP-12-R-NG-01, at 23-24. If BPA adopts a 1200 MW cap, NWG supports modifying the cap during the rate period. NWG Br. Ex., BP-12-R-NG-01, at 23-24.

BPA Staff's Position

Staff proposes limiting participation in the pilot to 1200 MW. Simpson *et al.*, BP-12-E-BPA-46, at 10.

Evaluation of Positions

NWG suggests that BPA should encourage as much intra-hour scheduling as possible and maintains that a cap on participation is unnecessary to prevent cost shifts or ensure revenue recovery. NWG Br., BP-12-B-NG-01, at 65-66. NWG supports leaving flexibility to adjust any cap during the rate period or adopt a cap that expires at the end of the first year of the rate period. *Id.*; see also Nelson, BP-12-E-SC-03, at 4-5.

The primary reason for limiting participation in the committed intra-hour scheduling pilot is the uncertainty associated with intra-hour scheduling due to the limited amount of such scheduling in BPA's balancing authority area up to this point. Simpson *et al.*, BP-12-E-BPA-46, at 10. BPA has no experience with the impacts of the consistent and repeated schedule changes every 30 minutes that BPA will experience under the committed intra-hour scheduling pilot. Limiting participation in the pilot to minimize any operational risk is appropriate under these circumstances. *Id.*

NWG argues that an initial cap of 1200 MW is too low and inadequately justified, but NWG also recognizes BPA's concern about lack of experience with intra-hour scheduling. NWG Br. Ex., BP-12-R-NG-01, at 23-24. The record contains no evidence to critically evaluate the claim that a 1200 MW cap is too low compared to another level. The amount of the cap is ultimately a matter of judgment, and Staff testified that it is unlikely that more than 1200 MW of wind generation will be in a position to participate in the pilot. Simpson *et al.*, BP-12-E-BPA-46, at 10. Staff's testimony adequately justifies adopting a cap of 1200 MW, especially in the absence of any evidence supporting another proposal.

Adopting an initial cap and retaining the ability to modify it during the rate period will help address NWG's concerns that 1200 MW might not be the "right" number. BPA wants to encourage participation in the pilot and intra-hour scheduling in general and does not want to unnecessarily limit the generators that can take part if the pilot proves successful. For all of these reasons, BPA is adopting an initial cap of 1200 MW but is retaining flexibility to adjust the

cap during the rate period. The specifics about adjusting the cap should be addressed in the implementation phase, but BPA expects that operational issues, cost recovery concerns, and other factors, including customer comments, will all play a role in that decision.

Decision

Participation in the committed intra-hour scheduling pilot is limited to 1200 MW initially, but BPA retains the right to modify that limit during the rate period.

Issue 3.2.9.5

Whether participants in the committed intra-hour pilot should be allowed to submit 15-minute schedules.

Parties' Positions

The OPUC recommends that BPA allow participants in the committed intra-hour pilot to submit 15-minute schedules rather than limiting scheduling to 30 minutes. OPUC Br., BP-12-B-PU-01, at 2-3. OPUC states that allowing 15-minute schedules would be consistent with the FERC NOPR proposal and provides other potential benefits. *Id.*

BPA Staff's Position

BPA does not currently have the ability to accept schedules on regular 15-minute intervals, and Staff does not believe it is likely or feasible to accept intra-hour schedules on 15-minute intervals during the rate period given the implementation issues. Mainzer *et al.*, BP-12-E-BPA-42, at 13-14.

Evaluation of Positions

The committed intra-hour scheduling pilot is one effort in a series of initial steps toward widespread intra-hour scheduling. At this point, it does not appear feasible for BPA to establish the technical capabilities to accept intra-hour schedules on 15-minute intervals during the rate period. Mainzer *et al.*, BP-12-E-BPA-42, at 13-14. The OPUC appears to be the only party that continues to seriously advocate for implementation of 15-minute scheduling during the rate period. NWG and Iberdrola, both of which support an ultimate goal of 15-minute scheduling, acknowledge that implementing 15-minute scheduling during the rate period may not be a realistic goal. Hall, Oral Tr. at 215; Skidmore, Oral Tr. at 138. BPA is not going to establish a committed intra-hour scheduling pilot for the rate period based on assumptions about technical capabilities that BPA does not currently have and is not developing. Adopting a committed intra-hour scheduling pilot that will use 30-minute scheduling intervals for the rate period does not preclude consideration of other options in the future.

Decision

For purposes of setting rates, BPA assumes that the committed intra-hour scheduling pilot will use 30-minute scheduling.

Issue 3.2.9.6

Whether BPA must determine in this rate proceeding the consequences if a participant in the committed intra-hour scheduling pilot fails to meet the scheduling requirements.

Parties' Positions

WPAG argues that BPA has not adequately addressed what happens to participants when they fail to meet requirements of the pilot. WPAG Br., BP-12-B-WG-01, at 23. WPAG suggests placing participants that fail to meet requirements of the pilot on provisional balancing service. *Id.* WPAG indicates that would be a particularly appropriate outcome if BPA does not allow wind generation sinking within the balancing authority area to participate in the pilot. WPAG Br. Ex., BP-12-R-WG-01, at 24-25.

NWG supports BPA's initial perspective that participants that fail to meet requirement of the committed intra-hour scheduling pilot should not be placed on provisional balancing service. NWG Br. Ex., BP-12-R-NG-01, at 24.

BPA Staff's Position

The implementation phase will address evaluation of scheduling performance and consequences for failure to schedule as required. Simpson *et al.*, BP-12-E-BPA-46, at 6.

Evaluation of Positions

The committed intra-hour scheduling business practice and participant agreements will establish the detailed requirements for participating in the pilot and the consequences for failing to satisfy those requirements. *Id.* Nevertheless, BPA would like to provide its current thinking regarding the consequences of a participant failing to schedule as required in the pilot.

The committed intra-hour scheduling pilot needs to include mechanisms to verify that participants are scheduling consistently and meeting the required accuracy standards. The rate discount is a substantial reduction from the VERBS rate, and participants must satisfy the scheduling requirements in order to justify that discount. BPA does not believe, however, that failure to satisfy those requirements should be a basis for shifting non-compliant participants to provisional balancing service as WPAG suggests. *See* WPAG Br., BP-12-B-WG-01, at 23. The committed intra-hour scheduling pilot is a temporary program to help evaluate the potential benefits of intra-hour scheduling on a consistent and accurate basis. Simpson *et al.*, BP-12-E-BPA-46, at 2. BPA wants to encourage participation in the program while ensuring that it maintains reliability and recovers its costs. A more appropriate consequence for failing to satisfy the scheduling requirements of the committed intra-hour pilot appears to be the loss of the rate discount and the re-allocation of reserves to pre-pilot amounts.

WPAG argues that allowing failed participants to return to full VERBS service could create cost shifts and impact the quality of service of other customers, and that these are exactly the types of risks that Provisional Balancing Service is intended to address. WPAG Br. Ex., BP-12-R-WG-01, at 25. Again, this is not an issue that BPA is resolving in the rate case, and the record

lacks evidence to demonstrate cost shifts or quality of service issues associated with the failure of committed intra-hour scheduling pilot participants to meet the scheduling requirements of the pilot. In addition, Staff's testimony regarding Provisional Balancing Service indicates that Provisional Balancing Service was developed to address issues other than the failure of committed intra-hour scheduling participants. Mainzer *et al.*, BP-12-E-BPA-23, at 34-35; Jackson *et al.*, BP-12-E-BPA-29, at 35; Jackson *et al.*, BP-12-E-BPA-47, at 27.

Decision

The committed intra-hour scheduling pilot business practice and participant agreement will establish the details for treatment of participants that fail to satisfy the requirements of the pilot.

3.2.10 VERBS Supplemental Service Issues

Staff did not include a specific proposal for VERBS Supplemental Service in the Initial Proposal. Staff did state a set of principles that any additional VERBS service would need to meet: (1) all costs of procuring additional non-Federal balancing reserve capacity to support VERBS Supplemental Service during this rate period would be directly assigned to the rate for VERBS Supplemental Service; (2) the design of such service would need to ensure no costs (including potential stranded costs) are shifted to other customers; (3) the design of such service must be consistent with maintaining the reliability of the system; (4) the design of such service must have no impact on BPA's ability to meet its Endangered Species Act or Clean Water Act requirements; (5) the design of such service cannot degrade the quality of VERBS for those customers that choose not to purchase the VERBS Supplemental Service; and (6) the customer purchasing such service must accept the risk that such service will not guarantee service on 100 percent of all hours, and the customer must determine whether the proposed service will meet its need for a higher quality of service. Mainzer *et al.*, BP-12-E-BA-23, at 41.

After holding a workshop on VERBS Supplemental Service on January 13, 2011, and reviewing customer comments in their direct cases, Staff proposes a more detailed VERBS Supplemental Service in its rebuttal testimony. The proposal had six main points: (1) BPA will offer VERBS Supplemental Service under a pilot during the FY 2012–2013 rate period to allow customers to purchase or self-supply non-Federal *inc* balancing reserve capacity to limit DSO 216 curtailments for a VER designated by the customer; (2) the pilot is expected to begin at some point during FY 2012, but VERBS Supplemental Service is not expected to be available on October 1, 2011; (3) BPA will establish a formula rate in the rate proceeding that collects the full cost of any purchases of supplemental balancing reserves that BPA makes for the participating customers; (4) BPA will establish an administrative charge in the rate proceeding to defray the cost of establishing a supplemental reserves program; (5) outside of the rate case, BPA will develop a business practice that will outline the implementation details for customer self-supply of supplemental reserves and BPA purchase of supplemental reserves; and (6) BPA will modify DSO 216 (outside of the rate case) to accommodate the use of supplemental reserves. Kitchen *et al.*, BP-12-E-BPA-45, at 10.

Although Staff believes it is unlikely that the purchase of VERBS Supplemental Service can completely eliminate the possibility of any DSO 216 curtailments of transmission schedules, Staff does believe that customers can greatly reduce the likelihood that their schedules will be cut in a DSO 216 event by purchasing VERBS Supplemental Service.

Issue 3.2.10.1

Whether BPA should offer a VERBS Supplemental Service during the FY 2012–2013 rate period.

Parties' Positions

MSR argues that BPA should not offer a VERBS Supplemental Service at this time. MSR Br., BP-12-B-MS-01, at 5. MSR argues that Staff's proposal does not provide sufficient "insurance" to prevent DSO 216 events and that Staff's rate analysis is flawed. *Id.* MSR urges BPA to focus its efforts on reliability upgrades and capital projects necessary to provide a higher-quality service rather than offering VERBS Supplemental Service. *Id.* In the alternative, MSR argues, if BPA offers VERBS Supplemental Service it should be handled through a separate proceeding in which separate reserves are acquired for those entities willing to pay for them, and the right to use those reserves is limited to the customers that purchase them. *Id.* at 13. MSR states that VERBS Supplemental Service should not depend upon or utilize current system flexibility or be considered in ratesetting. *Id.*

SCE supports the adoption of VERBS Supplemental Service as proposed by Staff. SCE Br., BP-12-B-SC-01, at 2-3. SCE supports the use of the formula rate to recover the cost of the purchase of any VERBS Supplemental Service balancing reserves. *Id.* SCE states that subscribers of the service should pay an appropriate formula rate for the service. *Id.* SCE also agrees that since VERBS Supplemental Service would be purchased and paid for by entities that desire the service, without subsidy from others, it is appropriate to include it in the rates adopted by BPA. *Id.* at 3.

OPUC supports Staff's VERBS Supplemental Service proposal. OPUC Br., BP-12-B-PU-01, at 5-6. OPUC states that the service will facilitate the coding of Northwest wind generation with "firm e-tags." *Id.*

Snohomish states that it generally supports Staff's proposed VERBS Supplemental Service, but also states that in order to avoid any unintended consequences of providing VERBS Supplemental Service, procurement of the supplemental reserves should be aligned with the notice provisions of other BPA balancing service elections. Snohomish Br., BP-12-B-SN-01, at 22-23.

JP06 states that it supports the adoption of VERBS Supplemental Service as long as 100 percent of the costs are recovered through the VERBS Supplemental Service rate and BPA can avoid service interruption to other customers. JP06 Br., BP-12-B-JP06-01, at 8-10.

BPA Staff Position

In response to customer comments, Staff proposes in its rebuttal testimony to offer a VERBS Supplemental Service for customers that want to pay for a level of service higher than the base level of service of 99.5 percent that Staff proposes. Some customers expressed a desire to have an option to purchase balancing reserves above the base rate to try to limit their exposure to DSO 216. Staff proposes to establish a formula rate that collects the full cost of any purchases of supplemental balancing reserves.

After making the VERBS Supplemental Proposal in rebuttal testimony, BPA filed, and the Hearing Officer granted, a motion to amend the procedural schedule to allow surrebuttal on the proposal. BP-12-HOO-53. Staff believes that the VERBS Supplemental Service as proposed will meet the set of principles and goals articulated in BPA's Initial Proposal and rebuttal testimony. Mainzer *et al.*, BP-12-E-BA-23, at 41; Kitchen *et al.*, BP-12-E-BPA-45, at 15.

Evaluation of Positions

MSR is the only party that opposes Staff's proposed VERBS Supplemental Service. All other parties that address the issue support the concept of Staff's proposed VERBS Supplemental Service. MSR argues that BPA should focus on upgrades to the FCRPS to improve the quality of service instead of providing VERBS Supplemental Service. This approach would not address the concerns expressed by customers that want the ability to purchase a higher level of service than the proposed base rate of 99.5 percent. Staff proposes to address the issue MSR has raised through different mechanisms, such as the *dec* purchase pilot under which Staff proposes to spend \$1 million a year on systems upgrades. Klippstein *et al.*, BP-12-E-BPA-25, at 21.

Decision

BPA will offer a VERBS Supplemental Service during the FY 2012–2013 rate period.

Issue 3.2.10.2

Whether BPA should include a separate formula rate for VERBS Supplemental Service.

Parties' Positions

SCE supports BPA's proposal to use a formula rate to recover the cost of the purchase of any VERBS Supplemental Service balancing reserves. SCE Br., BP-12-B-SC-01, at 2-3. SCE states that subscribers of the service should pay an appropriate formula rate for the service. *Id.* SCE also agrees that since VERBS Supplemental Service would be purchased and paid for by entities that desire the service, without subsidy from others, it is appropriate to include it in the rates adopted by BPA. *Id.*

JP06 states that it supports the adoption of VERBS Supplemental Service as long as BPA has a mechanism in place to ensure that 100 percent of the costs are recovered through the VERBS

Supplemental Service rate and BPA can avoid service interruption to other customers. JP06 Br., BP-12-B-JP06-01, at 8-10.

MSR states in its surrebuttal testimony on the VERBS Supplemental Service issue that BPA should defer the issue of whether or not to offer VERBS Supplemental Service until other issues, such as balancing authority responsibilities, use of contingency reserves, availability of supplemental reserves by season and system conditions, and tagging of wind resources” are determined. Arthur and Mayson, BP-12-E-MS-05, at 4. MSR argues that once these primary issues are understood, it will be possible to specify the quantity, cost, and benefits of VERBS Supplemental Service. *Id.* In its initial brief, MSR states that if BPA does adopt a VERBS Supplemental Service, then the procurement process for supplemental reserves should be conducted through a separate proceeding in which separate reserves are acquired for those entities willing to pay for them. MSR Br., BP-12-B-MS-01, at 13.

BPA Staff Position

Staff proposes that BPA establish a formula rate that collects the full cost of any purchases of supplemental balancing reserves that BPA makes from the participating customers. Kitchen *et al.*, BP-12-E-BPA-45, at 10-11. The rate will include a monthly charge for all supplemental reserves supplied by BPA during a month. *Id.* at 11. BPA would purchase supplemental reserves based on customer requests for specified periods during a year. *Id.* The rate for supplemental reserves will be established on a periodic basis for a period of a month or longer as established in the business practice covering VERBS Supplemental Service. *Id.* The rate would be based on the average cost of supplemental reserves purchased by BPA for all customers during the period of the purchase. *Id.* Outside the rate proceeding BPA will develop a business practice regarding the implementation of VERBS Supplemental Service for both supplemental reserves supplied by BPA and customer self-supply of supplemental reserves. *Id.* at 10.

Evaluation of Positions

While MSR argues that, if BPA does adopt VERBS Supplemental Service, it should be conducted through a different proceeding, MSR provides no details as to how BPA should go about setting up a separate proceeding for VERBS Supplemental Service. Staff’s proposal to use a formula rate to recover the costs of providing VERBS Supplemental Service is supported by SCE, which is the only party in this rate proceeding that indicates a desire to utilize the service. Staff proposes a formula rate that collects the full cost of any purchases of supplemental balancing reserves that BPA makes for the participating customers. *Id.* at 11. Thus, consistent with the principle Staff articulates in the Initial Proposal, there should be no costs passed on to customers that do not purchase VERBS Supplemental Service. The proposed formula rate will allow for the purchase of supplemental reserves on a timeline that will allow customers to make decisions about their VERBS Supplemental Service aligned with their risk management needs more closely than if BPA used a rate proceeding to establish the rate.

Decision

BPA will include a separate formula rate for supplemental balancing service.

Issue 3.2.10.3

Whether customers that purchase VERBS Supplemental Service should be exposed to VERBS rate increases associated with increased levels of service under Formula Rate II.

Parties' Positions

SCE argues that the VERBS Supplemental Service formula rate and the VERBS Formula Rate II are intended to recover the same costs. SCE Br., BP-12-B-SC-01, at 3-4.

SCE argues that both the Supplemental Service formula rate and the VERBS Formula Rate II are designed to allocate the cost to provide a higher level of service beyond the 99.5 percent standard. Nelson, BP-12-E-SC-03, at 6. SCE also argues that VERBS Supplemental Service participants that purchase a level of service that is equal to or greater than the VERBS level provided under the VERBS Formula Rate II should be exempt from the Formula Rate II. *Id.* SCE's witness provides two examples of this possibility. *Id.* at 6-7. SCE explains that a customer could purchase VERBS Supplemental Service to obtain a 99.8 percent level of service. Subsequently, BPA could decide to invoke the Formula Rate II in order to bring the base level of service up to 99.7 percent. In that instance, SCE claims, the customer taking the VERBS Supplemental Service should not have to pay for both Formula Rate II and Supplemental Service, because it is purchasing balancing reserves at a level that is higher than the level that the Formula Rate II is providing. *Id.* at 6.

In SCE's second example, a customer purchases VERBS Supplemental Service to receive balancing reserves at the 99.6 percent level of service. *Id.* at 6-7; SCE Br., BP-12-B-SC-01, at 4. Subsequently, BPA could invoke the Formula Rate II to provide a new base rate of 99.7 percent. In this example, SCE argues, the customer should be responsible for only the cost of balancing service to meet the additional 0.1 percent level provided by Formula Rate II, or the customer should not be obligated to pay the VERBS Supplemental Service rate. Nelson, BP-12-E-SC-03, at 6-7; SCE Br., BP-12-B-SC-01, at 4.

SCE argues that the Final ROD should clarify that purchasers of VERBS Supplemental Service will receive a higher level of service than the level of service received by customers that do not purchase VERBS Supplemental Service regardless of whether Formula Rate II is triggered. SCE Br. Ex., BP-12-R-SC-01, at 3-5. SCE also requests that the Final ROD clarify that purchasers of VERBS Supplemental Service will not be charged twice for the same service. *Id.* SCE argues that the record in this proceeding does not support the conclusion that VERBS Supplemental Service and Formula Rate II are not designed to recover the same cost. *Id.* at 5-8. SCE also states that "VERBS Supplemental Service could be designed so that a customer would be entitled to retain the additional reliability purchased on its behalf regardless of the level of reliability offered pursuant to VERBS Formula Rate II; *i.e.*, VERBS Supplemental Service would always be over and above the reliability offered to customers not purchasing such service." *Id.* at 10. Finally, SCE points out some contradictions in BPA's Draft ROD. *Id.* at 11.

BPA Staff's Position

Staff explains that Formula Rate II is designed to allow the Administrator to make a mid-rate period adjustment if: (1) one or more participants in the Pacific Northwest utility industry asks the Administrator to increase the amount of balancing reserve capacity set aside for VERBS in order to reduce the frequency of DSO 216 events, or (2) because of a legal challenge to DSO 216 that prevents BPA from utilizing DSO 216. Mainzer *et al.*, BP-12-E-BPA-42, at 18. If the Administrator does trigger Formula Rate II, then BPA will raise the base level of balancing reserve that it holds to a higher level than 99.5 percent. *Id.*; Mainzer *et al.*, BP-12-E-BPA-23, at 50-51; Generation Inputs Study, section 10.5 (describing the triggers for a formula rate adjustment). Staff explains the purchase of balancing reserve capacity under Formula Rate II as follows:

If BPA intends to make longer-term purchases to replace unavailable Federal generation or to increase the level of reserves beyond 99.5 percent, then BPA will initiate a public process to discuss our intention prior to executing purchase agreements. ACS-12 Rate Schedules, BP-12-E-BPA-10, section III.E.4. For these purchases, BPA will provide customers with 15 calendar days' advance notice of a public meeting to discuss the need and proposed purchase. BPA will take into account comments received during the meeting and written comments received within 15 calendar days after the meeting. *Id.* BPA will notify customers within 30 calendar days after the meeting of BPA's decision related to the proposed purchase.

BPA expects that short-duration purchases will be for terms of 60 days or less. *Id.* Staff proposes that BPA notify stakeholders after-the-fact if it makes short-duration purchases, or if BPA must make any emergency purchases to replace Federal generation that becomes unavailable during the rate period.

Jackson *et al.*, BP-12-E-BPA-29, at 38-39. Unlike Formula Rate II, VERBS Supplemental Service is an optional service under the VERBS rate. Customers taking VERBS Supplemental Service would purchase non-Federal balancing reserve capacity to decrease the number of curtailments a particular VER would face under DSO 216. Kitchen *et al.*, BP-12-E-BPA-45, at 1. Staff proposes to establish a formula rate adjustment to the VERBS rate to recover the net costs of replacing unavailable Federal generation with purchases from third-party suppliers. Jackson *et al.*, BP-12-E-BPA-29, at 38. The acquisitions would replace the costs of unavailable Federal generation. Staff proposes that BPA will establish a process for requesting bids from customers to purchase Supplemental Service from BPA. Kitchen *et al.*, BP-12-E-BPA-45, at 13-14. BPA would solicit offers from third parties to supply supplemental reserves and determine if any incremental balancing reserves are available in accordance with the participating agreement. *Id.* BPA would then notify the participating customers regarding the amount available and rate for supplemental reserves. The purchase process will be developed outside the rate process in the business practice. *Id.*

Evaluation of Positions

At the outset, BPA acknowledges SCE's assertion that the Draft ROD had some contradictory language. SCE Br. Ex., BP-12-R-SC-01, at 11. The statement in the Draft ROD that "VERBS

Supplemental Service may be purchased once an hour” is incorrect. VERBS Supplemental Service will need to be purchased for a minimum period to incorporate into AGC. This minimum period will be established in the business practice, but BPA’s expectation is that the minimum period will initially be three to six months. Once VERBS Supplemental Service is purchased, supplemental reserves can be deployed once an hour.

VERBS Supplemental Service and Formula Rate II are not designed to recover the same cost. Formula Rate II will trigger only under a very limited set of circumstances, and would raise the level of VERBS service for all purchasers of VERBS. The reserves purchased under VERBS Supplemental Service will be provided in addition to the reserves purchased under Formula Rate II and will increase the reliability of service for the purchaser of VERBS Supplemental Service. If the level of service is increased through Formula Rate II, the VERBS Supplemental Service customer may still want additional DSO 216 protection. The increased level of service does not necessarily end the need for VERBS Supplemental Service.

It will be incumbent upon purchasers of VERBS Supplemental Service to weigh the risks of longer-term purchases of reserves for VERBS Supplemental Service resulting in levels of service higher than their optimal purchase amount if BPA chooses to purchase reserves under Formula Rate II at a later date.

BPA intends that VERBS Supplemental Service will operate in the manner SCE suggests. SCE Br. Ex., BP-12-R-SC-01, at 10. SCE states that “VERBS Supplemental Service could be designed so that a customer would be entitled to retain the additional reliability purchased on its behalf regardless of the level of reliability offered pursuant to VERBS Formula Rate II; *i.e.*, VERBS Supplemental Service would always be over and above the reliability offered to customers not purchasing such service.” *Id.* If Formula Rate II is triggered, raising the base level of service from 99.5 percent to 99.7 percent, then a VERBS Supplemental Service purchaser will receive a level of service above the 99.7 percent level of service up to the amount of VERBS Supplemental Service it has purchased.

Decision

Customers that purchase supplemental balancing service will be exposed to VERBS rate increases associated with increased levels of service under Formula Rate II, but these customers should be able to manage the risk of oversupply.

Issue 3.2.10.4

Whether purchase of VERBS Supplemental Service should ensure that wind can be assigned a firm e-Tag and avoid DSO 216 curtailments except in extreme conditions.

Parties’ Positions

SCE argues that VERBS Supplemental Service should be designed so that energy from VERBS Supplemental Service participants’ generating facilities will be assigned a product code

Generation – Firm e-Tag and avoid DSO 216 curtailment of the resources, except in extreme conditions. SCE Br., BP-12-B-SC-01, at 3, 5-7. SCE argues that BPA has a legal obligation under the Northwest Power Act to encourage renewable energy in the Pacific Northwest and that handicapping the primary source of renewable energy in the Northwest by creating a degraded class of service that will trade at a material discount to other generation is at odds with this obligation. *Id.* at 5-7.

OPUC supports the adoption of Staff’s proposed VERBS Supplemental Service because it “will facilitate the coding of Northwest wind generation output with ‘firm’ e-Tags rather than firm contingent ‘e-tags,’ which will facilitate the competitive export of Northwest wind to other western sub-regions.” OPUC Br., BP-12-B-PU-01, at 5-6.

BPA Staff’s Position

Staff continues to support the adoption of the VERBS Supplemental Service rate as it proposed in the rebuttal testimony. Kitchen *et al.*, BP-12-E-BPA-45. Staff believes that tagging protocol is not a rate case issue. *Id.* at 4. Staff has consistently stated that e-Tag product code issues are outside the scope of this rate case. The Hearing Officer agrees. *See* BP-12-HOO-40; BP-12-HOO-41.

Evaluation of Positions

The VERBS Supplemental Service proposal is designed to provide a flexible option for customers to purchase additional balancing reserves beyond BPA’s base of 99.5 percent that does not depend on a particular outcome of the debate over the appropriate product code for wind generation.

On the issue of whether VERBS Supplemental Service should ensure energy can be tagged as firm, Staff states:

BPA is proposing Supplemental Service to allow customers to purchase additional balancing reserve capacity to reduce or eliminate the potential for DSO 216 curtailments of schedules from their VERs. However, the appropriate tagging protocol is not a rate case issue, and the outcome of the tagging issue is still unknown. Mainzer *et al.*, BP-12-E-BPA-42, section 2. We do not have an opinion in regard to Supplemental Service ensuring that the purchaser will be able to tag its wind as firm.

Kitchen *et al.*, BP-12-E-BPA-45, at 4. Staff does analysis to quantify the additional *inc* balancing reserve capacity needed above the 99.5 percent level to achieve different frequencies of DSO 216 under-generation tag curtailments. Puyleart *et al.*, BP-12-E-BPA-43, at 15-16, Attachment 4. The results are presented as the multiples of additional reserves needed above the 99.5 percent *inc* wind balancing reserve capacity requirements that correspond to a particular number of DSO 216 curtailments. *Id.* The analysis needed to assess the amount of supplemental service needed for individual wind facilities to avoid DSO 216 curtailments is a plant-specific analysis. Staff does not perform this analysis for the *dec* portion of DSO 216 because the overgeneration limitation or *dec* reserve portion of DSO 216 has performed adequately at the

99.5 percent level of service, and parties have not shown interest in supplementing the *dec* balancing reserve capacity for wind generation. Puyleart *et al.*, BP-12-E-BPA-43, at 17.

VERBS Supplemental Service will allow customers to make a determination of how much additional balancing reserve capacity is needed for a given generating plant to reduce its DSO 216 exposure to an acceptable level. While BPA cannot guarantee that a certain amount of supplemental reserves will ensure that a plant will incur zero DSO 216 events, VERBS Supplemental Service provides customers with the option of purchasing additional supplemental reserves to greatly reduce their exposure to DSO 216 events. As described in Staff testimony and discussed in Issue 3.2.2.2 above, BPA continues to invest significant resources to promote the development of wind in the Pacific Northwest and has gone to great lengths to integrate wind resources into the BPA system. The continued growth of wind generation development in BPA's balancing authority area is *prima facie* evidence that BPA's efforts to encourage the growth of renewable resources have been successful. The development of BPA's policies and rate proposals involves the careful consideration of all of the multiple purposes that BPA is statutorily instructed to meet, including the promotion of renewable resource development, maintaining system reliability, and cost recovery. As a result, BPA continues to satisfy the many objectives stated in the Northwest Power Act.

In addition, BPA's position regarding the outcome of e-tagging protocol discussions currently ongoing outside of this rate proceeding is addressed in Issues 3.2.2.6 and 3.2.8.1.

Decision

While not guaranteeing absolute immunity from DSO 216 events, VERBS Supplemental Service can greatly reduce customers' exposure to DSO 216.

Issue 3.2.10.5

Whether BPA should make excess FCRPS capacity available on a month-to-month basis to supplemental balancing service customers.

Parties' Positions

SCE argues that BPA should be required to make FCRPS excess capacity available for VERBS Supplemental Service. SCE Br., BP-12-B-SC-01, at 4-5. SCE states that if BPA determines that there is additional FCRPS capacity above BPA's reserve requirements, BPA should make such capacity available on a month-by-month basis. *Id.* SCE argues that permitting the FCRPS to provide VERBS Supplemental Service will give BPA the opportunity to maximize revenues. *Id.* at 5. SCE states that participation in the Committed Intra-Hour Scheduling Pilot may free up additional reserves, which may include FCRPS capacity, and that this additional capacity should be made available to provide VERBS Supplemental Service. *Id.*

NWG argues that BPA should not provide any VERBS Supplemental Service from the FCRPS. NWG Br., BP-12-B-NG-01, at 75. NWG argues that providing VERBS Supplemental Service

from the FCRPS to a limited set of customers is an inefficient use of the FCRPS capacity that does not make the best use of the geographic diversity of the wind fleet. *Id.* NWG states that VERBS Supplemental Service should be procured only from non-Federal resources, and that the costs should be directly assigned to the VERBS Supplemental Service customers. *Id.*

BPA Staff's Position

Staff does not believe providing Supplemental Reserves from the FCRPS is a viable option. The FCRPS does not have the capability to reliably provide balancing reserve capacity to support all foreseeable future increases in the size of the wind fleet in BPA's balancing authority area. Mainzer *et al.*, BP-12-E-BPA-42, at 17. Staff states that there is enough uncertainty about the ability to reliably provide capacity from the FCRPS that BPA needs to establish a rate construct that can enable purchases and cost recovery of additional balancing reserve capacity from non-Federal resources to continue to provide VERBS during the rate period. *Id.* One reason Staff proposes the VERBS Supplemental Service pilot is to explore and develop new processes and systems for purchasing balancing reserve capacity from non-Federal resources, assess available sources of non-Federal balancing reserve capacity in the market, and assess the ability to reliably integrate those resources to provide balancing reserve capacity in the BPA balancing authority area. Mainzer *et al.*, BP-12-E-BPA-23, at 38.

Evaluation of Positions

Customers wishing to acquire VERBS Supplemental Service will be requesting the service a few months prior to taking service, and the assumed duration is three to six months. BPA will not be able to predict if the necessary FCRPS capacity will be available that far in advance. In addition, there is nothing in the record to support the assertion that the FCRPS has the capability to reliably provide additional capacity, above and beyond what BPA has forecast it will have available during this rate period, so as to make additional FCRPS capacity available for VERBS Supplemental Service.

Decision

BPA will not make excess FCRPS capacity available on a month-to-month basis to supplemental balancing service customers.

Issue 3.2.10.6

Whether the proposed VERBS Supplemental Service will degrade VERBS service or increase costs for customers that do not purchase supplemental balancing service.

Parties' Positions

NWG states that it is "at best uninterested in a Supplemental VERBS (at least as currently proposed by BPA) that would 'firm up' the VERBS proposed in Staff's Initial Proposal." Yourkowski and Goggin, BP-12-E-NG-01, at 6. NWG argues that any supplemental balancing

service should not degrade VERBS service or increase costs for customers that do not purchase VERBS Supplemental Service. NWG Br., BP-12-B-NG-01, at 75.

JP06 agrees that VERBS Supplemental Service cannot violate certain principles articulated by BPA in the Initial Proposal, including:

- All costs of procuring additional non-Federal balancing reserve capacity to support supplemental service during this rate period would be directly assigned to the rate for supplemental service;
- The design of such service would need to ensure no costs (including potential stranded costs) are shifted to other customers;
- The design of such service cannot degrade the quality of VERBS for those customers that choose not to purchase the supplemental service.

JP06 Br., BP-12-B-JP06-01, at 9. JP06 argues that “VERBS Supplemental Service offered by BPA must not increase the costs, nor degrade the quality, of VERBS for those customers that choose not to purchase VERBS Supplemental Service. Furthermore, any decision to offer a VERBS Supplemental Service should demonstrate and explain how such service is consistent with these principles.” *Id.*

BPA Staff’s Position

Staff agrees that any VERBS Supplemental Service should not degrade VERBS service or increase costs for customers that do not purchase VERBS Supplemental Service. Mainzer *et al.*, BP-12-E-BPA-23, at 41; Kitchen *et al.*, BP-12-E-BPA-45, at 9-10. Staff proposes that BPA establish an administrative charge in the rate case to defray the cost of establishing a supplemental reserves program. *Id.*

Evaluation of Positions

The VERBS Supplemental Service is a stand-alone rate and does not adjust the base VERBS rate. VERBS Supplemental Service is an on-demand product providing balancing reserves for only those customers that request the service. The VERBS Supplemental Service rate will recover the total cost of providing the service solely from the customer requesting the VERBS Supplemental Service and ensure that the users of VERBS Supplemental Service do not shift costs to customers that do not use such service. Staff proposes to establish an administrative charge to defray the costs of establishing the pilot program. Kitchen *et al.*, BP-12-E-BPA-45, at 10. This administrative charge will be applied to all supplemental reserves supplied to the BPA balancing authority through direct purchase or self-supply. *Id.* at 11. VERBS Supplemental Service will be purchased by BPA for only customers that request it. All costs for VERBS Supplemental Service will be applied to the purchases of the service, including the administrative costs.

Decision

The supplemental balancing service will not degrade VERBS service or increase costs for customers that do not purchase supplemental balancing service.

Issue 3.2.10.7

Whether the formula for supplemental balancing service should include the cost of the reserved firm transmission capacity to the BPA interconnection point, real power losses, and administrative costs.

Parties' Positions

Snohomish argues that BPA has not anticipated additional costs that will be incurred in providing the proposed VERBS Supplemental Service. Snohomish Br., BP-12-B-SN-01, at 22-23. Examples of such costs include the cost of reserving firm transmission capacity to the BPA interconnection point, real power losses, any ancillary services, and administrative overhead required for BPA to implement the service. *Id.* Snohomish argues that neglecting to include such costs in the VERBS Supplemental Service rate will cause cost shifts to BPA's other customers. *Id.* at 23.

SCE agrees that VERBS Supplemental Service should satisfy the principles that Staff lists in the Initial Proposal. Nelson, BP-12-E-SC-01, at 4-5. SCE "supports the creation of VERBS Supplemental Service and believes that subscribers should pay an appropriate formula rate for this service. Because VERBS Supplemental Service would be purchased and paid for by entities that desire the service, without subsidy from others, it should be included in the rates adopted by the Administrator." SCE Br., BP-12-B-SC-01, at 2-3.

BPA Staff's Position

The parties who commented on this issue and Staff have similar opinions as to whether the VERBS Supplemental Service should recover all costs associated with it. Staff proposes to establish an administrative charge to defray the costs of establishing the pilot program. Kitchen *et al.*, BP-12-E-BPA-45, at 11-12. The charge would be applied to all supplemental reserves supplied to the BPA balancing authority through direct purchase or self-supply. *Id.* Revenues received from the administrative charge would be divided and credited to the power and transmission budgets where the costs are incurred.

Staff proposes to charge the administrative charge to customers that self-supply VERBS Supplemental Service because BPA will incur system development costs for VERBS Supplemental Service regardless of whether the supplemental reserve is procured by BPA or provided by a self-supplier. *Id.* at 12. In addition, a self-supplier would not necessarily be restricted from participating in the BPA auction process for supplemental reserves. Staff estimates that it would take about three to four FTE to develop and review the participant agreement and operations planning for VERBS Supplemental Service. *Id.* Staff estimates that, once the program is in place, it would take approximately one FTE to conduct the bid process and establish contracts for the capacity. Staff's proposed administrative charge is \$134 per megawatt per month of supplemental reserves. *Id.* at 12-13.

Evaluation of Positions

In the Initial Proposal, Staff outlines a set of principles that any VERBS Supplemental Service must meet. Mainzer *et al.*, BP-12-E-BPA-23, at 41. These principles include “[a]ll costs of procuring additional non-Federal balancing reserve capacity to support supplemental service during this rate period would be directly assigned to the rate for supplemental service” and “[t]he design of such service would need to ensure no costs (including potential stranded costs) are shifted to other customers.” *Id.* SCE supports the proposed administrative charge. SCE Br., BP-12-B-SC-01, at 2. In addition to administrative charges, Snohomish requests that BPA consider the cost of the reserved firm transmission capacity to the BPA interconnection point, real power losses, and ancillary services. Snohomish Br., BP-12-B-SN-01, at 22-23. No other party comments on Staff’s proposal to assign administrative costs to the VERBS Supplemental Service. Staff’s proposal seeks to capture the administrative costs associated with supplying VERBS Supplemental Service only from the parties choosing to take that service. The cost of transmission will be included in the capacity cost and paid by the supplier. Line losses are part of the on-demand product when the power is delivered. Since supplemental reserves are an on-demand product providing balancing reserves for use of the BPA balancing authority area, there is not an hourly energy schedule that would cause real power losses or any ancillary service costs to support that hourly energy schedule. The supplier will pay whatever costs are necessary for delivery and factor those costs into the capacity price it bids.

Decision

BPA will assign administrative costs to the VERBS Supplemental Service rate. The cost of transmission and firm transmission losses associated with the VERBS Supplemental Service will be included in the cost of the service.

Issue 3.2.10.8

Whether BPA should align the notice requirements to take supplemental balancing service with the other required balancing service elections.

Parties’ Positions

Snohomish expresses concerns regarding unintended consequences of BPA procuring supplemental balancing capacity through Requests for Proposals with six-month terms while providing the option for customers to purchase Supplemental VERBS for an individual month. Snohomish Br., BP-12-B-SN-01, at 23. Snohomish argues that BPA can avoid incurring stranded costs by aligning its notice provisions for VERBS Supplemental Service with its other Balancing Service Elections. *Id.*

BPA Staff’s Position

Under the VERBS Supplemental Service proposal, BPA would buy supplemental reserves for only monthly quantities of reserves that a buyer has committed to purchase. Kitchen *et al.*, BP-12-E-BPA-45, at 11. The business practice will require the buyer to state a quantity at a

maximum price by month for the purchase period. *Id.* at 13-14. BPA will then match buyers and sellers. If there is not a match between buyers and sellers, then there will be no supplemental reserves purchased.

Evaluation of Positions

Staff has designed VERBS Supplemental Service with an eye toward ensuring there are no stranded costs. Snohomish's concerns expressed here are based on an incorrect assumption as to how the VERBS Supplemental Service acquisition process will be run. BPA will be purchasing supplemental balancing reserves only as requested by VERBS Supplemental Service customers.

Decision

BPA will not align the notice requirements to take supplemental balancing service with the other required balancing service elections.

Issue 3.2.10.9

Whether BPA should adopt a different procurement methodology, such as an interruptible export to provide additional inc balancing reserves, and work with customers to identify balancing capacity resources that address the unique balancing needs of extreme wind events.

Parties' Positions

Iberdrola argues that Staff's proposed method for procuring balancing capacity resources for VERBS Supplemental Service is flawed. Iberdrola Br., BP-12-B-IR-01, at 28-29. Iberdrola claims that the type of balancing reserve product required above the 99.5 percent level is a fundamentally different type of product from what Bonneville currently holds to provide the 99.5 percent base level service. *Id.* at 28. Iberdrola suggests that BPA should consider a process to obtain proposals for a balancing capacity product that could be used to manage extreme wind events but which would not require a capacity-based payment. *Id.* Iberdrola and NWG both argue that BPA should consider a transaction with a counter-party for a large interruptible export to provide additional *inc* balancing reserves in lieu of a VERBS Supplemental Service capacity product. *Id.*; NWG Br., BP-12-B-NG-01, at 25.

BPA Staff's Position

BPA is currently exploring different ways of meeting its balancing reserve capacity needs. In prioritizing those needs for FY 2012–2013, BPA has committed itself to a Committed Intra-Hour Pilot as the best means of reducing the need for balancing capacity. Mainzer *et al.*, BP-12-E-BPA-23, at 45; Simpson *et al.*, BP-12-E-BPA-46, at 1-14. In addition, BPA plans to offer a pilot program for Supplemental Reserve service using on-demand resources to minimize the number of DSO 216 cuts that a wind generator would face. Kitchen *et al.*, BP-12-E-BPA-45, at 1-16.

Evaluation of Positions

BPA continues to explore new methods by which it can procure balancing capacity resources. BPA's efforts under the Committed Intra-Hour Pilot and the proposed VERBS Supplemental Service are designed to help BPA analyze methods that would allow BPA to reduce the amount of balancing reserves supplied by the FCRPS. NWG and Iberdrola's suggestions are premature for this rate period. The knowledge gained from these efforts will allow BPA to examine the ability to use on-demand resources to augment or replace some portion of the balancing reserve capacity BPA currently provides from the FCRPS.

Decision

BPA does not adopt a different procurement methodology in this rate proceeding, but may reevaluate its procurement methodology for VERBS Supplemental Service in the future.

3.3 Balancing Reserve Capacity Quantity Forecast Methodology

3.3.1 Introduction

The balancing reserve capacity quantity forecast estimates the amount of reserves that BPA needs to provide within-hour balancing services during the rate period. Generation Inputs Study, BP-12-FS-BPA-05, at 3. BPA must maintain load-resource balance within the hour to preserve system reliability and comply with reliability standards. *Id.* Power Services designates FCRPS generating resources under AGC to provide the generation inputs necessary to supply within-hour balancing services. *Id.* at 5. If load increases, or generation decreases, the AGC system increases (*inc*) generation. *Id.* at 4. If load decreases, or generation increases, the AGC system decreases (*dec*) generation. *Id.* The cumulative amounts of *inc* and *dec* generation required to maintain load-resource balance is the basis for quantifying the reserves for within-hour balancing services. *Id.*

BPA's balancing reserve capacity requirement consists of three components: regulating reserve, following reserve, and imbalance reserve. *Id.* at 5. For purposes of the reserve forecast, regulating reserve compensates for moment-to-moment differences between generation and load. *Id.* Following reserve compensates for larger differences occurring over longer periods of time during the hour. *Id.* The imbalance component compensates for differences between the generator's schedule and the generation during an hour (*i.e.*, imbalance). *Id.* The imbalance component differs from Generation Imbalance or Energy Imbalance.

Staff has developed a methodology to forecast the quantity of balancing reserve capacity necessary to provide within-hour balancing services during the rate period. *See* Puyleart *et al.*, BP-12-E-BPA-24, at 6. That methodology was litigated extensively in the WP-10 proceeding and discussed at length in the WP-10 ROD. WP-10 ROD, WP-10-A-02, at 263-299. For this proceeding, Staff proposes to change the methodology adopted in WP-10 to constrain the sum of regulation, following, and imbalance to the maximum *inc* and *dec* as calculated from the net station control error signal. Puyleart *et al.*, BP-12-E-BPA-24, at 7, 25-27; Puyleart *et al.*, BP-12-E-BPA-43, at 9-10. No party objects to Staff's proposed change, and NWG explicitly supports

the modification. NWG Br., BP-12-B-NG-01, at 73. As a result, BPA is adopting this change without further discussion. This leaves one contested issue regarding the balancing reserve capacity quantity forecast, which is discussed below.

3.3.2 Balancing Reserve Capacity Quantity Forecast Methodology Issue

Issue 3.3.2.1

Whether Staff's methodology for forecasting the total balancing reserve capacity requirement for the rate period is reasonable.

Parties' Positions

NWG maintains that Staff's method for forecasting balancing reserve capacity requirements is overly conservative and results in higher costs than reasonable, because Staff uses the maximum reserve value to establish the reserve requirement for a particular day of the study period. NWG Br., BP-12-B-NG-01, at 14.

PPC states that Staff's forecast of the balancing reserve capacity requirement is reasonable. PPC Br., BP-12-B-PP-01, at 4-5.

BPA Staff's Position

Staff supports its method for forecasting the balancing reserve capacity requirements. Staff does not use maximum reserve requirement values to forecast the total reserve requirement. Puyleart *et al.*, BP-12-E-BPA-43, at 11-12.

Evaluation of Positions

NWG's discussion of the use of maximum values to establish the reserve requirements for a particular day of the study period appears to be the result of confusion that Staff addresses in rebuttal testimony. NWG Br., BP-12-B-NG-01, at 14; Puyleart *et al.*, BP-12-E-BPA-43, at 11-12. Staff does not use maximum reserve requirement values to forecast the total reserve requirement. Puyleart *et al.*, BP-12-E-BPA-43, at 11-12. Staff uses maximum reserve requirement values to allocate the total reserve requirement. *Id.* Staff filed errata to its direct testimony regarding this topic to address the confusion. Puyleart *et al.*, BP-12-E-BPA-24-E01, at 1-3. The errata appears to address NWG's concern.

NWG makes other suggestions for improving BPA's method of forecasting balancing reserve capacity requirements, such as incorporating wind generation forecasts and developing rates with the expectation of more dynamically dispatching resources in response to wind generating patterns. NWG Br., BP-12-B-NG-01, at 14, 22. These issues are addressed in section 3.2.6 of this ROD but provide no basis to conclude that Staff's methodology is unreasonable. Indeed, despite its general criticism of the forecast resulting from the methodology as being overly conservative, NWG supports the specific results of the methodology when it comes to forecasting the reduction in balancing reserve capacity requirements associated with committed intra-hour scheduling. NWG Br., BP-12-B-NG-01, at 14; *see also* Kirby and Castille, BP-12-E-

NG-02, at 5-6 (stating that the incremental standard deviation methodology appears to correctly account for the lack of perfect correlation between categories). PPC agrees that Staff's forecast is a reasonable estimate of the balancing reserve capacity needed to reliably operate the system during the rate period. PPC Br., BP-12-B-PP-01, at 4-5.

Decision

BPA's methodology for forecasting the total balancing reserve capacity requirement for the rate period is reasonable.

3.4 Balancing Reserve Capacity Cost Allocation Methodology

3.4.1 Introduction

The purpose of the cost allocation methodology is to assign certain power costs from Power Services to Transmission Services consistent with BPA's statutory authority and the principle of cost causation. Many products provided by Transmission Services require generation to supply both power and capacity. This generation is referred to as generation inputs, and these inputs are necessary for most of the ancillary and control area services that Transmission Services provides under its OATT. In general, the cost allocation of generation inputs in this rate case involves the following: (1) a forecast of the necessary amount of generation inputs, energy and/or capacity; (2) an assignment of embedded costs associated with the generation system that is used to provide the generation inputs; (3) an assignment of variable costs, which captures the losses of efficiency and value of megawatts that is the result of having the system standing ready to, and actually deploying, generation inputs, and; (4) a direct assignment of two categories of costs to the VERBS rate, the costs of the Wind Integration Team and the *dec* Acquisition Pilot costs.

3.4.2 Embedded Cost Issues

Issue 3.4.2.1

Whether BPA should use the sum of both inc and dec reserve amounts as the allocator in the embedded cost methodology; or, in the alternative, use the higher of either inc or dec.

Parties' Positions

WPAG argues that BPA should allocate the embedded costs of the Big 10 hydro projects to both *inc* and *dec* components of the balancing services. WPAG Br., BP-12-B-WG-01, at 20-22.

WPAG argues that the suggestion to allocate embedded costs to both *inc* and *dec* components of the balancing services is rooted in the principle of cost causation. *Id.* at 20. According to WPAG, *dec* reserves require BPA to actually engage generating capacity at the top of each hour so that BPA can reduce its generation to facilitate increasing wind generation output during the hour. *Id.* at 20. WPAG argues that BPA's allocation of embedded costs to *incs* only does not reflect the fact that at the top of each hour BPA needs sufficient machine capacity to provide the full range of *incs* and *decs*, not *incs* only. *Id.* at 21.

JP01 argues that by not allocating any embedded costs of capacity to provide *dec* reserves, BPA is failing to require contribution for use of its capacity in excess of that amount needed to provide *inc* reserves. JP01, BP-12-B-JP01-01, at 30. JP01 disagrees with PPC that BPA should use the sum of *incs* and *decs* because, JP01 argues, to do that would not be equitable because it is not comparable to the way BPA charges load for capacity. *Id.* at 31. JP01 states that using the higher of either *inc* or *dec* would be a reasonable compromise that is consistent with Staff's position in WP-10 and is more consistent with cost causation than failing to recover any of the embedded costs for VERBS use of *dec* reserves. JP01 points to Staff's testimony in WP-10 where Staff stated that *dec* reserves put more strain on the system and are harder to produce or procure than *inc* reserves and that BPA might consider allocating embedded costs on the higher of the amount of *inc* or *dec* within-hour balancing reserves. While not providing a specific recommendation, JP01 states that "the VERBS rate should make *some* contribution to help defray the fixed costs." *Id.* (emphasis in original).

PPC also proposes that BPA use the sum of *incs* and *decs* in the allocation of embedded costs but states that, in the alternative, BPA should use the larger of the *inc* or *dec* reserve amounts to allocate the embedded costs. PPC Br., BP-12-B-PP-01, at 9-10. PPC states that using the *inc* reserve amount alone in the calculation misallocates the costs among the balancing reserve capacity-based services and that BPA's proposed methodology under-allocates a significant revenue requirement to Regulation and Frequency Response, VERBS, and DERBS. *Id.* at 12.

NWG argues that BPA should reject WPAG's and PPC's proposals because they are contrary to BPA's past rate policy, would require evidence not in the administrative record, and would result in rates that are excessive and not just and reasonable. NWG Br., BP-12-B-NG-01, at 50.

BPA Staff's Position

BPA Staff proposes to use the *inc* amount in the embedded cost allocation for balancing reserve capacity-based services. BPA has historically used the *inc* reserve quantity in allocating embedded costs in the 2002, 2007, 2007 Supplemental and 2010 rate proceedings. Klippstein *et al.*, BP-12-E-BPA-44, at 6. Using the *inc* reserve quantity as an allocator captures the proportionate share of capacity used to serve load and to provide balancing reserve services. Using the *inc* quantity is consistent with the treatment of other capacity uses in the calculation, such as Operating Reserves, which is only an *inc* use of reserves. Documentation, BP-12-FS-BPA-05A, Tables 3.1, 3.4, 3.6, and 4.9. Finally, *inc* and *dec* reserve amounts are taken into account in calculating the 120-hour capacity amount, which is used to allocate embedded costs. Klippstein *et al.*, BP-12-E-BPA-44, at 6-7; Klippstein *et al.*, BP-12-E-BPA-25, at 5-16.

Evaluation of Positions

BPA has consistently used the same embedded cost methodology for assigning costs to balancing reserve capacity services in the past four rate proceedings, and BPA is reluctant to depart from that approach in this proceeding unless the record clearly demonstrates that new facts justify a change. PPC points out that variable generation was added in the last rate case as a recipient of a balancing reserve capacity allocation and that its increasing share of reserves calls for a change in past practices. PPC Br., BP-12-B-PP-01, at 10. BPA agrees that changed

circumstances will sometimes justify departing from past practices, but BPA does not agree, as PPC claims, that the record in this proceeding demonstrates that “circumstances have overtaken past practices.” *Id.* at 11. JP01 does not have a specific recommendation as to how to calculate the contribution the VERBS rate should make toward the fixed costs of supplying dec reserves, although JP01 does suggest the “higher of” approach would be a reasonable compromise.

BPA does not believe there is a need for a compromise on this issue at this time. Staff’s testimony lays out the rationale for using the *inc* amount in the embedded cost allocation. The *inc* reserve quantity used as an allocator for the embedded costs captures the proportionate share of the capacity used to serve load and the capacity used to provide balancing reserve capacity services. Klippstein *et al.*, BP-12-E-BPA-44, at 7; Klippstein *et al.*, BP-12-E-BPA-25, at 5-16. Using the *inc* reserve quantity as an allocator captures the proportionate share of FCRPS costs to serve load and provide balancing reserves.

PPC disagrees with BPA’s proposed embedded cost methodology using only the *inc* balancing reserve amount as the allocator because PPC says it under-allocates a significant revenue requirement to balancing reserve capacity-based services. BPA’s use of the *inc* reserve quantity as an allocator captures the proportionate share of FCRPS costs to serve load and provide balancing reserves. Documentation, BP-12-FS-BPA-05A, Tables 3.1, 3.4, and 3.6; Klippstein *et al.*, BP-12-E-BPA-44, at 6-7; Klippstein *et al.*, BP-12-E-BPA-25, at 5-16. The allocation captures the relative use of the Big 10 hydro projects and does not under-allocate the revenue requirement.

Operating reserves are an input in the embedded cost allocation methodology, and by definition Operating Reserves are only *inc* reserves. Klippstein *et al.*, BP-12-E-BPA-44, at 7; Klippstein *et al.*, BP-12-E-BPA-25, at 5-16. The use of *incs* as a measurement for all capacity services provides a consistent basis for determining the unit cost of reserve capacity.

Using only the *inc* values for the balancing reserve capacity quantities in the embedded cost allocation calculation is consistent with the measurement metric for the other capacity uses in the calculation. Documentation, BP-12-FS-BPA-05A, Tables 3.1, 3.4, and 3.6. The use of *incs* as a measurement for all capacity services provides a consistent basis for determining the unit cost of reserve capacity. Klippstein *et al.*, BP-12-E-BPA-44, at 7. Since both *inc* and *dec* balancing reserve capacity are taken into account to calculate the 120-hour peaking capacity, that measurement is constrained by the amount of either *inc* or *dec* reserves needed for ancillary and control area services. *Id.*

Decision

BPA will continue to use only the inc reserve amounts as the allocator in the embedded cost methodology.

Issue 3.4.2.2

Whether BPA’s methodologies reflect the different values of the different capacity services.

Parties' Positions

NWG argues that under BPA's methodology all capacity reserves are valued at the same rate, and at the same rate as energy producing capacity. NWG Br., BP-12-B-NG-01, at 13. NWG states that, on average, most of the country provides following reserves at 80 percent less cost than regulation and imbalance reserves at 90 percent less cost than regulation. *Id.* NWG claims BPA's methodology requires all customers to pay the same proportional share of the net revenue requirements even though BPA provides different balancing services under the capacity rate. *Id.* Consequently, NWG claims, BPA's methodology does not reflect the different costs associated with providing lower-value spinning and non-spinning reserves in lieu of regulation. *Id.* at 13-14. NWG also argues that if the balancing services rate was reduced to reflect the lower cost in providing spinning and non-spinning reserves in lieu of regulation, the VERBS rate would be less than half of the rate in Staff's Initial Proposal. *Id.* at 14.

BPA Staff's Position

Staff states that BPA's methodology captures the different costs of the balancing components. Staff states in response to this issue in rebuttal testimony that:

First, the balancing reserve capacity quantity forecast captures the different values of the different services by forecasting the reserve need of each service. Second, the variable cost methodology includes assumptions for the amount of spinning and non-spinning capacity needed to provide the different components of balancing reserve capacity, and thus these differences in costs are reflected in the rates for the various services.

Klippstein *et al.*, BP-12-E-BPA-44, at 8 (internal citations omitted).

Evaluation of Positions

First, NWG argues that BPA fails to differentiate between categories of capacity reserves - regulation, following, and imbalance - in terms of value. NWG Br., BP-12-B-NG-01, at 13. Consequently, NWG maintains, BPA's capacity reserves are priced higher than the same reserves in other parts of the country. *Id.*

NWG overlooks the ways that the different values for capacity are accounted for in BPA's forecasting and pricing methodologies. The balancing reserve capacity quantity forecast reflects the different values of the different balancing reserve capacity-based services. Klippstein *et al.*, BP-12-E-BPA-44, at 8. Each service has different proportions of regulating, following, and imbalance components. For example, for the Regulation and Frequency Response rate, the balancing reserve capacity quantity forecast assigns the entire forecast quantity to the regulating component. Documentation, BP-12-FS-BPA-05A, Table 2.8. In comparison, for the VERBS rate, the balancing reserve capacity quantity forecast assigns about five percent of the amount to the regulating component, about one quarter of the amount to the following component, and about two-thirds of the amount to the imbalance component. *Id.* at Table 2.9.

In addition, the balancing reserve capacity-based service rates are set on a combination of the embedded, variable, and in some cases direct assignment costs. Klippstein *et al.*, BP-12-E-

BPA-25. The variable cost methodology recognizes the difference in value for the spinning and non-spinning components for balancing reserve capacity. The regulating component of balancing reserve is calculated as 100 percent spinning, and the following component of balancing reserve is calculated as 50 percent spinning and 50 percent non-spinning. The imbalance reserve component of balancing reserve is calculated as 100 percent non-spinning. Generation Inputs Study, BP-12-FS-BPA-05, at 52-53; Klippstein *et al.*, BP-12-E-BPA-25, at 29-30. These differences in value through the spinning and non-spinning assumptions in the GARD model are applied to both the stand-ready and deployment categories of variable cost.

NWG's claim that lower reserve capacity prices in other parts of the country demonstrate the impact of BPA's alleged failure to distinguish types of reserve capacity also does not tell the whole story. NWG Br., BP-12-B-NG-01, at 13. The discussion of Issue 3.2.3.4 addresses this issue in detail, but, in summary, NWG's is not an apples-to-apples comparison given the organized markets in other parts of the country and the apparent exclusion of certain costs from NWG's analysis.

Decision

BPA's methodologies accurately reflect the different values of the different capacity services.

Issue 3.4.2.3

Whether BPA should use instantaneous peaking capacity value, rather than the 120-hour peaking capacity, to allocate costs to the VERBS rate.

Parties' Positions

MSR argues that the use of the FCRPS 120-hour peaking capability makes little sense as the proxy for the operational costs being recovered in the VERBS rate. MSR Br., BP-12-B-MS-01, at 8. MSR argues that using the 120-hour peaking capability results in a complete disconnect between the rate and the actual cost and availability of the system. *Id.* MSR suggests that BPA use an analysis of operations and the ability of the system to respond instantaneously within-hour in determining costs. *Id.* at 8-9. MSR states that the 120-hour peaking capacity approach is an energy calculation and not a reserve calculation. MSR Br. Ex., BP-12-R-MS-01, at 8. MSR states that the demands on the FBS have increased, as have the number of megawatts of wind integrated into the BPA system, and that it is time to reexamine the use of the 120-hour peaking allocator to determine if it is a reliable and appropriate measure. *Id.* MSR concludes by urging the Administrator to consider this in future rate workshops. *Id.*

PPC states that BPA should retain the 120-hour peaking capacity measurement for allocating embedded costs. Baker *et al.*, BP-12-E-PP-04, at 8. PPC states that the FCRPS does not operate at its instantaneous peak capability, and that VERBS must be provided in approximately 99.5 percent of the hours in the year, not for only a single hour. *Id.* PPC points out that this issue was addressed in the WP-10 ROD, and there BPA found that the 120-hour peaking capacity is an appropriate metric for the purpose of allocating the embedded cost of the Big 10

hydro projects. *Id.* at 9. PPC states that since circumstances have not changed, there is no rationale for changing the decision made in the previous proceeding.

BPA Staff's Position

The 120-hour peaking capability more accurately captures the FCRPS's ability to meet hydro capacity obligations than other quantifications. Klippstein *et al.*, BP-12-E-BPA-44, at 3. Using instantaneous hydro capacity of the Big 10 hydro facilities would not provide a feasible representation of the hydro capacity available to serve load obligations. *Id.* at 2. The 120-hour peaking capability is the same embedded cost method used in the WP-02, WP-07, and WP-10 rate proposals.

Evaluation of Positions

BPA has used the 120-hour peaking capacity as the allocator for embedded cost in a number of previous proceedings, and BPA is reluctant to depart from that practice in this proceeding without a clear demonstration of facts that warrant a change. BPA's rationale for using the 120-hour peaking capacity as the allocator for embedded cost in the balancing reserve capacity-based services is stated by Staff :

The measurement of 120-hour capacity represents the ability of the FCRPS to meet its capacity obligations while meeting the physical characteristics and limits placed on modeled Columbia River Basin projects, including hard project constraints, project outages, balancing reserve capacity requirements, one-percent efficiency restrictions, and non-power constraints, such as flood control and fish operations pursuant to the Biological Opinions.

Klippstein *et al.*, BP-12-E-BPA-25, at 8.

The 120-hour peaking capacity as an allocator balances the requirement of the FCRPS to serve loads and to provide balancing reserves. The use of the instantaneous hydro capability of the Big 10 hydro facilities would not provide a feasible representation of the hydro capacity available to serve load obligations. Klippstein *et al.*, BP-12-E-BPA-44, at 2. The measurement of instantaneous capacity is based on the ability of the FCRPS to generate over an extremely short period of time. *Id.* Loads must be served throughout the hour, and the instantaneous peak would not be sustainable through the hour, so using that value would misrepresent BPA's obligation to serve load. In addition, using instantaneous capacity would not take into account the monthly physical characteristics of projects or the power and non-power constraints imposed on the FCRPS.

BPA believes that the rationale for using the 120-hour peaking capacity as an allocator remains sound. BPA acknowledges that as more wind comes onto the system there may be a need to consider whether the use of 120-hour peaking capacity as an allocator for costs to VERBS continues to be appropriate, but MSR has not articulated any new rationale or facts to support changing the decision made in the WP-10 proceeding.

Decision

BPA will continue to use the 120-hour peaking capability to allocate system costs to the embedded cost component of the VERBS rate.

Issue 3.4.2.4

Whether section 7(g) of the Northwest Power Act prohibits the allocation to the ACS rates of fish and wildlife costs associated with the Big 10 hydro projects.

Parties' Positions

Both Iberdrola and Northwest Wind Group argue that section 7(g) of the Northwest Power Act prohibits BPA from allocating fish and wildlife costs to the VERBS rate because the VERBS rate is not a power rate. NWG Br., BP-12-B-NG-01, at 48-50; Iberdrola, BP-12-B-IR-01, at 27-28. Both parties point out that in the WP-10 ROD, BPA stated that the wind balancing rate is a transmission rate, not a power rate. NWG Br., BP-12-B-NG-01, at 48, *citing* WP-10-A-02; Iberdrola, BP-12-B-IR-01, at 27, *citing* WP-10-A-02. NWG goes on to calculate that removing the fish and wildlife costs reduces the VERBS rate by 31 percent. NWG Br., BP-12-B-NG-01, at 49.

In its brief on exceptions, NWG argues that the conclusion that the Transmission System Act precludes application of section 7(g) of the Northwest Power Act is erroneous as a matter of law, because the Transmission System Act does not govern the allocation of costs and benefits. NWG Br. Ex., BP-12-R-NG-01, at 11. NWG claims that the Transmission System Act does not require the Administrator to use any particular method of allocating the costs and benefits of producing and transmitting electrical power, and that it deals with cost recovery, not allocation of costs and benefits. *Id.* at 12. NWG also argues that the Draft ROD does not cite any provisions of the Transmission System Act that require allocation of costs and benefits, much less a provision that conflicts with the express directives of section 7(g). NWG concludes by claiming that BPA's conclusion that the Transmission System Act precludes application of section 7(g) would mean that section 7(g) was a nullity at the time that Congress enacted it. *Id.*

Iberdrola argues that BPA is interpreting the term "equitably allocate to power rates" in section 7(g) of the Northwest Power Act as meaning "equitably allocate to power and transmission rates." Iberdrola Br. Ex., BP-12-R-IR-01, at 13. Iberdrola further argues that BPA is reversing "its past decisions and historical fish and wildlife cost treatment to lay the foundation for future discriminatory and unlawful cost allocations." Iberdrola Br. Ex., BP-12-R-IR-01, at 14-15. Iberdrola claims that "Bonneville is looking to create an alternative path to allocate its fish and wildlife costs to wind generators in anticipation that its Final ROD on Environmental Redispatch and Negative Pricing will be found unlawful." *Id.* at 14.

BPA Staff's Position

This is a legal issue; however, Staff states that fish and wildlife costs are one of the four components that make up the revenue requirement for the embedded cost methodology. In the

Initial Proposal, Staff proposes to allocate 91 percent of the fish and wildlife costs to the Big 10 hydro projects because the Big 10 hydro projects comprise 91 percent of the hydro system. The fish and wildlife costs represent actual costs associated with the operation of the Big 10 hydro projects. Staff has included the fish and wildlife cost associated with the Big 10 projects in ACS rates ever since these services were unbundled in the FY 2002 rate proceeding. The rationale for including these costs is that these costs are associated with the operation of the projects used to provide the balancing reserve capacity used to provide ACS.

Evaluation of Positions

In the WP-10 rate proceeding NWG pointed out that BPA provides a credit to the power rates of its public power utility customers for both BPA's secondary energy marketing revenues and the variable and embedded cost components of the wind balancing rate. NWG Br., WP-10-B-NG-01, at 21. NWG argued that BPA should credit the Wind Balancing Service rate with secondary sales revenues as well under these circumstances, because wind generators pay a significant portion of the embedded costs of the Big 10 resources. In the WP-10 ROD, BPA stated that section 7(g) of the Northwest Power Act specifically requires that secondary sales revenues be equitably allocated to power rates, and that the Wind Balancing Service is not a power rate so there was no reason for BPA to revisit the decision not to credit the Wind Balancing Service with secondary sales revenues. WP-10 ROD, WP-10-A-02, at 308. NWG and Iberdrola now argue that, because section 7(g) states that fish and wildlife costs are to be allocated to power rates, and because BPA decided in the WP-10 rate proceeding that the VERBS rate is not a power rate, it therefore is inappropriate to allocate fish and wildlife costs to the VERBS rate. NWG Br., BP-12-B-NG-01, at 48-50; Iberdrola, BP-12-B-IR-01, at 27-28. Iberdrola argues that BPA's decision in this proceeding departs from the historical treatment of fish and wildlife costs and that the "true intent" behind this alleged change is to create an alternative path to allocate these costs to wind generators in anticipation that BPA's Environmental Redispatch and Negative Pricing Policy will be found unlawful. *Id.* at 14.

As a preliminary matter, Iberdrola's allegation that Bonneville is reversing "its past decisions and historical fish and wildlife cost treatment" in this rate case is simply factually inaccurate. Iberdrola Br. Ex., BP-12-R-IR-01, at 14-15. BPA has allocated a portion of fish and wildlife costs to balancing reserve capacity based services since 2002. *See DeClerck et al.*, WP-02-E-BPA-26, at 13. Moreover, Iberdrola's allegation that "Bonneville is looking to create an alternative path to allocate its fish and wildlife costs to wind generators in anticipation that its Final ROD on Environmental Redispatch and Negative Pricing will be found unlawful" is unfounded. *Id.* at 14. Staff proposed to include the fish and wildlife allocation to the VERBS rate in the Initial Proposal in this rate case, which was well before the Environmental Redispatch Draft ROD was released. *See generally* Generation Inputs Study, BP-12-E-BPA-05, issued November 2010; Environmental Redispatch Draft ROD, issued May 13, 2011. BPA is allocating fish and wildlife costs in this proceeding in the same manner it has since 2002. *See DeClerck et al.*, WP-02-E-BPA-26, at 13; Bermejo *et al.*, WP-07-E-BPA-20, at 19.

NWG's and Iberdrola's interpretation of section 7(g) would suggest that a legitimate cost of providing capacity cannot be assigned to the users of that capacity. Their interpretation is contrary to ratemaking principles, ignores the historical changes in treatment of capacity services

by BPA and the industry as a whole, and ignores the clear language of the statutes governing BPA's ratemaking authority. Capacity from the FCRPS supports maintaining a reliable and efficient transmission system. As BPA has moved to unbundle the costs of providing power and transmission to its customers, the extent of the demand for reserves for ancillary services has been exposed, as have the costs of providing them. As discussed below, Congress has given BPA the discretion to allocate costs so as to meet BPA's statutory obligation to establish rates that ensure total cost recovery.

Section 7(g) does not modify the Administrator's responsibility to allocate costs in accordance with other provisions of law. Section 7(g) states:

Except to the extent that the allocation of costs and benefits is governed by provisions of law in effect on December 5, 1980, or by other provisions of this section, the Administrator shall equitably allocate to power rates, in accordance with generally acceptable ratemaking principles and the provisions of this chapter, all costs and benefits not otherwise allocated under this section, including, but not limited to, conservation, fish and wildlife measures, uncontrollable events, reserves, the excess costs of experimental resources acquired under [16 U.S.C. 839d], the cost of credits granted pursuant to [16 U.S.C. 839d], operating services, and the sale of or inability to sell excess electric power.

16 U.S.C. § 839e(g)(2006). The Transmission System Act was a provision of law that was in effect on December 5, 1980, and the above-cited language of section 7(g) of the Northwest Power Act makes it clear that, in passing the Northwest Power Act, Congress did not intend to supersede BPA's ratemaking authority under the Transmission System Act. Indeed, section 7(a)(i) of the Northwest Power Act provides that power and transmission rates shall be established in accordance with the Northwest Power Act, sections 9 and 10 of the Transmission System Act, and section 5 of the Flood Control Act of 1944. 16 U.S.C § 839e(a)(1)(2006).

Prior to the passage of the Northwest Power Act, BPA's statutory rate directives were very general and cursory. The Northwest Power Act added detailed allocation provisions when it came to certain categories of costs, but not for other costs, such as fish and wildlife costs. Congress ensured that the provisions of law in effect before the passage of the Northwest Power Act, such as the Transmission Act, was not displaced by section 7(g). Under the Transmission System Act, the Administrator has always had the authority to develop transmission rates to recover the costs associated with maintaining the stability and reliability of the transmission system, which includes allocating costs. NWG's argument fails to recognize the Administrator's ability to allocate costs under statutes that were in effect prior to the Northwest Power Act.

At the time the Northwest Power Act was passed, ACS rates were not unbundled, and the capacity that is used to balance generation was not defined or recognized as a transmission service or rate. While the laws of physics have always required that some generation capacity be used to support the variations of load and generation on an interconnected power system, the industry had not yet attempted to define this capacity as a separate ancillary service associated with transmission service when Congress passed the Northwest Power Act in 1980. ACS services and rates were unbundled and separately identified by the Commission as transmission

services in 1996 as part of Order No. 888. BPA did not have separate ACS rates until 2002. At the time the Northwest Power Act was passed, the generation capacity used to support transmission could have been seen as either a transmission or power service.

Section 9 of the Transmission System Act states in part that the Administrator's rates for the sale of power "and transmission of non-federal electric power over the Federal transmission system" shall be established:

1) with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles, (2) *having regard to the recovery (upon the basis of the application of such rate schedules to the capacity of the electric facilities of the projects) of the cost of producing and transmitting such electric power, including the amortization of the capital investment allocated to power over a reasonable period of years and payments provided for in section 838i(b)(9) of this title....*

16 U.S.C. § 838(g)(2006) (emphasis added). This language clearly authorizes transmission rates to be set to recover all costs attendant to the transmission of power. The fact that ACS rates are now defined as transmission rates does not change the nature of the service that is being provided, the source of that service, or the logic for assigning a small portion of the fish and wildlife costs to the ACS rates. The ACS rates at issue are capacity-based services that are necessary to maintain the reliability and stability of the transmission system. The balancing reserve capacity used to provide these services is produced as both *inc* and *dec* reserves from the Big 10 hydro projects, and the fish and wildlife cost that is assigned to these ACS rates is directly related to the operation of the Big 10 projects. Assigning fish and wildlife costs to all uses of the Big 10 project capacity is consistent with the fact that the transmission system cannot be operated without the support provided by the hydro system, and the hydro system must be operated consistent with BPA's environmental obligations and authorities, which are directly related to the fish and wildlife costs.

NWG maintains that interpreting section 9 of the Transmission System Act to allow allocation of a portion of fish and wildlife costs to ACS rates is improper because it renders section 7(g) of the Northwest Power Act a nullity. NWG Br. Ex., BP-12-R-NG-01 at 14. NWG argues that "[i]f BPA is now concluding that Section 9 of the Transmission System Act renders Section 7(g) a nullity, then it is effectively overruling its prior decision in WP-10 regarding the application of Section 7(g) to secondary revenues." *Id.* In the WP-10 proceeding, BPA did summarily conclude that since Wind Balancing Service is not a power rate, there was no need for BPA to revisit the issue of crediting Wind Balancing Service with secondary sales revenues. The evaluation did not consider the factual and statutory arguments and factors that have now been more fully and, BPA believes, correctly addressed in this ROD. While BPA believes the WP-10 conclusion not to credit the rates with secondary sales revenues was appropriate, given the context of basing Wind Balancing Service rates on average water, BPA does not believe it is appropriate to rely on section 7(g) as an absolute bar, given the appropriate facts, to assigning some portion of the fish and wildlife costs to ACS rates. Power customers have a take or pay obligation through their contracts that VERBS customers do not. In the WP-10 ROD the Administrator stated, "[w]hat NWG fails to recognize is that this treatment of secondary

revenues is consistent with the responsibility of power requirements customers to pay BPA's power costs. These customers are like the native load of a public utility. Given their responsibility to pay BPA power costs, they enjoy the credits from the secondary sales that BPA is able to make." WP-10 ROD, WP-10-A-02, at 308.

NWG's and Iberdrola's argument would preclude not only the allocation of fish and wildlife costs, but also the allocation of costs and benefits of the other items specifically listed in section 7(g). This would lead to cost shifts that would be inconsistent with the direction in section 7(g) that allocations be made "in accordance with generally acceptable ratemaking principles." 16 U.S.C. § 839e(g). For example, section 7(g) lists the costs of uncontrollable events as a cost to be equitably allocated to power rates. NWG's reading of section 7(g) would mean that all the costs associated with an uncontrollable event, such as an earthquake that destroyed transmission lines, must be allocated only to power rates. Such a cost shift would be inconsistent with sound ratemaking. As stated in Sub-Issue 3.2.5.1.5., BPA is respecting the exception in section 7(g) by allocating a portion of the fish and wildlife costs to transmission rates.

Section 7(a)(1) of the Northwest Power Act supports BPA's assignment of fish and wildlife costs to the ACS rates. Section 7(a)(1) expressly states that rates must be established as appropriate to recover, in accordance with sound business principles, the cost associated with, among other things, transmission of electric power. Also, as indicated earlier, section 7(a)(1) also states that such rates be established consistent with sections 9 and 10 of the Transmission System Act. By including the language "[e]xcept to the extent that the allocation of costs and benefits is governed by provisions of law in effect on December 5, 1980 ..." in section 7(g) of the Northwest Power Act, Congress sought to preserve existing ratemaking requirements.

As previously mentioned, since 2002 BPA has allocated an amount of fish and wildlife costs to the costs associated with providing balancing reserve capacity-based services. In the WP-02 rate case, Staff described the rationale for including fish and wildlife costs in the embedded cost for regulating reserve.

BPA's fish and wildlife costs result directly from production of real power at the FCRPS hydro facilities that provide regulating reserve to meet BPA Control Area obligations. Fish and wildlife programs are necessary to protect, mitigate, and enhance fish and wildlife affected by the development and operation of the FCRPS hydro projects. This approach is consistent with other utilities' FERC filings, where environmental compliance costs have been included in the embedded cost of regulating reserves. The "Big 10" share based on capacity (89 percent) is allocated to the cost of providing regulation service.

DeClerck *et al.*, WP-02-E-BPA-26, at 13; Bermejo *et al.*, WP-07-E-BPA-20, at 19. Since the WP-02 rates were established, BPA has continued to include fish and wildlife costs in the embedded cost revenue requirement used to assign costs to ACS rates. This is consistent with Congress's direction that the costs of providing transmission should be recovered in transmission rates, which include ancillary services costs. Because the provision of ancillary and control area services relies on the Big 10 projects, the fish and wildlife costs which result directly from the

production of real power and capacity at those projects are appropriately allocated to the embedded costs of the system. Therefore, a portion of such costs is assigned to the ACS rates.

NWG's and Iberdrola's argument—that based on the determination in WP-10 that the Wind Balancing Service rate is not a power rate, it is inappropriate for BPA to allocate fish and wildlife costs to the VERBS rate—misinterprets the statutory language of section 7(g) of Northwest Power Act. Section 7(g) states that “the Administrator shall equitably allocate to power rates ... all costs and benefits not otherwise allocated under this section[.]” 16 U.S.C. § 839e(g). NWG argues that BPA's conclusion that the term “equitably allocate” in section 7(g) of the Northwest Power Act does not mean “only allocate.” is erroneous. NWG Br. Ex., BP-12-R-NG-01, at 15. NWG argues that BPA does not give effect to the language “all costs and benefits.” *Id.* at 16. Similarly, Iberdrola argues that BPA is interpreting “equitably allocate to power rates” to mean “equitably allocate to power and transmission rates.” Iberdrola Br. Ex., BP-12-R-IR-01, at 13. Both NWG's and Iberdrola's interpretations ignore the plain meaning of the statute and fail to read the Northwest Power Act in conjunction with other provisions of law that govern BPA's ratemaking authority. The word “equitably” implies fairness and impartiality, whereas “only” implies no more and no less. If Congress intended for section 7(g) to require BPA to allocate fish and wildlife only to power rates, Congress would not have included the words “equitably allocate” and “in accordance with generally accepted ratemaking principles.” Accordingly, under the plain meaning of the statute, any fish and wildlife costs allocated to power rates need only consist of an equitable proportion of BPA's overall fish and wildlife costs incurred due to the generation of power by the FCRPS, not the entire proportion.

An example of this rationale was provided at oral argument:

MR. ROACH: Stay with the Fish and Wildlife costs for a second. Let's assume that Bonneville builds a transmission line that crosses a stream or a river, and in the process of it, a piling displaces some spawning ground and as a consequence Bonneville incurs costs to restore that, say, upstream, downstream. Is it your position that that is not a transmission cost?

MR. HALL: I don't know. I haven't thought about it.

Hall, Oral Tr. at 190. Logically, this example can be expanded to the Big 10 capacity that is used to provide ACS to transmission customers. As explained above, since the Transmission System Act directs the Administrator to set transmission rates and recover the cost of producing and transmitting such electric power, the Transmission System Act supports assigning ACS rates the portion of fish and wildlife costs associated with producing the capacity used by transmission customers.

NWG further argues that section 9 of the Transmission Act and section 7(a) of the Northwest Power Act govern only “recovery” of costs, while section 7(g) of the Northwest Power Act governs “allocation of costs and benefits.” NWG, BP-12-R-NG-01 at 13. NWG ignores the fact that in addition to BPA's authority to equitably allocate costs under section 7(g), BPA is directed, pursuant to section 10 of the Transmission System Act and section 7(a)(C) of the Northwest Power Act to equitably allocate the costs of the Federal transmission system between Federal and non-Federal power using the system. 16 U.S.C. § 838h; 16 U.S.C. § 839e(a)(2)(C).

Since ancillary and control area services are a use of transmission, and fish and wildlife is a cost of ancillary and control area services that are necessary to support the stability and reliability of the transmission system, then it is equitable to allocate ancillary and control area services costs to these uses, and thus to the ACS rates. This best ensures total cost recovery consistent with sound business principles. These statutory provisions further reinforce BPA's authority to equitably allocate a small portion of fish and wildlife costs to ACS rates, independent of section 7(g) of the Northwest Power Act.

The legislative history of the Northwest Power Act also supports BPA's interpretation of section 7(g). In passing the Act, Congress intended to ensure that BPA had the authority to recover all the costs of the system, including fish and wildlife costs. S. Rep. No. 96-272 at 32 (1979). The House Commerce Committee's Section-by-Section analysis on the Act states that section 7(g) "accommodates the need to allocate across all rates those costs that cannot be allocated to particular rates to meet the requirement of section 7(a). BPA's obligation and that of the customers is to ensure that all costs are recovered". H.R. Rep No 96-976, pt. I, at 69 (1979). This is consistent with the Committee's earlier statement that one of the purposes of the Act "is that the BPA customers and the consumers of those customers will continue to pay all the costs necessary to produce, transmit, and conserve resources to meet the region's electric power requirements. These costs include those related to fish and wildlife." *Id.* at 4.

Balancing reserve capacity from the FCRPS supports maintaining a reliable and efficient transmission system. Congress has given BPA the discretion to equitably allocate costs, which is an absolute necessity considering that one of the overriding statutory requirements for BPA is to establish rates that ensure total cost recovery. The Big 10 hydro projects provide the generation capacity for most of the ancillary services for BPA's customers, and fish and wildlife costs are real costs to those hydro projects. Therefore, it is appropriate, pursuant to BPA's governing statutes and principles of cost causation, for a small portion of those fish and wildlife costs to be allocated to the ACS rates as BPA has done since 2002.

Decision

Section 7(g) of the Northwest Power Act does not prohibit BPA from assigning fish and wildlife costs associated with the Big 10 hydro projects to ACS rates.

Issue 3.4.2.5

Whether BPA should use average or critical water in the methodology used to assign costs to the VERBS rate.

Parties' Positions

WPAG argues that BPA should calculate the VERBS rate using a critical water assumption rather than an average water assumption. WPAG Br., BP-12-B-WG-01, at 14-16. WPAG states that all other firm power rates are established using critical water, and Staff offers no compelling reason to depart from this standard. *Id.* at 14. WPAG also argues that use of average water gives

VERBS customers better treatment in the area of secondary revenues than BPA is proposing for preference customers. *Id.* WPAG objects to Staff’s proposal to use median water to calculate the secondary revenue credit for preference customers while using average water to calculate the secondary revenue credit for VERBS. *Id.* at 14-16. WPAG disagrees with BPA’s draft decision in the Draft ROD to use average water and reasserts its alternative argument that BPA should instead use median water to calculate ACS rates. WPAG Br. Ex., BP-12-R-WG-01, at 22. WPAG argues that if BPA is going to use median water to calculate the secondary revenue credit for power rates, it should likewise use median water to calculate ACS rates. *Id.* at 23. WPAG points out that BPA is moving from a mean or average water assumption to a more conservative median water assumption because hydro volumes in recent years have been below average, and the change is needed to address management’s tolerance for the risk that actual net secondary revenue used to calculate the PF Tier 1 Rate could be less than the forecast amount. *Id.* They state that the same rationale for moving to the median water assumption for power rates is applicable to the ACS rates.

NWG disagrees with WPAG and argues that use of critical water would improperly add costs to the VERBS cost allocation and the use of average water is appropriate. NWG Br., BP-12-B-NG-01, at 51-52. In addition, NWG points out that WPAG’s argument is contrary to BPA’s conclusion in the WP-10 ROD that using average water is a better representation of the peaking capability of the FCRPS than critical water for purposes of allocating costs to generation inputs. *Id.* NWG states that critical water does not account for significant non-firm uses of the Big 10 hydro facilities in allocating embedded costs under BPA’s 120-hour peaking capacity methodology. *Id.*

BPA Staff’s Position

Using average water spreads the cost of the system across the expected uses of the system. Klippstein *et al.*, BP-12-E-BPA-44, at 11. Using average water recognizes that the 120-hour capacity could be higher or lower over the 70 water conditions of record, which is an unbiased estimate. *Id.* In addition, using average water is consistent with BPA’s decision in the WP-10 ROD to use average water in the embedded cost calculation. *Id.*

Evaluation of Positions

BPA found in the WP-10 ROD that average water provides a better representation of the system’s average sustained peaking capability than critical water. WP-10 ROD, WP-10-A-02, at 311. Using average water recognizes that the 120-hour capacity could be higher or lower over the 70 water conditions of record, which is an unbiased estimate. Average water recognizes all uses of the system that vary by month and water condition over the study period. Using critical water, as WPAG suggests, would not capture the peaking capability of the FCRPS in the way that the use of average water does. In addition, BPA continues to be confident that the use of average water accounts for the non-firm uses of the Big 10 hydro facilities more accurately than the use of critical water.

BPA is using an average water assumption in the embedded cost allocation methodology for balancing reserve capacity-based ASC. This “average water assumption” does not use the

average of 70 water years, but rather a single water year chosen to be representative of normal, *i.e.*, non-extreme, water conditions. BPA selected the 1958 water year to represent “average water” since it is the year that most closely approximates annual average generation. Because the distribution of generation across water years is fairly symmetrical, the 1958 water year most closely matches both mean and median annual generation. This assumption has water as the only variable.

By contrast, the net secondary revenue credit for power rates is determined by selecting the median of a distribution of 3,500 games that include variability around gas and electricity prices and various risk factors including load variability, Columbia Generating Station (CGS) output, transmission availability, wind generation, and others. This calculation makes no use of median water; each of the 70 water years appears 50 different times in the distribution of 3,500 revenue outcomes.

Both calculations employ the concept of “median” but do so very differently. The embedded cost calculation uses a single water year to represent normality of a single variable, hydro generation; the credit for net secondary revenue uses a statistic—the median—calculated from a 3,500-game distribution that is generated from a great many different variables.

Decision

BPA will continue to use average water to assign costs to the VERBS rate, since in the Generation Inputs Methodology median water and average water are the same.

Issue 3.4.2.6

Whether Residential Exchange Program (REP) costs should be included in the revenue requirements for ACS rates.

Parties’ Positions

WPAG argues that REP costs should be allocated to ACS rates, whether established pursuant to the 2012 REP Settlement or pursuant to BPA’s authority under section 7(b)(3) of the Northwest Power Act. WPAG Br., BP-12-B-WG-01, at 16-19. WPAG argues that if the users of generation inputs seek the full benefits of the Federal system, they should also pay their share of the costs of the Federal system, which include the REP costs. *Id.* at 16-18. WPAG cites section 3.3.3 of the 2012 REP Settlement and states it clearly anticipates collecting a portion of the Settlement costs from other rates, such as the VERBS rate. *Id.* at 17.

BPA Staff’s Position

The balancing reserve capacity cost allocation methodology in the Initial Proposal is based on the principle of cost causation: those entities causing the costs should bear the responsibility for paying those costs. Klippstein *et al.*, BP-12-E-BPA-25, at 2. The embedded cost methodology is based on a defined portion of the power revenue requirement associated with the generation

resources that are used to provide the reserve services. *Id.* at 3. Staff does not propose to include REP costs in the embedded cost methodology.

Evaluation of Positions

An argument can be made that BPA could include several power costs, including REP costs and costs associated with nuclear power debt, in the revenue requirement for VERBS and other ACS rates. However, Staff has consistently assigned only those costs that are directly associated with the projects used to provide the ACS capacity.

The language in the 2012 REP Settlement BPA is adopting in the REP-12 proceeding permits BPA to collect a portion of the costs of the REP from one or more rates. This language, however, does nothing more than recognize BPA's current authority to set rates to recover BPA's costs consistent with section 7 of the Northwest Power Act. Nothing in section 3.3.3 of the Settlement commits BPA to making a finding in this rate proceeding that any of the rates BPA is developing in this case must be allocated a portion of the costs of the REP. Whether costs of the REP should be allocated to VERBS or any other rate necessarily depends on the type of rate at issue and whether such rate is required to be assigned costs of the REP. VERBS and the ACS services provided by BPA are transmission-related costs that BPA assigns to BPA transmission to recover in transmission rates. As such, the VERBS and ACS services are not the type of rates that would normally be assigned costs of the REP under section 7(b). Thus, BPA's decision not to assign costs of the REP to the VERBS rate or other ACS rates is both consistent with section 7 of the Northwest Power Act and BPA's obligations under the 2012 REP Settlement.

Decision

BPA will not allocate the REP costs to VERBS or other Ancillary and Control Area Services.

Issue 3.4.2.7

Whether the VERBS rate should contain a marginal capacity cost price signal.

Parties' Positions

WPAG argues that setting the VERBS rate at the marginal rate of capacity will address the perceived inequity between the treatment of BPA's preference customers, which pay the demand charge at the marginal capacity rate, and the VER customers, which receive balancing capacity under the VERBS rate at the lower cost of the Federal system capacity. WPAG Br., BP-12-B-WG-01, at 8-9. WPAG argues that using marginal cost would send a price signal to VERBS customers to alert them of the impending loss of Federal system capacity for VERBS service and the likely costs of the non-Federal resources that BPA will need to acquire to provide VERBS. *Id.* at 9.

BPA Staff's Position

It is inappropriate to set the VERBS rate at the marginal rate of capacity that will be adopted for the PF Tier 1 Rate for each rate period. Mainzer *et al.*, BP-12-E-BPA-42, at 32. Marginal capacity resources should be allocated to generation inputs only if BPA is forecasting that balancing reserves capacity will be acquired from such resources during the upcoming rate period. *Id.* The appropriate price signal will be sent through the proposed VERBS Formula Rates. *Id.*

Upon the establishment of a viable capacity market in the Pacific Northwest, BPA may choose to use a forecast of the demand rate in that market to establish the Tier 1 Demand rate. *Id.* Under such circumstances, the Demand rate may be an appropriate cost to use in setting the cost of generation inputs for balancing reserve capacity-based services. *Id.* at 32-33.

Evaluation of Positions

The marginal cost of capacity proposed for the PF Tier 1 Demand rate is based on the marginal capacity resource, including the annual fixed costs of that resource for each rate period. Mainzer *et al.*, BP-12-E-BPA-42, at 32-33. Establishing the Demand rate under BPA's power rates to send a price signal is different from assigning costs to a separate set of customers for generation inputs. *Id.* at 32. Cost causation principles suggest the cost for marginal capacity resources should be used to price generation inputs only if BPA is forecasting that balancing reserves capacity will be acquired from such resources during the upcoming rate period. *Id.* BPA is not forecasting acquisition of reserve capacity from marginal capacity resources in the FY 2012–2013 rate period.

BPA does not agree with WPAG that it is necessary to set the VERBS rate based on the marginal cost of capacity in order to send a price signal about the FCRPS limits in terms of providing balancing reserve capacity and the price associated with acquiring non-Federal balancing reserve capacity. BPA believes that the VERBS Formula Rates proposed in this proceeding appropriately signal the limits of the FCRPS and BPA's intent with respect to recovery of the costs of acquiring non-Federal capacity. ROD section 3.5.3 includes a detailed discussion of the Formula Rate.

Finally, many parties have mentioned that the longer-term solutions for acquiring balancing reserve capacity from resources other than FCRPS lie in the development of capacity markets. If a viable capacity market is developed in the Pacific Northwest, BPA may consider redesigning VERBS using either the Tier 1 Demand rate or some other methodology, provided the rate is based on a forecast of market prices from the viable Pacific Northwest capacity market.

Decision

The VERBS rate will not contain a marginal capacity cost price signal.

Issue 3.4.2.8

Whether the balancing reserve capacity used to provide VERBS comes from the idle or unused system capacity.

Parties' Positions

NWG argues in its testimony that balancing reserve capacity used to provide VERBS comes from idle or unused system capacity because Staff adds in the reserve amounts to (rather than subtracting them from) the energy-producing capacity. Kirby and Castille, BP-12-E-NG-02, at 10-11 (discussing Documentation Table 3.6). NWG argues that since the “capacity is not being used, there is no opportunity cost to BPA. Because there is no opportunity cost to BPA, it is unreasonable for BPA to charge the full embedded cost.” *Id.* at 11. NWG did not address this issue in its initial brief.

PPC disagrees with NWG’s argument. PPC argues that BPA forgoes sales in order to provide balancing reserve capacity products to variable generation and other customers. PPC Br., BP-12-B-PP-01, at 9.

BPA Staff’s Position

Staff disagrees with NWG’s assertion that the wind balancing reserve capacity used to provide VERBS comes from the idle or unused system capacity. Klippstein *et al.*, BP-12-E-BPA-44, at 13. NWG is mischaracterizing the Study, and the calculation in Documentation, BP-12-FS-BPA-05A, Table 3.6, discussed by NWG is a function of needing to add the reserve amounts to the 120-hour-peaking capacity because the reserve amounts were taken out as a system use in the process of calculating the 120-hour peaking capacity. Klippstein *et al.*, BP-12-E-BPA-44, at 13.

Evaluation of Positions

Table 3.6 of the Documentation depicts the detail of the hydro studies’ output and shows all the uses of capacity. Documentation, BP-12-FS-BPA-05A, Table 3.6. Since the balancing and operating reserve amounts were factored into the HYDSIM and HOSS models as a reduction to produce the 120-hour peaking capacity, they must be added to the 120-hour peaking capacity amount in order to represent all uses of capacity. The breakout in the table by balancing reserve type is necessary to show the cost allocation for each type of service (regulating reserve, operating reserve, VERBS, and DERBS). BPA’s ability to sell energy is reduced by the obligation to provide balancing reserve capacity-based services.

Decision

The balancing reserve capacity used to provide VERBS does not come from the idle or unused system capacity.

3.4.3 Direct Assignment Cost Issues

Issue 3.4.3.1

Whether it is appropriate to directly assign the Wind Integration Team (WIT) costs to the VERBS rate.

Parties' Positions

NWG argues that it is inappropriate to directly assign the costs of the WIT to the VERBS rate, because preference customers benefit from the WIT. NWG Br., BP-12-B-NG-01, at 45-46. NWG argues that the WIT contributes to the continued reliable operation of the FCRPS at the lowest cost consistent with sound business principles and that preference customers also purchase renewable energy and are likely to purchase more renewable energy in the future. *Id.* at 46. NWG states that the direct assignment of WIT costs to the VERBS rate is not consistent with cost causation; NWG recommends that WIT costs be included in the general revenue requirement. *Id.*

Iberdrola argues that though Staff says directly assigning the WIT costs to VERBS is consistent with the principle of cost causation, Staff also explains that many of the activities of the WIT benefit all users of the FCRPS. Iberdrola Br., BP-12-B-IR-01, at 26-27. Iberdrola adds that many of the WIT initiatives are activities that BPA should be undertaking as part of its overall move toward more efficient and cost-effective market structures for the benefit of all system users. *Id.* at 27. In addition, Iberdrola argues that since Staff does not propose to directly assign other team costs to other rates, it is discriminatory toward VERs to directly assign the WIT costs to VERBS. *Id.*; Iberdrola Br Ex., BP-12-R-IR-01, at 18. Iberdrola further argues that BPA's "but for wind" argument is irrelevant if other team costs are not directly assigned to the rates of customers to which they are purportedly linked. Iberdrola Br Ex., BP-12-R-IR-01, at 18.

PPC supports assigning the WIT costs to the VERBS rate because the need for the WIT is driven by the continued interconnection of wind generation onto BPA's system, and because preference customers do not measurably benefit from the WIT. PPC Br., BP-12-B-PP-01, at 17. PPC disagrees with Iberdrola that the direct assignment is discriminatory, and points to Staff testimony that BPA has directly assigned costs of teams such as the WIT in past rate proceedings when it was warranted. *Id.* PPC disagrees with NWG that preference customers receive a benefit from WIT projects, stating that preference customers do not receive a benefit from programs that reduce the amount of balancing reserve capacity needed for wind generation since preference customers are entitled to capacity when it is needed to meet their requirements load. *Id.*

BPA Staff's Position

Staff proposes directly assigning the cost of the WIT to the VERBS rate. Without the continued interconnection of wind generation onto BPA's system there would be no need for the WIT. Mainzer *et al.*, BP-12-E-BPA-23, at 4-5; Klippstein *et al.*, BP-12-E-BPA-44, at 14-15. Staff

does not agree with Iberdrola that the direct assignment of WIT costs to VERBS is discriminatory. Klippstein *et al.*, BP-12-E-BPA-44, at 14-15.

Evaluation of Positions

Assessing the nature and beneficiaries of the WIT costs requires some examination of the purposes of the WIT itself. The WIT originated in the settlement that resolved the WI-09 rate proceeding, and parties agreed in that settlement to address a variety of issues associated with the increasing use of balancing reserve capacity by the significant amounts of wind generation integrated into BPA's balancing authority area. The purpose of the WIT is to explore technical solutions to address the challenge of balancing loads and resources, and to preserve system reliability while at the same time accommodating the rapid development of wind energy in BPA's balancing authority area. Klippstein *et al.*, BP-12-E-BPA-44, at 14-15. NWG and Iberdrola do not seem to dispute the origin or purpose of the WIT but only that the benefits of the WIT initiatives accrue to customers other than wind generators, and thus the costs should be allocated to those beneficiaries.

The cost of the WIT is the direct result of continued wind interconnection, and principles of cost causation dictate that the customers that cause a cost should bear the responsibility of paying that cost. The continued requests to interconnect wind generation on BPA's transmission system mean that the work of the WIT continues to be an important tool to help BPA manage challenges associated with integrating that wind generation. The WIT helps BPA to clearly define and execute initiatives that support integrating wind generation in a manner that allows for the continued highly reliable operation of the FCRPS at the lowest cost consistent with sound business and operations practices.

NWG's and Iberdrola's argument that the WIT benefits all customers and therefore it is inappropriate to directly assign the cost of the WIT overlooks the fact that without the interconnection of wind onto BPA's system, the WIT would be unnecessary in the first place. Directly assigning the WIT costs to the VERBS rate is not unduly discriminatory because, but for wind interconnection onto BPA's system, the WIT would not exist. In addition, wind generators receive the economic benefit of WIT projects, which reduce the balancing reserve capacity forecast for wind generation. Iberdrola's allegation that BPA's "but for wind" argument is irrelevant because BPA does not directly assign any other team costs is erroneous. First, BPA has directly assigned certain costs in the past. (*See* WP-02 ROD, WP-02-A-09, Attachment 8-A-3, where BPA allocated all the initial implementation costs of the Slice product service to the Slice Revenue Requirement.) The record in this proceeding includes no evidence to demonstrate that there are other teams similar to the WIT, which works on initiatives prompted by the growth of wind generators on BPA's system, or that the costs of any such team are spread across all rates.

Second, BPA is required by statute to recover its costs, and the Administrator has discretion as to how those costs are recovered pursuant to certain statutory limitations and ratemaking principles. The fact that BPA directly assigns the WIT team costs to only the VERBS rate does not render irrelevant the fact that, without the interconnection of wind, the WIT would be unnecessary. BPA must recover the costs of the WIT incurred through its work to reliably integrate wind

generation into the FCRPS. It would be contrary to sound ratemaking principles to pass the costs of integrating wind to any customers other than those that are causing those costs.

Decision

It is appropriate that BPA directly assigns the WIT costs to the VERBS rate.

Issue 3.4.3.2

Whether it is appropriate for BPA to apply the Green Energy Premiums (GEPs) to offset Power's portion of the WIT costs.

Parties' Positions

JP02 argues that BPA should assign Power Services' costs of the WIT to the VERBS rate instead of applying the GEPs to offset Power's portion of the WIT costs. JP-02 Br., BP-12-B-JP02-01, at 19-21. JP02 argues that the issue of whether or not the GEPs should be used to pay a portion of the costs of the WIT is a rate case issue because it is a decision about the allocation of costs and benefits that is governed by the Northwest Power Act. *Id.*

NWG supports applying the GEP revenues from past rate periods to offset Power's portion of the WIT costs for this rate period. NWG Br., BP-12-B-NG-01, at 47-48.

BPA Staff's Position

Staff proposes that GEPs should be used to pay for Power Services' share of the WIT costs. In the IPR Final Close-Out Report BPA stated that BPA will honor its commitment in WP-07 and WP-10 to reinvest the unspent GEP revenues earned during these two rate periods in Renewable R&D projects. Klippstein *et al.*, BP-12-E-BPA-44, at 16; Mainzer *et al.*, BP-12-E-BPA-23, at 48.

Evaluation of Positions

GEPs are the revenues associated with the sale of Renewable Energy Certificates and Environmental Attributes associated with Environmentally Preferred Power (Subscription customers), and Alternative Renewable Energy (Pre-Subscription customers). In WP-07 and again in the May 2008 IPR (for the FY 2010–2011 rate period), BPA committed to reinvest GEPs in renewable research, development and/or demonstration (RD&D). The May 2008 long-term Regional Dialogue ROD gave BPA the ability to revisit this reinvestment commitment for 2012 and beyond. BPA is proposing to use the GEPs to, among other things, offset Power's portion of the WIT costs, which otherwise would have been funded by Tier 1 rates or eliminated in cost-cutting exercises. *See* IPR Renewable Follow-up Session, Green Energy Premiums, June 10, 2010, at 2. The use of GEP revenues to offset Power's portion of the WIT costs is not a rate case issue, because the decision was made in the IPR Final Close-Out Report. 2010 IPR Final Close-Out Report, at 40-41. The Federal Register notice for the BP-12 rate case states that

issues involving decisions made in the IRP Final Close-Out Report are outside the scope of the rate proceeding. 75 Fed. Reg. 70744, 70745-70746 (2010).

Decision

BPA will use the GEPs to offset Power Services' portion of the WIT costs.

Issue 3.4.3.3

Whether it is appropriate for BPA to directly assign to the VERBS rate \$4 million per year in costs of the dec Acquisition Pilot program, which is designated for system upgrades and the purchase of non-Federal decs.

Parties' Positions

Of the \$4 million per year costs for the *dec* Acquisition Pilot, NWG opposes directly assigning to the VERBS rate \$1 million per year for system upgrades because, NWG argues, the system upgrades from the *dec* Acquisition Pilot program will benefit all customers. NWG Br., BP-12-B-NG-01, at 46-47. NWG does not oppose the direct assignment to the VERBS rate of \$3 million for the purchase of non-Federal *decs*.

Iberdrola argues that the *dec* Acquisition Pilot program as proposed lacks transparency regarding the terms and conditions of BPA's procurement process in purchasing *decs* for the pilot, and this lack of transparency gives BPA a "blank check" with which to purchase *decs*. Iberdrola Br., BP-12-B-IR-01, at 27.

PPC supports the proposed direct assignment of the costs of the *dec* Acquisition Pilot. PPC Br., BP-12-B-PP-01, at 18-19.

BPA Staff's Position

Directly assigning the cost of the system upgrades to the *dec* Acquisition Pilot program is warranted based on cost causation. The pilot will facilitate the purchase of non-Federal *decs* necessary to accommodate the continued integration of wind generation. Klippstein *et al.*, BP-12-E-BPA-44, at 18. If it were not for the continued integration of wind onto BPA's system, the *dec* Acquisition Pilot project would not be necessary. *Id.* Staff also proposes the direct assignment of \$3 million to the VERBS rate for the purchase of non-Federal *decs*. *Id.* at 16-17.

Evaluation of Positions

The evaluation of Issue 3.4.3.1 reflects BPA's perspective generally on the direct assignment of costs associated with various wind initiatives. NWG opposes directly assigning to the VERBS rate the \$1 million per year for system upgrades because the upgrades will benefit all customers. NWG Br., BP-12-B-NG-01, at 46-48. NWG ignores the fact that the system upgrades for the purchase of non-Federal *decs* are the direct result of continued wind interconnection. BPA would not be pursuing the upgrades but for the increased demand for balancing reserve capacity

(and resulting need to purchase non-Federal *decs*) due to increasing amounts of wind generation. Principles of cost causation dictate that the customers that cause a cost should bear the responsibility of paying that cost. NWG is focusing on the \$1 million per year for system upgrades because that has a VERBS rate impact. NWG understands that the \$3 million per year for the *dec* purchases is offset by a \$3 million per year reduction in the variable costs for VERBS, so there is no VERBS rate impact.

There is little merit in Iberdrola's assertion that the *dec* Acquisition Pilot gives BPA a blank check. The concern that there is a danger of BPA having a "blank check" with which to purchase *decs* is unwarranted. The amount allocated to the *dec* pilot for the purchase of *decs* is \$3 million per year, and this amount represents the limit for purchasing *decs* under the pilot. BPA has no incentive or interest in purchasing additional amounts of reserves it has not budgeted for and does not need. However, BPA has an important interest in developing the infrastructure for, and gaining the experience of, augmenting the FCRPS to provide balancing reserve capacity. Therefore it is appropriate to directly assign the *dec* Acquisition Pilot costs to the VERBS rate, following the principle of cost causation. Klippstein *et al.*, BP-12-E-BPA-44, at 17-18.

Decision

BPA will directly assign \$4 million per year in costs of the dec Acquisition Pilot program to the VERBS rate.

Issue 3.4.3.4

Whether BPA should assume that the cost of a dec purchased in the dec Acquisition Pilot program will be equal to the variable cost of a megawatt of FCRPS dec reserve.

Parties' Positions

PPC disagrees with Staff's proposal to credit the cost of the acquired *dec* reserves against the variable cost portion of the VERBS rate based on the assumption that the purchase price for each megawatt of *dec* reserve will equal the variable cost of a megawatt of FCRPS *dec* reserve. PPC Br., BP-12-B-PP-01, at 18-19. PPC says BPA should use the actual cost of the purchased *dec* reserve capacity in offsetting the variable costs. *Id.*

BPA Staff's Position

The variable cost of providing a *dec* from the FCRPS is the best proxy for third-party *dec* reserve costs for the *dec* Acquisition Pilot, because reliable third-party cost estimates are not available. Klippstein *et al.*, BP-12-E-BPA-25, at 23. BPA's greatest resource need in the future is acquiring additional sources of balancing reserve capacity. The *dec* Acquisition Pilot will be used in part to expand BPA's understanding of its ability to acquire non-Federal balancing reserve capacity. Mainzer *et al.*, BP-12-E-BPA-23, at 49.

Evaluation of Positions

Staff assumes that *dec* capacity can be purchased at a cost approximately equal to the forecast variable cost of the FCRPS because that is the best price estimate BPA has in the absence of a developed Pacific Northwest balancing reserve capacity market. The *dec* Acquisition Pilot Program will provide beneficial experience and knowledge learned from the deployment of non-FCRPS *decs*, as well as avoided wear-and-tear on the FCRPS. The price risk in the difference between the assumption of the variable cost as a proxy for the *dec* Acquisition Pilot costs and the actual market cost when the *decs* are procured is mitigated by the cap of \$3 million per year on *dec* purchases.

Decision

BPA will assume that the cost of a dec purchased in the dec purchase pilot program will be equal to the variable cost of a megawatt of FCRPS dec reserve.

Issue 3.4.3.5

Whether directly assigning the WIT costs and the purchase of non-Federal decs through the dec Acquisition Pilot program will frustrate the region's ability to meet state and national policy objectives for renewable energy.

Parties' Positions

NWG argues that a number of Staff proposals, including the direct assignment of the WIT costs and the direct assignment of *dec* purchases through the *dec* Acquisition Pilot Program, will burden renewable energy producers with inappropriate and unreasonable charges and discourage additional clean energy projects from being developed in the Pacific Northwest. NWG Br., BP-12-B-NG-01, at 8-9.

BPA Staff's Position

The WIT and the *dec* Acquisition Pilot Program were created to assist BPA in its ability to continue to integrate variable energy resources in the balancing authority at reasonable cost.

BPA assembled an internal cross-agency Wind Integration Team (WIT) to explore technical solutions to address the challenge of balancing loads and resources to preserve system reliability while at the same time accommodating the rapid development of wind energy in the BPA Balancing Authority Area. The mission of the WIT is to clearly define and execute initiatives that support integrating wind generation in a manner that allows for the continued highly reliable operation of the FCRPS at the lowest cost consistent with sound business and operations practices.

Mainzer *et al.*, BP-12-E-BPA-23, at 5.

BPA's WIT has coordinated with regional stakeholders to establish priorities and timetables for a set of specific initiatives designed to address the broader

operational challenges associated with wind integration. These initiatives are designed to make better use of the existing system through improved wind forecasting and more flexible scheduling arrangements, to use dynamic scheduling to transfer some of the wind variability off of the BPA system, and to bring additional resources (especially the region’s thermal generators and demand side resources) into the marketplace for balancing services. Over time, these initiatives are intended to reduce dependence on the FCRPS for balancing reserve capacity-based balancing services and dampen the increase in the wind integration cost curve.

Id. at 5-6.

Evaluation of Positions

The *dec* Acquisition Pilot is an initiative to support the increasing amounts of wind forecast to integrate into the BPA system. The direct assignment of the *dec* Acquisition Pilot costs to the variable energy generators is consistent with the principle of cost causation, because it is the variable energy generators that will receive the benefits of the programs. NWG acknowledges the innovative policies and technical advances BPA has implemented outside the rate case process to accommodate renewable resources on its system. NWG Br., BP-12-B-NG-01, at 8. The list of policies and technical advances that NWG says have contributed to the significant additions of renewable energy generation in the Northwest over the past several years includes the *dec* pilot. *Id.*

Contrary to NWG’s assertion that the costs of these types of programs will frustrate the development of renewable energy, BPA believes that these programs assist in the development of renewable energy in the region. Programs such as the WIT and the *dec* Acquisition Pilot Program are designed to assist BPA with the reliable integration of the rapidly growing amount of renewable resources onto BPA’s system. These types of programs help to ensure the responsible development and the reliable integration of renewable energy in the region.

Decision

The costs of the WIT initiatives and dec Acquisition Pilot costs do not frustrate the region’s ability to meet state and national policy objectives for renewable energy.

3.4.4 Variable Cost Issues

Issue 3.4.4.1

Whether including the inc energy shift costs in the cost of providing VERBS would violate the Commission’s prohibition against “And” pricing.

Parties' Positions

NWG reiterates its arguments on “And” pricing that it made in the WP-10 rate proceeding. NWG argues that many of the variable costs that BPA is seeking to allocate are in fact opportunity costs, which is a violation of the Commission’s prohibition against “And” pricing. NWG states that to avoid imposing excessive and duplicative charges on BPA’s wind generator customers, BPA may charge the higher of its embedded or opportunity costs, but not both. NWG Br., BP-12-B-NG-01, at 54. NWG argues that in the WP-10 case BPA concluded that it was reasonable not to include *inc* energy shift costs in the Wind Balancing Service rate, that the evidentiary record supported not charging the energy shift costs, that such a charge would have been a departure from BPA’s past pricing policies, and that the proposal “has some potential of being cast as a double recovery and in violation of the ‘And’ pricing policy.” *Id.*, citing WP-10 ROD, WP-10-A-02, at 328. NWG points out that “BPA already allocated to the Wind Balancing Service rate (now VERBS rate) a share of embedded costs associated with *inc* reserves, all variable costs associated with *dec* reserves, plus six efficiency loss components associated with *inc* reserves.” NWG Br., BP-12-B-NG-01, at 54. Responding to the request by BPA for more briefing on this issue, NWG further argued that *inc* reserves do not consume fuel (*i.e.*, water). NWG Br. Ex., BP-12-R-NG-01, at 18-19. NWG states that instead the machine capability is in effect being taken out of service for energy sales because it has been committed to providing balancing reserves. *Id.* . NWG argues that regardless of the label BPA puts on these costs, they are “opportunity costs.” *Id.* at 19 NWG further argues that taking units out of service and thereby limiting its ability to make secondary sales is a classic example of opportunity costs. *Id.* at 19-20.

Iberdrola argues that BPA cannot point to anything other than its own statement that it has a strengthened belief that *inc* energy shift costs are not opportunity costs and to charge both would not constitute “And” pricing. Iberdrola Br. Ex., BP-12-R-IR-01 at 19. Iberdrola states that BPA does not have a basis for changing its position on *inc* energy shift costs and it should not do so. *Id.*

PPC also points out that in the WP-10 ROD, BPA found *inc* energy shift costs were not opportunity costs and do not violate FERC’s “And” pricing. PPC Br., BP-12-B-PP-01, at 13. PPC agrees with BPA’s determination in WP-10 that including the *inc* energy shift costs would not violate the Commission’s prohibition against “And” pricing. PPC Br. Ex., BP-12-R-PP-01, at 7-8. PPC states that “[t]he energy shift cost for *inc* reserves is not an opportunity cost and recovering the cost through the VERBS rates is not impermissible as a violation of FERC’s ‘and’ pricing policy.” *Id.* at 7. PPC also argues that the Commission does not have jurisdiction over BPA’s rates so as to apply the “And” pricing test to BPA’s rate methodology. *Id.* In response to NWG’s assertion that BPA has already allocated a number of costs to the VERBS rate, PPC states that the fact that BPA has carefully described, categorized, and quantified its costs is not a reason to exclude a legitimate category of those costs. *Id.*

BPA Staff's Position

This is a legal issue, but Staff does explain that BPA’s legal determination in the WP-10 rate case was that the inclusion of the *inc* energy costs in the VERBS rate would not violate FERC’s

prohibition against “And” pricing. This determination still holds true in this rate proceeding. Klippstein *et al.*, BP-12-E-BPA-44, at 21. Staff continues to have the opinion that the *inc* energy shift cost is not an opportunity cost, and that even if it was an opportunity cost, BPA is not subject to FERC’s “And” pricing policy. *Id.*, citing WP-10 ROD, WP-10-A-02, at 322.

Evaluation of Positions

The Commission’s “And” pricing policy states that it is inappropriate to charge both embedded and opportunity costs. NWG quotes selected portions of the WP-10 ROD to insinuate that the decision not to include energy shift *inc* costs turned on NWG’s argument that charging both embedded cost and variable costs violates the ‘And’ pricing policy. NWG Br., BP-12-B-NG-01, at 54. NWG argued in the WP-10 proceeding that variable costs are analogous to opportunity costs and that the Wind Balancing Service rate should be charged embedded costs or variable costs, not both. NWG Br., WP-10-B-NG-01, at 24-27. BPA explained in the WP-10 ROD on the question of whether variable costs are opportunity costs, “[v]ariable costs are operating costs that measure the efficiency losses and energy shift of providing capacity reserves. These costs are analogous to fuel costs of thermal generators, and they are not opportunity costs as the term is used in the Commission’s “And” pricing policy.” WP-10 ROD, WP-10-A-02, at 324. BPA stated that “[t]he “And” pricing issue in this proceeding turns on whether or not the variable costs are seen as opportunity costs or incremental fuel costs.” *Id.* at 325. BPA stated that:

BPA has justified charging wind generators variable costs as recovering legitimate and identifiable costs and that the calculations of the components of the embedded and variable costs are supported with substantial evidence, including evidence of how each component recovers discrete system costs. BPA agrees that the costs of providing balancing reserves that are recognized in the variable costs are not duplicative of the Generation Imbalance charge, that they are not opportunity costs, and that recovery of the embedded and variable costs is not “And” pricing.

Id. at 328.

In the WP-10 ROD, however, BPA did consider the potential for double recovery and concluded that:

BPA is not subject to the Commission’s “And” pricing policy. In any case, recovering both embedded and variable costs in the Wind Balancing Service rate does not violate “And” pricing policy. However, in the interest of ensuring that BPA’s Wind Balancing Service rate is not overstated, BPA will modify the variable costs in the final studies to include only the variable costs for *dec* reserves and the efficiency losses for *inc* reserves. The energy shift component of the variable cost methodology for *inc* reserves will be removed from this rate, but may be reconsidered in future rates.

WP-10 ROD, WP-10-A-02, at 329.

The WP-10 ROD did rationalize that the energy shift *inc* cost has some potential of being cast as a double recovery and in violation of the ‘And’ pricing policy. *Id.* at 328. This was primarily

based on a combination of arguments raised by Cowlitz and NWG and a compromise suggested by Staff. Staff stated that “the only category of variable costs that could possibly fit NWG’s premise of selling the same MW of generating capacity twice is the *inc* portion of the Energy Shift component of the Stand Ready Costs.” Mainzer *et al.*, WP-10-E-BPA-41, at 27. While Staff continued to believe that the *inc* energy shift cost was not an opportunity cost and would not pose an “And” pricing violation, Staff believed there was room for compromise for that rate period. In the WP-10 ROD BPA stated, “BPA does not believe this component represents an opportunity cost. However, since it is based on the difference between the HLH and LLH pricing, and this component is different from BPA’s pricing in past rate proposals, BPA will remove the *inc* reserve Energy Shift costs from the variable cost pricing proposal in the Final Proposal.” WP-10 ROD, WP-10-A-02, at 327. BPA has used the HLH and LLH pricing methodology since October 2010, and BPA’s experience has strengthened its belief that variable costs are not opportunity costs but rather a form of fuel costs, and that including the *inc* energy shift cost would not violate the Commission’s prohibition against “And” pricing. In addition, BPA agrees with PPC that “[t]he fact that BPA has carefully described, categorized and quantified its costs is not a reason to exclude a legitimate category of those costs.” PPC Br. Ex., BP-12-R-PP-01, at 8. The *inc* energy shift cost is not duplicative, but rather represents one of the costs incurred by the FCRPS as a result of providing the VERBS service. As further discussed in the next issue, BPA has quantified the costs associated of spilling water or shifting generation into LLH time periods in order to provide the VERBS service.

In response to BPA’s statement in the Draft ROD that no party has put anything on the record to refute the determination that these costs are analogous to fuel costs (BP-12-A-01, at 325), NWG responded that “[e]ven if water is considered to be equivalent to gas for purposes of BPA’s analogy, *inc* reserves do not consume fuel (i.e. water).” NWG, Br. Ex., BP-12-R-NG-01 at 19. As is further discussed below, this argument ignores the fact that the water must pass the respective FCRPS projects in a timed fashion in order to meet hydraulic objectives. If the water is not being used to generate during the HLH period and storage is available to hold back until LLH, the water will pass the turbines during the LLH. The alternative is to spill. Either way, the provision of *inc* reserves results in energy being produced during suboptimal periods or water being spilled. The description of how energy is moved in order to make available machine capability is detailed in Klippstein *et al.*, BP-12-E-BPA-25, at 32-35 and BP-12-FS-BPA-05, section 3.4.3.1.

Decision

Inclusion of inc energy shift costs in the cost of providing VERBS does not violate the Commission’s prohibition against “And” pricing.

Issue 3.4.4.2

Whether BPA should include the inc energy shift costs in the costs associated with providing VERBS.

Parties' Positions

In its brief on exceptions, JP01 changes its recommendation to BPA on this issue. In its initial brief, JP01 argued that it is not “appropriate [for BPA] to charge for the full embedded cost of capacity and simultaneously charge for not having that same capacity available for some other use.” JP01 Br., BP-12-B-JP01-01, at 32. JP01 states that VERBS customers paying the full embedded costs will reimburse BPA completely for this *inc* energy shift cost. *Id.* In its brief on exceptions, JP01 reiterates its argument that the embedded costs of providing capacity for *inc* reserves would completely reimburse BPA for the variable energy shift costs. JP01 Br. Ex., BP-12-R-JP-01, at 3. While JP01 state that it would be better for BPA to develop a specific and conceptually sound mechanism to recover the full embedded costs of capacity from the VERBS customers, it acknowledges that at this stage of the proceeding it is not possible for BPA to do so. *Id.* JP01 therefore encourages BPA to adopt the *inc* energy shift costs to offset the revenue lost from BPA’s decision not to recover any of the embedded costs used to provide *dec* reserves to VERBS customers. *Id.* at 3-4.

NWG disagrees with including the *inc* energy shift costs in the variable costs allocated to the VERBS rate. NWG Br., BP-12-B-NG-01, at 54-56. NWG agrees with BPA’s conclusion in the WP-10 ROD that it was “prudent and reasonable” not to include the *inc* energy shift costs in the Wind Balancing Service rate. *Id.* at 54. NWG points out that BPA found that not including the *inc* energy shift cost is prudent and reasonable considering that BPA already allocated to the Wind Balancing Service rate a share of embedded costs associated with the *inc* reserves, all variable cost associated with *dec* reserves, and the six efficiency loss components associated with *inc* reserves. NWG argues that in WP-10 BPA found that “such a charge would have been a departure from BPA’s past pricing policies, and that the proposal ‘has some potential of being cast as a double recovery and in violation of the ‘And’ pricing policy.’” NWG Br., BP-12-B-NG-01, at 54.

NWG argues that including the *inc* energy shift costs would be selling the same service twice because it represents the cost of two incompatible services that BPA cannot perform simultaneously. NWG Br. Ex., BP-12-R-NG-01, at 17. NWG states that when BPA commits resources to provide balancing reserves it forgoes other opportunities, such as the ability to make on-peak energy sales. *Id.* at 18. NWG states that BPA can either commit machine capability to provide balancing reserves and charge embedded costs and appropriate variable costs for such service, or BPA can use the capacity to make energy sales. *Id.* at 18. NWG claims that by adding the *inc* energy shift costs to the VERBS rate BPA would be accomplishing through rates what it says it cannot do in the real world; *i.e.*, providing capacity to one customer and making energy sales to another customer from the same resource at the same time. *Id.*

NWG also argues that the record lacks sufficient evidence to justify adding *inc* energy shift costs to the VERBS rate. NWG claims that any decision to impose *inc* energy shift costs on VERBS customers should take into account the request to credit the VERBS rate with a proportionate share of secondary energy sales and periods in which generation is curtailed due to Environmental Redispatch. *Id.* at 21. NWG points out that BPA has not explained what experience BPA has gained to support its assertion that BPA’s belief that variable costs are not opportunity costs but are rather a form of fuel costs has been strengthened. *Id.* at 21. NWG

claims that BPA is inappropriately shifting the burden of proof to the parties to prove that *inc* energy shift costs are opportunity costs. *Id.* at 22.

WPAG recommends that *inc* energy shift costs be allocated to the capacity-based Ancillary and Control Area rates since these services incur the cost in the first place. WPAG Br., BP-12-B-WG-01, at 19-20. WPAG concurs with what it characterizes as Staff's conclusions that (1) it was reasonable to include these costs in generation inputs rates; (2) *inc* energy shift costs were not opportunity costs; and (3) the Commission's "And" pricing policy does not apply to BPA. WPAG Br., BP-12-B-WG-01, at 19-20. WPAG states that not allocating *inc* energy shift costs to generation inputs rates lowers the secondary energy credit to power rates and transfers a significant portion of capacity reserves costs to the preference customer rate. *Id.* at 19. WPAG argues that the *inc* energy shift costs should be allocated to the VERBS rate. WPAG, Br. Ex., BP-12-R-WG-01, at 18. WPAG states that not allocating the *inc* energy shift costs will shift costs to BPA's power customers. WPAG states that since there does not seem to be any genuine dispute that *inc* energy shift costs are real costs arising from the provision of balancing reserves from the FCRPS, cost causation dictates that BPA include these costs in balancing service rates. *Id.* at 19-20.

PPC states that *inc* energy shift costs should be included in the variable cost calculation. PPC Br., BP-12-B-PP-01, at 12. PPC states that not including *inc* energy shift costs in the price for balancing reserves reduces the value of the secondary energy, the effect of the reduced secondary energy credit is recovered through power rates. *Id.* at 13. PPC argues that including the *inc* energy shift costs would be equitable. PPC Br. Ex., BP-12-R-PP-01, at 8. PPC disagrees with JP01's assertion in its initial brief that the embedded costs of providing capacity for *inc* reserves would completely reimburse BPA for the variable energy shift costs. *Id.* at 8-9. PPC argues that BPA recovers a different cost through this embedded charge that reflects the "capital cost, operations and maintenance cost and other costs particular to the physical structures that compromise the Big 10 hydro units." PPC states that variable costs such as *inc* energy shift costs recover other costs related to the value of water. *Id.* at 9. PPC also argues that the continued increase of variable generation's need for balancing reserves and the limit of the FCRPS to produce those reserves further justifies the inclusion of energy shift costs for *inc* reserves. *Id.* PPC states that BPA has done a creditable job of revealing the costs of the continued integration of wind on the FCRPS system to wind developers and the inclusion of these costs further provides transparency of costs to potential future wind developers. *Id.* at 11. PPC points out that failure to allocate these costs to the VERBS customers and to instead make power customers subsidize this cost would be unjust and unreasonable to BPA's power customers. *Id.*

MSR opposes the inclusion of *inc* energy shift costs for three reasons. MSR Br. Ex., BP-12-R-MS-01, at 8. MSR states that the record is insufficient to support the allocation at this time. MSR states that BPA's decision not to include this cost is sound, and nothing in the docket has changed that analysis. *Id.* MSR states that the impact of including this cost in times of low load or high BPA generation is unclear. *Id.*

BPA Staff's Position

As discussed in Issue 3.4.4.1 above, Staff explains that the two issues decided by BPA in the WP-10 ROD were that *inc* energy shift costs are not opportunity costs and that by including *inc* energy shift costs BPA would not be in violation of the Commission's "And" pricing policy. Klippstein *et al.*, BP-12-E-BPA-44, at 21. Staff states that despite these findings, in the WP-10 ROD BPA decided not to include the *inc* energy shift costs based on the findings that (1) only *inc* energy shift costs could possibly fit NWG's premise of selling the same megawatt of generating capacity twice, and (2) *inc* energy shift, although not an opportunity cost, is different from BPA's pricing in past rate proposals. *Id.* at 20-21. In the WP-10 ROD, BPA stated it would remove the *inc* energy shift cost "in the interest of ensuring that BPA's Wind Balancing Service rate is not overstated." WP-10 ROD, WP-10-A-02, at 329. Staff concludes that the reserves rate would not be overstated if the *inc* energy shift costs was included in the reserves rate. Klippstein *et al.*, BP-12-E-BPA-44, at 21.

Evaluation of Positions

In the WP-10 ROD, BPA stated that "BPA will remove the *inc* reserve Energy Shift costs from the variable cost pricing proposal in the Final Proposal. BPA will make this adjustment in this rate proceeding, but BPA may re-evaluate the need for this cost component in future rate proceedings." WP-10 ROD, WP-10-A-02, at 327. BPA found that the record in WP-10 would have supported including the energy shift *inc* costs in the variable costs, but that it was reasonable not to include those costs given some of the questions raised in that proceeding. *Id.* at 329. The issue of whether BPA should include the *inc* energy shift costs in the costs associated with providing VERBS, including the questions from WP-10, have been thoroughly discussed in the testimony and briefs in this rate proceeding. As explained below, BPA believes that these discussions more clearly define the real cost impacts of the *inc* energy shift and justify including those costs in variable costs.

JP01 argues that the issue is not a question of opportunity costs, but rather whether BPA has an alternative use for the capacity if BPA did not stand ready to provide balancing reserves. JP01 Br., BP-12-B-JP01-01, at 32. JP01 states that the embedded costs of providing capacity for *inc* reserves would completely reimburse BPA for the variable energy shift costs. JP01 Br. Ex., BP-12-R-JP-01, at 3. But, while JP01 still argues that it would be better for BPA to develop a specific and conceptually sound mechanism to recover the full embedded costs of capacity from the VERBS customers, JP01 acknowledges that at this stage of the proceeding it is not possible for BPA to do so. *Id.* at 4. Therefore, JP01 encourages BPA to adopt the *inc* energy shift costs to offset the revenue lost from BPA's decision not to recover any of the embedded costs used to provide *dec* reserves to VERBS customers. *Id.* at 3-4.

NWG points out that BPA found in the WP-10 rate proceeding that not including the *inc* energy shift cost is prudent and reasonable:

considering that BPA already allocated to the Wind Balancing Service rate a share of embedded costs associated with the *inc* reserves, all variable cost associated with *dec* reserves, and the six efficiency loss components associated with *inc* reserves. ... [T]hat such a charge would have been a departure from BPA's past

pricing policies, and that the proposal “has some potential of being cast as a double recovery and in violation of the ‘And’ pricing policy.”

NWG Br., BP-12-B-NG-01, at 54, *quoting* WP-10 ROD, WP-10-A-02, at 328.

NWG claims that Staff disagrees with PPC’s contention that not including the *inc* energy shift creates a cost shift to the power customers. NWG Br., BP-12-B-NG-01, at 55. This is an incorrect statement. The result of not allocating the *inc* energy shift cost to the VERBS rate is that “the secondary energy credit to power rates is lower than if *inc* energy shift costs were assigned to the reserves rate. The reduced value of the secondary energy due to the provision of capacity reserves is recovered through the power rates.” Klippstein *et al.*, BP-12-E-BPA-44, at 22. The *inc* energy shift costs are known and quantifiable; Staff has calculated the *inc* energy shift cost for all generation inputs to be \$8,614,191. *Id.*; Documentation, BP-12-FS-BPA-05A, Table 3.11, lines 2-3.

WPAG and PPC argue that it is appropriate for BPA to include the *inc* energy shift costs in the cost of VERBS because the costs associated with the *inc* energy shift are significant. WPAG Br., BP-12-B-WG-01, at 19; PPC Br., BP-12-B-PP-01, at 12-13. WPAG and PPC argue that including these costs is consistent with the principle of cost causation, and not to include them would be unjust and unreasonable. WPAG Br., BP-12-B-WG-01, at 19-20; PPC Br., BP-12-B-PP-01, at 14.

PPC also argues that the continued increase of variable generation’s need for balancing reserves and the limit of the FCRPS to produce those reserves further justifies the inclusion of energy shift costs for *inc* reserves. PPC Br. Ex., BP-12-R-PP-01 at 9-11. BPA has calculated and quantified the *inc* energy shift cost as the real cost of providing the VERBS service. Principles of cost causation dictate that the customer that causes a cost to the FCRPS should bear those costs, so it is appropriate to allocate the *inc* energy shift cost to the VERBS rate. PPC points out that in the WP-10 Final Record of Decision, BPA found *inc* energy shift costs were not opportunity costs, did not duplicate other costs, and do not violate the Commission’s “And” pricing. *Id.* PPC asserts that the cost causation principle demands including the *inc* energy shift costs in the variable costs, and misallocation of these costs to power customers would be unjust and unreasonable. PPC Br., BP-12-B-PP-01, at 13.

BPA agrees with WPAG and PPC that principles of cost causation suggest that the *inc* energy shift costs should be included in the cost of the VERBS. While the *inc* energy shift costs are quantifiable, the concept of how BPA incurs costs by holding *inc* reserves may not be readily apparent given BPA’s historical circumstance of being long on capacity and short on energy. Traditionally, the machine capability of the FCRPS was rarely a limiting factor in operations planning. Now, with substantial quantities of balancing reserve capacity being provided from the FCRPS, the reservation of machine capability for the provision of *inc* reserves has become a substantial planning and operations factor. From the perspective of BPA hydro operations, reserving machine capability for *inc* reserves is analogous to taking units out of service (unit outages) equal to the quantity of *inc* reserves being held. Combining the large quantity of *inc* reserves with planned and unplanned unit outages, along with the BiOp requirements for generating units to operate within one percent peak efficiency, all adds up to a significant

reduction in FCRPS capability. Consequently, providing *inc* reserves often limits the amount of generation the FCRPS can provide during the daytime or superpeak hours. The generation limitations and the corresponding limitations on the hydro system's flexibility yield considerable cost to BPA in terms of the need to purchase from the market in order to meet peak loads, as well as the cost of operating to a flattened, sub-optimized generation pattern. Typically, absent provision of balancing reserve capacity, BPA would maximize the amount of energy produced and sold during the higher-valued hours.

NWG argues that there is a "lack of any new evidence to support including the *inc* energy shift costs in the VERBS rate" NWG Br. Ex., BP-12-R-NG-01, at 16. NWG's argument focuses only on the result in WP-10 and suggests that new evidence is necessary in this proceeding to justify including energy shift *inc* costs in the VERBS rate. The discussion in the WP-10 ROD and the PPC and WPAG briefs in this proceeding demonstrate that is incorrect. WP-10 ROD, WP-10-A-02, at 328; PPC Br., BP-12-B-PP-01, at 13; WPAG Br. Ex., BP-12-R-WG-01, at 18-19. All of the analysis and evidence in WP-10 showed a variable energy shift cost to providing *inc* capability. Bermejo *et al.*, WP-10-E-BPA-25, at 9-11. The evidence to support the allocation of energy shift costs to the VERBS rate is on the record in both the WP-10 rate proceeding and this rate proceeding. BPA has explained the energy shift impacts associated with providing both *inc* and *dec* capability. Klippstein *et al.*, BP-12-E-BPA-25, at 32-35. Staff stated it is necessary to consider the super-peak and graveyard time blocks; otherwise, the energy shift impact would be understated. *Id.* at 34-35. The refinement in energy shift pricing goes hand-in-hand with the very detailed model refinements made for BP-12. As part of the improved modeling, increased impacts to energy shift were observed, as well as a decrease in total efficiency losses due to the detailed modeling of all unit families. As WPAG points out, there does not seem to be any genuine dispute that *inc* energy shift costs are real costs arising from the provision of balancing reserves from the FCRPS. WPAG Br. Ex., BP-12-R-WG-01, at 19.

NWG also states that "BPA's method for holding reserves is inefficient and leads to an unreasonable VERBS rate, because of BPA's assumption that BPA has machine capability fully committed to providing balancing reserves." NWG Br. Ex., BP-12-R-NG-01, at 17. This is not an assumption; it is an operational fact, barring conditions in which non-power constraints prevent BPA from fully carrying balancing reserves. NWG argues that BPA should dynamically carry reserves as the need dictates using a wind power production forecast. *Id.* at 17. BPA fully addresses NWG's suggestion in Issue 3.2.4.8. In short, NWG's proposal is unlikely to result in the benefits that NWG assumes, because it does not account for the need to plan the hydro system well in advance of the day-ahead or hour-ahead timeframes in which wind power production forecasts may provide value.

NWG states:

By adding *inc* energy shift costs to the VERBS rate, BPA would be accomplishing through rates what it says it cannot do in the real world; i.e., providing capacity to one customer and making energy sales to another customer from the same resources at the same time. Thus if BPA were to include *inc* energy shift costs in the VERBS rate it would be, in effect, selling the same

capacity twice because it would be charging VERBS for an alternative use that is incompatible with the service being provided

NWG Br. Ex., BP-12-R-NG-01, at 18. This argument equates embedded and variable costs with uses of the system. Embedded and variable costs are not uses of the system; rather, they are cost allocation methodologies designed to quantify different costs to the system. Embedded costs refers to the actual depreciated cost of an electrical system, such as the cost of generation facilities used to provide balancing reserve capacity, operation and maintenance costs, and other associated costs. Klippstein *et al.*, BP-12-E-BPA-25, at 3. Variable costs in this context refers to the losses of efficiency and value that occur as the FCRPS is set up to allow balancing reserve capacity to be carried, and the additional losses that occur as the reserves are actually deployed. *Id.* at 24. PPC acknowledges this difference and states that “[r]ecovering one cost does not make up for the failure to recover other costs.” PPC Br. Ex., BP-12-R-PP-01, at 9. NWG’s argument also ignores the fact that hydraulic operations dictate the output of the FCRPS and that the FCRPS is an inter-connected system. Regardless of the desire to produce power and/or make available *inc* capability, hydraulic objectives must be met. The most basic of these objectives is the coordinated release of water through the hydro system. When providing *inc* capability for balancing purposes, there are times when less water can be put through turbines in order to have *inc* capacity ready and available.

NWG quotes Black’s Law Dictionary’s definition of “opportunity costs” as “[t]he cost of acquiring an asset measured by the value of an alternative investment that is forgone <her opportunity cost of \$1,000 in equipment was her consequent inability to invest that money in bonds.” NWG’s quote is only a partial, incomplete definition of opportunity cost. A more complete definition of opportunity cost is “[t]he opportunity cost of some decision is the value of the next best alternative that must be given up because of that decision.” Baumol, William J. and Alan S. Blinder, *Economics: Principles and Policy*. Eighth Edition, Harcourt, 2001. The key words are “next best alternative.” Making energy sales has not been determined to be the next best alternative to providing balancing reserves.

The issue of whether BPA should include the *inc* energy shift costs in the costs associated with providing VERBS has now been more thoroughly discussed in the testimony and briefs in this rate proceeding than it was in the WP-10 proceeding. BPA believes that it has a much better understanding of the real cost impacts of the *inc* energy shift now than it did in the WP-10 rate proceeding. Based on this record and the understanding described above, BPA believes that it is appropriate to include the *inc* energy shift cost in the VERBS rate.

Decision

BPA will include the inc energy shift costs in the costs associated with providing VERBS.

Issue 3.4.4.3

Whether BPA should account for the super-peak and graveyard periods in calculating the energy shift variable cost.

Parties' Positions

NWG argues that BPA is overestimating the energy shift cost allocated to VERBS by using a refinement to the HLH/LLH price spread. NWG Br., BP-12-B-NG-01, at 52. The energy shift costs in the variable cost methodology are calculated by comparing the cost when energy is shifted from higher-value hours to less-valuable hours due to carrying balancing reserve capacity. NWG states that the cost calculation is not reasonable because the cost calculated between the super-peak, graveyard, shoulder HLH, and shoulder LLH prices is much greater than the average HLH/LLH spreads in the study period. *Id.* NWG states that “the validity of Staff’s analysis is difficult to assess, particularly since Staff relies on models, as opposed to data showing actual costs incurred from energy shifting between different periods.” *Id.* at 53. NWG recommends that BPA should use the Heavy Load Hour/Light Load Hour price spread from an independently published, publicly available source to determine the energy shift variable cost, or alternatively, use the HLH/LLH spread from BPA’s market price forecast. *Id.*

PPC argues that BPA’s assessment of power prices from AURORA used within the GARD model is more accurate and sophisticated than using a single published spread number to determine the cost of shifting energy between hours. PPC Br., BP-12-B-PP-01, at 14. It would be inequitable to choose a less-accurate pricing methodology over one that understates the costs to be recovered through ancillary and control area service rates. *Id.*

BPA Staff’s Position

AURORA is a reasonable model to use in calculating levels of shifts between Super Peak and graveyard hours for all months and water years in the rate period. Klippstein *et al.*, BP-12-E-BPA-44, at 23-24. As is observable in the AURORA-generated price tables, Documentation, Tables 3.8-3.11, the price differential between the super-peak and graveyard period can materially differ from the prices between HLH and LLH. The amount of energy moved out of the super-peak period and into the lesser-valued shoulder HLH can be a significant amount of the shift quantity due to the substantial differences in generation that may exist between the super-peak and shoulder HLH period. *Id.* at 23. BPA has found AURORA to be an accurate predictor of the financial impacts associated with holding reserves, especially in times of high water. If only the average HLH period is considered, there are a substantial number of instances where no energy shift would be indicated when in fact holding *inc* reserves causes energy to be shifted out of the super-peak into the lower-value periods.

Evaluation of Positions

After further consideration BPA believes it better understands NWG’s argument’s on this issue. AURORA provides prices that change with hydrologic conditions, natural gas prices, and resource availability. AURORA provides an entire distribution of outcomes over the 70 historical water years as opposed to an instantaneous snapshot of prices. Klippstein *et al.*, BP-12-E-BPA-44, at 23-24; Documentation, Tables 3.8-3.11. NWG states that the average spread for annual energy shift translates to \$17.85 per MWh, but the forecast for HLH/LLH spreads used to calculate power rates for the study period has an average of \$12.12. NWG Br., BP-12-B-NG-01, at 52-53. NWG incorrectly infers that this difference means that the energy

shift variable cost calculation is unreasonable. *Id.* at 52. NWG's suggestion to remove the HLH/LLH price spread would remove some of the inherent uncertainty or volatility associated with providing balancing reserve capacity. Removing the value associated with this uncertainty would greatly underestimate the energy shift while inheriting the additional risk associated with volatility. An example of such risk is very low prices during the graveyard period. Accounting for the super-peak and graveyard periods results in a more accurate description of the FCRPS operation and the impacts of providing reserves.

The AURORA model is publicly available, and has been made available by BPA to rate case parties to test the assumptions in this BPA rate proceeding. BPA has employed the AURORA model for rate cases since the 2002 rate proceeding. Users of the AURORA model can examine the assumptions that produced the market price forecast. The assumptions used in the market price forecast from an independent, published source such as the Energy Marketing Report are unknown.

BPA uses the AURORA model to forecast market prices for the other studies in the power portion of the rate proceeding. This consistency of market price assumptions across the secondary sales revenue forecast, power purchase forecast, augmentation purchase forecast, and energy shift variable costs for ancillary and control area services allows transparency in the ratemaking process. Valuing the energy shift based on only a price quote would remove another layer of value while ignoring the uncertainty.

Decision

BPA will continue to use the Aurora model and account for the super-peak and graveyard periods in calculating the energy shift variable cost.

3.5 Ancillary and Control Area Services Rate Design

3.5.1 Introduction

Ancillary services are needed with transmission service to maintain reliability within and among the balancing authority areas affected by transmission service. Jackson *et al.*, BP-12-E-BPA-29, at 1. BPA offers six ancillary services: (1) Scheduling, System Control, and Dispatch Service; (2) Reactive Supply and Voltage Control from Generation Sources; (3) Regulation and Frequency Response Service; (4) Energy Imbalance Service; (5) Operating Reserve – Spinning Reserve Service; and (6) Operating Reserve – Supplemental Reserve Service. *Id.*

BPA also offers control area services to meet the reliability obligations of generation or loads in the BPA balancing authority area (also referred to as the BPA control area). BPA offers five control area services: (1) Regulation and Frequency Response Service; (2) Generation Imbalance Service; (3) Operating Reserve – Spinning Reserve Service; (4) Operating Reserve – Supplemental Reserve Service; and (5) Variable Energy Resource Balancing Service (VERBS) (formerly known as Wind Balancing Service).

In this section of the ROD, BPA evaluates the issues raised pertaining to Dispatchable Energy Resource Balancing Service (DERBS); VERBS; Provisional VERBS (also known as Provisional Balancing Service); VERBS for solar resources; Operating Reserve (Spinning and Supplemental Reserve) Service; and Persistent Deviation for Imbalance Services. These issues are discussed further below.

3.5.2 Dispatchable Energy Resource Balancing Service (DERBS) Issues

BPA Staff proposes DERBS as a new control area service for Dispatchable Energy Resources in the BPA balancing authority area. DERBS would provide the generation capability (ability to both increase and decrease generation) to follow within-hour variations caused by Dispatchable Energy Resources in the BPA balancing authority area. Jackson *et al.*, BP-12-E-BPA-29, at 40. This service would help to maintain the power system frequency at 60 Hertz in conformance with NERC and WECC reliability standards and provide the regulation, following, and imbalance balancing reserve capacity needed to support unexpected variations in output of Dispatchable Energy Resources (*e.g.*, thermal generators). *Id.* Dispatchable Energy Resources within BPA’s balancing authority area would be required to either purchase this service from BPA or make alternative comparable arrangements to satisfy their within-hour balancing service obligation. *Id.*

For purposes of DERBS, a *Dispatchable Energy Resource* is defined as any non-Federal thermally-based generating resource that schedules its output or is included in BPA’s Automatic Generation Control systems. Jackson *et al.*, BP-12-E-BPA-47, Attachment 1, at 1-18.

Issue 3.5.2.1

Whether the process followed for review of the proposed DERBS rate complies with the Northwest Power Act and provides an adequate basis to adopt a DERBS rate in this proceeding.

Parties’ Positions

WPAG argues against adoption of a DERBS rate in this proceeding. WPAG Br., BP-12-B-WG-01, at 28-29. WPAG asserts that the entities that would be subject to the DERBS rate have not had adequate time and information to fully evaluate Staff’s revised DERBS rate proposals or formulate informed and reasoned responses to such proposals. *Id.* at 29.

ICNU states that the parties have not had sufficient time to review the many various aspects of the charge, including BPA’s underlying data, the assumptions regarding reserve requirements associated with thermal generation, or how the charge would impact their facilities. ICNU Br., BP-12-B-IN-01, at 3. ICNU states that these flaws cannot be fully remedied in this proceeding; thus, BPA should defer adoption of the DERBS rate. *Id.*

ICNU also argues that no party has justified why a DERBS rate must be imposed in this proceeding, and that nothing has changed in terms of operations or number of thermal generators to require a DERBS rate at this time. *Id.* ICNU states that the costs of balancing reserve

capacity will still be recovered as they always have and charged to preference utilities as part of BPA's load balancing requirements; therefore, BPA should maintain this status quo and not change how these costs currently are recovered. *Id.* at 7.

Iberdrola suggests that BPA consider alternatives to the DERBS rate. Iberdrola Br., BP-12-B-IR-01, at 29. Iberdrola raises the concern that since customers have had only a short time to analyze the impact of the DERBS rate and that such analysis is both lengthy and complex, BPA is not getting a full and accurate response from customers that will be subject to the rate. *Id.* at 30.

JP02 notes that although significant problems would remain, the revised DERBS proposal would be a significant improvement over BPA's initial DERBS proposal. JP02 Br., BP-12-B-JP02-01, at 3.

BPA Staff's Position

BPA Staff recommends that BPA adopt a rate to recover BPA's costs associated with making balancing reserve capacity available for Dispatchable Energy Resources during the rate period. Jackson *et al.*, BP-12-E-BPA-47, at 2-4.

Evaluation of Positions

In the 2010 rate case, parties argued that BPA unduly discriminated against wind generators because BPA proposed to charge wind generators for balancing reserve capacity services but not Dispatchable Energy Resources. WP-10 ROD, WP-10-A-02, at 299; Administrator Wright, Oral Tr. at 30. In that rate proceeding, BPA had not done an in-depth analysis of the uses of balancing reserve capacity by Dispatchable Energy Resources and, thus, did not adopt a rate for such use. Staff committed, however, to examine balancing reserve capacity use by Dispatchable Energy Resources in the future. WP-10 ROD, WP-10-A-02, at 471.

For this rate proceeding, Staff evaluated all imbalances within the BPA balancing authority area to identify and fix areas that may have resulted in subsidization by other ratepayers in the past. Jackson *et al.*, BP-12-E-BPA-29, at 41. Staff discovered "a use of balancing reserve capacity by Dispatchable Energy Resources to meet the hourly imbalances between generator estimates and actual generation that was more significant than anticipated." *Id.* at 41. Staff testifies that Dispatchable Energy Resources, as a class, use a more significant amount of capacity than originally anticipated—enough to justify establishing a rate. *Id.*; Puyleart *et al.*, BP-12-E-BPA-24, at 18. This result was unexpected, but it demonstrates that non-Federal Dispatchable Energy Resources are consuming significant amounts of balancing reserve capacity due to their scheduling and operational practices.

Having identified costs of a balancing reserve capacity requirement attributable to non-Federal Dispatchable Energy Resources, Staff set out to lay the groundwork for a rate to recover those costs from those resources. Prior to the BP-12 Initial Proposal, Staff discussed the use of balancing reserve capacity with the owners of several Dispatchable Energy Resources to gain a more complete understanding of the source of imbalances for these generators and to determine

if changes to operating and scheduling practices could reduce the imbalances. Mainzer *et al.*, BP-12-E-BPA-23, at 53. Based on those discussions, Staff determined that generators could significantly reduce their use of balancing reserve capacity. *Id.* At workshops prior to the Initial Proposal, Staff discussed proposals for a balancing service rate for Dispatchable Energy Resources on July 15, August 19, and September 16, 2010.

In the Initial Proposal, Staff proposed a DERBS rate that was based on a “use-based pro rata share of the hourly revenue requirement for the reserves held for balancing dispatchable energy resources.” Jackson *et al.*, BP-12-E-BPA-29, at 41. Staff also proposed a penalty charge for excessive use of balancing reserve capacity to provide an economic incentive for thermal generators to limit their individual use of capacity. *Id.* at 43. To allow Dispatchable Energy Resources an opportunity to improve their scheduling and operational accuracy and thereby reduce their use of balancing reserve capacity on the system, Staff stated that BPA would “monitor the schedules and actual generation for non-Federal dispatchable generators from October 2010 through January 2011 to determine if there is a basis for adjusting the amount of balancing reserve capacity BPA will hold and use to establish the DERBS rate for the FY 2012-2013 rate period.” Mainzer *et al.*, BP-12-E-BPA-23, at 53-54.

In direct testimony, the rate case parties signaled their overwhelming disapproval and opposition to a DERBS rate that was based on a pro rata share of the revenue requirement and the proposed penalty charge. Many parties also offered suggestions for improvements to the DERBS rate design. *See, e.g.*, Skeahan *et al.*, BP-12-E-JP01-01, at 19-22; Wolverton, BP-12-E-IN-01, at 9-11; Baker *et al.*, BP-12-E-PP-03, at 4-5, 9-12; Saleba *et al.*, BP-12-E-WG-01, at 31-32; Froese *et al.*, BP-12-E-IR-01, at 37-38; Scott *et al.*, BP-12-E-JP01-02, at 9; Miles and Finley, BP-12-E-SN-01, at 8-9.

In rebuttal testimony issued on March 8, 2011, Staff revised the DERBS rate proposal based on the suggestions and comments of those parties, specifically eliminating the pro-rata billing factor and penalty charge. Jackson *et al.*, BP-12-E-BPA-47, at 2-3. The revised proposal simplifies the design of the DERBS rate to consist of a fixed base charge plus a variable charge based on actual use that would apply above 2 MW. *Id.* As an alternative, Staff also proposes a per-megawatt charge that would apply above a 2 MW dead band. Staff’s intent is to design a rate for DERBS that aligns more with actual use of balancing reserve capacity by a Dispatchable Energy Resource. These rates are designed to provide an economic incentive for accurate scheduling and operational practices by non-Federal Dispatchable Energy Resources and to recover the cost of balancing reserve capacity used to provide DERBS for non-Federal Dispatchable Energy Resources within the BPA balancing authority area. Jackson *et al.*, BP-12-E-BPA-47, at 16; Administrator Wright, Oral Tr. at 30-31.

Recognizing that the rate proceeding schedule, which was negotiated among the parties prior to the case and adopted without objections at the Prehearing Conference (*see* Prehearing Conference Tr., BP-12-TPH-BPA-01, at 2-7), did not provide any additional opportunities for parties to comment on the record, in rebuttal testimony Staff stated that BPA would file a motion to amend the schedule to allow surrebuttal testimony on the DERBS rate “to give the parties an opportunity to comment on the record regarding our reexamination of Dispatchable Energy

Resource balancing reserve capacity usage since the Initial Proposal ... and our proposed revisions to the DERBS rate proposal” Jackson *et al.*, BP-12-E-BPA-47, at 4. No party objected to BPA’s motion to amend the rate case schedule or requested additional time to respond to Staff’s revisions to the DERBS rate proposal, and the Hearing Officer granted BPA’s motion for surrebuttal testimony due March 23, 2011. BP-12-HOO-53.

On March 11, 2011, Staff held a clarification session with the parties to discuss Staff’s rebuttal testimony and the revised DERBS proposal. In addition, before surrebuttal testimony was due, Staff held a workshop with the parties to give them an additional opportunity to provide feedback and to ask questions about Staff’s revised DERBS rate proposal. *See* Jackson *et al.*, BP-12-E-BPA-47, at 5. Parties also had the opportunity to conduct discovery to obtain data or other information pertaining to Staff’s revised DERBS rate proposal. BP-12-HOO-53. Staff responded to approximately 18 data requests regarding its revised proposal. Procedurally, each rate case party was also given an opportunity to cross-examine BPA’s witnesses, but the parties waived cross-examination on Ancillary and Control Area Service rates. *See* BP-12-HOO-56.

Despite the above process, ICNU, WPAG, and Iberdrola allege that the process to develop a DERBS rate in this proceeding was insufficient. ICNU Br., BP-12-B-IN-01, at 3; Iberdrola Br., BP-12-B-IR-01, at 30; WPAG Br., BP-12-B-WG-01, at 28-29. With the exception of ICNU, WPAG, and Iberdrola, no other parties raise procedural issues regarding the development of the DERBS rate.

BPA acknowledges the efforts of the parties to review and comment on the DERBS rate within the confines of the rate proceeding schedule. However, BPA disagrees that the schedule in this proceeding is inadequate or that BPA should forgo establishing a DERBS rate because parties had insufficient time for review. First, BPA has fulfilled the procedural requirements for rate proceedings under the Northwest Power Act. The rate case record is clear that at all times the parties were afforded an opportunity to enter comment in the “form of written and oral presentation of views, data, questions, and argument related to [] proposed rates,” 16 U.S.C. § 839e(i)(2), and that each party was “provided an adequate opportunity by the hearing officer to offer refutation or rebuttal of any material submitted by any other person or the Administrator.” *Id.* § 839(e)(i)(2)(A). The facts indicate that Staff proposed a DERBS rate in the Initial Proposal, received extensive comments on that proposal from the parties, and responded to those comments with a revised DERBS rate proposal designed to address the parties’ concerns. All of this occurred consistent with the schedule adopted by the Hearing Officer in this proceeding. BP-12-HOO-01; BP-12-HOO-53. Staff could have chosen to continue to defend the Initial Proposal, but that approach would not have addressed many of the concerns of the parties.

Second, as mentioned above, once Staff published its revised DERBS proposal in rebuttal testimony, the hearing officer amended the procedural schedule specifically to allow parties to submit surrebuttal testimony on the revised proposal and other topics. ICNU and WPAG acknowledge this fact. ICNU Br., BP-12-B-IN-01, at 5-6; WPAG Br., BP-12-B-WG-01, at 28-29. Rate case parties were provided with opportunities to comment on the revised proposal, and many did. Smith and Lincoln, BP-12-E-CP-03; Froese *et al.*, BP-12-E-IR-03; Wolverton, BP-12-E-IN-05; Scott, BP-12-E-PN-03; Miles *et al.*, BP-12-E-SN-06; Saleba *et al.*,

BP-12-E-WG-05. In addition, had the parties desired, they could have cross-examined BPA's witnesses regarding Staff's revised DERBS rate. They chose not to do so. Finally, at any time after Staff filed its rebuttal testimony, any party could have submitted a motion for additional time to respond to Staff's revised proposal, but the record indicates that no party did so. Given that no party requested additional time to review Staff's revised DERBS proposal, and that parties waived the right to cross examine BPA's witnesses under the procedural schedule, BPA is not persuaded that inadequate procedure or insurmountable timing concerns prevented the opportunity to fully understand Staff's revised proposal.

BPA acknowledges ICNU's concern that generator-specific data is required to analyze Staff's revised DERBS proposal, but BPA disagrees that the fact that ICNU obtained this data from BPA shortly before the deadline for surrebuttal testimony requires BPA to delay adoption of a DERBS rate, as ICNU claims. ICNU Br., BP-12-B-IN-01, at 6-7. The generator-specific data that the parties obtained from Staff should have already been available to the parties from their own generators. Staff testifies that it "assume[s] that each generator has access to its own schedule and power output data for the test period." Jackson *et al.*, BP-12-E-BPA-47, at 13. Nothing in the record contradicts this assumption. Thus, it would be inappropriate now to hold BPA accountable for the inability of a party to obtain its own generation data, especially when Staff clearly put all generators on notice that for the purpose of DERBS, BPA would be monitoring the scheduling accuracy and balancing reserve capacity usage of thermal generators in the BPA balancing authority area during the test period stated in the Initial Proposal. Mainzer *et al.*, BP-12-E-BPA-23, at 53.

The record indicates that the parties had approximately two weeks to provide surrebuttal testimony, and over an additional month before the filing date for parties' initial briefs. The record also indicates that both ICNU and Calpine were able to calculate the impacts of the DERBS rate proposal on their own generators to at least some extent. Calpine Br., BP-12-B-CP-01, at 10; ICNU Br., BP-12-B-IN-01, at 8. Nevertheless, BPA does not presume to know what analyses the parties intended to conduct regarding the DERBS rate or the amount of time that would be required to complete them. Given the important cost recovery and policy purposes that support the establishment of a DERBS rate, BPA finds no merit in delaying implementation of the DERBS rate based on the parties' concerns.

ICNU asserts that in contrast to the current rate proceeding, BPA and interested stakeholders spent numerous years and workshops developing wind integration charges to meet the within-hour capacity needs of wind generation before proposing wind integration charges in a rate proceeding. ICNU Br., BP-12-B-IN-01, at 4.

BPA believes it is unnecessary to initiate a more time-consuming process for DERBS. First, much of the time spent discussing the methodologies and design of the wind balancing service rate was the result of the negotiated settlement in the WI-09 proceeding. Second, in contrast to BPA's development of wind balancing service (now referred to as the VERBS), DERBS, by definition, is less intricate because it involves resources that are dispatchable, as opposed to variable. Jackson *et al.*, BP-12-E-BPA-47, at 23 (explaining that "imbalances that consume balancing reserve capacity are preventable to a certain extent."). This lack of variability

contributes to an overall lower balancing reserve capacity and revenue requirement for Dispatchable Energy Resources than for variable energy resources.

Moreover, there are notable differences in the complexities and issues associated with VERBS when compared to the DERBS rate. Unlike for VERBS, BPA is not forecasting a significant increase in new non-Federal thermal generation; nor is BPA expecting non-Federal thermal generators to have schedule errors that could potentially exhaust the total balancing reserve capacity available for load and generation in BPA's balancing authority area. Given the breadth of issues that are associated with variable energy resources, a unique and extensive public process was appropriate. In contrast, for DERBS, BPA believes its various rate case workshops and statutory rate case process were more than adequate to provide the parties an opportunity to evaluate BPA's DERBS rate proposal.

Finally, despite the evidence of significant use of balancing reserve capacity by Dispatchable Energy Resources, the parties have not demonstrated why BPA should abandon a DERBS rate. As Staff explains in rebuttal testimony:

The DERBS rate is necessary to recover the costs of balancing reserve capacity quantity used to balance non-Federal dispatchable energy resources.... The primary goal of rate design is to recover costs. Our approach examined all uses of balancing reserve capacity in our balancing authority area and allocated the balancing reserve capacity requirement consistent with the use of balancing reserve capacity. We continue to adhere to the ratemaking principle of cost causation in charging users of balancing reserve capacity for their use of that capacity. If we did not follow that approach, the result would be an inequitable cost shift to other users of the balancing reserve capacity on the system.

Jackson *et al.*, BP-12-E-BPA-47, at 16-17.

Notably, ICNU asserts that BPA has always recovered its costs under the status quo and that a DERBS rate is not necessary to recover those costs. ICNU Br., BP-12-B-IN-01, at 7. Although many parties may be content with continuing to recover these cost through the PF rate, sound policy and cost causation principles support adopting a rate designed to recover from Dispatchable Energy Resources the costs of balancing reserve capacity use by those resources. The DERBS rate serves an important cost recovery function, but what ICNU overlooks is that the rate also serves an important policy function: to provide an incentive for better scheduling and operational accuracy. Thus, even if BPA disregards the principle of cost causation and continues to recover its costs for DERBS from other ratepayers, there would be nothing to ensure that Dispatchable Energy Resources would continue to improve their scheduling accuracy and operations and reduce their use of balancing reserve capacity on the system.

Consequently, the record indicates that the DERBS rate was not developed arbitrarily, but evolved based on the comments and suggestions from the rate case parties. Indeed, WPAG acknowledges that "BPA should be applauded for listening to the concerns of its customers regarding BPA's initial DERBS proposal. The revised DERBS proposals are both a marked improvement and a step in the right direction compared to the initial DERBS proposal." WPAG

Br., BP-12-B-WG-01, at 28. JP02 also states that in response to its concerns and the concerns of other rate case parties, Staff introduced a significantly revised DERBS proposal in its rebuttal testimony. JP02 Br., BP-12-B-JP02-01, at 2. JP02 notes that PNGC and its members filed surrebuttal testimony in response to Staff’s revised proposal and that although significant problems remain with the proposal, the revised proposal is a significant improvement over Staff’s initial DERBS proposal. JP02 Br., BP-12-B-JP02-01, at 3. In addition, JP01 states that “BPA has responded appropriately to customer input concerning the proposed rate design for DERBS during the rate case” JP01 Br. Ex., BP-12-R-JP01-01, at 7.

As discussed in the issues that follow, BPA’s decisions are supported by the rate case record, which contains substantial evidence of the use of balancing reserve capacity by non-Federal Dispatchable Energy Resources, cost causation resulting from that use, and the need to recover those costs in a rate. *See* Jackson *et al.*, BP-12-E-BPA-47, at 6, 16; Generation Inputs Study, BP-12-FS-BPA-05, section 2.10.

The DERBS rate has received significant attention in this rate proceeding, and BPA recognizes the significant work and effort of the parties to evaluate and comment on BPA’s DERBS rate design proposals. BPA will continue to work with the parties to evaluate the DERBS rate over the upcoming rate period and will consider improvements in future rate proceedings.

BPA notes that several parties have raised concerns specific to the DERBS rate design, rate level, and implementation date. BPA addresses these issues below.

Decision

The section 7(i) rate proceeding is sufficient process for the DERBS rate. The rate case record contains substantial evidence in support of a DERBS rate.

Issue 3.5.2.2

Whether BPA should establish a DERBS rate composed of a base charge linked to a Dispatchable Energy Resource’s installed capacity and a variable per-megawatt charge based on each Dispatchable Energy Resource’s use of balancing reserve capacity.

Parties’ Positions

Calpine states that if BPA adopts a DERBS rate, BPA should adopt a variable rate design without a base charge. Calpine Br., BP-12-B-CP-01, at 9.

ICNU states that Staff presents two rate design proposals: one based on a base charge and variable charge that applies above a 2 MW dead band, and another based solely on a variable charge that applies above a 2 MW dead band. ICNU Br., BP-12-B-IN-01, at 11-12. ICNU claims that Staff does not provide any reasoned basis for these rate proposals, and that neither seems to be based on actual data or any specific ratemaking theory. *Id.* at 12. ICNU argues that if BPA adopts a DERBS rate, BPA should adopt ICNU’s alternative rate design, which recovers

about half the costs through capacity charges and half the costs through usage charges. *Id.* ICNU states that the fixed charge should be based on the generation resource's maximum demand over the most recent 24-month period rather than potentially inaccurate nameplate capacity. *Id.* at 12-13.

Snohomish argues that the DERBS rate should be comprised of a base charge and a variable charge. Snohomish Br., BP-12-B-SN-01, at 18.

WPAG argues that if BPA adopts a DERBS rate, the rate should be based solely on usage. WPAG Br., BP-12-B-WG-01, at 30. WPAG states that a per-megawatt usage charge above a 2 MW dead band to collect the entire revenue requirement would be more equitable and more consistent with cost causation principles than a fixed base charge. *Id.* In the alternative, WPAG states, if BPA adopts a rate based on a fixed base charge the rate should use 12 monthly base charges, with each such monthly base charge being based on the highest historical generation level achieved by a thermal resource during each month in the previous 3-year period. *Id.* at 33.

JP01 states that it does not oppose the use of a variable per-megawatt charge for DERBS. JP01 Br. Ex., BP-12-R-JP01, at 7.

JP02 states that if BPA insists on implementing a DERBS charge, it should implement the revised proposal with the base charges proposed by Staff in rebuttal testimony and modified by PNGC's surrebuttal testimony pertaining to certain exceptions to the DERBS usage charge. JP02 Br., BP-12-B-JP02-01, at 3.

Grays Harbor supports a variable rate instead of a fixed charge and a variable charge. Grays Harbor Br. Ex., BP-12-R-GH-01, at 1-2.

BPA Staff's Position

Staff supports either a DERBS rate with a base charge and a variable per-megawatt charge that applies above a 2 MW dead band, Jackson *et al.*, BP-12-E-BPA-47, at 2, and Attachment 1, at 1-14, or a rate based solely on a per-megawatt variable charge that applies above a 2 MW dead band, Jackson *et al.*, BP-12-E-BPA-47, at 3.

Evaluation of Positions

Staff proposes two rate design options for DERBS. Staff's preferred rate design consists of a base charge tied to the generator's nameplate generating capacity and a per-megawatt charge that would be applied above 2 MW. Jackson *et al.*, BP-12-E-BPA-47, at 2. This rate is designed to recover 20 percent of the DERBS revenue requirement from the base charge and 80 percent of the revenue requirement from the variable charge above 2 MW. *Id.* Staff also proposes a rate design based solely on a higher per-megawatt charge that applies above a 2 MW dead band that would also meet the "objective for cost recovery consistent with cost causation." *Id.* at 3.

ICNU disagrees with both of Staff's rate design proposals. ICNU Br., BP-12-B-IN-01, at 12. ICNU supports a higher base charge plus a variable charge. ICNU states that its analysis of the

data provided by Staff supports recovering a larger portion of the DERBS rate in a higher fixed charge, and that it is reasonable to recover at least 40 percent of the reserve costs in a capacity charge. *Id.* ICNU explains that it is appropriate to recover a larger portion of the reserve capacity costs through a fixed charge because the DERBS rate is designed to recover capacity costs associated with thermal generation resources. *Id.* ICNU states that because the DERBS rate is an entirely new type of charge, there is no basis not to simply split the costs evenly between usage and capacity. *Id.*

Snohomish and JP02 support Staff's preferred rate design based on a base charge and variable charge designed to collect 20 percent and 80 percent of the revenue requirement respectively. Snohomish states that such an approach improves certainty for both customers and BPA, and reduces the risk that BPA will not be able to fully recover the costs it incurs to provide balancing reserve capacity. Snohomish Br., BP-12-B-SN-01, at 18-19. Likewise, JP02 states, the base charge is preferable to the alternative with no base charge, because the base charge would ensure that all thermal generators make some contribution to the costs of balancing capacity. JP02 Br., BP-12-B-JP02-01, at 4.

WPAG challenges Snohomish's and JP02's position. WPAG asserts that a usage-based rate ensures that the charge assessed to customers is based on their actual usage of the service, as opposed to collecting the charge based on the size of the generator. WPAG Br., BP-12-B-WG-01, at 30. WPAG also argues that a cost shift or cross-subsidization may occur if there is a base charge. *Id.* at 31. Specifically, WPAG challenges the idea of a base charge based on the nameplate capacity of a generator because that would shift a substantial portion of the DERBS revenue requirement to such generators. *Id.* at 32.

WPAG also states that a base charge of 20 percent would provide limited certainty regarding the recovery of the total revenue requirement. *Id.* at 31. WPAG argues that there is little rationale for charging a portion of the revenue requirement to those that do not use the service, as would be the potential outcome of a base charge approach. *Id.* Moreover, WPAG claims, there is no evidence in the record that supports the proposition that the size of the deviations from schedules is in any manner causally related to the nameplate capacity of the generator. *Id.* at 32.

Like WPAG, Calpine also supports a per-megawatt variable DERBS charge. Calpine Br., BP-12-B-CP-01, at 10. According to Calpine, a variable rate design would give Dispatchable Energy Resources the best opportunity to minimize use of balancing reserve capacity because if they use no balancing reserves, they would receive no charges. *Id.* Calpine explains that a variable rate design creates a significant and continuous incentive to reduce dependence on BPA reserves, whereas an unavoidable fixed charge creates no incentive. *Id.* In addition, Calpine notes that a variable rate design would not expose generators to DERBS charges for months in which a thermal plant was off-line and not utilizing any reserve capacity. *Id.*; Smith and Lincoln, BP-12-E-CP-03, at 8.

Similarly, Grays Harbor expresses support for a variable DERBS rate. Grays Harbor Br. Ex., BP-12-R-GH-01, at 1-2. Grays Harbor states that a variable charge provides an appropriate price signal for dispatchable generators to reduce their usage of balancing services and is consistent

with cost causation principles. *Id.* Grays Harbor explains that by utilizing a variable charge, DERBS properly accounts for the fact that many thermal plants operate during only a portion of the year by charging generators only when they actually utilize balancing reserve capacity. *Id.* Grays Harbor argues that a fixed charge as originally proposed would charge generators during periods in which the plant was not operating and would not properly incent generators to improve their scheduling and operational control practices. *Id.*

In addition, JP01 clarifies that it does not oppose the use of a variable per-megawatt charge, which “moots [JP01’s] specific concerns related to the relationship of the size of the tolerance band or ‘dead band’ and the fixed charges assessed customers.” JP01 Br. Ex., BP-12-R-JP01-01, at 7.

An important aspect of BPA’s decision to adopt a DERBS rate is to emphasize that greater scheduling accuracy and operational precision will help reduce the use of balancing reserve capacity. Mainzer *et al.*, BP-12-E-BPA-23, at 54. BPA agrees with WPAG, Calpine, Grays Harbor, and JP01 and finds that a per-megawatt DERBS charge is the appropriate rate design under the circumstances. A variable rate design creates a significant and continuous incentive to reduce dependence on BPA balancing reserve capacity. Calpine Br., BP-12-B-CP-01, at 10; *see also* WPAG Br., BP-12-B-WG-01, at 30. A variable DERBS rate will also account for the fact that many Dispatchable Energy Resources do not operate during certain portions of the year since the charge will only apply when such resources actually utilize balancing reserve capacity under DERBS. Grays Harbor Br. Ex., BP-12-R-GH-01, at 1-2.

Given the relatively small revenue requirement associated with DERBS, Generation Inputs Study, BP-12-FS-BPA-05, Table 1, line 11, BPA does not find it necessary to maintain a base charge to mitigate cost recovery risk over the rate period. Although Snohomish and JP02 argue that a base charge will ensure at least some level of cost recovery, Staff’s base charge proposal would recover only 20 percent of the revenue requirement under the base charge. Jackson *et al.*, BP-12-E-BPA-47, at 2. The majority of costs would be recovered through the per-megawatt variable charge. As a result, the level of cost recovery risk between the two rate design options is relatively insignificant. Staff testifies that the per-megawatt charge above a 2 MW dead band would meet the objective for cost recovery consistent with cost causation. *Id.* at 3. Accordingly, BPA believes a per-megawatt charge will create an incentive for balancing reserve capacity users to reduce their use and improve their scheduling and operational accuracy. *See* Issue 3.5.2.3 below for discussion regarding the appropriate size of the dead band.

BPA is not convinced by ICNU’s argument that BPA should establish a fixed charge and variable charge that would each recover a proportional amount of the revenue requirement. Under ICNU’s approach, the variable charge would be lower since more of the revenue requirement would be spread across the base charge. BPA believes that approach may weaken the price signal that would provide an incentive for Dispatchable Energy Resources to improve their operational and scheduling accuracy and reduce their station control errors: generators that have high station control errors would pay a lower variable charge. BPA notes that ICNU’s assumptions regarding the stability of cogenerators suggest that a variable charge would be more beneficial for those facilities. ICNU Br., BP-12-B-IN-01, at 7. Given the apparent disconnect

between ICNU's assumption about the predictability of cogeneration operations and ICNU's advocacy for a larger fixed cost component of the rate, BPA would be hesitant to adopt a large fixed rate component on the basis of ICNU's analysis. Indeed, a per-megawatt charge appears to be ideal for a generator that maintains operational and scheduling accuracy since it would enable that generator to avoid or reduce its use of DERBS altogether. As explained further below, BPA is adopting a 2 MW dead band under the DERBS rate, which should be of sufficient size to manage most station control errors. This approach will also better ensure that the users of DERBS compensate BPA to the extent they utilize DERBS above 2 MW.

BPA acknowledges, however, that this is a new rate and that BPA will need to reevaluate the rate design as BPA gains experience with the DERBS charge. BPA will continue to work with the parties over the rate period to develop improvements to the DERBS rate design for evaluation in a future rate proceeding.

Decision

BPA is adopting a DERBS rate based on a per-megawatt charge only.

Issue 3.5.2.3

Whether BPA should establish a dead band based on 2 MW inc and dec balancing reserve capacity under the DERBS charge.

Parties' Positions

Calpine argues that instead of a 2 MW dead band for *inc* and *dec* balancing reserve capacity under DERBS, BPA should adopt a dead band of the greater of 2 MW or 1 percent of nameplate capacity. Calpine Br. Ex., BP-12-R-CP-01, at 2-3.

While Grays Harbor supports the concept of a dead band, Grays Harbor asserts that a dead band that is not adjusted for generator size has a disproportionately large impact on large generators and blunts the incentives for improved operational control for smaller generators. Grays Harbor Br. Ex., BP-12-R-GH-01, at 2.

Snohomish states that BPA should increase the 2 MW balancing reserve capacity allocation to each Dispatchable Energy Resource to 3 MW. Snohomish Br., BP-12-B-SN-01, at 20.

BPA Staff's Position

Staff proposes a DERBS rate design that would provide 2 MW of imbalance as part of a nameplate capacity-based charge, with balancing reserve capacity use beyond 2 MW charged on a per-megawatt basis. Jackson *et al.*, BP-12-E-BPA-47, at 2-3, 20-21. Staff also proposes an alternative rate design based solely on a per-megawatt charge and a dead band of 2 MW. *Id.*

Evaluation of Positions

As explained in Issue 3.5.2.2 above, BPA’s decision is to adopt a DERBS rate based solely on a per-megawatt charge. Staff proposes to apply a 2 MW dead band for all generators that are subject to DERBS before recovering 100 percent of the revenue requirement through a per-megawatt charge for any use of *inc* or *dec* balancing reserve capacity that exceeds 2 MW. Jackson *et al.*, BP-12-E-BPA-47, at 3.

Calpine argues that a dead band of only 2 MW for both *inc* and *dec* reserves is unfair and discriminatory because it disregards the size of the generator. Calpine Br., BP-12-B-CP-01, at 11; Calpine Br. Ex., BP-12-R-CP-01, at 2-3. Calpine states that use of a static 2 MW dead band would hold larger units to a much higher standard of scheduling and operational precision, and thereby unduly penalize the generators that are making the greatest contributions to Northwest energy supplies. Calpine Br., BP-12-B-CP-01, at 11. Calpine suggests BPA adopt a dead band based on the greater of 2 MW or 1 percent of the generator’s nameplate capacity. Calpine Br. Ex., BP-12-R-CP-01, at 2-3. Calpine states that this approach would substantially reduce the discriminatory impact on larger generators while avoiding the cost shifting BPA fears, and leaving larger generators with sufficient incentive to closely monitor their use of balancing reserve capacity. *Id.*

Grays Harbor also disagrees with a dead band that is independent of generator size. Grays Harbor Br. Ex., BP-12-R-GH-01, at 2. Grays Harbor states that the degree of operational control a thermal generator has over its output on a megawatt basis is roughly commensurate with its nameplate capacity. *Id.* Therefore, the incentive for increasing operational performance is inversely proportional to the size of the generator which results in discriminatory treatment for larger generators. *Id.* Grays Harbor states that BPA should not ignore the operational realities of larger thermal units and should adopt a dead band structure that provides equivalent performance incentives regardless of the size of the generator. *Id.*

BPA finds no factual or legal basis in the rate case record to conclude that a 2 MW dead band unduly discriminates against larger Dispatchable Energy Resources. A 2 MW dead band ensures that all generators are provided an incentive to improve their station control errors, regardless of size. While a fixed 2 MW dead band may provide larger generators with less opportunity than smaller generators to avoid paying for balancing reserve capacity that is utilized under DERBS, larger generators are more likely than smaller generators to utilize significant amounts of balancing reserve capacity and adversely impact operations of the BPA’s system. Thus, even if Calpine’s and Grays Harbor’s assertion that a fixed dead band “discriminates” against larger generators were true, such discrimination would not be undue given their greater use of balancing reserve capacity.

BPA also notes that Grays Harbor offers no evidence in the record to support its assertion that the “degree of operational control a thermal generator has over its output on a megawatt basis is roughly commensurate with its nameplate capacity.” Many generators do not operate at full nameplate capacity; thus, if BPA establishes a dead band tied to nameplate capacity, some generators may obtain a significant benefit from the larger dead band based on their actual level of generation output. For example, if a generator operates at half of its nameplate capacity,

under Calpine’s and Grays Harbor’s proposal, the generator would continue to receive a dead band tied its nameplate capacity despite the generator’s lower generation output. As a result, a larger dead band may act as a disincentive for some generators to improve their station control errors and reduce their balancing reserve capacity use under DERBS.

Indeed, Calpine’s proposal would result in roughly 16 MW of *inc* and *dec* balancing reserve capacity for the largest Dispatchable Energy Resource in BPA’s balancing authority area, equating to a total dead band of 32 MW. Given that Staff forecasts a total reserve requirement of approximately 70 MW *inc* and *dec* (each) for non-Federal thermal generators, Jackson *et al.*, BP-12-E-BPA-47, at 6, a 16 MW dead band for *inc* and *dec* use would be disproportionately large in relation to the total reserve requirements. Larger generators, which have greater potential to impact the reliability of the BPA system than smaller generators, would have less incentive to monitor their station control error and balancing reserve capacity consumption if granted a dead band tied to their installed capacity.

More importantly, a 2 MW dead band ensures that the balancing reserve capacity costs associated with large station control errors are not shifted to other users of DERBS. By including a dead band under DERBS, the costs associated with the balancing reserve capacity under the dead band are spread across a higher per-megawatt rate. See Jackson *et al.*, BP-12-E-BPA-47, at 3 (stating that a per-megawatt DERBS rate with a 2 MW dead band results in a higher per-megawatt rate). Thus, as the size of the dead band increases, so do the costs associated with the larger dead band, which materialize in the form of a higher per-megawatt rate for all users of DERBS. Under Calpine’s and Grays Harbor’s approach, a dead band based on a percentage of a generator’s installed capacity would effectively increase the amount of balancing reserve capacity that BPA must provide under the dead band. Although a larger dead band would exempt Dispatchable Energy Resources from the DERBS charges in many scheduling periods, the costs associated with the balancing reserve capacity consumed within the dead band are still realized by BPA. Because an increase in the dead band results in an increase in the per-megawatt rate, rather than reduce any alleged discriminatory impact to Dispatchable Energy Resources, a higher dead band under DERBS would shift costs to all other generators since the costs associated with the higher dead band would be reflected in a higher DERBS rate paid by all users of DERBS. BPA finds no policy or legal basis in the record to support such an inequitable assignment of costs.

Calpine also states that the use of a “static 2 MW dead band would hold larger units to a much higher standard of scheduling and operational precision, and thereby unduly penalize the generators that are making the greatest contributions to Northwest energy supplies.” Calpine Br., BP-12-B-CP-01, at 11. BPA disagrees that a 2 MW dead band unduly penalizes larger generators. As Calpine points out, “[t]he goal of the DERBS rate is to recover the costs associated with a Dispatchable Energy Resource’s use of balancing reserve capacity, regardless of whether the use is avoidable or unavoidable.” *Id.* at 22. A larger dead band would artificially limit cost recovery from the users that create the costs.

A 2 MW dead band, in contrast, is reasonable under the circumstances to capture *de minimis* deviations while preserving BPA’s ability to recover its costs and providing incentive for

Dispatchable Energy Resources to monitor and improve their scheduling and operational accuracy. *See Saleba et al.*, BP-12-E-WG-01, at 35 (supporting a dead band for *de minimis* deviations); and Baker *et al.*, BP-12-E-PP-03, at 12, 15-16 (supporting a dead band for *de minimis* deviations). A 2 MW dead band is also reasonable under the circumstances when considering the fact that some smaller generators cannot schedule in whole megawatt increments. Baker *et al.*, BP-12-E-PP-03, at 5 (raising concerns regarding generators that cannot generate in whole megawatt increments); Wolverton, BP-12-E-IN-01, at 10-11 (raising concerns regarding generators that cannot generate in whole megawatt increments).

Finally, Snohomish suggests that BPA increase the dead band to 3 MW to better align the dead band with BPA's application of the DERBS rate to Dispatchable Energy Resources that are of 3 MW nameplate capacity or greater. Snohomish Br., BP-12-B-SN-01, at 20. BPA disagrees with Snohomish's rationale. The DERBS rate applies to resources of 3 MW nameplate rated capacity or greater. Jackson *et al.*, BP-12-E-BPA-47, Attachment 1, at 1-14. Instead of aligning the dead band with the applicability of the DERBS rate, a 3 MW dead band would effectively exempt 3 MW resources from the rate, even though 3 MW resources are included in BPA's AGC system and contribute to the DERBS balancing reserve capacity requirement, thus altering the applicability of the rate to resources in excess of 3 MW. *See id.* at 11, 15. A higher dead band would also shift more of the revenue requirement to customers that utilize more than 3 MW of DERBS. BPA finds no basis in the rate case record to support such an exemption. Snohomish's proposal would also result in a total dead band of 6 MW (3 MW of *inc* and 3 MW of *dec* balancing reserve capacity) under the DERBS rate. As explained above, a larger dead band weakens the incentive to improve scheduling and operational accuracy over the rate period. Based on the evidence in the record, a dead band of 2 MW strikes the right balance to enable generators to manage their station control errors within an acceptable range without degrading the incentive to improve operational and scheduling accuracy.

Decision

BPA establishes a 2 MW dead band of inc and dec balancing reserve capacity under the DERBS rate. The DERBS charge will not apply within the dead band. BPA is open to revisiting the size of the dead band issue in a future rate proceeding.

Issue 3.5.2.4

Whether BPA should delay implementation of the DERBS rate until BPA adopts intra-hour scheduling on a 30-minute or shorter basis for all transmission customers.

Parties' Positions

According to Calpine, before adopting a DERBS rate BPA must first implement intra-hour scheduling for thermal generators, ideally on a 15-minute basis, but on a 30-minute basis at most, and then BPA must reforecast the need for balancing reserve capacity in light of experience under intra-hourly scheduling. Calpine Br., BP-12-B-CP-01, at 7-9. Calpine asserts that absent such steps, BPA's adoption of a DERBS charge at this time would be unjust, unreasonable, and

unduly discriminatory to transmission customers that operate Dispatchable Energy Resources within the BPA balancing authority area. *Id.* at 1.

Alternatively, Calpine argues, if BPA decides to adopt a DERBS rate for the rate period, BPA should delay implementation of the rate in the rate period until BPA implements intra-hour scheduling for thermal generators to give customers a fair chance to minimize their exposure to the DERBS charge. *Id.* at 9-10; Calpine Br. Ex., BP-12-R-CP-01, at 3.

Grays Harbor acknowledges that BPA intends to make intra-hour scheduling available by the start of the rate period, but states that the DERBS rate should be contingent on the adoption of intra-hour scheduling by BPA. Grays Harbor Br. Ex., BP-12-R-GH-01, at 3.

Similarly, ICNU argues that BPA should adopt a DERBS rate only after BPA has implemented all reasonable non-rate alternatives to reduce balancing reserve capacity needs, including but not limited to 30-minute intra-hour scheduling. ICNU Br., BP-12-B-IN-01, at 11.

BPA Staff's Position

This issue, raised in surrebuttal testimony, responds to Staff's revised DERBS proposal. Staff has not presented a position on this issue; however, Staff recognizes improvements in the use of *dec* balancing reserve capacity by Dispatchable Energy Resources in the BPA balancing authority area during the test period, and Staff adjusts the balancing reserve capacity quantity forecast for DERBS accordingly. Jackson *et al.*, BP-12-E-BPA-47, at 5-6.

Evaluation of Positions

Calpine states that it appreciates that BPA has taken a step in the right direction with respect to making intra-hour scheduling available by the start of the rate period, but suggests that BPA delay implementation of a DERBS rate to allow BPA to reevaluate the use of balancing reserve capacity by Dispatchable Energy Resources. Calpine Br. Ex., BP-12-R-CP-01, at 3-4.

Similarly, Grays Harbor and ICNU argue that BPA should delay implementation of a DERBS rate until BPA enables intra-hour scheduling for Dispatchable Energy Resources. Calpine Br. Ex., BP-12-R-CP-01, at 3; Grays Harbor Br. Ex., BP-12-R-GH-01, at 3; ICNU Br., BP-12-B-IN-01, at 11. If BPA implements intra-hour scheduling for the rate period, ICNU urges BPA to "first adopt 30-minute scheduling, see how much of an impact that has on the need for thermal balancing reserves, and then decide to set a revenue requirement that will allow you to obtain cost recovery." Sanger, Oral Tr. at 75.

Although BPA is not required to offer intra-hour scheduling, BPA expects to make intra-hour scheduling available to all generation resources by October 1, 2011. Simpson *et al.*, BP-12-E-BPA-46, at 10. This expectation is consistent with ICNU's and Calpine's suggestion to make intra-hour scheduling available if BPA adopts a DERBS rate. Indeed, on June 28, 2011, BPA expanded its intra-hour scheduling pilot, phase 2, to include all generators, including Dispatchable Energy Resources. *See* BPA's Intra-Hour Scheduling Pilot Program (Phase 2) business practice. It is important to note, however, that BPA has no assurance that DERBS

customers or other customers will actually utilize intra-hour scheduling during the rate period. Mainzer *et al.*, BP-12-E-BPA-23, at 44-45; *see also* Issue 3.5.2.5 below. What BPA does have is substantial evidence that Dispatchable Energy Resources have used and continue to use significant amounts of balancing reserve capacity. Jackson *et al.*, BP-12-E-BPA-47, at 6; *see also* Issue 3.5.2.5 below. Thus, even without intra-hour scheduling, the record supports establishing a rate to recover BPA's costs and incent better scheduling and operational accuracy by Dispatchable Energy Resources.

ICNU argues that the costs of balancing reserves will still be recovered as they always have and charged to preference utilities as part of BPA's load-balancing requirements. ICNU Br., BP-12-B-IN-01, at 7. ICNU also suggests that not imposing the DERBS rate in this case will simply maintain the status quo and not change how these costs have been recovered since "time immemorial." *Id.*

BPA is not persuaded by this argument. The fact that cross-subsidization may have occurred through rates in the past is no reason for continuing a cost shift to other users of balancing reserve capacity. Further, the various uses of balancing reserve capacity have increased significantly in the last several years, placing a higher demand on this valuable and limited resource. It is therefore more critical for BPA to identify and recover its costs associated with making balancing reserve capacity available for balancing services than it may have been in past years. As explained above, in addition to cost recovery, the DERBS rate serves an important policy goal by providing an economic incentive to Dispatchable Energy Resources to improve their operational and scheduling accuracy and thereby reduce their use of balancing reserve capacity. Given that the DERBS rate will be based on a generator's station control error, generators that improve their operational and scheduling accuracy significantly over the rate period will be able to reduce their use of balancing reserve capacity and avoid paying the per-megawatt DERBS charge. *See* Issue 3.5.2.2 above.

Finally, Calpine asserts that absent the availability of intra-hour scheduling for Dispatchable Energy Resources, BPA's adoption of a DERBS charge at this time would be unjust, unreasonable, and unduly discriminatory to transmission customers that operate thermal Dispatchable Energy Resources within the BPA balancing authority area. Calpine Br., BP-12-B-CP-01, at 1. In support of its intra-hour scheduling argument, Calpine relies upon the Commission's preliminary findings in the Variable Energy Resource Notice of Proposed Rulemaking regarding the current hourly scheduling paradigm and benefits of intra-hour scheduling. *Id.* at 8-9.

BPA addresses the relationship of the VER NOPR to issues in this proceeding in section 3.2.6 of this ROD. It is important to note that the legal standards that govern BPA ratemaking derive from the Flood Control Act and from BPA's organic statutes, which do not include an undue discrimination standard. Although BPA has voluntarily filed a reciprocity tariff with the Commission in the past and adheres to open access principles in its sale of transmission, the Commission's proposed rules, as well as related open access principles, are not legally binding on BPA and do not form part of either Commission or Ninth Circuit review of BPA's rates. 16 U.S.C. § 839e(a)(2); *see* ROD sections 1.1.3 and 1.2.5.2.

As explained above, BPA intends to make intra-hour scheduling available for all generation resources in the BPA balancing authority area by the start of the rate period; thus, ICNU's, Calpine's and Grays Harbor's argument that BPA should first make intra-hour scheduling available before adopting a DERBS rate is noted but is essentially moot. ICNU and Calpine suggest, however, that BPA first collect data based on intra-hour scheduling before adopting a DERBS rate. These parties appear to rely on the erroneous assumption that BPA will over-recover its costs for DERBS after intra-hour scheduling is implemented. *See* Calpine Br., BP-12-B-CP-01, at 11; ICNU Br. Ex., BP-12-R-IN-01, at 4. BPA is already absorbing the risk of underrecovery under the DERBS rate by virtue of adopting a per-megawatt rate above a 2 MW dead band. If customers improve their scheduling accuracy and reduce their use of DERBS significantly, as the parties suggest will occur, BPA will receive less revenues and customers will pay less in DERBS charges. Given the relatively small revenue requirement, BPA has determined any underrecovery risk to be acceptable under the circumstances. *See also* Jackson *et al.*, BP-12-E-BPA-47, at 2-3. Nevertheless, it is highly unlikely, given the design of the DERBS rate, that BPA will overcollect its costs for DERBS during the rate period if Dispatchable Energy Resources improve their station control error during the rate period. Under BPA's intra-hour scheduling pilot, Dispatchable Energy Resources are currently able to participate in intra-hour scheduling. Even in the unlikely chance that BPA is unable to make intra-hour scheduling available on a non-pilot basis for all resources by the start of the rate period, however, BPA's decision to adopt a DERBS rate is not unjust, unreasonable, or unduly discriminatory because it is designed to appropriately recover the cost of providing balancing reserve capacity from the users of DERBS.

Moreover, as explained earlier in this ROD, in the last rate proceeding several parties argued that BPA unduly discriminated against them because BPA did not charge Dispatchable Energy Resources for their use of balancing reserve capacity. Administrator Wright, Oral Tr. at 30. BPA has since identified significant uses of balancing reserve capacity by Dispatchable Energy Resources, enough to justify establishing a rate to recover those costs. Jackson *et al.*, BP-12-E-BPA-29, at 41. Currently, those costs are not being recovered from the users that create those costs. Thus, contrary to ICNU's and Calpine's arguments, it would be unreasonable for BPA to abandon or delay cost recovery under the DERBS rate based solely on the availability of intra-hour scheduling now that those costs have been identified.

Decision

Although BPA expects to expand the limited intra-hour scheduling currently available to all generators by the start of the rate period, the DERBS rate's function as a cost recovery mechanism and scheduling and operational incentive outweighs the need to delay implementation of the DERBS rate until full intra-hour scheduling is available.

Issue 3.5.2.5

Whether BPA should reduce its balancing reserve capacity quantity forecast for DERBS based on the assumption that Dispatchable Energy Resources will improve their scheduling accuracy during the rate period.

Parties' Positions

Calpine argues that the per-unit charges under Staff's proposed DERBS rates would materially over-recover BPA's associated revenue requirement for imbalance reserve capacity during the rate period. Calpine Br., BP-12-B-CP-01, at 11. Calpine states that a reduction in the use of balancing reserve capacity by 50 percent is a reasonable estimate, and such a reduction should translate into a 50 percent reduction in the DERBS rates for *inc* and *dec* reserves. *Id.* at 12.

ICNU states that BPA should reduce the DERBS rate by half to reflect that the rate has not been adequately reviewed and the high likelihood that it will significantly over-recover BPA's costs. ICNU Br., BP-12-B-IN-01, at 3; ICNU Br. Ex., BP-12-R-IN-01, at 3-4. ICNU explains that generators will likely change their operations and reduce BPA's actual needs for balancing reserve capacity; thus, BPA should assume further reductions in the balancing reserve capacity requirements for Dispatchable Energy Resources. *Id.* at 10; ICNU Br. Ex., BP-12-R-IN-01, at 3. ICNU adds that the DERBS rate should be reduced if BPA believes 30-minute scheduling for thermal resources can be implemented during the rate period and states that BPA's actual needs for balancing reserves could also be reduced if BPA adopts 30-minute scheduling for thermal resources during the rate period. ICNU Br., BP-12-B-IN-01, at 11.

Iberdrola states that Staff's balancing reserve capacity forecast for DERBS may be overstated. Iberdrola Br., BP-12-B-IR-01, at 29-30. Iberdrola claims that it is likely that owners of generation plants will have some sort of response to the new pricing mechanism and that some plants may have already altered their behavior as a result of BPA's proposed DERBS rate. *Id.* Iberdrola recommends a transitional revenue requirement because customers have only had a short time to analyze the impact of the DERBS rate and BPA may not be getting the full and accurate response from customers that will be subject to the rate. *Id.* at 30.

Grays Harbor supports BPA's decision to take the latest improvements in Dispatchable Energy Resource operations into consideration when calculating the DERBS rate. Grays Harbor Br. Ex., BP-12-R-GH-01, at 3. Grays Harbor states that because BPA expects to have intra-hour scheduling available at the beginning of the rate period, Grays Harbor proposes that at a minimum the DERBS rate should be based on the "expected reduction in balancing service requirements under an intra-hour scheduling regime." *Id.*

BPA Staff's Position

The historical data used in Staff's analysis is reflective of the actual use of balancing reserve capacity by Dispatchable Energy Resources. Jackson *et al.*, BP-12-E-BPA-47, at 7. Staff identifies improvements during the test period between the Initial Proposal and rebuttal

testimony in the use of *dec* balancing reserve capacity by thermal generators and adjusts the Balancing Reserve Capacity Quantity Forecast for DERBS accordingly. *Id.* at 8.

Evaluation of Positions

Prior to the Initial Proposal, BPA discussed the use of balancing reserve capacity with the owners of several Dispatchable Energy Resources to gain a more complete understanding of the source of imbalances for these generators and to determine if changes to operating and scheduling practices could reduce the imbalances. Mainzer *et al.*, BP-12-E-BPA-23, at 53. Based on those discussions, Staff states that those generators could significantly reduce their use of balancing reserve capacity. *Id.* Staff agreed to monitor the schedules and actual generation for non-Federal dispatchable generators from October 2010 through January 2011. *Id.* Staff also indicates that it would consider adjusting the balancing reserve capacity quantity forecast for DERBS if it observed significant reduction in the use of balancing reserve capacity by dispatchable non-Federal generation during the rate proceeding. Jackson *et al.*, BP-12-E-BPA-29, at 43.

In rebuttal testimony, Staff testifies that in the fall and winter of 2010, non-Federal thermal generation reduced its overall *dec* balancing reserve usage by 19 percent from that of the previous year. However, Staff found no improvement in the non-Federal thermal generation *inc* balancing reserve usage during the fall and winter of 2010 compared to the previous year. Jackson *et al.*, BP-12-E-BPA-47, at 6.

Calpine states that BPA has already observed a drop in balancing reserve capacity use by Dispatchable Energy Resources, and that no one, including BPA, can estimate with certainty the magnitude of the price response that will accompany implementation of DERBS. Calpine Br., BP-12-B-CP-01, at 11-12. Calpine states that BPA should reduce the balancing reserve capacity requirement and rate for DERBS by 50 percent to account for that response. *Id.*

Similarly, ICNU states that if BPA does not withdraw the DERBS rate, then it would be reasonable to reduce the rate by half to account for the potential reductions in BPA's actual need for balancing reserve capacity associated with thermal generation. ICNU Br., BP-12-B-IN-01, at 10-11.

Iberdrola suggests that given the uncertainties surrounding the impact of the rate, BPA should establish a "transitional" revenue requirement of half of the revenues that Staff proposes to collect for DERBS. Iberdrola Br., BP-12-B-IR-01, at 29. Iberdrola also notes that there are likely to be improvements by Dispatchable Energy Resources over the rate period, and Staff's balancing reserve capacity forecast is likely to overstate those requirements. Iberdrola Br., BP-12-B-IR-01, at 29-30.

BPA has observed additional reductions in the use of balancing reserve capacity by Dispatchable Energy Resources. Between the October 2009 to April 2010 period and the October 2010 to April 2011 period, BPA observed a 20.9 percent reduction in the use of *inc* balancing reserve capacity. This change in behavior, combined with (1) the decision to hold reserves at a 99.5 percent adequacy rather than a 99.7 percent adequacy, and (2) several generators leaving the

BPA Balancing Authority Area, resulted in a reduced reserve quantity requirement for DERBS of 28 percent for *inc* and 9 percent for *dec* when compared to the Initial Proposal. BPA is taking these recent improvements into consideration and is reducing the balancing reserve capacity quantity forecast and the DERBS rate accordingly. Additionally, market price estimates reduced the per-megawatt cost of holding these reduced reserves. The overall rate reduction from the initial proposal is 34 percent. BPA believes a 34 percent reduction to the DERBS revenue requirement is a reasonable reduction given that non-Federal Dispatchable Energy Resources have had time since the Initial Proposal to demonstrate significant improvements in their use of balancing reserve capacity under DERBS. In contrast, the record does not support a 50 percent reduction, as suggested by some parties.

ICNU argues that the DERBS balancing reserve capacity requirement and DERBS rate should be reduced to account for intra-hour scheduling for thermal resources during the rate period. ICNU Br., BP-12-B-IN-01, at 11. ICNU asserts that it would be “arbitrary and capricious for BPA to design a rate that provides significant incentives that it knows will reduce its costs of providing services, but then to assume that no parties will actually reduce their use of balancing reserves.” *Id.* ICNU argues that “while there is ‘no guarantee’ that all generators will use intra-hour scheduling, it is not reasonable for BPA to assume that no generators will use intra-hour scheduling.” ICNU Br. Ex., BP-12-R-IN-01, at 3 (emphasis in original).

Similarly, Grays Harbor argues that it is reasonable to expect that a rate designed to be an incentive for Dispatchable Energy Resources to monitor and improve their scheduling and operational accuracy would materially alter the amount of balancing reserve capacity required for Dispatchable Energy Resources. Grays Harbor Br. Ex., BP-12-R-GH-01, at 3-4. Grays Harbor adds that accounting for improved scheduling accuracy will reduce the likelihood that the DERBS rate will result in over-recovery of the cost of providing this service. However, Grays Harbor argues that the balancing reserve quantity must also reflect the expected improvement in scheduling accuracy that will result from the adoption of intra-hour scheduling. *Id.* at 4.

As explained in Issue 3.5.2.4 above, BPA expects to make intra-hour scheduling available by the start of the rate period. However, BPA has no guarantee that Dispatchable Energy Resources or any other resources will utilize voluntary intra-hour scheduling or make attempts to improve their scheduling accuracy over the rate period. BPA lacks data to support assumptions about the extent of voluntary intra-hour scheduling during the rate period or the impact that it might have on balancing reserve capacity requirements. Mainzer *et al.*, BP-12-E-BPA-23, at 44-45; Puyleart *et al.*, BP-12-E-BPA-24, at 29. The record does not support adjusting BPA’s reserve requirement forecast or DERBS rate in this proceeding based on assumptions about the impact of voluntary intra-hour scheduling during the rate period.

Further, as described above in Issue 3.5.2.4, the parties’ arguments that BPA will materially over-recover its costs under the DERBS are unfounded. If customers improve their scheduling accuracy and reduce their use of DERBS significantly, as ICNU and Grays Harbor suggest will occur, BPA will receive less revenues and customers will pay less in DERBS charges. Given the relatively small revenue requirement, BPA has determined this underrecovery risk to be acceptable under the circumstances. *See also* Jackson *et al.*, BP-12-E-BPA-47, at 2-3.

Nevertheless, it is highly unlikely, given the design of the DERBS rate, that BPA will overcollect its costs for DERBS during the rate period if Dispatchable Energy Resources improve their station control error during the rate period, whether as a result of intra-hour scheduling or any other means. Regardless of the potential for such operational improvements, BPA has no basis to assume that some or all Dispatchable Energy Resources will utilize intra-hour scheduling in all scheduling periods or that operational improvements will occur. BPA has already reduced the reserve requirement to reflect the latest actual improvements in the station control errors of Dispatchable Energy Resources. Additional balancing reserve capacity reductions would improperly shift operational and cost recovery risk onto BPA and other users of balancing reserve capacity. Thus, contrary to the parties' arguments (*see* ICNU Br. Ex., BP-12-R-IN-01, at 3; Grays Harbor Br. Ex., BP-12-R-GH-01, at 3-4), it would be unreasonable and arbitrary for BPA to discount the DERBS rate based solely on the assumption that some or all Dispatchable Energy Resources will utilize intra-hour scheduling or make improvements in their operations.

Decision

Based on the best information available, BPA is taking into consideration recent improvements in the Dispatchable Energy Resources' use of balancing reserve capacity and reducing the balancing reserve capacity quantity forecast and DERBS rate accordingly.

Issue 3.5.2.6

Whether BPA's expectation with respect to linear ramps within a 20-minute span reflect operating realities of thermal generation, particularly during startup, shutdown, and output ramps.

Parties' Positions

According to Calpine, BPA expects thermal generators to produce flat blocks of energy across each hour that change in amount only at the top of the next hour. Calpine Br., BP-12-B-CP-01, at 4. Calpine states that, with a minor exception, BPA expects the generator to ramp precisely and unvaryingly according to its calculation, but BPA's expectation does not track with the operating realities of thermal generation. *Id.*

Calpine states that BPA must adopt the higher dead band allotment of the greater of 2 MW or 1 percent of nameplate, as well as intra-hour scheduling, in order to ensure that thermal operators are, in fact, adequately equipped with the tools to enable the most efficient use of balancing reserve capacity during the rate period. Without those tools, Calpine takes exception to BPA's decision regarding Dispatchable Energy Resource operations. Calpine Br. Ex., BP-12-R-CP-01, at 5.

Grays Harbor states that it is not technically feasible to follow linear ramps because combustion turbines have minimum output levels that are designed to mitigate air emissions. *Id.* Further, thermal expansion of the different components within the units can cause the unit to trip offline to prevent damaging the equipment; therefore, the ramps must be controlled to maintain proper

temperature differentials, not simply to meet arbitrary linear ramps. *Id.* Grays Harbor states that comparing the actual operation of a thermal unit to the hypothetical operation implied by a linear ramp results in a significant unavoidable regulatory burden for thermal generators. *Id.*

BPA Staff's Position

The use of balancing reserve capacity by Dispatchable Energy Resources may not always be avoidable during startup, ramps, and shutdown. Jackson *et al.*, BP-12-E-BPA-47, at 22. However, imbalances require generation inputs for balancing reserve capacity whether those imbalances are preventable or not. *Id.* Staff's position is that the provider of that balancing reserve capacity should be compensated for those generation inputs. *Id.*

Evaluation of Positions

According to Calpine, "BPA's experience in operating a hydro-based system does not translate precisely to the different operating characteristics of thermal power resources." Calpine Br., BP-12-B-CP-01, at 3. Calpine also asserts that BPA expects thermal generators to produce flat blocks of energy across each hour that change in amount only at the top of the next hour:

When inter-hour changes in output (ramps) occur, BPA expects that the change will occur at a linear rate exclusively within a 20 minute span—from 10 minutes before the hour to 10 minutes after the hour. The linear rate is calculated each hour by dividing the MW change by the 20 minute ramp period. With a minor exception, BPA simply expects the generator to ramp precisely and unvaryingly according to its calculation.

Calpine Br., BP-12-B-CP-01, at 4. Calpine claims that BPA's "expectation does not track with the operating realities of thermal-generation. Although it is flexible, thermal generation is not as responsive as unconstrained hydroelectric generation." *Id.*

Similarly, Grays Harbor argues that the expectation that ramps for thermal generators follow a linear 20-minute ramp rate schedule used in the WECC region is unrealistic because of the physical nature of the units at issue and the environmental regulations for air emissions. Grays Harbor Br. Ex., BP-12-R-GH-01, at 4.

Staff responded to Calpine's concerns regarding actual thermal generation operations:

Contrary to Calpine's assertion, we did not assume that thermal generators have infinite ramping capability. We did assume, however, that generators could keep their ramps confined to the applicable NERC standard ramp periods. Marketing decisions by the generator to make schedule changes between scheduling periods that exceed the capabilities of the generator to ramp within the ramp periods seem inconsistent with the intent of the ramp periods.

Jackson *et al.*, BP-12-E-BPA-47, at 23.

Staff also explained why it would be inappropriate to exempt Dispatchable Energy Resource ramping periods, including start-up, shut-down, and ramps, from the DERBS rate:

Whether the use of balancing reserve capacity is preventable or not is largely irrelevant. What is relevant is whether balancing reserve capacity is used. If balancing reserve capacity is used, then the users of that capacity should compensate the provider of that balancing reserve capacity. We acknowledge that not all use of balancing reserve capacity is unavoidable during startup, ramps, and shutdown. However, there are large thermal generators that use very little balancing capacity relative to other generators with the same combined-cycle generating technology. The goal of the DERBS rate is to recover the costs associated with a dispatchable energy resource's use of balancing reserve capacity, regardless of whether the use is avoidable or unavoidable.

Jackson *et al.*, BP-12-E-BPA-47, at 22.

BPA acknowledges Calpine's and Grays Harbor's concerns regarding actual thermal generation operations and appreciates their expertise regarding such operations. To clarify, BPA's expectations regarding actual thermal generation operations are informed by the applicable NERC requirements and BPA's experience with generation within BPA's balancing authority area. Jackson *et al.*, BP-12-E-BPA-47, at 13-15. Calpine and Grays Harbor challenge BPA's expectations of actual thermal generation conditions, however, without addressing the fact that BPA does not set the NERC requirements that apply to thermal generators, and without explaining why BPA should ignore such reliability requirements under the facts in this proceeding. However, the issue at hand is whether BPA should recover its balancing reserve capacity costs from the users that create those costs. No party disputes Staff's analysis that Dispatchable Energy Resources have used balancing reserve capacity in the past. Jackson *et al.*, BP-12-E-BPA-47, at 5-6. Based on the facts in the record and the best information available, BPA believes that it is appropriate to recover its costs from the users that create those costs under the DERBS rate.

Calpine explains that BPA should first provide the tools to enable generators to reduce their use of balancing reserve capacity to ensure that BPA is recovering the true costs of unavoidable errors. Gannett, Oral Tr., at 31-32. BPA believes it has designed the DERBS rate and provided a path toward intra-hour scheduling that puts Dispatchable Energy Resources largely in control of their balancing reserve capacity use. BPA expects to have intra-hour scheduling available for all generators by the start of the rate period, and BPA is forecasting the balancing reserve capacity requirement for DERBS based on the most recent data available. *See* Issue 3.5.2.5 above.

BPA also is adopting a DERBS rate design based solely on a per-megawatt charge above a 2 MW dead band. This rate design will provide some margin for error to account for operating constraints or other issues and will enable generators to reduce their DERBS charges by improving scheduling and operational accuracy over the rate period. BPA will also take any such improvements into consideration for the FY 2014–2015 rate proceeding. Hence, BPA believes that non-Federal generators will be equipped with the tools to reduce their station control errors and overall use of DERBS. To the extent such generators utilize DERBS, it is appropriate for BPA to be compensated for that use.

Finally, in relation to its arguments regarding Dispatchable Energy Resource operational capabilities, Calpine raises several arguments regarding the size of the dead band under DERBS and the availability of intra-hour scheduling in relation to the DERBS rate. BPA addresses these arguments in Issues 3.5.2.3 and 3.5.2.4 above. Accordingly, BPA finds that Dispatchable Energy Resources will be equipped with the tools to enable the most efficient use of DERBS during the rate period.

Decision

Dispatchable Energy Resources will be equipped with the tools to enable the most efficient use of DERBS during the rate period. To the extent those resources utilize DERBS, however, BPA will recover its costs through the DERBS rate.

Issue 3.5.2.7

Whether the fixed billing factor for the DERBS rate should be based on a demonstrated maximum peak capacity of a non-Federal thermal generator or the generator's nameplate installed capacity.

Parties' Positions

Snohomish argues that the billing determinant for the base DERBS charge should be on the resource's demonstrated maximum peak capacity, measured as the maximum one-minute output (in megawatts) during the previous three years of operation. Snohomish Br., BP-12-B-SN-01, at 19.

Similarly, ICNU argues that BPA should not base the DERBS charge on an outdated and potentially inaccurate nameplate capacity, but rather on the generation resource's maximum demand over the most recent 24-month period. ICNU Br., BP-12-B-IN-01, at 12.

WPAG states that if BPA adopts a rate design with both a base charge and variable charge, the rate should use 12 monthly base charges, with each such monthly base charge being based on the highest historical generation level achieved by a thermal resource during each month in the previous three-year period. WPAG Br., BP-12-B-WG-01, at 33.

BPA Staff's Position

BPA Staff supports a billing factor that constitutes a Monthly Base Rate based on the greater of the maximum one-minute average generating capability of the Dispatchable Energy Resource as measured by BPA or the Dispatchable Energy Resource's nameplate generating capability. Jackson *et al.*, BP-12-E-BPA-47, Attachment 1, at 1-14.

Evaluation of Positions

As explained above, BPA is adopting a DERBS rate based on a per-megawatt rate above a 2 MW dead band. As a result, the parties' concerns pertaining to a fixed base charge under the DERBS rate are now moot.

Decision

Since BPA is adopting a per-megawatt rate for DERBS, it is unnecessary to adopt a maximum one-hour generated energy during the previous rate period for the DERBS rate.

Issue 3.5.2.8

Whether the DERBS rate recovers the costs already collected under the Regulation and Frequency Response Service rate for non-Federal thermal resources that are behind the meter of load customers.

Parties' Positions

Snohomish argues that Staff fails to fully explain how the DERBS rate, which includes three within-hour components (regulating reserves, following reserves, and imbalance reserves) is not already being collected for the regulating component that is embedded in the Regulation and Frequency Response ("RFR") rate when applied to behind the meter resources. Snohomish Br., BP-12-B-SN-01, at 20.

BPA Staff's Position

Staff identifies the generators, including certain behind-the-meter generators that will be subject to the proposed DERBS rate. Jackson *et al.*, BP-12-E-BPA-47, at 11. Staff explains that these non-AGC controlled generators are included in BPA's AGC system. *Id.* By being included in AGC, the generator's actual output and scheduled or estimated output are part of the balancing authority area total generation actual and schedule. *Id.* Thus, these generators contribute to the balancing reserve capacity requirement regardless of their status as behind-the-meter resources. *Id.*

Evaluation of Positions

Snohomish argues that loads and behind-the customer-meter resources inside the BPA balancing authority area already pay BPA's RFR rate. Snohomish Br., BP-12-B-SN-01, at 20. Snohomish states that BPA has not adequately demonstrated that there is no double-collection of the regulating reserve component within DERBS and RFR as applied to non-Federal thermal resources. *Id.* at 21.

BPA disagrees with Snohomish that the RFR rate recovers the cost of balancing reserve capacity used by non-Federal behind-the-meter thermal resources. Staff explains why it is appropriate to include non-Federal behind-the-meter resources in BPA's balancing reserve capacity quantity forecast for DERBS:

[W]e have identified the generators, including certain behind-the-meter resources, that will be subject to the proposed DERBS rate.... These non-AGC controlled generators are included in BPA's AGC system. By being included in AGC, the generator's actual output and scheduled or estimated output are part of the balancing authority area total generation actual and schedule. Thus, these generators contribute to the balancing reserve capacity requirement regardless of their status as "behind-the-meter" resources. For the BP-12 Initial Proposal, the balancing authority area net load used in the balancing reserve capacity quantity forecast is a derived value from the total generation for the balancing authority area minus the sum of all interchanges for the balancing authority area. Since all of the identified non-Federal thermal generators are part of the total generation for the balancing authority area, the variability of those generators is not accounted for in net load for the balancing authority area. Therefore, additional *inc* and *dec* reserves are needed, and the costs associated with supplying those reserves currently are not being recovered through rates.

Jackson *et al.*, BP-12-E-BPA-47, at 11.

Furthermore, the allocation of balancing reserve capacity supports Staff's conclusion. Staff's method for allocating the total balancing reserve requirement among load and the various types of generation will account for the amount that the load balancing reserve requirement decreases due to the allocation of a portion of the total balancing reserve requirement to non-Federal Dispatchable Energy Resources. *See* Puyleart *et al.*, BP-12-E-BPA-24, at 25-26; Puyleart *et al.*, BP-12-E-BPA-24-E01; Generation Inputs Study, BP-12-FS-BPA-05, at 23-25. Since all of the identified non-Federal thermal generators are part of the total generation for the balancing authority area, the variability of those generators is not accounted for in net load for the balancing authority area. Therefore, additional *inc* and *dec* reserves are needed, and the costs associated with supplying those reserves currently are not being recovered through the RFR rate. Consequently, there is no double-recovery of the same costs, as Snohomish suggests.

Decision

The RFR rate does not collect the same costs as the DERBS rate for balancing reserve capacity used by behind-the-meter resources.

Issue 3.5.2.9

Whether the DERBS rate should apply to both non-Federal and Federal thermal generation in BPA's balancing authority area.

Parties' Positions

JP06 argues that Staff's evidence does not support assertions in the Initial Proposal that Federal thermal generation balancing reserve capacity requirements are minimal in comparison with non-Federal thermal generation balancing reserve capacity requirements in BPA's balancing authority area. JP06 Br., BP-12-B-JP06-01, at 5. JP06 concludes that the record in this

proceeding does not support BPA's adoption of a DERBS rate that applies to non-Federal thermal generation within the BPA balancing authority area but not Federal thermal generation within the BPA balancing authority area. *Id.* at 7.

BPA Staff's Position

The costs for all balancing reserve capacity beyond the capacity requirements assigned to DERBS and VERBS are recovered by including those balancing reserve capacity requirements in the load balancing reserve capacity requirements. Jackson *et al.*, BP-12-E-BPA-47, at 6. Though the ratio of megawatts of balancing reserve capacity to megawatts of nameplate capacity is relatively close for both Federal and non-Federal thermal generation, Federal thermal generation is considered part of the overall Federal resource stack. As such, balancing reserve capacity for Federal generation is essentially self-supplied, because the Federal resource stack is dispatched automatically through BPA's AGC system. *Id.* at 6-7.

Evaluation of Positions

According to JP06, the Federal and non-Federal thermal generation balancing reserve capacity requirements appear to be roughly equivalent. JP06 Br., BP-12-B-JP06-01, at 7. JP06 asserts that BPA's projected average total *inc* and *dec* balancing reserve capacity requirements for Federal thermal generation expressed as a percentage of average Federal thermal installed capacity are greater than BPA's projected average total *inc* and *dec* balancing reserve capacity requirements for non-Federal thermal generation expressed as a percentage of average non-Federal thermal installed capacity. *Id.* JP06 asserts that the record in this proceeding does not support BPA's adoption of a DERBS rate that applies to non-Federal thermal generation within the BPA balancing authority area but does not apply to Federal thermal generation within the BPA balancing authority area. *Id.*

Contrary to JP06's assertions, the rate case record contains substantial evidence in support of a DERBS rate for non-Federal Dispatchable Energy Resources. As BPA Staff explains:

The costs for all balancing reserve capacity beyond the capacity requirements assigned to DERBS and Variable Energy Resource Balancing Service (VERBS) are recovered by including those balancing reserve capacity requirements in the load balancing reserve requirements, as explained in the [Generation Inputs Study, BP-12-E-BPA-05, section 2.8]. Though the ratio of megawatts of balancing reserve capacity to megawatts of nameplate capacity is relatively close for both Federal and non-Federal thermal generation, Federal thermal generation is considered part of the overall Federal resource stack. As such, balancing reserve capacity for Federal generation is essentially self-supplied due to the fact that the Federal resource stack is dispatched automatically through BPA's [AGC system]. In addition to dynamically dispatching all reserves required for the balancing authority area, basepoint adjustments of the Federal system can be made at any time prior to or during the operating hour if needed to respond to changes in output or projected output of the Federal generation.

Jackson *et al.*, BP-12-E-BPA-47, at 6-7.

Despite the fact that balancing reserve capacity for Federal thermal generation is self-supplied by the Federal system, JP06 contends that BPA should essentially pay itself for the costs of balancing reserve capacity that it supplies to Federal thermal generation. BPA finds no basis in the record for the increased administrative expense of assessing a DERBS charge on Federal thermal generation when Federal thermal generation is considered part of the overall Federal resource stack. Accordingly, applying the DERBS rate to Federal thermal generation is unnecessary: the costs associated with balancing reserve capacity for Federal thermal generation are recovered by including those requirements in the load balancing reserve capacity requirement. Generation Inputs Study, BP-12-FS-BPA-05, section 2.10.

Decision

Since the balancing reserve capacity for Federal thermal generation is self-supplied by the Federal system and the costs for such capacity are recovered from preference customer load, it is unnecessary to charge Federal generation the DERBS rate.

Issue 3.5.2.10

Whether BPA should ensure that there is a clear and unambiguous basis for the calculation of station control error for the DERBS rate.

Parties' Positions

Calpine recommends that BPA implement technology that would provide generators with a specific “Go To” point, which would then be compared to telemetered generation output to attain a station control error calculation for the DERBS rate. Calpine Br. Ex., BP-12-R-CP-01, at 6. Calpine Br., BP-12-B-CP-01, at 12. Absent such an automated minute-by-minute signal, Calpine asks that BPA reconsider the frequency of determining the station control error and use a 10-minute average station control error. Calpine Br., BP-12-B-CP-01, at 12. Without the immediate, real-time data provided by the “Go To” point to guide generators, Calpine states, it is simply unfair to use a very short time interval within which to measure the average station control error. Calpine Br. Ex., BP-12-R-CP-01, at 6. At a minimum, Calpine recommends, BPA should develop a detailed business practice that will describe the calculation of DERBS charges under various operational conditions. *Id.*

Grays Harbor supports Calpine’s suggestion for a “Go To” point or electronic dispatch signal to enable generators to respond to the incentives inherent in the DERBS rate. Grays Harbor Br. Ex., BP-12-R-GH-01, at 5. In order to be effective, Grays Harbor states, the go-to point must be telemetered in real time to the generators control center. *Id.* Grays Harbor adds that the data used to calculate the DERBS rate should also be provided to the generator as part of the settlement process. *Id.*

BPA Staff's Position

This issue is first raised in surrebuttal testimony responding to Staff’s revised DERBS proposal. Staff does not present a position on this issue.

Evaluation of Positions

Calpine recommends that, at a minimum, BPA should develop a detailed business practice that will describe the calculation of DERBS charges under various operational conditions. Calpine Br., BP-12-B-CP-01, at 12. Calpine requests that BPA seriously consider the implementation of a “Go To” point or use of a 10-minute average station control error. Without the immediate, real-time data provided by the “Go To” point to guide generators, Calpine states, it is simply unfair to use a very short time interval within which to measure the average station control error. Calpine Br. Ex., BP-12-R-CP-01, at 6.

In addition, Grays Harbor states that while the use of balancing reserves may be physically unavoidable for thermal generators, the demand for reserves can be mitigated by the system operator. Grays Harbor Br. Ex., BP-12-R-GH-01, at 4. Grays Harbor appreciates that BPA supports a structure whereby Dispatchable Energy Resources will be equipped with the tools to enable the most efficient use of DERBS but states that short of 5-minute scheduling or a dead band proportional to the size of the generator, the most useful tool would be an electronic dispatch signal that provides an unambiguous real-time reference point that defines the center of the dead band used in determining the DERBS charge. *Id.* Grays Harbor states that BPA should ensure that it has appropriated the funds required to ensure that the tools necessary to meet these objectives are available. *Id.* Grays Harbor states that because these tools will be required for generators to effectively reduce their reliance on balancing services, these tools should be in place before the start of the rate period. *Id.*

With regard to Calpine’s suggestion regarding use of 10-minute average station control error to calculate the DERBS rate, using 10-minute average station control error to calculate DERBS charges would eliminate compensation for all of the regulation and part of the following component for the balancing used by non-Federal Dispatchable Energy Resources. As a result, a 10-minute average station control error is incompatible with recovering costs on a consistent basis for all uses of balancing reserves.

Both Calpine and Grays Harbor suggest a “Go To” point. Calpine Br. Ex., BP-12-R-CP-01, at 6; Grays Harbor Br. Ex., BP-12-R-GH-01, at 5. BPA currently provides such a real-time unambiguous reference point. All generators that are on BPA’s Generator Inter Control-Center Communication Protocol (GenICCP) receive their basepoints in real-time, which is the center of the DERBS dead band and is exactly where the generation level is supposed to be. However, generator owners and operators need to include their plants in BPA’s GenICCP to receive the signal, and some generators have chosen not to do so. BPA may be able to provide additional forward-looking information about where the plant should be 5 to 20 minutes out, but this element is appropriate for a Business Practice rather than as a component of the DERBS rate. BPA will work with interested generators that are not currently receiving a real-time basepoint to include them into BPA’s existing GenICCP system. BPA will also coordinate with its customers on the development of a business practice that describes the conditions, such as dispatch orders, under which DERBS charges do not apply. In addition, BPA is adopting specific exceptions to the DERBS rate in the rate schedule. These exceptions are discussed in Issue 3.5.2.11 below.

Finally, Grays Harbor states that the data used to calculate the DERBS rate should also be provided to the generator as part of the settlement process. Grays Harbor Br. Ex., BP-12-R-GH-01, at 6. BPA agrees with Grays Harbor's suggestion and will supply the hourly *inc* and *dec* billing data with interested DERBS customers in their monthly billing process.

Decision

BPA will work with interested generators to ensure that they receive an unambiguous real-time basepoint through BPA's GenICCP. BPA will also coordinate with its customers on the development of a business practice that describes the conditions, such as dispatch orders, where DERBS charges do not apply so that there is a clear basis for the calculation of station control error for the DERBS rate. BPA will also supply hourly billing data to interested customers.

Issue 3.5.2.11

Whether the DERBS rate schedule should state the conditions under which the DERBS rate will be waived.

Parties' Positions

Calpine states that BPA should expressly include in the DERBS rate schedule any exceptions to the DERBS rate to minimize ambiguity regarding the circumstances for waivers. Calpine Br., BP-12-B-CP-01, at 13; *see also* Calpine Br. Ex., BP-12-R-CP-01, at 6. Calpine suggests that the DERBS rate not apply during any hour in, or for which: (1) BPA has issued a Dispatch Order (of any kind, including redispatch, Environmental Redispatch, or transmission curtailment or outage-related order or request) and the customer's generator is responding to such order or for hours during which customer's generator is coming back on line after responding to such order; (2) the customer's generator has a qualifying contingency event and has called on contingency energy; (3) an e-Tag has been curtailed; (4) the customer's generator is requested to go offline by the local utility; (5) the customer is changing generation levels to avoid a Failure to Comply (FTC) charge; or (6) BPA waives the charge because the generator was responding to or recovering from an emergency or reliability concern not described above. Calpine Br., BP-12-B-CP-01, Attachment A, at 2.

WPAG states that inclusion of BPA's three proposed exemptions under the DERBS rate schedule is good policy. WPAG Br. Ex., BP-12-R-WG-01, at 26. However, WPAG states that BPA should reconsider whether to also include a general waiver process for DERBS charges. WPAG states that a general waiver process would offer an avenue of relief to customers who incur unreasonable DERBS charges due to unique, unforeseeable circumstances that are outside the scope of the three exemption categories, while at the same time allow BPA to reject unfounded waiver requests. *Id.* at 26-27. WPAG states that it would be prudent for BPA to retain the ability to waive a usage charge incurred for emergency or reliability reasons in order to have the flexibility to address unforeseen situations. *Id.* at 33. WPAG explains that the DERBS rate is not intended to capture the specific events it has identified above because each of those events is attributable to causes outside the control of the resource sponsor. *Id.*

Similarly, ICNU recommends that BPA should not apply the DERBS charge during events in which the cogenerator's schedule changes for reasons beyond its control, including unplanned or forced outages, or changes in response to third-party directions. ICNU Br., BP-12-B-IN-01, at 3-4, 13.

JP02 suggests that BPA not charge the usage charge for DERBS to a generator in any hour: (1) whenever a generator has called upon contingency energy during a qualifying event; (2) during which BPA has issued a dispatch order (of any kind including curtailment of generation, redispatch, Environmental Redispatch, or transmission curtailment- or outage-related order or request) and the generator is responding to such order or for hours during which generator is coming back on line after responding to such order; (3) the generator is requested to go offline or change generation level by the local utility; (4) a generator's e-Tag has been curtailed; (5) the generator is changing generation levels to avoid a Failure to Comply penalty charge; (6) that BPA waives the usage charge because the generator was responding to or recovering from a reliability concern not described above. JP02 Br., BP-12-B-JP02-01, at 3; Scott, BP-12-E-PN-03, at 3-4.

Grays Harbor supports an exemption for the extraordinary circumstance where a BPA dispatch order, dispatch order from a host utility within BPA's balancing authority area, or qualifying contingency event causes a customer to utilize balancing reserve capacity under DERBS. Grays Harbor Br. Ex., BP-12-R-GH-01, at 6.

BPA Staff's Position

Staff proposes that BPA should not charge for DERBS during scheduling periods in which the generator must change its operations pursuant to a BPA Dispatch Order. Jackson *et al.*, BP-12-E-BPA-47, at 21. This proposed exemption should be sufficient to address the parties' concerns regarding operations during curtailments or redispatch. *Id.*

Evaluation of Positions

Staff proposes not to assess the DERBS rate "during scheduling periods in which the generator must change its operations pursuant to a BPA Dispatch Order." Jackson *et al.*, BP-12-E-BPA-47, at 21. Staff believes this exemption would address the parties' concerns regarding operations during curtailments or redispatch. *Id.*

Calpine, TransAlta, WPAG, and JP02 state that BPA should include specific exemptions in the rate schedule for actions that are beyond a generator's control. Calpine Br., BP-12-B-CP-01, at 13; Calpine Br. Ex., BP-12-R-CP-01, at 6; WPAG Br., BP-12-B-WG-01, at 32-33; WPAG Br. Ex., BP-12-R-WG-01, at 26; ICNU Br., BP-12-B-IN-01, at 13; JP02 Br., BP-12-B-JP02-01, at 3.

BPA agrees with the parties that the rate schedule should include specific language for any exemption to the DERBS rate. In general, the extraordinary circumstances identified by the parties appear to fall within the three categories: (1) BPA dispatch orders; (2) dispatch orders from a host utility within BPA's balancing authority area; and (3) qualifying contingency events.

An e-Tag curtailment requires a BPA dispatch order. Changes in operation that are directed by a host utility within BPA's balancing authority also require a dispatch order from the host utility. Further, unplanned or forced outages generally qualify as a contingency event. Thus, the three categories identified above are sufficient to cover the circumstances that may cause a Dispatchable Energy Resource to alter its operations in a manner that affects the applicable charge under DERBS. BPA will specify the three exemption categories in the DERBS rate schedule.

The parties also raise concerns about the applicability of DERBS when BPA assesses a Failure to Comply penalty charge. Calpine Br., BP-12-B-CP-01, at 13, Attachment A at 2; WPAG Br., BP-12-B-WG-01, at 32; JP02 Br., BP-12-B-JP02-01, at 3. If a BPA dispatch order causes a customer to change its operations, the fact that a customer may incur an FTC penalty charge for its failure to comply with such dispatch order is irrelevant to the applicability of DERBS. As explained above, the DERBS charge will not apply when a BPA Dispatch Order requires a change in operations that consumes balancing reserve capacity under DERBS.

In addition, several parties request that BPA include general waiver language in the DERBS rate schedule for unforeseen circumstances. WPAG Br., BP-12-B-WG-01, at 33; WPAG BR. Ex., BP-12-R-WG-01, at 26; Calpine Br., BP-12-B-CP-01, Attachment A, at 2; ICNU Br., BP-12-B-IN-01, at 3-4, 13. BPA does not believe, however, that it is necessary to include a general waiver process for DERBS charges. To the extent a Dispatchable Energy Resource utilizes balancing reserve capacity in the absence of a dispatch order from BPA or the generator's host utility within BPA's balancing authority area or a qualifying contingency event, that resource should pay for its use of that balancing reserve capacity. There is also nothing in the rate case record indicating that the three categories BPA identifies above are insufficient to cover the extraordinary circumstances that could cause a customer to utilize balancing reserve capacity under DERBS. Moreover, BPA is already accepting the financial risks associated with a per-megawatt DERBS rate. BPA sees no basis to take on additional risk by including a waiver provision under DERBS to cover the unlikely situation that a customer may incur DERBS charges due to "unique, unforeseeable circumstances that are outside the scope of the three exemption categories" that BPA is adopting in this ROD. BPA cannot safeguard its customers against all business risks; thus, to the extent a customer utilizes DERBS in a situation that does not fall within the three categories BPA is adopting in this ROD, the customer should compensate BPA for that use.

Finally, ICNU suggests that BPA exempt situations that are beyond a cogenerator's control. ICNU Br., BP-12-B-IN-01, at 3-4. The rate case record does not support the broad exemption that ICNU requests. To the extent a cogenerator experiences a qualifying contingency, BPA will not charge the DERBS rate to such generator. However, BPA disagrees that it should bear all the risks associated with a generator's operations. If a generator consumes balancing reserve capacity outside of a contingency or BPA dispatch order, the generator should compensate BPA for that use.

Decision

BPA is including an exemption in the DERBS rate schedule for the extraordinary circumstance where a BPA dispatch order, dispatch order from a host utility within BPA's balancing authority area, or qualifying contingency event causes a customer to utilize balancing reserve capacity under DERBS.

Issue 3.5.2.12

Whether the DERBS rate will disproportionately harm cogenerators.

Parties' Positions

ICNU asserts that although titled "dispatchable" rate, the DERBS rate applies to all thermal generation resources, including cogenerators that have limited dispatchability because their generation is a byproduct of their business operations. ICNU Br., BP-12-B-IN-01, at 7. ICNU argues that this new, unplanned-for rate increase will likely have harmful impacts on cogenerators' business operations and will make it more difficult to recover from the recent economic recession. *Id.*

BPA Staff's Position

Cogeneration resources that are larger than 3 MW are included in BPA's AGC system and also contribute to the overall balancing reserve capacity requirement. Jackson *et al.*, BP-12-E-BPA-47, at 20. Therefore, the DERBS rate should apply to them.

Evaluation of Positions

ICNU raises concerns about the applicability of the DERBS rate to cogeneration resources. ICNU states that cogenerators "typically have predictable operations, which "are not likely to cause BPA to need a significant amount of capacity to meet its within-hour capacity needs, but BPA's rate design may result in them paying a disproportionate share of the DERBS rate.'" ICNU Br., BP-12-B-IN-01, at 7.

ICNU also asserts concerns regarding its inability to properly assess the impact of the DERBS rate to cogeneration resources:

The DERBS rate will impose surprisingly high charges upon some cogeneration resources. ICNU was only able to conduct extremely limited analysis of the impact of the DERBS rate because ICNU did not learn how the rate would affect certain ICNU cogenerators until two days before testimony was due. For example, ICNU was unable to review the impact upon all of ICNU's cogenerators, and ICNU was not provided data regarding all cogeneration resources in BPA's balancing authority. ICNU's analysis, however, demonstrated

that the size of the charges for some cogenerators would likely be “shockingly high.”

Id. at 8.

Finally, ICNU claims that the “potentially shockingly high DERBS rate is an unplanned increase in these facilities’ operating costs during a period of extremely difficult economic conditions.”

Id. at 9 (internal citations omitted).

BPA disagrees with ICNU that the DERBS rate will disproportionately harm cogeneration resources. Staff testifies that “the historical data we used in our analysis is reflective of the actual use of balancing reserve capacity by dispatchable energy resources.” Jackson *et al.*, BP-12-E-BPA-47, at 7. Staff then explains why cogeneration resources should be subject to the DERBS rate:

Cogeneration resources that are larger than 3 MW are included in BPA’s AGC system, and also contribute to the overall balancing reserve capacity requirement. Attachment 2, Dispatchable Energy Resources Subject to DERBS. We agree that these resources have a lesser cumulative imbalance (and balancing reserve capacity) need than the cumulative imbalances from larger thermal resources. However, we note that ICNU has submitted no evidence that the balancing reserve capacity requirement contribution of these resources is insignificant; accordingly, we see no basis to exempt such resources from the proposed definition of dispatchable energy resource and the DERBS rate proposal given the use of balancing reserve capacity by such resources.

Jackson *et al.*, BP-12-E-BPA-47, at 20.

There is no evidence in the rate case record to support ICNU’s contention that cogeneration resources contribute less to the balancing reserve capacity requirement for DERBS than other resources. *Id.* ICNU’s analysis appears to indicate that its cogenerators would be subject to high DERBS charges. ICNU Br., BP-12-B-IN-01, at 8. Under the rate design BPA is adopting in this ROD, charges will be proportional to actual use of DERBS. *See* Issue 3.5.2.2 above. Thus, cogenerators that do not maintain stable operations and scheduling accuracy will be assessed the DERBS per-megawatt rate above a 2 MW dead band. But if cogenerators typically have predictable operations that are not likely to cause BPA to need a significant amount of capacity to meet its within-hour capacity needs, then they should be able to manage their station control errors and reduce their exposure to the DERBS rate, and pay for only the amount of DERBS that they use above the 2 MW dead band.

The intent of the DERBS rate is not to unduly penalize generators. Rather, the DERBS rate serves to recover BPA’s costs of balancing reserve capacity use from the users that create those costs and to provide an economic incentive for better scheduling and operational accuracy. As Staff testifies: “The goal of the DERBS rate is to recover the costs associated with a dispatchable energy resource’s use of balancing reserve capacity, regardless of whether the use is avoidable or unavoidable.” Jackson *et al.*, BP-12-E-BPA-47, at 22.

Finally, BPA reflects any improvements by Dispatchable Energy Resources in their use of balancing reserve capacity based on the latest information available and accordingly has reduced the DERBS rate from the level in the Initial Proposal. This reduction will minimize the impact of the DERBS rate to all Dispatchable Energy Resources, including cogeneration resources.

Decision

The DERBS rate will not disproportionately harm cogeneration resources.

Issue 3.5.2.13

Whether the DERBS rate will create cross-subsidies among different generator types.

Parties' Positions

ICNU asserts that the DERBS rate will likely result in significant cross-subsidies between generators. ICNU Br., BP-12-B-IN-01, at 8. ICNU argues that cogenerators that normally have stable and predictable operations may be required to pay for a large portion of the reserve balancing costs caused by other generators. *Id.*

BPA Staff's Position

The historical data used in Staff's analysis is reflective of the actual use of balancing reserve capacity by Dispatchable Energy Resources. Jackson *et al.*, BP-12-E-BPA-47, at 7. Staff identifies improvements in the use of *dec* balancing reserve capacity by thermal generators and adjusts the Balancing Reserve Capacity Quantity Forecast for DERBS accordingly. *Id.* at 8.

Cogeneration resources that are larger than 3 MW are included in BPA's AGC system and also contribute to the overall balancing reserve capacity requirement. Jackson *et al.*, BP-12-E-BPA-47, at 20.

Evaluation of Positions

According to ICNU, a properly designed charge would be expected to allocate a smaller percentage of the costs to cogenerators because they "are typically smaller in size, operate in a predictable manner, and may change less than generators responding to market prices and wind changes." ICNU Br., BP-12-B-IN-01, at 8. ICNU argues that it is inequitable to require cogenerators to pay "far more" than the actual balancing reserve requirements they impose on the system. *Id.*

Based on the rate case record, BPA disagrees with ICNU that cogenerators should be exempt from the DERBS charge or given disparate treatment through a reduced or different DERBS rate design. ICNU appears to suggest that BPA should design DERBS rates based on the actual balancing reserve requirements of each individual non-Federal Dispatchable Energy Resource, *id.* at 9, but ICNU does not propose a viable rate design alternative to BPA's DERBS rate that would ensure BPA's recovery of costs. Even assuming that there was some basis in the record to

support individual rates based on the forecast balancing reserve usage of each generator, those rates would be administratively inefficient and would not capture the diversity benefits of pooling reserves. In contrast, BPA's balancing reserve capacity quantity forecast captures the diversity benefits of load and other generators to produce a lower overall balancing reserve capacity requirement for DERBS. Jackson *et al.*, BP-12-E-BPA-47, at 13. As a result, the DERBS rate produces benefits for all generators under that approach.

As explained above in Issue 3.5.2.2, BPA is adopting in this ROD a DERBS rate based on a per-megawatt charge above a 2 MW dead band. This rate design excuses DERBS charge deviations of 2 MW or less but charges users for their actual use of DERBS beyond this. If a generator has stable operations and consumes small quantities of balancing reserve capacity, that generator should be able to avoid or reduce any applicable DERBS charge. The DERBS rate design avoids any cross-subsidization among generators because it is based on an individual generator's station control error.

Cogeneration resources that are larger than 3 MW are included in BPA's AGC system, and those resources also contribute to the overall balancing reserve capacity requirement. Jackson *et al.*, BP-12-E-BPA-47, at 20. As a result, it is appropriate to charge cogenerators the DERBS rate since they contribute to the overall balancing reserve capacity requirement.

BPA recognizes that the DERBS rate is a new rate for BPA and BPA's customers. Thus, BPA will continue to evaluate the impact of the DERBS rate on all resource types over the rate period, and propose any necessary adjustments to the rate design in the next rate proceeding.

Decision

The DERBS rate does not create cross-subsidies among different generator types.

Issue 3.5.2.14

Whether implementation of the DERBS rate will harm economic recovery in the region.

Parties' Positions

ICNU argues that the DERBS rate constitutes an unplanned increase in the operating costs of cogeneration facilities during a period of extremely difficult economic conditions. ICNU Br., BP-12-B-IN-01, at 8-9. ICNU asserts that end use customers will unlikely be able to pass on the unplanned cost increase, and these additional costs will likely need to be absorbed through cost reductions, including potential layoffs. *Id.* at 9. ICNU notes that in past proceedings, BPA has recognized the importance of minimizing the impact of its rate increases and made discretionary decisions to lower its rate increase, especially during difficult economic conditions, and urges BPA to not adopt a DERBS rate to avoid potential harm to generators. *Id.*

BPA Staff's Position

This issue is first raised in surrebuttal testimony responding to Staff's revised DERBS proposal. Staff does not present a position on this issue.

Evaluation of Positions

ICNU raises concerns regarding the impact of the DERBS rate on cogeneration resources. ICNU Br., BP-12-B-IN-01, at 7-9. ICNU states that end use customers will unlikely be able to pass on the unplanned cost increase, and these additional costs will likely need to be absorbed through cost reductions, including potential layoffs. *Id.* at 9.

BPA is sensitive to ICNU's concerns; however, BPA must balance these concerns with the impact of cost shifts to other ratepayers. Nevertheless, BPA has taken several steps to lessen the impact of the DERBS rate while ensuring that BPA recovers its costs during the rate period.

First, BPA is adopting a DERBS rate based on a per-megawatt charge above a 2 MW dead band. This rate design excuses deviations of 2 MW or less from the DERBS charge but charges users for their actual use of DERBS. Most generators should be able to manage much of their station control errors within this 2 MW dead band. To the extent generators require balancing reserve capacity for DERBS above the 2 MW dead band, BPA believes it is appropriate to recover the costs of such use under the DERBS rate.

Second, BPA reduced the overall DERBS balancing reserve capacity requirement to reflect recent improvements in the use of balancing reserve capacity by Dispatchable Energy Resources. This will reduce the overall DERBS rate for all non-Federal Dispatchable Energy Resources and lessen any economic impact in the region.

Third, although not legally required to offer intra-hour scheduling, BPA expects to make intra-hour scheduling available by the start of the rate period. Intra-hour scheduling will enable cogenerators to reduce their station control error and thereby reduce their consumption of balancing reserve capacity under DERBS. To the extent such generators utilize DERBS, however, the DERBS rate will appropriately recover the costs for that use.

Finally, the DERBS rate also provides an incentive for better scheduling and operational accuracy. If BPA disregards the principle of cost causation and continues to recover its costs for DERBS from the ratepayers that do not take DERBS from BPA, there would be nothing to ensure that non-Federal Dispatchable Energy Resources would continue to improve their scheduling accuracy and operations and reduce their use of balancing reserve capacity on the system. The DERBS rate provides a strong incentive for non-Federal Dispatchable Energy Resources to reduce their use of balancing reserve capacity and thereby reduce costs on the system.

Consequently, because there is a limited amount of dollars at stake and it is spread across a wide base, BPA believes the DERBS rate will have a minimal impact on the regional economy.

Decision

Given the design of the DERBS rate, reduction in the balancing reserve capacity requirement, and availability of intra-hour scheduling during the rate period, the DERBS rate will have a minimal impact on economic recovery in the region.

3.5.3 Variable Energy Resource Balancing Service (VERBS) Issues

BPA provides VERBS (referred to as “Wind Balancing Service” in the ACS-10 rate schedules) as a control area service to wind and solar generating facilities in the BPA balancing authority area. VERBS provides the generation capability (ability to both increase and decrease generation) to follow within-hour variations of variable energy resources, primarily wind, in the BPA balancing authority area. VERBS is required to maintain the power system frequency at 60 Hertz in conformance with NERC and WECC reliability standards and provide regulation, following, and imbalance reserve needed to support wind and solar resources. The VERBS rate establishes charges for the three components of VERBS: regulation, for moment to moment variability; following, for longer-term variability within the hour; and imbalance, for additional longer-term variability within the hour caused by scheduling error. Jackson *et al.*, BP-12-E-BPA-29, at 30. Wind and solar generating facilities within the BPA balancing authority area must either purchase this service from BPA or make alternative comparable arrangements to satisfy their within-hour balancing service obligation. *See id.* at 34-36; Mainzer *et al.*, BP-12-E-BPA-23, at 34.

In this ROD, BPA is adopting two new formula rates under the VERBS rate schedule. Formula Rate I is designed to recover the costs of balancing reserve capacity purchases from non-Federal sources that are necessary to *replace* Federal balancing reserve capacity that becomes unavailable during the rate period. Jackson *et al.*, BP-12-E-BPA-47, Attachment 1, at 1-31 to 1-32. Formula Rate I is triggered if BPA can no longer provide the forecast amount of balancing reserve capacity from the FCRPS. *Id.*

Formula Rate II is designed to recover the costs of balancing reserve capacity purchases from non-Federal sources that are necessary to provide VERBS at a higher quality of service than BPA forecast (*i.e.*, higher than 99.5 percent) or if one or more participants in the Pacific Northwest utility industry, including regional organizations, asks BPA to increase the amount of balancing reserve capacity provided for VERBS or, because of a legal challenge to DSO 216, BPA is prevented from implementing DSO 216 or is required to amend it materially. Jackson *et al.*, BP-12-E-BPA-47, Attachment 1, at 1-32.

BPA evaluates policy issues pertaining to the VERBS Formula Rates in section 3.2.7 of this ROD.

Under the VERBS rate schedule, BPA is also adopting rates for VERBS Supplemental Service, described in section 3.2.10 of this ROD, and VERBS for Committed Intra-Hour Service Pilot Participants. In addition, BPA is adopting Provisional VERBS (also referred to as “Provisional Balancing Service”) in this ROD. Provisional VERBS is discussed in section 3.5.4 below.

Issue 3.5.3.1

Whether BPA should recover under VERBS Formula Rate I the “net” cost of non-Federal balancing reserve capacity purchases by BPA that are necessary to replace Federal balancing reserve capacity that becomes unavailable to provide VERBS during the rate period.

Parties’ Positions

PPC prefers a gross cost formula rate and disagrees with Staff’s Formula Rate I proposal. PPC Br., BP-12-B-PP-01, at 22. But PPC agrees that, overall, BPA Staff’s approach is consistent with preference provisions and rate directives set out in BPA’s statutes. *Id.*

NWG and Iberdrola disagree with PPC’s proposal to charge the gross cost of any incremental balancing reserve capacity purchases under the VERBS rate if Federal generation becomes unavailable. NWG Br., BP-12-B-NG-01, at 45; Iberdrola Br., BP-12-B-IR-01, at 31. NWG states that PPC’s approach would result in wind energy producers potentially paying twice for the same service: once under the VERBS rates and a second time as BPA actually procures the resource from a non-Federal source. NWG Br., BP-12-B-NG-01, at 45. NWG adds that under PPC’s proposal, preference customers would receive and retain the benefit of revenues from selling forecast balancing reserve capacity even if BPA did not provide such services from the Federal system. *Id.* NWG concludes that PPC’s proposal does not satisfy the principles of cost causation or equity. *Id.*

BPA Staff’s Position

Staff disagrees with PPC’s proposal to allocate to the VERBS Formula I rate the gross cost of any BPA purchases of incremental balancing reserve capacity from non-Federal sources that are necessary to replace federal balancing reserve capacity that becomes unavailable during the rate period. Jackson *et al.*, BP-12-E-BPA-47, at 41-42. If BPA did not take a net cost approach, customers paying a VERBS rate adjusted by the Formula Rate I would be paying duplicate costs for reserves supplied by third parties. *Id.* at 41.

Evaluation of Positions

PPC argues that the total cost of incremental purchases of balancing reserve capacity should be added to the VERBS rate. Baker *et al.*, BP-12-E-PP-01, at 20. PPC reasoned that “[r]ates for all customers are based on forecasts and we all take the risk that forecasts will be wrong. The fact that the forecast was wrong or a piece of equipment breaks does not relieve the customer from the need to pay the full rate. The piece of equipment has to be fixed, after all.” *Id.* at 20-21.

Staff disagrees with PPC’s suggestion. Staff explains:

BPA has proposed to implement Formula Rate I only in the event of unexpected loss of FCRPS ability to supply balancing reserve capacity. Without the net cost calculation, customers paying a VERBS rate adjusted by the Formula Rate I would be paying additional duplicate costs for reserves supplied by third parties. These third party reserves would replace FCRPS services that, by definition, were

unavailable. Power customers benefit from the provision of reserves from the FCRPS through a revenue credit based on forecast sales of reserves. Under the net cost approach, power customers and reserves customers share the cost of the inability of the FCRPS to supply these forecast reserves. Consequently, we believe that charging VERBS customers twice for the same supply of balancing reserve capacity would be inappropriate.

Jackson *et al.*, BP-12-E-BPA-47, at 41-42.

NWG and Iberdrola disagree with PPC's proposal to charge the gross cost of any incremental balancing reserve capacity purchases under the VERBS rate if Federal generation becomes unavailable. NWG Br., BP-12-B-NG-01, at 45; Iberdrola Br., BP-12-B-IR-01, at 31. NWG states that PPC's approach would result in wind energy producers potentially paying twice for the same service: once under the VERBS rates and a second time as BPA actually procures the resource from a non-Federal source. NWG Br., BP-12-B-NG-01, at 45. NWG adds that under PPC's proposal, preference customers would receive and retain the benefit of revenues from selling forecast balancing reserve capacity even if BPA did not provide such services from the Federal system. *Id.* NWG concludes that PPC's proposal does not satisfy the principles of cost causation or equity. *Id.*

PPC does not expressly oppose the net cost approach for Formula Rate I in its initial brief and appears to agree with Staff's overall approach to VERBS Formula Rate I. PPC Br., BP-12-B-PP-01, at 22. Thus, it appears unnecessary under these circumstances to resolve PPC's gross cost proposal for Formula Rate I. Nevertheless, to the extent this remains a contested issue, BPA agrees with NWG and Iberdrola that it would be inappropriate to charge VERBS customers the gross cost of incremental purchases of balancing reserve capacity during the rate period under Formula Rate I.

Since power customers benefit from the provision of reserves from the FCRPS through a revenue credit based on forecast sales of reserves, the net cost approach allows power customers and reserves customers to share the cost of the inability of the FCRPS to supply those forecast reserves. Jackson *et al.*, BP-12-E-BPA-47, at 41-42. As result, it would be inappropriate to charge VERBS customers twice for the same supply of balancing reserve capacity. *Id.*

Decision

BPA adopts a net cost approach under VERBS Formula Rate I.

Issue 3.5.3.2

If BPA must purchase incremental balancing reserve capacity from non-Federal sources because BPA underestimated the system's total balancing reserve capacity requirement using the BP-12 methodology and the 99.5 percent standard, whether BPA should recover those purchase costs from the VERBS Formula II rate.

Parties' Positions

NWG disagrees with PPC's testimony that if BPA needs to purchase additional balancing reserve capacity because it has under-estimated the system's total balancing reserve capacity need using the BP-12 methodology and the 99.5 percent standard, the costs of those purchases should be recovered under the VERBS Formula Rate II because this does not constitute a forecast error. NWG Br., BP-12-B-NG-01, at 74, *citing* Baker *et al.*, BP-12-E-PP-01, at 29-30.

PPC did not specifically raise this issue in its initial brief, but it comments generally that BPA's forecast of the balancing reserve capacity requirement is reasonable and supported by the record. PPC Br., BP-12-B-PP-01, at 4.

BPA Staff's Position

The forecast methodology in this case constrains the total balancing reserve capacity requirement to the incidental reserve usage by using incremental standard deviation. Puyleart *et al.*, BP-12-E-BPA-43, at 9. This is a change from the methodology used to forecast balancing reserve capacity requirements in the BPA-10 rate case. *Id.* The new methodology decreases the reserve requirements; however, even with the lower reserve requirements, BPA will continue with reliable operation of the FCRTS. *Id.* at 9-10.

Staff proposes a level of quality of service consistent with a 99.5 percent standard for VERBS. Generation Inputs Study, section 2.7.4; Jackson *et al.*, BP-12-E-BPA-29, at 39. If BPA decides to increase the quality of service of VERBS by increasing the quantity of balancing reserve capacity available to provide VERBS (*e.g.*, to satisfy a 99.7 percent balancing service standard), BPA may need to purchase balancing reserve capacity from non-Federal sources during the rate period to continue to provide the higher-quality VERBS. *Id.* at 39-40; Mainzer *et al.*, BP-12-E-BPA-23, at 50-51.

Formula Rate II may be triggered by a request for increased service levels beyond 99.5 percent or because DSO 216 curtailments are restricted by rule or court decision. Generation Inputs Study, section 10.5.3; Jackson *et al.*, BP-12-E-BPA-47, at 40.

Evaluation of Positions

In direct testimony, PPC stated several concerns regarding Staff's BP-12 balancing reserve capacity quantity forecast methodology. PPC stated that "BPA errs when it claims that use of the 99.5% standard in the FY 2010–11 period indicates future reliable operations in FY 2012-13." Baker *et al.*, BP-12-E-PP-01, at 28. PPC suggested that BPA calculate the amount of balancing reserve capacity requirements needed by the system using the methodology used in the BPA-10 rate case. *Id.* at 29. PPC reasoned that this "would cause BPA to set aside a greater amount of balancing reserves that would be consistent with the amount set aside during the FY 2010 period in which BPA has demonstrated reliable operations." *Id.* At a minimum, PPC stated, "BPA should acknowledge that if BPA needs to purchase additional reserves because it has under-estimated the system's total balancing reserve need using the BP-12 methodology and 99.5% standard, the costs of those incremental purchases should be recovered under the Formula Rate 2 in VERBS because this does not constitute 'forecast error.'"

Id. at 29-30. PPC’s brief states, in contrast, that the balancing reserve capacity forecast is reasonable. PPC Br., BP-12-B-PP-01, at 4.

NWG disagrees with PPC that forecast error associated with the BP-12 methodology should be recovered under Formula rates. NWG Br., BP-12-B-NG-01, at 74. NWG argues that PPC’s suggestion is unsupported by any ratemaking principle and is so broad that any forecast error or methodological error connected with any aspect of the Generation Inputs Study could arguably be allocated solely to the VERBS rate. *Id.*

In rebuttal testimony, Staff acknowledges that the BP-12 methodology results in a lower total balancing reserve capacity requirement and addresses PPC’s reliability concerns:

BPA will continue with reliable operation of the Federal Columbia River Transmission System (FCRTS). BPA has consistently been in compliance with North American Electric Reliability Corporation BAL standards and is allowing a small amount of reserve reduction (0.2 percent) in order to lessen the burden on the FCRPS. This may increase the number of events that fall into the parameters spelled out in DSO 216, but that does not equate to a decrease in system reliability.

Puyleart *et al.*, BP-12-E-BPA-43, at 10.

The primary issue PPC raised in testimony was that BPA should demonstrate it could maintain system reliability under a balancing reserve capacity requirement forecast using the BP-12 methodology. Baker *et al.*, BP-12-E-PP-01, at 28. Staff’s testimony demonstrates that the BP-12 methodology will not degrade system reliability despite any increase in DSO 216 events, and the statements in PPC’s brief that the BP-12 forecast is reasonable and supported by the record suggest that Staff resolved PPC’s reliability concern. Puyleart *et al.*, BP-12-E-BPA-43, at 9-10; PPC Br., BP-12-B-PP-01, at 4.

It appears unnecessary under these circumstances to resolve PPC’s alternative proposal that BPA rely on Formula Rate II if BPA purchases additional balancing reserve capacity associated with “forecast error.” Baker *et al.*, BP-12-E-PP-01, at 30. In addition, PPC does not raise this issue in their brief. If this were a contested issue, however, BPA is not convinced that PPC’s alternative proposal defines “forecast error” with enough specificity for BPA to actually implement that proposal. The record lacks evidence for BPA to develop a rate that defines when it would be necessary to trigger Formula Rate II to manage any “forecast error.” BPA is not precluded from utilizing VERBS Formula Rate II in the event one or more participants in the Pacific Northwest utility industry, including regional organizations, asks BPA to increase the amount of balancing reserve capacity provided for VERBS. Jackson *et al.*, BP-12-E-BPA-47, Attachment 1, at 1-13.

Decision

The forecast of the balancing reserve capacity requirements using the BP-12 methodology will not decrease system reliability; thus, it is unnecessary to include “forecast error” as a criterion under VERBS Formula Rate II.

Issue 3.5.3.3

Whether BPA should replace VERBS Formula Rates I and II by conducting a mid-rate period section 7(i) ratemaking process to set a rate to recover the cost of incremental purchases of non-Federal balancing reserve capacity that are necessary during the rate period to provide VERBS.

Parties' Positions

NWG states that BPA is proposing to move resource acquisition and ratemaking decisions from the statutory section 7(i) process into a notice and comment process. NWG Br., BP-12-B-NG-01, at 44. NWG argues that if BPA anticipates the need to acquire more than a *de minimis* amount of resources, BPA should initiate another rate proceeding and establish rates for such service under a full section 7(i) rate proceeding. *Id.*

BPA Staff's Position

For purchases of balancing reserve capacity for a term not longer than 2 months, Staff proposes that BPA give notice after-the-fact by posting the adjusted VERBS rate (revised to include the short-term purchase cost) on OASIS. Jackson *et al.*, BP-12-E-BPA-47, Attachment 1, at 1-12. For purchases of balancing reserve capacity for a term of longer than 2 months, Staff proposes that BPA give 15 calendar days' advance notice on its OASIS of a public meeting to discuss the proposed purchase and the expected adjusted rate. *Id.* Staff proposes that BPA take written comments on the proposed purchase up to 15 calendar days after the public meeting, and notify customers on OASIS within 30 days of the public meeting of BPA's decisions regarding the purchase and the adjusted VERBS rate. *Id.*

The intent of the public process is to review BPA's proposed purchases of non-Federal balancing reserve capacity with customers before committing to the purchase. *Id.* at 36. The proposed public process provides the necessary flexibility for BPA to make purchases of non-Federal balancing reserve capacity as necessary to continue to provide VERBS on both a short-term and long-term basis. *Id.* Moreover, when considering that BPA's rate period is only two years, the proposed public process affords interested parties adequate notice and comment opportunities for any purchases of balancing reserve capacity during this short timeframe.

Evaluation of Positions

NWG argues that under Staff's proposed public process for the VERBS Formula Rates, customers will have no ability to question the need for or the reasonableness of the cost of acquiring long-term resources. NWG Br., BP-12-B-NG-01, at 44. NWG adds that in the case of short-term purchases, customers are not entitled to the right of prior notice or comment. *Id.* NWG states that BPA Staff's Formula Rate proposal "raises procedural concerns." *Id.*

NWG's procedural due process concerns are without merit. Procedural due process generally requires notice and the opportunity to be heard prior to depriving one of a protected property interest. *Carpenter v. Mineta*, 432 F.3d 1029, 1036 (9th Cir. 2005). To sustain a procedural due process claim, NWG must prove that it has a protectable liberty or property interest and was

denied the process that it was due. *See Richard D. Foss v. Nat'l Marine Fisheries Serv.*, 161 F.3d 584, 589-590 (9th Cir. 1998). Even if NWG has standing to represent its members' due process complaint, NWG has made no demonstration in the rate case record that it has a protected property or liberty interest that would be deprived of due process by virtue of the VERBS Formula Rates.

Assuming NWG can prove a protectable property interest, NWG must then prove that BPA has not afforded it the process that it was due. *Id.* NWG argues that BPA is moving its ratemaking decisions into a notice and comment period instead of conducting a section 7(i) rate proceeding. NWG Br., BP-12-B-NG-01, at 44. This argument is based on the erroneous assumption that BPA would be required to initiate a section 7(i) rate proceeding during the rate period in order to recover the cost of non-Federal balancing reserve capacity purchases that are necessary to continue to provide VERBS. The purpose of a formula rate is to enable BPA to respond to clearly defined circumstances, and the formula rate is being subject to this section 7(i) rate proceeding. BPA decisions to incur a cost are not ratemaking and, hence, are not subject to a section 7(i) rate proceeding. It also appears that NWG misunderstands BPA's resource acquisition authority, which does not require BPA to initiate a section 7(i) rate proceeding to review BPA's decisions. 16 U.S.C. § 839d(a). Despite NWG's arguments to the contrary, the only process required for BPA to adopt a rate is the section 7(i) proceeding in which the Formula Rates are first adopted. NWG does not, however, contest the procedural due process afforded to it in this rate proceeding.

NWG is also mistaken to the extent that it implies that BPA lacks the authority to adopt a formula rate design to recover costs. As stated in section 1.1.2 of this ROD, the Administrator has broad discretion to interpret and implement statutory standards applicable to ratemaking. These standards focus on cost recovery and do not restrict the Administrator to any particular rate design methodology or theory. *See Pacific Power & Light Co. v. Duncan*, 499 F. Supp. 672 (D. Or. 1980); *accord City of Santa Clara v. Andrus*, 572 F.2d 660, 668 (9th Cir. 1978) ("most widespread use" standard is so broad as to permit "the exercise of the widest administrative discretion"); *Electricities of North Carolina v. Southeastern Power Admin.*, 774 F.2d 1262, 1266 (4th Cir. 1985). Formula rates are commonly used in the industry and are consistent with sound business principles. In addition, the Commission has confirmed several of BPA's formula rates in previous rate periods. *See United States Dep't of Energy – Bonneville Power Admin.*, 132 FERC ¶ 62,098 (2010) (confirming BPA's Reactive Supply and Voltage Control from Generation Sources formula rate); *United States Dep't of Energy – Bonneville Power Admin.*, 128 FERC ¶ 61,058 (2009) (confirming BPA's DSI formula rate). Hence, the VERBS Formula Rates are well within BPA's statutory authority to establish and fulfill BPA's responsibility to recover costs.

An additional section 7(i) process would also result in relitigation of the issues already addressed in this rate proceeding, such as the assignment of any VERBS balancing reserve capacity costs to the VERBS rate. At some point the rate case process must conclude and BPA must make a decision on the VERBS rate. Under the facts of this case, the VERBS Formula Rates provide administrative usefulness by avoiding the need to set new rates every time it is necessary to

purchase additional balancing reserve capacity to provide VERBS. As Staff explains in testimony:

The time required for a supplemental 7(i) process, even if expedited, would significantly impede BPA's ability to acquire any needed resources and recover those costs in a timely manner. We believe that the process we have proposed to support the formula VERBS rate will provide customers adequate opportunity to review and comment on any BPA-proposed resource acquisitions and the associated application of the formula rate to the cost of those acquisitions. *See Jackson et al.*, BP-12-E-BPA-29, section 7.2; *Jackson et al.*, BP-12-E-BPA-47, section 3.2. If BPA were to use a 7(i) process for setting rates for these resource acquisitions, in addition to running a procurement process and setting up precedent purchase agreements, we would need to prepare for and run a rate proceeding lasting a minimum of 90 days, and then put the rate into effect. Our view is that the formula rate simplifies the process and reduces the time for the process but still provides for adequate customer involvement to help inform resource acquisition and pricing decisions. *See Jackson et al.*, BP-12-E-BPA-47, section 3.2.

Mainzer *et al.*, BP-12-E-BPA-42, at 30-31. By virtue of containing a formula, the VERBS Formula Rates are also sufficient to put ratepayers on notice of those cost inputs. Such cost components are specified in the VERBS rate schedule. *Jackson et al.*, BP-12-E-BPA-47, Attachment 1, at 1-11 to 1-13; *see also* Issue 3.5.3.5 below.

An additional section 7(i) rate proceeding is also unnecessary to ensure that BPA minimizes its non-Federal balancing reserve capacity purchase costs. Since BPA can trigger the VERBS Formula Rates only to recover the costs of balancing reserve capacity that is necessary to maintain the quality level of service for VERBS, the costs recovered under the VERBS Formula Rates are proportional and limited to the services that are provided to VERBS customers. If BPA did not make purchases of balancing reserve capacity when needed, customers could be subject to increased DSO 216 curtailments or an overall degradation of VERBS. *Jackson et al.*, BP-12-E-BPA-47, at 34-35. There is nothing in the record indicating that customers are prepared to accept a degradation of service as an alternative to paying for non-Federal balancing reserve capacity that is necessary for BPA to continue to provide VERBS at the requisite quality level of service. *See also* Roach, Oral Tr. at 208, and Hall, Oral Tr. at 208.

Finally, BPA provides transparency to balancing reserve capacity purchases, where possible, to create incentives to minimize cost exposure. BPA is adopting a public process for stakeholders to review BPA's decisions to purchase non-Federal balancing reserve capacity during the rate period for the purpose of providing VERBS. In explaining this rationale, Staff states:

BPA does not operate in isolation, independent from public review or scrutiny. Indeed, one of the primary goals in designing the proposed formula rates was to ensure transparency through the process. The proposed public process provides an additional check to ensure that BPA incurs only reasonable costs that are necessary under the circumstances. Staff recognizes that customers will not have advance notice of balancing reserve capacity purchases of a term of two months

or less. However, Staff believes this flexibility is necessary for BPA to maintain system reliability while continuing to provide VERBS to its customers.

Jackson *et al.*, BP-12-E-BPA-47, at 39-40. Given the reliability concerns that may require a short-term purchase of balancing reserve capacity, BPA believes after-the-fact notice is appropriate. Although BPA is not adopting a formal comment period as part of the public process, customers are not precluded from submitting written comments to BPA before BPA posts the formula-adjusted VERBS rate regarding short-term purchases of non-Federal balancing reserve capacity to provide VERBS. Accordingly, BPA believes the VERBS Formula Rates public process is sufficient to provide notice and comment opportunities given the circumstances in which BPA may need to purchase balancing reserve capacity and will ensure that BPA takes all steps necessary to minimize costs that are recovered through the VERBS Formula Rates.

Decision

The VERBS Formula Rates are well within BPA's statutory authority to recover costs. An additional section 7(i) rate proceeding is unnecessary. BPA will provide a public process to review long-term purchases (greater than 60 days) of non-Federal balancing reserve capacity.

Issue 3.5.3.4

Whether the VERBS formula rates lack incentives for BPA to manage resources and costs effectively.

Parties' Positions

NWG argues that Staff's proposal would allow BPA to pass through all costs incurred after the fact, giving BPA little incentive to manage costs or procure balancing reserves efficiently, especially with respect to short-term purchases. NWG Br., BP-12-B-NG-01, at 44-45.

NWG asserts that there are no limits on the potential rate increases that could be passed through to customers taking service under the VERBS rate, and that other rate adjustments, such as the CRAC, are subject to limits. *Id.* at 43-44.

Iberdrola argues that BPA will likely over-procure and over-pay for balancing reserve capacity given the current market structure. Iberdrola Br., BP-12-B-IR-01, at 32-33.

BPA Staff's Position

The potential cost exposure from formula rates is reasonable. Jackson *et al.*, BP-12-E-BPA-47, at 40. The formula rates are designed to ensure that BPA can continue to provide the expected quality level of balancing service to all VERBS customers during the rate period. The proposed rates also ensure that those who create the costs bear the costs. *Id.* at 39.

Evaluation of Positions

NWG argues that Staff's VERBS Formula Rates proposal would allow BPA to pass through all costs incurred after the fact, giving BPA little incentive to manage costs or procure balancing reserves efficiently, especially with respect to short-term purchases. NWG Br., BP-12-B-NG-01, at 44-45.

Staff disagrees:

We disagree with NWG that the proposed formula rates provide no incentive for BPA to minimize costs. The purpose of the proposed formula rates is not to arbitrarily increase costs to VERBS customers. To the contrary, the proposed formula rates are designed to ensure that BPA can continue to provide the expected quality level of balancing service to all VERBS customers during the rate period. The proposed rates also ensure that those who create the costs bear the costs.

Jackson *et al.*, BP-12-E-BPA-47, at 39 (emphasis added). Staff also testifies as to why the formula rates for VERBS are sufficient to minimize cost impacts during the rate period:

BPA does not operate in isolation, independent from public review or scrutiny. Indeed, one of [the] primary goals in designing the proposed formula rates was to ensure transparency through the process. We proposed a public process specifically to ensure customer review of BPA's decisions regarding non-Federal balancing reserve capacity purchases. The proposed public process provides an additional check to ensure that BPA incurs only reasonable costs that are necessary under the circumstances.

We recognize that customers will not have advance notice of balancing reserve capacity purchases of a term of two months or less. However, we believe this flexibility is necessary for BPA to maintain system reliability while continuing to provide VERBS to its customers.

Jackson *et al.*, BP-12-E-BPA-47, at 39-40 (emphasis added). NWG does not refute these facts. As discussed above in section 3.2.7, it is the growth of variable energy resources in the BPA balancing authority area that contributes to the need for significant quantities of balancing reserve capacity to provide VERBS. In the event that BPA can no longer provide forecast levels of balancing reserve capacity, BPA must have the ability to recover its costs if it must purchase balancing reserve capacity from non-Federal sources.

As explained above, BPA provides transparency to balancing service purchases, where possible, to create incentives to minimize cost exposure. Through the VERBS Formula Rates public process, customers will have opportunities to examine BPA's decisions regarding purchases of balancing reserve capacity during the rate period, giving BPA sufficient incentives to minimize the cost exposure of VERBS customers under the Formula Rates.

NWG also states that “there are no limits on the potential rate increases that could be passed through to customers taking service under the VERBS rate. Other rate adjustments, such as the CRAC, are subject to limits.” NWG Br., BP-12-B-NG-01, at 43-44.

When considering the real reliability and quality of service impacts associated with an insufficiency of balancing reserve capacity during the rate period, BPA believes a cap on the cost exposure under the VERBS Formula rates would be inconsistent with cost causation and the overall purpose of the VERBS Formula Rates. With the exception of variable energy resources, no other customer class is likely to consume the total amount of balancing reserve capacity available in the balancing authority area due to its own schedule error. To maintain system reliability under such circumstances, BPA must stand ready with balancing reserve capacity to provide VERBS and must utilize its operational and reliability protocols to keep the deployment of balancing reserve capacity within defined limits.

NWG does not respond to Staff’s concerns regarding system reliability or maintaining the quality of service of VERBS during the rate period. Rather, NWG argues that BPA would not treat other customers similarly. NWG Br., BP-12-B-NG-01, at 44; Hall, Oral Tr. at 208. That argument is unpersuasive. The record indicates that BPA expects a significant growth of variable energy resources in the BPA balancing authority area over the rate period. Puyleart *et al.*, BP-12-E-BPA-24, at 12. No other customer class is growing at a similar pace. It is this growth that is driving the need for balancing reserve capacity in the BPA balancing authority area. Jackson *et al.*, BP-12-E-BPA-47, at 38-39. Accordingly, it is the need for balancing reserve capacity that requires a cost recovery mechanism such as the VERBS Formula Rates to protect other ratepayers from cost shifts.

In addition, BPA finds no basis in the record to shift the cost risks associated with purchases of non-Federal balancing reserve capacity to provide VERBS to customers that do not take VERBS from BPA. If BPA established a cap on the Formula Rates, NWG’s logic would require BPA to subsidize a portion of the balancing reserve capacity requirements for variable energy resources instead of allocating those risks to VERBS customers. As explained above in section 3.2.7.5, however, the Formula Rates allow BPA to recover costs consistent with the principle of cost causation in the event of unforeseen changes to operations of the FCRPS. Without Formula Rates, BPA would be forced to use financial reserves to fund balancing reserve capacity purchases that are needed to continue to provide VERBS. This would create an inequitable cost shift to the customers that do not take VERBS. Jackson *et al.*, BP-12-E-BPA-47, at 33.

PPC states that since any incremental balancing reserve capacity purchases “will be used during the FY 2012–2013 rate period ... and it is best that these costs be collected during that rate period.” Baker *et al.*, BP-12-E-PP-01, at 20. BPA agrees. Considering the fact that balancing reserve capacity purchased during the rate period will be used during the rate period to provide VERBS, recovering costs during the rate period is consistent with sound business principles.

Finally, Iberdrola raises concerns that BPA may overprocure and overpay for balancing reserve capacity during the rate period under the current market structure. Iberdrola Br., BP-12-B-IR-01, at 32-33; *see also* NWG Br., BP-12-B-NG-01, at 44-45. Iberdrola states that in the short term,

few incremental balancing reserve capacity acquisition options exist given the absence of a market in the West. Iberdrola Br., BP-12-B-IR-01, at 32-33. Iberdrola notes that multiple initiatives are currently underway that may provide BPA with access to flexible generation outside of the BPA balancing authority area at a much lower cost, such as an Energy Imbalance Market. *Id.* at 33. Iberdrola makes several recommendations for BPA to maximize existing Federal system capacity to ensure that wind generation within BPA's balancing authority area can be reliably integrated until an Energy Imbalance Market can be implemented. *Id.* at 33-34.

BPA acknowledges that the current market structure is not ideal. As Iberdrola notes, multiple initiatives are currently underway that may improve flexibility and options in the marketplace. BPA supports these initiatives; however, BPA cannot forgo its cost recovery mechanisms given the possibility that BPA may need to purchase balancing reserve capacity from non-Federal sources to continue to provide VERBS during the rate period. This is especially true considering that the only alternatives are to degrade the quality of service to VERBS customers or shift the costs of such purchases to ratepayers that do not take VERBS. Those alternatives are not supported by the rate case record. *See* PPC Br., BP-12-B-PP-01, at 22; Skeahan *et al.*, BP-12-E-JP01-01, at 13.

Even under the current market structure, however, BPA does not believe the cost exposure under the VERBS Formula Rates is unreasonable:

Cost recovery under the proposed Formula Rate I is limited to the amount of balancing reserve capacity that is necessary to maintain BPA's balancing reserve capacity quantity forecast for the rate period. Formula Rate I does not recover costs for un-forecast increases in VERBS service levels.

Jackson *et al.*, BP-12-E-BPA-47, at 40.

Furthermore, BPA cannot utilize Formula Rate II to increase the rate for VERBS arbitrarily. Any purchase of balancing reserve capacity to provide VERBS must be limited to the quality of service requirement of VERBS. Formula Rate II ensures that BPA will be able to provide VERBS at the requisite quality level of service for VERBS and recover those costs:

The proposed Formula Rate II may be triggered by a request for increased service levels above 99.5 percent or because DSO 216 curtailments are restricted by rule or court decision. Study, section 10.5.3. However, we do not believe the cost exposure under Formula Rate II is unreasonable. In the event that the proposed Formula Rate II is triggered, any BPA purchase of non-Federal balancing reserve capacity would be for the purpose of continuing to provide VERBS to BPA's customers at the requested or required quality level of service.

Jackson *et al.*, BP-12-E-BPA-47, at 40. DSO 216 serves as BPA's primary tool for managing reliability of the BPA balancing authority area and for enforcement of limits on BPA's balancing reserve capacity commitment. Mainzer *et al.*, BP-12-E-BPA-42, at 19. In the event BPA's use of DSO 216 is prohibited, Formula Rate II allows BPA to recover the additional costs of maintaining service level and system reliability, and therefore is necessary under the circumstances.

As discussed above, it is also appropriate to assign the risks associated with Formula Rate II to VERBS customers because BPA would not need to purchase non-Federal balancing reserve capacity but for the growth and balancing requirements of variable energy resources:

BPA Staff has forecast a significant increase in the amount of wind generation integrating into the BPA balancing authority area during the rate period. Documentation, Table 2.1. If BPA did not offer VERBS or integrate variable energy resources, BPA would have sufficient FCRPS balancing reserve capacity available to provide the forecast balancing reserve capacity requirements for forecast loads and other resources in the BPA balancing authority area. In that case, it would be unnecessary to make non-Federal purchases of balancing reserve capacity.

Jackson *et al.*, BP-12-E-BPA-47, at 38-39. Accordingly, BPA believes that assigning the costs of non-Federal balancing reserve capacity purchases to provide VERBS during the rate period is consistent with the principle of cost causation and is, therefore, appropriate. Additionally, based on the facts and circumstances under which the Formula Rates would apply, the record indicates that there are adequate incentives for BPA to minimize the cost exposure of VERBS customers under the Formula Rates.

Decision

BPA has sufficient incentives to minimize cost exposure under the VERBS Formula Rates.

Issue 3.5.3.5

Whether the VERBS billing factor should be based on a per-megawatt usage charge.

Parties' Positions

According to SCE, the current VERBS rate structure based on nameplate capacity is inefficient and does not follow principles of cost causation. SCE Br., BP-12-B-SC-01, at 7. SCE cites to Staff's DERBS rate proposal as an example of a rate with a billing factor based on the use of balancing reserve capacity by each generator, calculated independently of other generators. *Id.* at 8. Citing to Staff's justification for the DERBS rate, SCE argues that BPA should follow the same approach for the VERBS rate to avoid inequitable cost shifts to other users of the balancing reserve capacity on the system. *Id.* SCE states that all generators should be subject to a base charge to recover a portion of the revenue requirement; however, the remainder of the revenue requirement should be recovered on an individual generator basis from a per-megawatt charge based on the maximum one-minute station control error of the generator. *Id.*

NWG argues that Staff's proposed VERBS rate does not meet the Commission's proposed standards for such a rate due to its lack of a volumetric charge. NWG Br., BP-12-B-NG-01, at 19. NWG states that structuring BPA's VERBS rate as proposed by the Commission would

provide transparency to BPA's pricing and send appropriate price signals that a capacity-based rate, such as the current VERBS rate, cannot. *Id.*

BPA Staff's Position

Staff supports a billing factor based on installed capacity or highest monthly generation output. *See Jackson et al.*, BP-12-E-BPA-29, section 7; Jackson *et al.*, BP-12-E-BPA-47, section 3.5.

Evaluation of Positions

In the Initial Proposal, Staff noted that it considered two rate designs for VERBS. Jackson *et al.*, BP-12-E-BPA-29, at 32-33. The first was a customer's share of the BPA system within-hour variability during a month or a quarter, called the Incremental Standard Deviation. *Id.* at 32. Staff also considered using the average of the monthly or quarterly absolute deviation. *Id.* Each alternative would have recovered the same fixed monthly revenue requirement. Staff decided not to propose these alternatives for the rate period because it would be unlikely that BPA could implement necessary changes to its billing systems prior to the start of the rate period.

Notably, in direct testimony, no party proposed an alternative to Staff's proposal to continue to use installed capacity (or the highest monthly generation output, as discussed in Issue 3.5.3.6 below) as the billing factor for VERBS. In their briefs, SCE and NWG argue that BPA should adopt a new billing factor for the VERBS rate. NWG cites to the Commission's VER NOPR as support of a rate design for VERBS that includes a volumetric charge. NWG Br., BP-12-B-NG-01, at 19. Specifically, SCE states that BPA should adopt for VERBS a rate design that is similar to that of DERBS. SCE Br., BP-12-B-SC-01, at 8. SCE asserts that a VERBS rate structure based on nameplate capacity is inefficient and inconsistent with principles of cost causation. *Id.* at 7.

Neither SCE nor NWG proposes a specific VERBS rate design alternative that would ensure that BPA recovers the costs associated with providing balancing reserve capacity for VERBS. SCE suggests that BPA adopt the DERBS rate design for VERBS. The rate case record, however, does not contain substantial evidence to support a similar rate design alternative for VERBS. There is more cost risk associated with setting a variable rate for variable energy resources than there is for Dispatchable Energy Resources. VERBS has a larger revenue requirement and deals with variable energy resources that are dependent on weather conditions and significant quantities of balancing reserve capacity that must be available to manage operational uncertainty. *See Mainzer et al.*, BP-12-E-BPA-23, at 4; Mainzer *et al.*, BP-12-E-BPA-42, at 14; and Klippstein *et al.*, BP-12-E-BPA-44, Attachment 5, at 5-1. In contrast, Dispatchable Energy Resources are able to control their output to a certain extent (*see Jackson et al.*, BP-12-E-BPA-47, at 23) and have relatively stable fuel sources, and thus, produce a smaller need for balancing reserve capacity, lower associated revenue requirement, and less under-recovery risk associated with a variable rate. *See also Jackson et al.*, BP-12-E-BPA-47, at 6-8 (describing the recent operational improvements of Dispatchable Energy Resources and the balancing reserve capacity quantity forecast for DERBS).

In addition, Staff proposes a usage charge rate for DERBS to gain experience with this rate design, and to explore the billing issues and efficacy of that rate design on a smaller scale. Although NWG points to the Commission's VER NOPR as support of a new rate design for VERBS, the Commission has not yet adopted a final rule regarding a Generator Regulation and Frequency Response rate. Moreover, although the Commission's guidance in the NOPR may be instructive, the Commission's proposal is currently not specific enough to develop a rate design that will ensure BPA's recovery of costs for VERBS.

Although BPA believes a combination of a fixed and volumetric charge for VERBS that ensures some level of cost recovery may be appropriate in the future, it would be inappropriate for BPA to adopt a new VERBS rate design at this stage in the rate proceeding, especially without knowing the administrative and billing impacts associated with such a rate design. However, BPA will continue to explore VERBS rate design alternatives and intends to set up technical workshops with its customers over the rate period in preparation for the next rate proceeding.

BPA notes that the parties had several opportunities to suggest alternative rate designs and to raise this issue in their direct testimony, but failed to do so. In contrast, BPA has had ample experience and success with a billing factor for the current Wind Balancing Service rate based on installed capacity. BPA does not believe the evidence in the rate case record supports SCE's contention that a billing factor based on installed capacity is inefficient or inconsistent with cost causation principles. Indeed, the record indicates the opposite—that the billing factor for VERBS is appropriate because it has not been a significant issue in this proceeding.

Therefore, when considering the rate case record as a whole, BPA believes a VERBS rate with a billing factor based on installed capacity is appropriate.

Decision

During the FY 2012–2013 rate period, BPA will continue to explore in a series of technical workshops with customers the design of a VERBS rate that includes a volumetric charge, but will use a billing factor based on installed capacity (or highest monthly generation output as described in Issue 3.5.3.6 below) for the VERBS rate during the rate period.

Issue 3.5.3.6

Whether the VERBS billing factor should be based on the greater of a wind or solar plant's highest monthly generation output or installed capacity.

Parties' Positions

NWG supports Staff's proposal for revising the VERBS billing factor. NWG clarifies that the current billing determinant is not an uncompensated use of balancing reserves since any wind generation amounts above nameplate capacity have already been accounted for in BPA's revenue requirement for the VERBS rate. NWG Br., BP-12-B-NG-01, at 77.

BPA Staff's Position

Staff proposes modifying the VERBS billing factor to address a situation in which there is a mismatch between reported nameplate capacity and the actual maximum output of the facility. Jackson *et al.*, BP-12-E-BPA-47, at 50.

Evaluation of Positions

Staff proposes that BPA modify the VERBS billing factor to resolve instances where there is a mismatch between the reported nameplate capacity of a wind generating facility and the actual maximum output of the facility. Jackson *et al.*, BP-12-E-BPA-47, at 50.

NWG supports Staff's proposal, NWG Br., BP-12-B-NG-01, at 77, and no rate case party opposes this modification.

BPA agrees that the modification is necessary to address the situation where there is a mismatch between the reported nameplate capacity and actual maximum output of the generating facility.

Decision

BPA is modifying the VERBS billing factor to be based on the greater of the maximum one-hour generation or the nameplate of the plant in kilowatts.

3.5.4 Provisional VERBS Issues

Provisional VERBS is a new Control Area Service under the VERBS rate schedule for the FY 2012–2013 rates. This service cannot be requested, but it is offered to generating customers that are subject to VERBS rates if (1) they cannot meet the requirements to continue self-supplying one or more elements of balancing service (regulation and following, imbalance); or (2) the customer had an expected interconnection date after the FY 2012–2013 rate period (facility not included in reserve forecasts), and the customer accelerates the interconnection date into the FY 2012–2013 rate period. When a Generating Customer takes Provisional VERBS, BPA does not provide any additional *inc* and *dec* balancing reserve capacity to provide Provisional VERBS to the customer. Mainzer *et al.*, BP-12-E-BPA-23, at 34-35; Jackson *et al.*, BP-12-E-BPA-29, at 36.

Issue 3.5.4.1

Whether BPA should offer Provisional Balancing Service to generating customers that either (1) fail to continue to self-supply the imbalance component to VERBS during the rate period, or (2) fail to make a balancing service election to take VERBS from BPA during the rate period, but accelerated their interconnection date into the rate period.

Parties' Positions

Iberdrola argues that it is inappropriate to charge the full VERBS rate to a customer when the customer is able to access the VERBS service only to a limited extent. Iberdrola Br., BP-12-B-IR-01, at 19. Iberdrola asserts that BPA will over-collect for VERBS, the customer will pay for a service that it does not receive, and the frequencies of DSO 216 limitations and curtailments are likely to severely impact the customer's business. *Id.* at 20. Iberdrola also argues that BPA Staff's proposal for Provisional Balancing Service is unduly discriminatory, particularly when combined with DSO 216 impacts. *Id.* at 19.

BPA Staff's Position

Staff proposes offering Provisional Balancing Service to generating customers that fail to continue to self-supply during the rate period or that have accelerated their interconnection date into the rate period. Jackson *et al.*, BP-12-E-BPA-29, at 35-36.

Charging the full VERBS rate for such customers will provide an incentive for customers to commit to the services they intend to take, whether from BPA or through self-supply for the rate period. Jackson *et al.*, BP-12-E-BPA-47, at 29. BPA required each customer to elect to take either VERBS from BPA or self-supply by May 1, 2011. It is critical that BPA receives this information in advance of the Final Proposal in order to set rates and to plan the BPA system to provide VERBS for the rate period.

Evaluation of Positions

In the Initial Proposal, Staff proposed a new service called Provisional VERBS or "Provisional Balancing Service":

Provisional Balancing Service is a new Control Area Service proposed for FY 2012–2013 rates. The service cannot be requested, but it is offered to Generating Customers that are subject to VERBS rates if (1) they cannot meet the requirements to continue to self-supplying one or more elements of Balancing Service (regulation and following, imbalance); or (2) the Generator had an expected interconnection date after the FY 2012–2013 rate period (facility not included in reserve forecasts), and the Customer accelerates the interconnection date into the FY 2012–2013 rate period. BPA will not increase the maximum *inc* and *dec* balancing reserve capacity available to provide balancing service to Provisional Balancing Service customers.

Jackson *et al.*, BP-12-E-BPA-29, at 35-36 (internal citations omitted). Under Staff's Initial Proposal, BPA would charge Provisional Balancing Service customers the full VERBS rate. In rebuttal testimony, Staff revised this proposal to charge a discounted rate to Provisional Balancing Service customers that fail to continue to self-supply during the rate period because BPA recalled an award of dynamic transfer capability. Jackson *et al.*, BP-12-E-BPA-47, at 26-28. This issue is discussed further in Issue 3.5.4.2 below.

Iberdrola asserts that it is unclear what a transmission customer receives when it pays for Provisional Balancing Service, and that BPA is proposing to charge and collect as if balancing

reserves were fully set aside for such customer when in actuality no reserves are set aside. Iberdrola Br., BP-12-B-IR-01, at 20. Iberdrola states that charging the full VERBS rate to a Provisional Balancing Service customer when that customer is able to access the VERBS service to only a limited extent is inconsistent with cost causation. *Id.*

BPA disagrees with Iberdrola's contentions. BPA believes it is appropriate to charge VERBS customers the full VERBS rate for limited access to the total pool of balancing reserve capacity for several reasons.

First, charging the full VERBS rate to Provisional Balancing Services is appropriate given that the quality of service under Provisional Balancing Service should be very similar to VERBS:

Customers taking Provisional Balancing Service will be subject to a lower threshold for curtailment under DSO 216. Given that DSO 216 events are relatively low in frequency, those customers taking Provisional Balancing Service would receive the same quality of service as customers taking full VERBS most of the time and would receive a lesser quality of service for a small percentage of the time. We believe that charging the full VERBS rate, but setting the rate discount under certain conditions consistent with the threshold for DSO 216 under Provisional Balancing Service [i.e., when BPA recalls an award of DTC that causes a self-supplier to fail the self-supply requirements], is consistent with cost causation while simultaneously protecting the quality of service for other VERBS customers.

Jackson *et al.*, BP-12-E-BPA-47, at 29 (emphasis added).

Second, charging the full VERBS rate (notwithstanding the limited circumstance where BPA recalls an award of DTC from a self-supplier), provides an incentive to customers to commit to the services they intend to take during the rate period:

[W]e believe charging the full VERBS rate for such customers will provide an incentive for customers to commit to the services they intend to take, whether from BPA or through self-supply for the rate period. BPA is requiring each customer to elect to take either VERBS from BPA or self-supply by May 1, 2011. It is critical that BPA receives this information in advance of the final rate proposal in order to set rates and to plan the BPA system.

Id. As the balancing authority, BPA is responsible for maintaining load and resource balance at all times. Mainzer *et al.*, BP-12-E-BPA-23, at 11. This important reliability function depends, in large part, on BPA's ability to ensure sufficient availability of balancing reserve capacity to provide VERBS and other services within the BPA balancing authority area. Charging the full VERBS rate to Provisional Balancing Service customers ensures that customers will take all actions possible to continue to abide by their self-supply requirements. It also ensures that the customers that did not elect to take VERBS from BPA for the rate period do not later impact the quality of service of the customers that complied with the balancing service election requirements. Each Customer is given a choice prior to the rate period to simply elect to take VERBS during the rate period or self-supply their VERBS requirement.

Third, the goals of the Provisional Balancing Service rate are not limited to cost causation principles. Penalty or default rates, for example, may have important cost components, but those rates also serve important policy objectives that are consistent with sound business principles. As described above, Provisional Balancing Service serves important business and policy purposes when a customer fails to abide by the self-supply requirements or fails to elect to take VERBS from BPA during the rate period. Charging the full VERBS rate provides an incentive for those customers to abide by BPA's planning, operational, and reliability requirements. Nevertheless, for the reasons discussed above regarding the quality of service provided under Provisional Balancing Service, BPA believes that the design of the rate for Provisional Balancing Service satisfies the principle of cost causation.

Finally, Iberdrola alleges that Provisional Balancing Service is unduly discriminatory, particularly when combined with DSO 216 impacts. Iberdrola Br., BP-12-B-IR-01, at 19. Based on the important cost and policy reasons that support Provisional Balancing Service, BPA disagrees with Iberdrola's assertion. First, however, it is important to clarify that the legal standards that govern BPA ratemaking do not include an undue discrimination standard. As stated in section 1.3 of this ROD, the legal standards that govern BPA ratemaking derive from the Flood Control Act and from BPA's organic statutes. Commission review of BPA's rates is limited to the three criteria specified in section 7(a)(2) of the Northwest Power Act. 16 U.S.C. § 839e(a)(2); *see also* ROD section 1.3. BPA has voluntarily filed a reciprocity tariff with the Commission and adheres to open access principles in its sale of transmission. However, Order No. 890 and related open access principles are not legally binding on BPA and do not form part of either Commission or Ninth Circuit review of BPA's rates. Nevertheless, BPA will address Iberdrola's factual arguments.

BPA believes Provisional Balancing Service is not unduly discriminatory, but is reasonable based on the facts that distinguish the customers that might be eligible for the service. Under the facts, a customer must do one of two things to receive Provisional Balancing Service: fail to meet the self-supply standards to which the customer agreed, or accelerate its interconnection date into the rate period and fail to elect to take VERBS from BPA. These circumstances are the business risks that the customer chooses to bear, and they have no causal relationship to BPA.

The level of balancing reserve capacity and treatment under DSO 216 for Provisional Balancing Service customers is appropriate given these facts. BPA must forecast the need for balancing reserve capacity for planning and reliability purposes. Increasing the balancing reserve capacity requirement to enable Provisional Balancing Service customers to take full VERBS would shift the costs of any additional balancing reserve capacity to other customers. In addition, as stated above, customers taking Provisional Balancing Service will be subject to a lower threshold for curtailment under DSO 216. Jackson *et al.*, BP-12-E-BPA-47, at 29; *see also* Mainzer *et al.*, BP-12-E-BPA-23, at 6, 31-32 (describing DSO 216). If BPA allows Provisional Balancing Service customers to utilize the same pool of reserves that VERBS customers use without a lower DSO 216 curtailment threshold, Provisional Balancing Service customers would shift the risk of DSO 216 curtailments to all other VERBS customers and degrade the overall quality of service of VERBS. There is nothing in the rate case record to support such a result. As

explained below in Issue 3.5.4.2, however, to the extent BPA contributes to a customer's failure to self-supply during the rate period because BPA recalls an award of DTC, BPA will offer that customer a discounted Provisional Balancing Service rate.

Further, Provisional Balancing Service provides an incentive for customers to commit to the services they intend to take, whether from BPA or through self-supply for the rate period. Jackson *et al.*, BP-12-E-BPA-47, at 29. This incentive provides additional justification for the differences between Provisional Balancing Service and full VERBS.

Decision

Provisional Balancing Service is appropriate under the circumstances and is not unduly discriminatory. BPA will charge the full VERBS rate to Provisional Balancing Service to customers that fail to continue to self-supply during the rate period (except under the circumstance where the self-supplier fails because BPA recalls an award of DTC) or accelerate their interconnection dates into the rate period without first having elected to take VERBS from BPA in accordance with BPA's Balancing Service Election requirements.

Issue 3.5.4.2

Whether customers that fail to self-supply during the rate period because BPA recalls an award of DTC award should pay 70 percent to the VERBS rate.

Parties' Positions

Iberdrola states that it is inappropriate for self-suppliers to bear all of the risk associated with failure of self-supply participation due to a BPA decision to recall DTC. Iberdrola Br., BP-12-B-IR-01, at 21. Iberdrola states that BPA should reduce the Provisional Balancing Service rate to reflect the limited nature of the service. *Id.* Iberdrola recommends that, at a minimum, BPA should discount the Provisional Balancing Service rate by 50 percent to reflect the significant risk imposed on customers forced to take an inferior service. *Id.*

BPA Staff's Position

Staff proposes to charge the full VERBS rate for Provisional Balancing Service. Jackson *et al.*, BP-12-E-BPA-47, at 29. However, if BPA recalls an award of DTC for the remainder of the rate period from a VERBS customer that is self-supplying balancing reserves and, as a result of BPA's recall of such award, that customer must take Provisional Balancing Service, Staff proposes to charge such customer 70 percent of the VERBS rate. Jackson *et al.*, BP-12-E-BPA-47, at 28.

Evaluation of Positions

In rebuttal testimony, in response to Iberdrola's concerns, Staff revised its Initial Proposal to address the unlikely situation in which BPA may recall an award of dynamic transfer capability from a self-supplying customer during the rate period:

Although BPA does not anticipate recalling Dynamic Transfer Capability (DTC) during the rate period, we have revised our proposal for Provisional Balancing Service to address that issue. We propose that if, as a result of limited DTC on BPA's system, BPA were to recall an award of DTC for the remainder of the rate period from a VERBS customer that is self-supplying balancing reserves and, as a result of BPA's recall of such award, that customer must take Provisional Balancing Service, then the discounted rate for Provisional Balancing Service would be set at 70 percent of the VERBS rate. Under those circumstances, we are proposing to set the discounted Provisional Balancing Service rate at an amount equal to the percentage of balancing reserves used by BPA's balancing authority that would trigger a DSO 216 event for such customer. Because we anticipate that the trigger would be 70 percent of available reserves used by the balancing authority, we have established the discount for Provisional Balancing Service accordingly.

Jackson *et al.*, BP-12-E-BPA-47, at 27-28.

Iberdrola does not address Staff's proposal to reduce the VERBS rate to cover the unlikely situation in which BPA recalls an award of DTC for a self-supplier. Instead, Iberdrola states that "It is not appropriate for self-suppliers to bear all of the risk associated with failure of self-supply participation due to Bonneville's decision to recall DTC." Iberdrola Br., BP-12-B-IR-01, at 21. Hence, Iberdrola argues, BPA should discount the Provisional VERBS rate by 50 percent to cover that situation "to reflect the significant risk imposed on customers forced to take this inferior service." *Id.*

BPA agrees with Iberdrola that a discounted Provisional Balancing Service rate is appropriate if BPA recalls an award of DTC and causes a self-supplier to fail BPA's self-supply requirements. However, BPA disagrees with the level of the discount suggested by Iberdrola.

BPA believes charging 70 percent of the VERBS rate for Provisional Balancing Service if BPA recalls a DTC award is reasonable given the quality of the service provided to cover the DTC situation:

[W]e are proposing to set the discounted Provisional Balancing Service rate at an amount equal to the percentage of balancing reserves used by BPA's balancing authority that would trigger a DSO 216 event for such customer. Because we anticipate that the trigger would be 70 percent of available reserves used by the balancing authority, we have established the discount for Provisional Balancing Service accordingly.

Jackson *et al.*, BP-12-E-BPA-47, at 28. Iberdrola does not rebut Staff's cost basis for a 70 percent charge, and there is no evidence in the rate case record that supports a 50 percent discount.

BPA also believes charging 70 percent of the VERBS rate is appropriate given the fact that the self-supplier will continue to retain whatever allocation of balancing reserve capacity it had during self-supply:

We also clarify that, for DSO 216 purposes, the allocation of reserves that a self-supply customer has when it purchases the Regulation and Following components from BPA will still be available to the customer if it must take Provisional Balancing Service during the rate period. This is not an increase in the reserve requirement for the BPA balancing authority area. Rather, it reflects the customer's use of the Regulation and Following Reserves that it was paying for as a self-supply customer.

Id. Thus, under the unanticipated circumstance that BPA recalls an award of DTC from a customer that self-supplies a component of VERBS, and that recall causes the customer to fail BPA's self-supply requirements, BPA believes it would be reasonable to charge a discounted rate of 70 percent of the VERBS rate to that Provisional Balancing Service customer.

Decision

If BPA recalls an award of DTC from a self-supplying VERBS customer and causes that self-supplying customer to fail to continue to self-supply during the rate period, BPA will offer that customer a rate based on 70 percent of the VERBS rate for Provisional Balancing Service.

3.5.5 VERBS Rate for Solar Resources Issues

Issue 3.5.5.1

Whether BPA should adopt a VERBS solar rate.

Parties' Positions

NWG argues that BPA runs the risk of establishing a VERBS rate for solar resources that is arbitrary, not cost-based, and not based on sufficient evidence. NWG Br., BP-12-B-NG-01, at 76. Given that the amount of solar resources expected to come online in the FY 2012–2013 rate period is negligible, and given that the revenue forecast is only \$57,540 per year, NWG believes it would be more prudent for BPA to postpone application of the VERBS rate for solar resources until there is measurable effect on BPA's balancing reserve capacity and sufficient data to develop a reasonable, cost-based rate. *Id.* at 77.

Snohomish agrees with Staff that establishing a rate for providing balancing reserve capacity for solar resources inside BPA's balancing authority area is appropriate. Snohomish Br., BP-12-B-SN-01, at 21. However, Snohomish states that Staff's proposed VERBS rate for solar generators could collect more revenues than needed to offset the cost of providing balancing reserve capacity. *Id.*

BPA Staff's Position

Based on Staff's analysis of solar within-hour variability using solar data, Staff believes it has sufficient information to justify the establishment of a rate to recover the costs of balancing reserve capacity used to provide VERBS for solar resources. Jackson *et al.*, BP-12-E-BPA-47,

at 48. Although Staff's analysis supports the establishment of a higher rate, Staff is aware that the balancing reserve capacity quantity forecast does not reflect the benefit that a diversity of additional resource types such as wind and non-Federal thermal and the effect of load variation may bring to reduce the reserve requirement. *Id.* Thus, based on a forecast of 34 MW of installed solar generating facility capacity by the end of the rate period, Staff recommends that BPA establish a VERBS solar rate based on one-half of the regulation and following components of the VERBS rate for wind resources. *Id.* Staff believes it is reasonable to focus the solar rate primarily on Regulation and Following costs for the first rate period and allow time for development of historical data, as BPA did for wind resources in the 2009 Wind Integration case. *Id.* at 49. The alternative is to adopt a higher rate based on the actual solar data and resulting balancing reserve capacity quantity forecast. *Id.*

Evaluation of Positions

In the upcoming rate period, a new type of variable energy resource is now expected to join the variable energy resource fleet in BPA's balancing authority area. Staff forecasts an average of 34 MW of new solar resources will integrate into the BPA balancing authority area by the end of the rate period. Jackson *et al.*, BP-12-E-BPA-47, at 45. BPA has learned from the integration of wind resources that BPA must maintain significant amounts of balancing reserve capacity to provide balancing services, and that there are costs associated with providing balancing reserve capacity for those services. It is within that context that Staff began to explore the necessity of a solar rate to recover BPA's costs.

The rate case record indicates that solar resources, like wind resources, will require BPA to provide balancing reserve capacity for balancing services. Jackson *et al.*, BP-12-E-BPA-47, at 45-49. Staff performed an analysis of solar within-hour variability using solar data obtained from the University of Oregon Solar Radiation Monitoring Laboratory. There is no scheduling data available in the BPA balancing authority area for solar resources, but Staff explains that "the University of Oregon data set can be used to assess the Regulation and Following imbalance components required to balance solar resources." Jackson *et al.*, BP-12-E-BPA-47, at 45. Staff testifies why that data set was a reasonable proxy for grid-tied solar data:

Output from a grid-tied solar photovoltaic array is directly related to the radiation received by the array. The solar data set is the radiation available for the time series data collected at the sites. We believe these data are the best available to assess solar variability. Attachment 4, List of Solar Data.

Id.

Staff's analysis discovered a significant balancing reserve capacity requirement for solar resources that would merit a solar rate of \$1.40 per kilowatt per month for Regulation and Following requirements based on the same cost allocation methodology used for the VERBS rate and spread over 22.8 MW of installed capacity over the rate period. *Id.* at 48. Despite these findings, however, Staff proposes an alternative:

Although our analysis supports the establishment of a higher rate, we are aware that the balancing reserve capacity quantity forecast does not reflect the benefit

that a diversity of additional resource types such as wind and non-Federal thermal and the effect of load variation may bring to reduce the reserve requirement. Thus, as an alternative and preferred approach, we propose to establish a VERBS rate for solar resources based on one-half of the VERBS regulation and following component rates, for a total VERBS rate of \$0.21 per kilowatt per month. In our opinion, it is reasonable to focus the solar rate primarily on Regulation and Following costs for the first rate period and allow time for development of historic data, as we did for wind resources in the 2009 Wind Integration case. The alternative to our preferred approach is to adopt a higher rate based on the actual solar data and resulting balancing reserve capacity quantity forecast. We will continue to evaluate solar operational data during the rate period and propose adjustments as necessary in the next rate proceeding.

Jackson *et al.*, BP-12-E-BPA-47, at 48-49.

Staff also explains why it was important to include its analysis of solar data, despite their proposal for a rate that disregards that analysis:

We included our analysis to inform policymakers and the BP-12 parties that solar resources are likely to contribute significantly to the balancing reserve capacity requirements of the BPA balancing authority. It is important to recognize that there are tangible costs associated with these resources, and our analysis supports the establishment of a rate to recover those costs.

Id. at 49.

Snohomish agrees that establishing a rate for providing balancing reserve capacity for solar resources inside BPA's balancing authority area is appropriate. Snohomish Br., BP-12-B-SN-01, at 21. However, Snohomish is concerned that the proposed VERBS rate for solar resources could collect more revenues than needed to offset the cost of providing balancing reserves. *Id.*

Snohomish also states that a "rate that is higher than necessary could be a disincentive for future solar projects in BPA's [balancing authority area], while a rate that is set too low could create costs shifts." *Id.*

NWG states that "Staff's revised proposal is an improvement from its Initial Proposal, and NWG appreciates Staff doing additional analysis and providing additional information to policymakers about the impacts of grid-tied solar." NWG Br., BP-12-B-NG-01, at 76. NWG states, however, that more information "will be required to fully understand and efficiently integrate solar energy facilities into the grid." *Id.*

NWG also raises concerns regarding Staff's basis to support a solar rate:

Staff has still not demonstrated, within the context of the diversity of the total balancing authority reserve requirement, that there is any incremental reserve requirement associated with Staff's revised solar interconnection forecast. NWG recognizes that Staff is attempting to account for this by assuming perfect

schedules and reducing the regulation and following costs by one-half. However, NWG has no way of verifying whether or not these adjustments are sufficiently accurate. As such, BPA runs the risk of establishing a VERBS rate for solar resources that is arbitrary, not cost-based, and not based on sufficient evidence. Given the amount of solar resources expected to come online in the FY 2012–2013 rate period is negligible (and is now less than Staff originally anticipated), and given that the most up-to-date revenue forecast is \$57,540 per year (Jackson *et al.*, BP-12-E-BPA-47 at 49), NWG believes it would be more prudent for BPA to postpone application of the VERBS rate to solar resources until there is a measurable effect on BPA’s use of balancing reserves and sufficient data to develop a reasonable, cost-based rate.

NWG Br., BP-12-B-NG-01, at 76-77.

BPA believes that a solar rate is supported by the rate case record. The evidence in the record demonstrates that solar resources would require balancing reserve capacity for balancing services and that there are tangible costs associated with solar integration. Establishing a rate ensures cost recovery, informs developers and policymakers of integration costs, and prevents cost shifts to other users of balancing reserve capacity services. Jackson *et al.*, BP-12-E-BPA-47, at 49.

In addition, from a business perspective, BPA believes it is prudent to put a price signal in place to ensure that solar generator developers are on notice of the potential balancing reserve requirements of their resources. Establishing a price signal will provide an economic incentive for solar generation operators to take steps now to maximize their scheduling accuracy and reduce their overall balancing reserve capacity requirements. BPA’s experience with wind integration is instructive, since wind scheduling accuracy improved significantly once BPA began to recover its costs for providing balancing reserve capacity for balancing services. WP-10 ROD, WP-10-A-02, at P-4. Without a solar rate, solar developers and operators will not have an incentive to invest in forecasting improvements or to monitor their scheduling accuracy to reduce their use of VERBS.

BPA acknowledges that there are currently no grid-tied solar resources in the BPA balancing authority but believes that Staff’s study of the balancing reserve requirements of solar resources is clearly indicative of the fact that solar resources would require balancing reserve capacity for VERBS. To account for the lack of actual solar scheduling data, however, BPA is discounting the VERBS rate for solar resources. A rate based on one-half of the regulation and following components of the VERBS rate for wind resources is reasonable for the first rate period and will allow time to continue to refine the analysis supporting the rate. A rate discount will also reasonably account for any diversity benefits that solar resources will receive by virtue of interconnecting within the BPA balancing authority area. Notably, BPA is not charging for the imbalance capacity, which may be significant, as observed in wind resources, to allow time to further analyze the impact of solar resources to the BPA system.

No party contests Staff’s forecast of the increase in solar resources in BPA’s balancing authority area. The fact that solar resources are expected to integrate into BPA’s balancing authority area by itself supports BPA decision to identify costs and to recover those costs. Solar resources are

intermittent and highly dependent on the weather. BPA's experience with variable energy resources is that balancing reserve capacity is necessary to ensure load and resource balance within BPA's balancing authority area at all times. Indeed, there is no evidence in the rate case record indicating that solar resources will not require balancing reserve capacity under VERBS.

Finally, BPA disagrees with Snohomish's concerns that BPA may over-recover its costs during the rate period. Given the low revenue requirement, the resulting rate will allow BPA to recover costs with little risk of over-recovery while also sending a price signal that there are costs associated with the balancing reserve capacity requirements for solar resources.

Based on Staff's analysis of solar data, it is possible that those costs may be higher over time as solar resources expand within BPA's balancing authority area. BPA will continue to monitor the scheduling accuracy of solar resources as they integrate into the BPA balancing authority area and propose to adjust the VERBS solar rate accordingly.

Decision

BPA is establishing a VERBS rate for solar resources based on one-half the VERBS Regulation and Following component rates for wind resources.

Issue 3.5.5.2

Whether BPA should exempt solar projects of less than 20 MW nameplate capacity from the VERBS solar rate during FY 2012.

Parties' Positions

According to Snohomish, a rate that is higher than necessary could be a disincentive for future solar projects in BPA's balancing authority area, while a rate that is set too low could create cost shifts. Snohomish Br., BP-12-B-SN-01, at 21. Snohomish recommends that to "get it right," BPA should exempt solar projects of less than 20 MW AC nameplate capacity from the VERBS solar rate during fiscal year 2012. *Id.*

BPA Staff's Position

This issue is first raised in surrebuttal testimony. Staff does not present a position on this issue.

Evaluation of Positions

Snohomish recommends that to set an appropriate VERBS rate for solar resources, BPA should exempt solar projects of less than 20 MW AC nameplate capacity from the VERBS solar rate during fiscal year 2012. *Id.* at 21-22. Snohomish contends that this would allow BPA a full year to collect the minute-by-minute generation and hourly schedule data to more accurately determine the solar balancing reserve capacity requirements for northwest solar resources. *Id.* at 22. Snohomish states that BPA could then develop and implement, in FY 2013, a VERBS solar rate that fairly and accurately collects BPA's costs for providing reserves. *Id.*

For several reasons, BPA disagrees with Snohomish’s approach. First, an exemption for solar resources during the first year of the rate period would effectively exclude all solar resources from the rate, rendering the rate meaningless.

Second, although Snohomish does not explain how BPA could revise the VERBS solar rate for the second year of the rate period based on data observed in the first year of the rate period in the absence of a section 7(i) rate proceeding, BPA assumes Snohomish is suggesting that BPA initiate an expedited section 7(i) rate proceeding either prior to or during the second year of the rate period. Given the low revenue requirement associated with the VERBS rate for solar resources, BPA believes it would be imprudent to initiate a costly and resource-intensive section 7(i) rate proceeding to set a rate based on actual data obtained during the first year of the rate period.

Finally, as explained in Issue 3.5.5.1, BPA believes that a solar rate for the rate period will provide an incentive for solar operators and developers to improve their scheduling accuracy over the rate period, while ensuring that BPA recovers costs. BPA finds no basis to support Snohomish’s proposal to abandon those important policy considerations. In any case, BPA will evaluate the scheduling accuracy of solar resources over the rate period and propose adjustments to the balancing reserve capacity requirement for solar resources as necessary in the next rate proceeding.

Decision

BPA is not exempting solar resources of 20 MW or less from the VERBS rate for solar resources during the rate period.

3.5.6 Operating Reserve (Spinning and Supplemental Reserve) Service Issue

Issue 3.5.6.1

Whether BPA should pay negative prices for Contingency Energy under the Operating Reserve (Spinning and Supplemental Reserve Services) rate schedules.

Parties’ Positions

This issue is first raised in this ROD.

BPA Staff’s Position

This issue is first raised in this ROD. Staff does not present a position on this issue.

Evaluation of Positions

The Northwest Power Pool (NWPP) is currently considering to set a floor of zero for the price of contingency energy delivered by the NWPP reserve sharing group. The reason for such an action is to protect transmission providers from having to pay customers for the contingency energy

provided by the reserve sharing group that they take from the transmission provider when the market price index for energy is negative.

Accordingly, BPA expects the NWPP to reach a decision that sets a floor of zero when a contingency event occurs, contingency energy is taken by a customer from the NWPP reserve sharing group, and the market price index for energy is negative. BPA is taking official notice of the NWPP's actions and will modify the Operating Reserve Spinning and Supplemental Service rate schedules to include a floor of zero for contingency energy taken in any hour that the market price index is negative. However, even if the NWPP decides not to set a floor of zero for contingency energy delivered from the NWPP reserve sharing group during negative market prices, BPA believes setting a floor of zero is reasonable and good policy since BPA should not be required to pay customers to take contingency energy during the customer's contingency event. Doing so would contradict the incentives for customers to avoid contingency events. Setting a floor of zero during when the market price index for energy is negative is also consistent with BPA's treatment of Generation and Energy Imbalance Services rates during such market conditions.

Decision

BPA is modifying the Operating Reserve (Spinning and Supplemental) Service rate schedules to include a floor of zero for contingency energy taken in any hour that the market price index is negative.

3.5.7 Persistent Deviation Issues

The Persistent Deviation penalty is part of the Ancillary and Control Area Services rates and applies to both Generation Imbalance and Energy Imbalance. During the FY 2010–2011 rate period, the Persistent Deviation penalty applied to positive and negative schedule deviations that exceed both 15 percent of schedule and 20 MW in an hour for four consecutive hours. 2010 Transmission and Ancillary Service Rate Schedules, TR-10-A-02-AP03, at 107-108.

Staff proposes to modify the existing Persistent Deviation criteria and add three new criteria to further decrease the amount of imbalance energy that is accumulating on the system. Jackson *et al.*, BP-12-E-BPA-29, at 18-20. Staff also proposes to exempt variable energy resources from the penalty for any hour in which such resources meet or beat a 30-minute persistence schedule. *Id.* at 19. In this Record of Decision, BPA adopts these proposals for the FY 2012–2013 rate period.

Issue 3.5.7.1

Whether BPA should eliminate the Persistent Deviation penalty.

Parties' Positions

WPAG supports the penalty as proposed as applied to variable energy resources. WPAG Br., BP-12-B-WG-01, at 25. WPAG asserts that BPA has legitimate concerns that the Persistent Deviation penalty is addressing and believes there is sufficient evidence to justify the proposed changes to variable energy resources, but not to load or dispatchable resources. *Id.* WPAG states, “BPA has identified legitimate concerns, including energy accumulation and operational problems, which arise from large and/or persistent scheduling errors by wind generators in BPA’s balancing authority area. [citations omitted] The continued application of the Persistent Deviation penalty to wind generators is an appropriate response to address these concerns, as are the proposed modifications to the definition of Persistent Deviation.” *Id.*

Iberdrola acknowledges that BPA has some legitimate concerns regarding scheduling errors, stating “Bonneville’s testimony clearly articulates the constraints under which the FCRPS operates and presents good arguments for the need to minimize scheduling errors and the associated generation imbalance.” Iberdrola Br., BP-12-B-IR-01, at 24. However, Iberdrola advocates that BPA eliminate the Persistent Deviation penalty altogether. *Id.* at 21-26; Iberdrola Br. Ex., BP-12-R-IR-01, at 21. Iberdrola argues that if BPA does not eliminate the penalty altogether, BPA should leave the penalty in its current form. Iberdrola Br., BP-12-B-IR-01, at 26; Iberdrola Br. Ex., BP-12-R-IR-01, at 21.

Similarly, SCE argues the proposed Persistent Deviation penalty is not useful and should not be retained. SCE Br., BP-12-B-SC-01, at 10-11.

BPA Staff's Position

The Persistent Deviation penalty charge serves as a necessary tool for many reasons, including: to minimize accumulation of imbalance energy in either a positive or negative direction, maintain operational reliability, reduce market risk, and encourage accurate scheduling. Jackson *et al.*, BP-12-E-BPA-29, at 12-13. For the most part, the Persistent Deviation penalty charge has been successful at achieving BPA’s goals—the incidence of large and persistent schedule errors has decreased in comparison to FY 2009. *Id.* at 13. Staff proposes several changes to the Persistent Deviation criteria to better prevent accumulation of imbalance energy and to motivate parties to reduce their schedule errors more quickly. *Id.* at 18.

Evaluation of Positions

There are many important reasons for the Persistent Deviation penalty, including minimizing accumulation of imbalance energy, encouraging accurate scheduling, and keeping balancing reserve capacity requirements as low as possible. Jackson *et al.*, BP-12-E-BPA-29, at 12-13. The Persistent Deviation penalty charge serves as a necessary tool to accomplish many goals, as explained in Staff’s testimony. *Id.* Iberdrola acknowledges that BPA “presents good arguments for the need to minimize scheduling errors and the associated generation imbalance.” Iberdrola Br., BP-12-B-IR-01, at 24.

However, Iberdrola states that there is no proof that the penalty has been successful. *Id.* at 24. Iberdrola criticizes some of the reasoning Staff uses to show that the penalty has contributed to

scheduling improvements, stating, “such statistics do not demonstrate a conclusive correlation between improved scheduling and the enforcement of the Persistent Deviation penalty.” *Id.* Iberdrola states that much advancement in scheduling accuracy occurred in the second half of FY 2009, which is before the current Persistent Deviation penalty was implemented. *Id.* at 24-25. Iberdrola argues that the reduction in instances of Persistent Deviation is likely due to improved scheduling skill. *Id.* at 25. Additionally, Iberdrola argues that the penalty is overly broad and captures some normal conditions that do not involve poor scheduling behavior. *Id.*

Iberdrola’s assertion that there is no proof that the penalty has been successful, Iberdrola Br., BP-12-B-IR-01, at 24; Iberdrola Br. Ex., BP-12-R-IR-01, at 21, is incorrect. Evidence in the record shows that the number of Persistent Deviation events has decreased and scheduling accuracy has increased since the penalty went into effect in FY 2010. Generation Inputs Study, BP-12-FS-BPA-05, section 10.8.5.1. There was a documented decline in Persistent Deviations in FY 2010. *See* Generation Inputs Study Documentation, BP-12-FS-BPA-05A, Table 10.1. Figure 1 in the Generation Inputs Study shows the trend for scheduling accuracy was much better in FY 2010, when the penalty was in effect, than FY 2009, before the penalty was in effect. While this evidence of improved scheduling accuracy may not conclusively demonstrate that Persistent Deviation was the sole cause of the improvement, this evidence provides a strong indication that the Persistent Deviation penalty has a positive impact on scheduling accuracy. No party has provided conclusive evidence that the Persistent Deviation penalty is not contributing to the improvement of scheduling accuracy. The presence of a penalty and negative economic consequences of inaccurate scheduling are inherently more likely to motivate change than the absence of such a penalty. Jackson *et al.*, BP-12-E-BPA-47, at 52.

In its brief on exceptions, Iberdrola takes exception to BPA’s use of the term “conclusive” in BPA’s statement that “[n]o party has provided conclusive evidence that Persistent Deviation is not contributing to the improvement of scheduling accuracy.” Iberdrola Br. Ex., BP-12-R-IR-01, at 21, *citing* Draft ROD, BP-12-A-01, at 391. Iberdrola asserts that BPA has set an unreasonably high bar that a party must provide *conclusive* evidence that the Persistent Deviation penalty has not made any contribution to the improvement in scheduling accuracy. Iberdrola Br. Ex., BP-12-R-IR-01, at 21. However, BPA merely used the term “conclusive” in response to Iberdrola’s original argument that the statistics BPA used to show that Persistent Deviation is having a positive effect on scheduling accuracy “do not demonstrate a *conclusive* correlation between improved scheduling and the enforcement of the Persistent Deviation penalty.” Iberdrola Br., BP-12-B-IR-01, at 24 (emphasis added); Draft ROD, BP-12-A-01, at 391. In its brief on exceptions, Iberdrola fails to recognize this point, and instead places blame on BPA for raising the concept of “conclusive” evidence. In responding to Iberdrola’s assertion, BPA points out that while BPA may not have provided a “conclusive correlation” between the penalty and improved scheduling accuracy, neither have any other parties provided conclusive evidence of the lack of such correlation. Draft ROD, BP-12-A-01, at 390-391. Iberdrola’s accusation, that BPA has somehow created a new standard of requiring “conclusive evidence” by merely responding to Iberdrola’s argument that BPA had not met such standard, is unwarranted.

Iberdrola points to an error Staff made in its Initial Proposal on a calculation that shows the correlation between wind ramps and Persistent Deviation criteria. Iberdrola Br., BP-12-B-IR-01,

at 25. This is the same calculation error that Iberdrola pointed out in its direct testimony, Froese *et al.*, BP-12-E-IR-01, at 29, and Staff corrected in an errata shortly thereafter. Erratum to Generation Inputs Study Documentation, BP-12-E-BPA-05A-E02. Besides the fact that Staff quickly corrected the calculation, this error did not significantly alter Staff’s analysis. The corrected calculation shows that wind ramps occurred for two consecutive hours for 1.66 percent of the time, for three consecutive hours only 0.24 percent of the time, and for four consecutive hours 0.04 percent of the time. *Id.* While these corrected numbers are higher than the original numbers presented, the corrected numbers are still very small and do not change Staff’s conclusion that the percentage of time that wind ramps exceed the 20 MW and 15 percent Persistent Deviation band is very low. Jackson *et al.*, BP-12-E-BPA-47, at 68.

As to Iberdrola’s argument that the penalty is overly broad and captures some normal conditions that do not involve poor scheduling behavior, Iberdrola Br., BP-12-B-IR-01, at 25; Iberdrola Br. Ex., BP-12-R-IR-01, at 20, the Persistent Deviation provisions of the rate schedule provide the opportunity to request a waiver of the penalty if the customer can demonstrate extraordinary circumstances or that it took mitigating actions to reduce the persistent deviation. 2010 Transmission and Ancillary Service Rate Schedules, TR-10-A-02-AP03, at 51-52, 60; Generation Inputs Study, BP-12-FS-BPA-05, section 10.8.10. Iberdrola argues that the waiver is an ineffective safeguard because Persistent Deviations occur during wind ramps that presumably would not be considered “extraordinary events,” and “the wind generator is attempting to mitigate the situation by continuing to provide the most accurate schedule possible.” Iberdrola Br. Ex., BP-12-R-IR-01, at 20. However, BPA believes this opportunity for a waiver provides some protection from customers being assessed a penalty in truly unwarranted circumstances.

An additional benefit of the Persistent Deviation penalty is that it will likely encourage intra-hour scheduling. Because Persistent Deviation encourages customers to schedule as accurately as possible, and adjusting schedules mid-hour provides additional opportunities for customers to achieve accurate schedules, it follows that Persistent Deviation may incent customers to utilize intra-hour scheduling. Encouraging intra-hour scheduling is one of BPA’s goals for the FY 2012–2013 rate period, because more frequent scheduling changes have the potential to reduce the scheduling error that contributes to overall balancing reserve capacity requirements.

The problems and risks being addressed with the penalty are significant, and wind-related impacts on hydro system constraints are expected to increase. The amount of wind forecast to be integrated into the BPA balancing area during the FY 2012–2013 rate period is expected to nearly double from current levels. Jackson *et al.*, BP-12-E-BPA-47, at 51. Given these ongoing and increasing concerns, it is important that BPA retain the Persistent Deviation penalty.

Decision

BPA will not eliminate the Persistent Deviation penalty.

Issue 3.5.7.2

Whether the Persistent Deviation penalty encourages poor scheduling practices.

Parties' Positions

Iberdrola, OPUC, and SCE argue that the proposed Persistent Deviation penalty encourages poor scheduling practices.

Iberdrola states that the “Persistent Deviation penalty charge does not incentivize accurate scheduling—and the changes Staff proposes in its Initial Proposal will not achieve this purpose, either.” Iberdrola Br., BP-12-B-IR-01, at 22. In its brief on exceptions, Iberdrola reiterates its position that the Persistent Deviation penalty does not encourage good scheduling practices. Iberdrola Br. Ex., BP-12-R-IR-01, at 20. Iberdrola states that the penalty puts “variable generators in a perverse scenario where they continue to provide their best schedule to the detriment of their self-interest.” *Id.* Iberdrola also states that decreasing the 15 percent/20 MW criterion from four hours to three hours will “increase the contradictory pressure between penalty avoidance and good scheduling practices.” *Id.* at 21. Iberdrola states that during wind ramps, the direction of schedule change needed to avoid a Persistent Deviation penalty is “often contrary to the schedule change indicated by atmospheric trends and forecasts.” Iberdrola Br., BP-12-B-IR-01, at 22. Iberdrola and SCE note that after they have gone two hours outside of the acceptable Persistent Deviation range, the scheduler then must decide whether to submit a schedule that reflects the operator’s best judgment or a schedule that will avoid the penalty. *Id.*; SCE Br., BP-12-B-SC-01, at 10-11.

Similarly, OPUC states that a move from a four- to three-hour window “increases the risk that a VER operator may schedule to avoid penalties, rather than to reflect the operator’s professional judgment regarding wind conditions.” OPUC Br., BP-12-B-PU-01, at 4. OPUC asserts that Staff’s proposal “would exacerbate the problem with perverse incentives created by the Persistent Deviation penalty.” *Id.* at 5. SCE also asserts that the proposed penalty will “perversely incent a generator to not use the best available scheduling data in order to be sure that it does not get penalized.” SCE Br., BP-12-B-SC-01, at 10.

Additionally, OPUC challenges BPA’s assertion that no party has submitted material evidence to show that parties use poor scheduling practices because of Persistent Deviation. OPUC states, “[i]n its surrebuttal [*sic*] testimony, BPA asserts that no party has ‘submitted evidence in support of the argument that operators may override best judgment and submit schedules designed to avoid penalties.’” OPUC Br., BP-12-B-PU-01, at 5. Similarly, Iberdrola argues that the fact that no party has provided material evidence that the penalty has caused parties to conduct poor scheduling practices “is immaterial.” Iberdrola Br. Ex., BP-12-R-IR-01, at 20.

BPA Staff’s Position

BPA Staff disagrees that the Persistent Deviation penalty incentivizes poor scheduling practices. Jackson *et al.*, BP-12-E-BPA-47, at 53. A Persistent Deviation can be avoided with a schedule that is within the accuracy bands defined for each criterion, and a perfect schedule would avoid any possibility of incurring a Persistent Deviation. There is no need for parties to deliberately incur large scheduling errors in the opposite direction to avoid the penalty. Although parties make general assertions that they believe the penalty encourages scheduling practices that contradict their best professional judgment, parties have provided no material evidence showing

that such behavior has actually occurred. Since the Persistent Deviation penalty was implemented in October of 2009, there has been a significant decline in the instances of schedule error that produce large amounts of energy accumulation on the system. *Id.* at 54; Jackson *et al.*, BP-12-E-BPA-29, at 13.

Evaluation of Positions

Given the improved scheduling performance record since the Persistent Deviation penalty was implemented, BPA is unpersuaded by the arguments made by Iberdrola, SCE, and OPUC. The Persistent Deviation penalty has been in effect since the beginning of the FY 2010–2011 rate period, and scheduling data since that time should provide a basis for parties to support claims about scheduling practices designed to avoid the penalty. Although parties make general assertions that the penalty encourages them to schedule in a way that differs from their best judgment, no party has provided material evidence based on actual scheduling data that this has happened.

In an attempt to discern whether certain parties had scheduling data that supports these assertions, Staff made data requests to both Iberdrola and Northwest Wind Group asking whether they have used any poor and arbitrary scheduling practices in the past. (In the data response, Iberdrola defines “poor and arbitrary scheduling practices” as “an ongoing practice of submitting generation schedules that significantly vary from the best forecasting information available to the scheduler at the time the schedule is due.”) Both parties respond that they have not used poor and arbitrary scheduling practices. Jackson *et al.*, BP-12-E-BPA-47, Attachments 8 and 9.

Additionally, in oral argument the Administrator asked Iberdrola whether there is any evidence in the record that the Persistent Deviation penalty has caused parties to schedule opposite of their best forecast to avoid the penalty. In response, Ms. Skidmore stated, “I think some people have acknowledged doing it; not at Iberdrola.” Skidmore, Oral Tr. at 149. However, this statement was incorrect based on the evidence in the record: no party has stated on the record that it has scheduled in a way that differs from its best forecast because of the Persistent Deviation penalty.

In attempt to disprove Staff’s assertion that parties have not provided sufficient evidence to show that the Persistent Deviation penalty encourages poor scheduling practices, OPUC states, “BPA asserts that no party has ‘submitted evidence in support of the argument that operators may override best judgment and submit schedules designed to avoid penalties. Jackson *et al.*, BP-12-E-BPA-47, at 56.’” OPUC Br., BP-12-B-PU-01, at 5. However, OPUC misquotes Staff. The section of Staff’s rebuttal testimony cited by OPUC actually states, “[t]he *OPUC* has not provided any *material evidence* to support its assertion that moving the window from 4 to 3 hours will cause ‘a substantial risk...that [Variable energy resource] operators may override their best judgment and submit schedules designed to avoid penalties.’” Jackson *et al.*, BP-12-E-BPA-47, at 56 (emphasis added). BPA acknowledges that parties have made some general statements asserting that the current and proposed Persistent Deviation penalty incents poor scheduling practices, but parties have provided no objective or verifiable evidence to support those statements. As stated above, in response to data requests, Iberdrola and NWG both say they have not engaged in poor scheduling practices. Jackson *et al.*, BP-12-E-BPA-47, Attachments 8 and 9.

OPUC's assertion is incorrect that Iberdrola's mere "observations of scheduling behavior" are sufficient evidence to show that the Persistent Deviation penalty encourages parties to override their best judgment when scheduling. Similarly, BPA disagrees with Iberdrola's assertion that the fact that no party has provided material evidence that the penalty has caused parties to conduct poor scheduling practices "is immaterial." Iberdrola Br. Ex., BP-12-R-IR-01, at 20. Iberdrola clearly states in response to Data Request No. BPA-IR-22 that Iberdrola has not used poor and arbitrary scheduling practices in the past. Jackson *et al.*, BP-12-E-BPA-47, Attachment 9. OPUC's assertion that Staff's proposal "would exacerbate the problem with perverse incentives created by the Persistent Deviation penalty," OPUC Br., BP-12-B-PU-01, at 5, is not supported by substantial evidence in the record.

Staff's testimony and Generation Inputs Study and Documentation comprise the primary evidence in the record based on actual scheduling data since the Persistent Deviation penalty took effect, and it shows that the instances of Persistent Deviation have decreased since the penalty was implemented in its current form. Jackson *et al.*, BP-12-E-BPA-47, at 54. BPA finds it difficult to assign significant weight to OPUC's, SCE's and Iberdrola's anecdotal statements regarding scheduling practices designed to avoid the penalty under these circumstances, especially given Iberdrola's concession at oral argument and the response to BPA's data requests on this subject. Skidmore, Oral Tr. at 149; Jackson *et al.*, BP-12-E-BPA-47, Attachments 8 and 9. The OPUC's observations appear to be based primarily on representations made by other parties rather than independent facts. OPUC Br., BP-12-B-PU-01, at 4-5. The balance of the evidence in the record provides no basis to conclude that Persistent Deviation is encouraging scheduling practices designed to avoid the penalty. The record does not contain substantial evidence to prove that the Persistent Deviation penalty causes poor scheduling behavior. To the contrary, the record indicates that scheduling has improved since Persistent Deviation was implemented in FY 2010.

Decision

Substantial evidence on the record does not support the conclusion that the Persistent Deviation penalty causes poor scheduling.

Issue 3.5.7.3

Whether BPA should modify the Persistent Deviation penalty as proposed, by decreasing the existing 15 percent/20 MW criterion to three hours after intra-hour scheduling is implemented, and adding the three additional criteria of longer duration.

Parties' Positions

Iberdrola states that "Bonneville has not demonstrated a need for shorter Persistent Deviation penalty windows." Iberdrola Br., BP-12-B-IR-01, at 23. Iberdrola states that the only justification Staff provides for moving from a four- to three-hour window is BPA's proposed exemption for hours in which the schedule meets or beats a 30-minute persistence schedule. *Id.*

at 24. Iberdrola states, “Bonneville uses this available exemption as justification for movement to a 3 hour standard but provides no other argument to justify this significant change.” *Id.*

As explained above, OPUC does not believe the penalty should be modified because it thinks the proposal will incentivize scheduling practices that are aimed to avoid the penalty rather than based on the operator’s best forecast. OPUC Br., BP-12-B-PU-01, at 4-5.

SCE states that the “proposed penalty is not useful, is extremely difficult to operationally manage due to the complex and numerous categories ..., and ... can send the wrong market signals.” SCE Br., BP-12-B-SC-01, at 10.

JP01 questions whether the transition to intra-hour scheduling will go well, and argues that “Staff’s own rejection of intra-hour scheduling for the Slice product suggests strongly that the transition to intra-hour scheduling may not be as smooth and easy as Staff seems to assume. Like most things, intra-hour scheduling is likely to encounter unanticipated road blocks and produce unintended consequences.” JP01 Br., BP-12-B-JP01-01, at 38. JP01 states that “[t]he likely inability of a significant portion of BPA’s customers to take advantage of intra-hour scheduling in the near term is a very important and specific reason that BPA should not shorten the first band to three hours at this time.” JP01 Br. Ex., BP-12-R-JP01-01, at 5.

JP01 states that one reason JP01 is opposed to the change from four to three hours is because Persistent Deviation is a penalty rather than a cost-based rate, and BPA has not shown that the first band of the current penalty fails to recover costs imposed on BPA due to the scheduling errors BPA seeks to prevent. JP01 Br., BP-12-B-JP01-01, at 38-39; JP01 Br. Ex., BP-12-R-JP01-01, at 6. JP01 states that “[a]bsent some showing that market participants will allow customers to shift to intra-hour scheduling, BPA should not assume customers will be able to utilize intra-hour scheduling to avoid the Persistent Deviation penalty charge.” JP01 Br. Ex., BP-12-R-JP01-01, at 6. JP01 states that it does not think BPA should move from the four-hour standard to a three-hour standard in the upcoming rate period, and does not think the record indicates an urgent need to decrease the criterion to three hours until after BPA observes how the market reacts to intra-hour scheduling. JP01 Br., BP-12-B-JP01-01, at 39; JP01 Br. Ex., BP-12-R-JP01-01, at 6.

WPAG asserts that BPA has legitimate concerns that the Persistent Deviation penalty is addressing and believes there is sufficient evidence to justify the proposed changes to the Persistent Deviation penalty charge applied to variable energy resources, but not to load or dispatchable resources. WPAG Br., BP-12-B-WG-01, at 25. WPAG states, “BPA has identified legitimate concerns, including energy accumulation and operational problems, which arise from large and/or persistent scheduling errors by wind generators in BPA’s balancing authority area. The continued application of the Persistent Deviation penalty to wind generators is an appropriate response to address these concerns, as are the proposed modifications to the definition of Persistent Deviation.” *Id.* (internal cites omitted).

BPA Staff's Position

Staff proposes to change the 15 percent/20 MW band from a four-hour to three-hour interval once intra-hour scheduling has been implemented. Jackson *et al.*, BP-12-E-BPA-29, at 19. Once intra-hour scheduling is implemented, Persistent Deviation would apply to each scheduled period. BPA would provide 90 days' notice before implementing this change. Jackson *et al.*, BP-12-E-BPA-47, at 57. Staff's analysis shows that refining the Persistent Deviation criteria would identify and penalize more of the accumulation of imbalance energy on the system that occurs from deviations that are significant and persistent. Generation Inputs Study, BP-12-FS-BPA-05, section 10.8.9.1.3; Generation Inputs Study Documentation, BP-12-FS-BPA-05A, Table 10.8; Jackson *et al.*, BP-12-E-BPA-29, at 21-22; Jackson *et al.*, BP-12-E-BPA-47, at 55.

Staff also proposes to add criteria of longer duration and narrower bands to capture observed schedule deviations that a scheduling agent should have corrected, but allowed to persist, and that were not explicitly covered by the current criteria. Generation Inputs Study, BP-12-FS-BPA-05, section 10.8.2 and section 10.8.8, figures 5, 6 and 7.

Evaluation of Positions

Parties' comments that address the change from four to three hours specifically with respect to load or dispatchable resources are addressed in the next two issues in this section.

Iberdrola's assertion that the proposed exemption for scheduling that meets 30-minute persistence is the only justification Staff provides for moving to a three-hour window, Iberdrola Br., BP-12-B-IR-01, at 24, is incorrect. While Staff proposes the exemption for variable energy resources, Staff does not state that this exemption is the sole justification for the change to three hours. To the contrary, Staff provides several reasons for the change from four to three hours.

One major reason for moving from a four- to three-hour standard is that Staff has observed patterns of schedule error where it appears that scheduling agents are waiting until the fourth hour to correct schedule errors that are large and have persisted for three hours. Jackson *et al.*, BP-12-E-BPA-29, at 25. Staff wants to encourage more prompt correction of large errors. *Id.* A change to three hours should encourage parties to adjust schedules earlier.

Another reason it is reasonable to set a higher expectation of scheduling accuracy and move to three hours is the expectation that customers will be able to submit intra-hour schedules during the rate period, which is why Staff proposes the three-hour window not become effective until intra-hour scheduling is implemented. Jackson *et al.*, BP-12-E-BPA-29, at 19. With intra-hour scheduling, parties will have more opportunities to adjust their schedules before incurring a Persistent Deviation than they currently do. Jackson *et al.*, BP-12-E-BPA-47, at 55.

JP01 states, "Staff's own rejection of intra-hour scheduling for the Slice product suggests strongly that the transition to intra-hour scheduling may not be as smooth and easy as Staff seems to assume. Like most things, intra-hour scheduling is likely to encounter unanticipated road blocks and produce unintended consequences." JP01 Br., BP-12-B-JP01-01, at 38. BPA disagrees with JP01's attempt to draw a correlation between the fact that BPA has not allowed

intra-hour scheduling for Slice, and the likelihood of successful intra-hour scheduling implementation. The Slice Agreement does not allow for intra-hour scheduling, as discussed in section 3.2.9.1. BPA's experience with intra-hour scheduling thus far has been positive. BPA has offered intra-hour scheduling to wind resource schedulers on a pilot basis since December 2009, and this pilot has been a success. Mainzer *et al.*, BP-12-E-BPA-23, at 7. In addition, BPA is on track to implement generally applicable intra-hour scheduling by the beginning of the rate period. Simpson *et al.*, BP-12-E-BPA-46, at 10. Further, BPA is offering a 34 percent discount for customers who participate in the Committed Intra-Hour scheduling pilot program. Simpson *et al.*, BP-12-E-BPA-46, at 7. This willingness to provide a discount indicates BPA's level of confidence that intra-hour scheduling will be implemented successfully. The fact that customers will be unable to schedule Slice resources on an intra-hour basis is wholly unrelated to the likelihood of success of intra-hour scheduling. *See* section 3.2.9.1. In addition, JP01 has not presented a convincing reason to delay the change to three hours until after observing how the market responds to intra-hour scheduling. As explained above, the availability of intra-hour scheduling is only one of various factors supporting decreasing this criterion to three hours. Additional arguments related to intra-hour scheduling are addressed in the next issue.

BPA is not persuaded by JP01's argument that BPA has not shown that the first band of the current penalty fails to recover costs imposed on BPA due to the scheduling errors BPA seeks to prevent. JP01 Br., BP-12-B-JP01-01, at 38-39; JP01 Br. Ex., BP-12-R-JP01-01, at 6. JP01 is correct to state that Persistent Deviation is a penalty, not a cost-based rate. Although BPA incurs costs as a result of Persistent Deviations, the penalty is not designed to forecast and recover specific costs incurred because of persistent scheduling deviations. Rather, the penalty is designed to incent accurate scheduling and thereby minimize accumulation of imbalance energy and adverse reliability impacts on the system. BPA has chosen to use a penalty structure to disincent inaccurate scheduling because parties that over-use or mis-use VERBS service impose risks and costs on other parties. The penalty is designed to be avoidable, and BPA assumes a 30-minute persistence level of scheduling accuracy in establishing the VERBS rate, instead of assuming historical scheduling accuracy and including persistent deviations. Using this penalty approach, BPA is able to partially mitigate the risks to other ratepayers associated with use of an assumed level of schedule accuracy, and keep the rate lower than it would be if the VERBS rate was based on actual scheduling accuracy. Under this structure, only those that cause persistent scheduling deviations pay, rather than spreading costs to all ratepayers. Because the penalty is not a cost-based rate, there is no need for BPA to show that the four-hour criterion fails to recover costs imposed on BPA, contrary to JP01's assertion. Staff's testimony explains the need to move to three hours to incent more accurate scheduling and provides analysis showing that the proposed changes will decrease the amount of accumulated imbalance energy put on the transmission system. Jackson *et al.*, BP-12-E-BPA-29, at 21-23, 25; Generation Inputs Study, BP-12-FS-BPA-05, section 10.8.9.1.3; Generation Inputs Study Documentation, BP-12-FS-BPA-05A, Tables 10.7 and 10.8. BPA has demonstrated that the changes to the Persistent Deviation penalty are necessary and appropriate to mitigate the types of harms it seeks to avoid.

BPA will provide 90 days' notice before moving from the four-hour to three-hour criterion and applying Persistent Deviation to each scheduled period. This notice will be posted on BPA's

OASIS website and will specify the date this change will become effective. Progress toward full implementation of intra-hour scheduling is going well, so BPA anticipates that this notice will likely be provided before the beginning of the FY 2012–2013 rate period for the change to go into effect early in the rate period.

While several parties express general disapproval of the proposed changes to the Persistent Deviation penalty and provide specific reasons why they do not support changing the 15 percent/20 MW criterion from four to three hours, parties have not provided any specific reasons for opposing the proposed additional criteria of longer duration and narrower bands. Staff provides an explanation and analysis showing that these additional criteria will capture ongoing scheduling deviations that are correctable, but are being allowed to persist, and are not captured by the existing 15 percent/20 MW criterion. *See* Generation Inputs Study, BP-12-FS-BPA-05, sections 10.8.8, 10.8.9, 10.8.9.1.1, 10.8.9.1.2 and 10.8.9.1.3 ; Generation Inputs Study Documentation, BP-12-FS-BPA-05A, Tables 10.4-10.8; Jackson *et al.*, BP-12-E-BPA-29, at 21-22.

SCE makes generalized statements of opposition and says the penalty is complex and therefore difficult to manage. SCE Br., BP-12-B-SC-01, at 10. There is no doubt that wind forecasting and scheduling is a complex enterprise. Staff proposes to add three new criteria to the penalty, but as long as schedulers pay attention to their forecasts and to their current schedule error, these criteria should be avoidable. SCE asserts that the Persistent Deviation penalty can send the wrong market signals, but SCE does not provide any explanation as to what types of market signals or impact it is referring to. *Id.*

As explained in the previous issue, OPUC’s argument that the changes will encourage scheduling practices that are specifically geared to avoid the penalty and are not in line with forecasters’ best judgment is not supported by material evidence.

Staff analysis shows that refining the Persistent Deviation criteria will identify and penalize more of the potential imbalance accumulation associated with these schedule errors that appear to be biased and controllable. Generation Inputs Study, BP-12-FS-BPA-05, sections 10.8.8 and 10.8.9.1.3; Generation Inputs Study Documentation, BP-12-FS-BPA-05A, Table 10.8. Staff analysis also shows that the new criteria will help decrease the amount of imbalance accumulation by showing the amount of additional imbalance the new criteria would capture. Generation Inputs Study Documentation, BP-12-FS-BPA-05A, Tables 10.7 and 10.8.

Decision

BPA will modify the Persistent Deviation penalty as proposed. After intra-hour scheduling is implemented and BPA has provided 90 days’ notice, the existing 15 percent/20 MW criterion will be decreased to three hours and Persistent Deviation will apply to each scheduled period. Also, three additional criteria of longer duration will be added to the definition of Persistent Deviation, effective at the beginning of the FY 2012–2013 rate period.

Issue 3.5.7.4

Whether the modifications to the Persistent Deviation penalty should apply to load customers, including Slice customers.

Parties' Positions

PPC argues that the proposed changes to the Persistent Deviation penalty should not apply to preference customers that cannot change their schedules of Federal power within the hour (*i.e.*, Slice customers). PPC Br., BP-12-B-PP-01, at 23. PPC states that Staff's assertion that Slice customers can adjust non-Federal resources within the hour is "unsupported speculation." *Id.* at 24. PPC adds that Slice customers may be prohibited by their non-Federal contracts from scheduling on an intra-hour basis and may be unable to renegotiate these contract terms. *Id.* PPC asserts that although Staff believes the increase in instances of the penalty on load customers with the change from four to three hours is *de minimis*, it is not fair to increase the stringency of the penalty and also not allow the parties to schedule on an intra-hour basis. *Id.* at 25. PPC states that the arguments it has raised show that the record in this proceeding "contains substantial evidence that the penalty is inequitable." *Id.*

Like PPC, JP01 disagrees with Staff's assertion that Slice customers will be able to schedule non-Federal resources on an intra-hour basis. JP01 Br., BP-12-B-JP01-01, at 37. JP01 notes that hourly scheduling has been the norm in the region since scheduling began, and hourly scheduling is required by existing contracts that cannot be unilaterally changed by BPA's customers. *Id.* JP01 states that Staff's assertion that parties can schedule non-Federal resources on an intra-hour basis is not supported by any experience or evidence. *Id.*; JP01 Br. Ex., BP-12-R-JP01-01, at 5-6. JP01 states that it is unlikely that counterparties will be willing to agree to intra-hour scheduling terms if other utilities have not moved to intra-hour scheduling on BPA's timeframe. JP01 Br., BP-12-B-JP01-01, at 37. JP01 questions why it is reasonable to assume that other counterparties will agree to allow intra-hour scheduling, when BPA is not willing to so allow for the Slice contract. *Id.* at 38; JP01 Br. Ex., BP-12-R-JP01-01, at 6.

WPAG does not think it is equitable to subject load to the proposed amendments to the penalty because unlike wind, load is subject to all three bands of Energy/Generation Imbalance Service, and load will not be able to utilize the proposed exemption for hours that meet or beat a 30-minute persistence schedule. WPAG Br., BP-12-B-WG-01, at 25-26. WPAG states that BPA's analysis shows that wind generators, not load, are the cause of the vast majority of the accumulated energy problem; therefore, there is no need to make the penalty more stringent on load. *Id.*

BPA Staff's Position

Staff states the proposed changes to Persistent Deviation should apply to load, including Slice customers. Jackson *et al.*, BP-12-E-BPA-47, at 58-59. The risk of incurring Persistent Deviation penalties is very low for loads, even without intra-hour scheduling flexibility: only three out of 25 load customers would be expected to incur a Persistent Deviation event, based on historical scheduling data, and these few events are expected to be avoidable even without

contracting for intra-hour scheduling flexibility. Generation Inputs Study, BP-12-FS-BPA-05, section 10.8.9.1.2. However, given the different circumstances and characteristics between load and variable energy resources, Staff acknowledges that it would also be reasonable to consider retaining the four-hour criterion for load. Jackson *et al.*, BP-12-E-BPA-47, at 59.

Evaluation of Positions

Load customers that purchase load following service are not subject to the Persistent Deviation penalty, because they do not submit schedules and BPA dynamically responds to their intra-hour variability. Jackson *et al.*, BP-12-E-BPA-47, at 58. Slice customers, on the other hand, are subject to the Persistent Deviation penalty. Although they cannot schedule their Federal resource on an intra-hour basis, they are not precluded from obtaining non-Federal resources or contracts that they can schedule on an intra-hour basis. *Id.*

PPC and JP01 argue that it is unfair to assume that Slice customers can negotiate resource contracts that allow for intra-hour scheduling. PPC Br., BP-12-B-PP-01, at 23; JP01 Br., BP-12-B-JP01-01, at 37. BPA acknowledges that Slice customers may currently have non-Federal contracts that do not allow intra-hour scheduling. However, this situation is likely true for other customers too, including wind generators, since most contracts are currently scheduled hourly. If any party scheduling to a load does not wish to renegotiate non-Federal contracts to allow for intra-hour scheduling, their exposure to Persistent Deviations with the proposed changes is still very small. Staff's analysis shows that load service customers scheduling hourly are expected to be able to avoid nearly all Persistent Deviations. Generation Inputs Study, BP-12-FS-BPA-05, sections 10.8.9.1.2 and 10.8.9.1.3; Jackson *et al.*, BP-12-E-BPA-47, at 58. To avoid all instances of Persistent Deviation, load customers would need only slight improvements in scheduling accuracy, sufficient to avoid one potential Persistent Deviation event per year. Based on historical data, only three of the 25 BPA load customers would be expected to have a Persistent Deviation event in a year, even without purchase of intra-hour scheduling flexibility. Generation Inputs Study, BP-12-FS-BPA-05, section 10.8.9.1.2. Should a load customer determine that avoiding these unlikely events is accomplished more economically by purchasing intra-hour scheduling flexibility, only a small amount of such flexibility would be needed. *Id.*

JP01 is correct to state that hourly scheduling has been the norm in the region for many years. However, circumstances are changing, and the region is moving toward intra-hour scheduling. PPC, WPAG, and JP01 have not introduced evidence to support their claims that non-Federal contracts could not be renegotiated to allow intra-hour scheduling. Given that BPA expects the movement toward intra-hour scheduling to continue, the reasonable assumption that non-Federal resource contracts can be renegotiated to allow intra-hour scheduling, and the very small exposure load customers have to Persistent Deviations, BPA is not persuaded that it should alter its proposal as to load customers.

WPAG argues that the proposed amendments to Persistent Deviation should not apply to load because, unlike wind, load is subject to all three bands of Energy/Generation Imbalance Service. WPAG Br., BP-12-B-WG-01, at 25-26. The Persistent Deviation penalty serves a different purpose from the GI and EI bands, however, and therefore Persistent Deviation is not duplicative of Band 3. The GI and EI deviation bands are intended to address relatively small deviations that

are short in duration. Jackson *et al.*, BP-12-E-BPA-47, at 59. The Persistent Deviation penalty exists to address deviations associated with larger or longer-term persistent deviations. *Id.*

Another reason WPAG gives for stating that the proposed Persistent Deviation changes should not apply to load is that load will not be able to utilize the proposed exemption for hours that meet or beat a 30-minute persistence schedule. WPAG Br., BP-12-B-WG-01, at 26. However, it does not make sense to provide this exemption for load, because loads schedule based on historical patterns and weather; a persistence schedule would be inaccurate during the known daily ramp periods. While load does not have access to the proposed exemption, the Persistent Deviation waiver provision provides all customers the ability to request a waiver from the penalty for extraordinary circumstances or if they took mitigating actions to reduce the persistent deviation. 2012 BPA Initial Rate Proposal Transmission Rate Schedules, BP-12-E-BPA-10, at 8, 16; Jackson *et al.*, BP-12-E-BPA-47, Attachment 1, at 1-22, 1-25.

Nor is the fact that load is not responsible for as much of the accumulated energy imbalance problem as wind a reason to exempt load from the proposed changes. BPA is attempting to encourage all schedulers to remain attentive to schedules rather than create incentives that could lead to relaxation of existing practices. The penalty is useful as an incentive to schedule accurately, and analysis shows that the proposed changes will have a minimal impact, if any, on load. Generation Inputs Study, BP-12-FS-BPA-05, sections 10.8.9.1.2 and 10.8.9.1.3. By observing and adjusting when schedule error increases, load should be able to avoid the Persistent Deviation penalty.

Decision

The modifications to the Persistent Deviation penalty will apply to load customers, including Slice customers.

Issue 3.5.7.5

Whether the modifications to the Persistent Deviation penalty should apply to dispatchable resources.

Parties' Positions

WPAG states that it is not equitable to subject dispatchable resources to the proposed amendments to the penalty because, unlike wind, dispatchable resources are subject to all three bands of Energy/Generation Imbalance Service, and dispatchable resources will not be able to utilize the proposed exemption for hours that meet or beat a 30-minute persistence schedule. WPAG Br., BP-12-B-WG-01, at 26. WPAG states that Staff's analysis shows that wind generators, not dispatchable resources, are the cause of the vast majority of the accumulated energy problem; therefore there is no need to make the penalty more stringent on dispatchable resources. *Id.* WPAG asserts that Staff fails to show a need to apply the proposed changes to the Persistent Deviation penalty to dispatchable resources and that the proposed changes will achieve

no better results for dispatchable resources than are already being achieved by the current structure. *Id.* at 27.

BPA Staff's Position

Staff believes the Persistent Deviation penalty should apply to dispatchable resources. Jackson *et al.*, BP-12-E-BPA-47, at 61. Dispatchable resources should not be exempted from the change from four to three hours, because dispatchable resources are controllable, and therefore the penalty is avoidable. *Id.* Further, the Persistent Deviation penalty acts as a deterrent and serves as risk mitigation to avoid situations in which a scheduler neglects to adjust its schedule for several hours when generation changes. *Id.* at 62.

Evaluation of Positions

WPAG's arguments with regard to dispatchable resources are nearly identical to its arguments regarding load. It does not make sense, however, to exempt dispatchable energy resources from the Persistent Deviation penalty for several reasons. First, unlike loads and variable energy resources, dispatchable energy resources are not subject to unpredictable variations. Jackson *et al.*, BP-12-E-BPA-47, at 61. Dispatchable resources are controllable, and therefore an entity should always be able to meet its schedule on the hour. *Id.* If an outage occurs, dispatchable resources notify the dispatcher and adjust their next hour schedules accordingly.

It is important that the Persistent Deviation penalty apply to dispatchable energy resources because even though this type of resource is controllable, the risk of poor scheduling and large or persistent deviations exists if the scheduler neglects to align the schedule with generation for several hours. *Id.* at 62. The Persistent Deviation penalty serves as an incentive for dispatchable resources to stay attentive to their schedules, and the penalty is avoidable for dispatchable energy resources. *Id.*

WPAG argues that the proposed amendments to Persistent Deviation should not apply to dispatchable resources because unlike wind, dispatchable resources are subject to all three bands of Energy/Generation Imbalance Service. WPAG Br., BP-12-B-WG-01, at 25-26. However, the Persistent Deviation penalty serves a different purpose from the GI and EI bands, and therefore Persistent Deviation is not duplicative of Band 3. The GI and EI deviation bands are intended to address relatively small deviations that are short in duration. Jackson *et al.*, BP-12-E-BPA-47, at 59, 62. The Persistent Deviation penalty exists to address deviations associated with larger or longer-term persistent deviations. *Id.*

It is true that the proposed exemption for scheduling that meets or beats 30-minute persistence will not apply to dispatchable energy resources, but that is inconsequential because dispatchable energy resources maintain scheduling accuracy by dispatching the resource rather than using persistence scheduling or weather forecasting, making the exemption unnecessary. *Id.* at 61. Additionally, customers may request a waiver if their Persistent Deviation was due to extraordinary circumstances or if they took mitigating actions to reduce the deviation. 2010 Transmission and Ancillary Service Rate Schedules, TR-10-A-02-AP03, at 60; Generation Inputs Study, BP-12-FS-BPA-05, section 10.8.10.

The fact that dispatchable resources have not encountered many Persistent Deviations and are not the cause of the majority of the problem is not a reason to exempt them from the changes to Persistent Deviation. BPA is attempting to encourage all schedulers to remain attentive to schedules rather than creating incentives that could lead to relaxation of existing practices. Since dispatchable resources are controllable, the changes to the Persistent Deviation penalty should not impact them. Jackson *et al.*, BP-12-E-BPA-47, at 61.

Decision

The modifications to the Persistent Deviation penalty will apply to dispatchable resources.

Issue 3.5.7.6

Whether the proposed exemption for variable energy resources that meet a 30-minute persistence schedule is equitable.

Parties' Positions

WPAG notes that load and dispatchable generators will not be able to use the 30-minute persistence exemption. WPAG Br., BP-12-B-WG-01, at 26. WPAG believes it is “inequitable to provide an exemption to wind generators, who are the cause of the problems BPA is trying to address with the Persistent Deviation penalty, and not provide it to load and dispatchable generation, who are not a cause of the problems persistent deviation penalties are designed to address.” *Id.*

BPA Staff's Position

Staff proposed an exemption for hours in which scheduling meets or beats a 30-minute persistence schedule. Generation Inputs Study, BP-12-FS-BPA-05, section 10.8.10. In response to comments received from WPAG, in rebuttal testimony, Staff clarified that this proposed exemption would apply to only variable energy resources, not load or dispatchable energy resources. Jackson *et al.*, BP-12-E-BPA-47, at 59.

Evaluation of Positions

WPAG is correct that load and dispatchable resources will not be able to use the proposed exemption for scheduling that meets or beats a 30-minute persistence forecast. The reason load and dispatchable resources are not subject to this exemption is that they do not use persistence-based forecasting to forecast accurately; therefore, it makes no sense to apply a persistence-based forecasting exemption to them. Load generally forecasts based on historical use patterns and weather, and dispatchable resources are controllable, so they forecast based on the planned operation. To provide an exemption for these customers based on 30-minute persistence forecasting would run the risk of encouraging them to undertake scheduling practices that result in less-accurate schedules than they are currently achieving, which would result in more accumulated imbalance energy on the system and exacerbate the problem.

Wind generators, on the other hand, are encouraged to use 30-minute persistence forecasting because analysis shows that for wind, this forecasting methodology results in better average scheduling accuracy than current scheduling practices. Jackson *et al.*, BP-12-E-BPA-47, at 63. Although persistence scheduling may not yield the highest level of accuracy during large wind ramps, Staff's study shows that such wind ramps occur only a small portion of the time. Documentation, BP-12-FS-BPA-05A, Table 10.3. Additionally, when a wind generator requests a waiver from Persistent Deviation, one of the factors BPA considers is whether the customer's schedule met or beat a 30-minute persistence accuracy standard. This exemption formalizes that waiver factor for the specific hours. It provides an exemption for variable energy generators, for those hours, without requiring them to request a waiver, while retaining the remainder of the persistent deviation event as subject to the penalty.

BPA is also planning to exempt Committed Intra-Hour Pilot participants from the Persistent Deviation penalty because those participants are required to demonstrate, on an ongoing basis, that they achieve 30-minute persistence or superior scheduling accuracy. Jackson *et al.*, BP-12-E-BPA-47, at 68-69. The 30-minute persistence exemption for the Persistent Deviation penalty parallels the exemption provided for Committed Intra-Hour Pilot participants.

WPAG also argues that it is unfair to provide an exemption to wind when wind is responsible for the problems BPA is trying to address through the Persistent Deviation penalty. WPAG Br., BP-12-B-WG-01, at 26. However, the reason wind causes much more accumulated energy imbalance than load or dispatchable resources is because wind is inherently less predictable than loads or dispatchable resources. Therefore, it is reasonable to provide variable energy resources this exemption given their unique forecasting challenges.

Although load and dispatchable resource customers do not have access to the 30-minute persistence exemption, it is important to remember that they always have the ability to request a waiver of the Persistent Deviation penalty for extraordinary circumstances or if the customer took mitigating actions to reduce the deviation. 2012 BPA Initial Rate Proposal Transmission Rate Schedules, BP-12-E-BPA-10, at 8, 16; Generation Inputs Study, BP-12-FS-BPA-05, section 10.8.10; Jackson *et al.*, BP-12-E-BPA-47, Attachment 1, at 1-22, 1-25.

Decision

The proposed exemption for variable energy resources that meet a 30-minute persistence schedule is equitable given the different circumstances affecting variable energy resources. BPA adopts this exemption.

Issue 3.5.7.7

Whether BPA should adopt the proposed wording changes to Part C of the Persistent Deviation definition.

Parties' Positions

Iberdrola notes that BPA has proposed minor changes to the language of Part C of the Persistent Deviation definition, but states that BPA “does not provide a concrete definition around those changes.” Iberdrola Br., BP-12-B-IR-01, at 23.

BPA Staff's Position

Staff explains that the current language contained in Part C has some words omitted, and Staff proposes to correct those omissions to make clear that Part C is intended to apply equally to both Energy Imbalance and Generation Imbalance. Jackson *et al.*, BP-12-E-BPA-47, at 65-66.

Evaluation of Positions

This is a minor wording correction that merely clarifies the existing language of Part C of the penalty. Jackson *et al.*, BP-12-E-BPA-47, at 65-66. The original language that is contained in Part C of the FY 2010–2011 rate schedules reads “(c) A pattern of under-delivery or over-use of energy occurs generally or at specific times of day.” 2010 Transmission and Ancillary Service Rate Schedules, TR-10-A-02-AP03, at 108. This language appears to cover only generation imbalance service situations in which actual generation is less than schedule and energy imbalance service situations in which actual load is greater than schedule, because the words “or over,” “of generation,” and “under or” were omitted. The language is intended to cover generation imbalance service situations in which actual generation is both less than or greater than schedule and energy imbalance situations in which actual load is both less than or greater than schedule. Jackson *et al.*, BP-12-E-BPA-47, at 66. The proposed word additions clarify this intent. Staff proposes that the language read “a pattern of under- or over-delivery of generation or under- or over-use of energy that occurs generally or at specific times of the day.” *Id.* The edits clarify that Part C applies equally to both generation imbalance and energy imbalance.

Decision

BPA adopts the proposed wording changes to Part C of the Persistent Deviation definition.

4.0 TRANSMISSION TOPICS

4.1 Partial Transmission Settlement Agreement

BPA Staff proposes FY 2012–2013 transmission rates and rates for the two required ancillary services (Scheduling, System Control, and Dispatch Service and Reactive Supply and Voltage Control from Generation Sources Service) that reflect the terms of the Partial Settlement Agreement that BPA entered into with many of the rate case parties. Bermejo *et al.*, TR-12-E-BPA-35, at 3. As noted in ROD section 1.1.1.3, only one rate case party preserved the right to object to the partial settlement proposal, and that party did not ultimately object to any aspect of the settlement. Therefore, Staff recommends that the Administrator establish rates consistent with the Partial Settlement Agreement.

The Montana Intertie, Eastern Intertie, and Townsend-Garrison Transmission rates are not included in the partial settlement. All of the proposed FY 2012–2013 final transmission rates and the ancillary services rates that are included in the Partial Settlement Agreement are unchanged from existing rates. BPA determined that existing rates are sufficient for Transmission Services to recover its costs during the rate period. *Id.* The rate levels for BPA’s FY 2012–2013 transmission rates and for the ancillary services rates subject to the settlement are listed in Attachment 1 to the Partial Settlement Agreement, Appendix A to this ROD.

Under the partial settlement agreement, the transmission and ancillary services rate schedules are revised as follows:

a) **Failure to Comply Penalty Charge**

Staff proposes to change the charge from 1,000 mills per kilowatthour to the greater of 500 mills per kilowatthour or 150 percent of an hourly energy index in the Pacific Northwest. Several parties suggested that the existing rate is too high. Staff agrees that BPA can achieve compliance with its orders with the lower charge. *Id.* at 4.

b) **Network Integration Rate Schedule**

Staff proposes to eliminate the credit for customer-served load (CSL), consistent with the 2006 transmission rate case settlement agreement, under which the parties agreed that the credit for CSL would continue until October 1, 2011. *Id.* at 5. Staff proposes to replace CSL with a short-distance discount (SDD) to replace some of the economic benefits of CSL and provide an incentive for NT customers to locate new generating facilities closer to load. The SDD will apply to the NT Base Charge for Network Resources that are designated in an NT customer’s service agreement for one year or longer and that use less than 75 circuit miles of Federal transmission facilities for delivery to Network Load. *Id.* at 6. Staff estimates that the SDD will result in \$2.1 million in credits per year during the rate period. *Id.* at 7.

c) Unauthorized Increase Charge

Staff proposes to eliminate the NT unauthorized increase charge because it applies only to NT customers with customer-served load, which is expiring at the end of the FY 2010–2011 rate period. *Id.*

d) Integration of Resources Rate Schedule

Staff proposes to add language to the Integration of Resources rate schedule providing that relief from the Ratchet Demand is not available in the month in which the Ratchet Demand was established. This language is not a change from existing practice but instead is intended to clarify the extent to which BPA would waive or reduce the Ratchet Demand. *Id.* at 7-8.

e) Rate Schedule Definitions

Staff proposes changes to the definitions of Dynamic Schedule and Dynamic Transfer to ensure that they match the definitions that BPA adopts in its Dynamic Transfer Operating and Scheduling business practice. Staff proposes to delete unnecessary wording from the definitions of Daily Service, Monthly Service, and Weekly Service. *Id.* at 8.

Decision

The rates proposed in the Partial Settlement Agreement satisfy BPA's statutory ratemaking standards and are adopted for the Final Proposal.

4.2 Transmission Revenue Requirement

4.2.1 Introduction

The transmission and ancillary services rates established herein are designed to recover BPA's costs as set forth in the transmission revenue requirement. BPA determines generation and transmission revenue requirements using separate repayment studies, consistent with the Commission's 1984 order. *See United States Dep't of Energy–Bonneville Power Admin.*, 26 FERC ¶ 61,096 (1984). Rates to recover the costs set forth in BPA's generation revenue requirement have been established in the power portion of the BP-12 case. The costs established in the power portion of the case also include inter-business line costs that one business line charges to the other. For example, Power Services charges Transmission Services for the costs of generation inputs used to provide ancillary services and for the annual costs of the U.S. Army Corps of Engineers and U.S. Bureau of Reclamation transmission facilities that are included in the network and utility delivery segments. Transmission Services assesses the ancillary and control area services rates to transmission customers to recover these costs and passes the revenues on to Power Services. For additional information, please see ROD Chapter 3.

Consistent with BPA's statutory obligations, the transmission revenue requirement establishes the level of revenue required to recover all of BPA's costs of transmitting electric power, which include the Federal investment in transmission and transmission-supporting facilities; operations and maintenance (O&M) expenses; transmission marketing and scheduling expenses; the cost of

generation inputs for ancillary services and reliability; and all other transmission-related costs incurred by the Administrator. Transmission Revenue Requirement Study, BP-12-FS-BPA-07, section 1.1.

4.2.2 Revenue Requirement Development

BPA develops its revenue requirement to recover its costs in conformance with its statutory obligations and the financial, accounting, and repayment requirements of the Department of Energy's Order No. RA 6120.2. *Id.*

BPA calculated its transmission revenue requirement for the FY 2012–2013 rate period using a cost accounting analysis consisting of three components:

1. Repayment studies are conducted for each year of the two-year rate period to determine the schedule of amortization payments and to project annual interest expense for bonds and appropriations that fund the Federal investment in transmission. Repayment studies include a 35-year repayment period.
2. Operating expenses functionalized to transmission and minimum required net revenues (if needed) are projected for each year of the rate period (FY 2012–2013).
3. Annual planned net revenues for risk (PNRR), if any, are determined based on the risks identified, BPA's cost recovery goals, and risk mitigation measures.

Id.

Based on these analyses, BPA sets the transmission revenue requirement at the revenue level necessary to fulfill BPA's cost recovery requirements. Department of Energy Order No. RA 6120.2 requires that BPA demonstrate the adequacy or inadequacy of its existing rates to recover its costs. BPA conducts a current revenue test to determine whether transmission revenues projected from current rates meet cost recovery requirements for the rate test and repayment periods. If the current revenue test indicates that cost recovery and risk mitigation requirements can be met, BPA can extend current rates. BPA determined that current rates were insufficient to demonstrate cost recovery because of costs associated with certain ancillary and control area services. *Id.* Accordingly, the current revenue test was not met.

After calculating proposed rates, BPA conducts a revised revenue test to determine the adequacy of the proposed rates. The revised revenue test determines whether projected revenues from proposed rates will meet cost recovery requirements for the rate test and repayment periods. Because the results of the current revenue test demonstrated the sufficiency of the current rates for transmission and for certain ancillary services rates, those rates were continued at current levels for the revised revenue test. BPA has increased the remaining rates to ensure cost recovery. The revised revenue test demonstrates that the rates proposed are sufficient to meet cost recovery requirements for the rate test and repayment periods. *Id.*

4.2.3 Assumptions About the Use of Transmission Financial Reserves

4.2.3.1 Use of Reserves to Fund Transmission Expenses

Over the last several years, revenues from transmission rates provided funds in excess of cash requirements, resulting in a buildup of cash reserves attributed to Transmission Services. To encourage settlement and allow BPA to maintain transmission rates at current levels, the Administrator authorized the use of up to \$67 million of cash reserves to fund a portion of the O&M expenses during the rate period. Accordingly, for this rate period, transmission rates will be based on Transmission Services' net expenses, after application of cash reserves. Homenick *et al.*, BP-12-E-BPA-31, at 3.

4.2.3.2 Use of Reserves to Finance Capital Projects

As in the previous four rate cases, BPA plans to use \$15 million of cash reserves attributed to Transmission Services in each year of the FY 2012–2013 rate period (or a total of \$30 million in the two-year rate period) as a funding source for transmission capital programs, rather than using Treasury borrowing authority. This reserve financing assumption is included in the rate period revenue requirements. *Id.* at 5.

4.2.3.3 Reliance by Power Services on Reserves Attributed to Transmission Services

As discussed in ROD section 2.5.1.3, Power Services will not rely on reserves attributed to Transmission Services in establishing power rates.

4.2.4 Transmission Risk Analysis

In the 1993 Final Proposal BPA determined that, as a long-term policy, it would set its rates to maintain financial reserves sufficient to achieve a 95 percent probability of meeting Treasury payments in full and on time for each two-year rate period. 1993 Final Rate Proposal, Administrator's ROD, WP-93-A-02, at 72-73.

The probability of meeting BPA's Treasury payment obligation is the primary measure of BPA's ability to recover its costs. BPA has applied the same risk analysis for the FY 2012–2013 rate period as in the past. Homenick *et al.*, BP-12-E-BPA-31, at 9. To achieve the above Treasury Payment Probability (TPP), BPA used the following risk mitigation tools:

1. *Starting reserves*: Starting financial reserves include cash and the deferred borrowing balance attributed to the transmission function. Transmission Revenue Requirement Study, section 2.2.1.
2. *Planned Net Revenues for Risk*: PNRR is a component of the revenue requirement that is added to annual expenses. PNRR adds to cash flows so that financial reserves are sufficient to mitigate short-run volatility in costs and revenues and achieve the TPP goal. No PNRR was required to meet the TPP standard in this rate filing. *Id.*

3. *Two-Year Rate Period:* The rates established in this record will be effective for a two-year rate period. The ability to revise rates after two years, or more frequently if necessary, serves as an important risk mitigation tool. A two-year rate period limits the effects of uncertainty. *Id.* Moreover, even though the Administrator is adopting the transmission partial settlement, BPA retains the right to raise rates during the rate period if necessary.

To quantify risks, BPA used a Monte Carlo simulation method to analyze the effects of uncertainty in costs and revenues on transmission cash flows. The analysis estimated the probability of successful Treasury payment (on time and in full) for both years of the rate period. Successful Treasury payment is deemed to occur when the end-of-year transmission cash reserve, after Treasury payments are made, is sufficient to cover the transmission liquidity reserves requirement of \$20 million. The liquidity reserves threshold is based on the monthly net cash flow patterns and requirements for the transmission function. *Id.*, section 2.2.3.

The risk analysis covers the period FY 2011 through FY 2013. This timeframe is used to permit analysis of the change in revenues, costs, and accrual-to-cash adjustments that is expected to occur between the development of the Final Proposal and the end of the rate period. The advantage of this approach is that cash reserves at the start of the FY 2012–2013 rate period may be estimated, thus helping to define the starting conditions for the rate period. *Id.*

The Monte Carlo simulation is conducted in a spreadsheet model that incorporates the effects of risk and risk mitigation to provide an estimate of start-of-year cash reserves for the first year of the rate period and end-of-year cash reserves for each year of the rate period. The estimates of end-of-year cash reserves are used to determine the probability of Treasury payments being made during the rate period. Cash reserve levels at the end of a fiscal year determine whether BPA is able to meet its Treasury payment obligation. *Id.* If cash reserves are sufficient to cover working capital requirements at the end of the fiscal year, it can be assumed that the Treasury payment was made in full and on time that fiscal year. *Id.*

The transmission risk analysis conducted for this rate case demonstrated that BPA exceeds the 95 percent Treasury Payment Probability standard for the FY 2012–2013 rate period. *Id.*, section 2.2.5. The risk analysis simulation included the use of up to \$105 million in reserves attributed to Transmission Services to partially fund transmission O&M expenses (up to \$67 million) and capital projects (\$30 million). *Id.*, section 2.2.2.

No issues regarding the transmission revenue requirement were raised by parties to the BP-12 rate proceeding.

4.3 Montana Intertie

For ratesetting purposes, BPA allocates the rate period transmission revenue requirement to the various transmission rates based on projected use of the system. Because the entire system is not needed to provide each type of service, this method of cost allocation is more equitable than one that does not segment facilities and their associated costs. The Partial Transmission Settlement

provides that such issues with respect to the Montana Intertie may be contested in this rate proceeding.

According to the Federal Register notice announcing the BP-12 Initial Proposal:

Under the Partial Settlement Agreement the Administrator will establish the Montana Intertie (IM) and Eastern Intertie (IE) rates, and consider revisions to the Townsend-Garrison Transmission rate, in a contested process in this rate case. However, under the agreement, BPA staff will propose that the IM and IE rates be no higher than the existing rates, and the signatories to the settlement agreement agree not to present evidence or argument that either rate should be higher than the existing rates.

75 Fed. Reg. 78694 (2010). Staff proposes to set the Montana Intertie (IM-12) and Eastern Intertie (IE-12) Rates at the levels shown in Attachment 1 to its direct testimony and proposed no changes to the Townsend-Garrison Transmission (TGT-12) rate. Fredrickson *et al.*, BP-12-E-BPA-32, at 2.

Staff takes no position on the issue of whether to roll BPA's share of the Montana Intertie into the Integrated Network and set the IM rate at zero, but invited parties to file testimony on that issue. *Id.* at 3-4. Staff explains that BPA's share of the Montana Intertie is actually a share of the costs of the Townsend-to-Garrison transmission segment, known as the Eastern Intertie, and that BPA's share of the costs of that segment is the ratio of the amount of BPA's firm transmission service over that segment divided by the sum of 1730 MW and the amount of BPA's firm service. Fredrickson *et al.*, BP-12-E-BPA-48, at 2-3.

Roll-in of BPA's share of the Eastern Intertie costs would include, or "roll in," those costs within the Integrated Network. Without roll-in, transmission customers seeking service on BPA's system from eastern Montana would pay the IM rate from the eastern-most point on BPA's system, which is at Townsend in Montana where BPA's ownership of the Eastern Intertie begins, west to Garrison Substation, where the Eastern Intertie connects to BPA's Integrated Network. From Garrison Substation they would pay a BPA Network rate for service on the Integrated Network. *See Baker et al.*, BP-12-E-JP10-01, at 3-4. The combination of the IM rate and a BPA Network rate for customers that would take service from Townsend to a point west of Garrison is characterized by Northwest Wind Group as a "pancake." *See Williams*, BP-12-E-NG-03, at 7.

Staff notes that BPA had sent notice terminating the exchange provision of the Montana Intertie Agreement effective October 1, 2011, resulting in a proposed Montana Intertie rate of \$0.598 per kW per month, as described in BPA's Initial Proposal. Fredrickson *et al.*, BP-12-E-BPA-48, at 2.

Staff states that if BPA set the Montana Intertie rate at a level lower than the proposal, or rolled the costs of BPA's share of the Eastern Intertie into the Integrated Network, BPA would rely on financial reserves to cover any shortfall. Fredrickson *et al.*, BP-12-E-BPA-32, at 4; Fredrickson *et al.*, BP-12-E-BPA-48, at 3. Various parties filed testimony either supporting or opposing roll-in or setting the IM rate at zero, as discussed below.

In rebuttal testimony, Staff proposes a modification to the proposed TGT-12 rate to provide a credit to the costs of the Eastern Intertie included in the TGT formula for any sales of non-firm transmission service under the IM-12 rate. Fredrickson *et al.*, BP-12-E-BPA-48, at 2. Puget Sound Energy (Puget) and NorthWestern Energy (NWE) make slightly different proposals for the same purpose. Puget Br., BP-12-B-PS-01, at 5; NWE Br., BP-12-B-NC-01, at 4.

Neither BPA nor any other party proposes a change to the proposed IE-12 Rate. As a result, BPA adopts the proposed IE-12 Rate.

4.3.1 Roll-in of BPA’s Share of Eastern Intertie Capacity or Setting the IM Rate at Zero

Issue 4.3.1.1

Whether roll-in of BPA’s share of the costs of the Eastern Intertie would be inconsistent with BPA’s segmentation methodology.

Parties’ Positions

JP11 argues that the use of the Eastern Intertie for importing generation of a few generators from Montana has not changed from the use described in the 2002 Final Segmentation Study. JP11 Br., BP-12-B-JP11-01, at 3. JP11 argues that there is no substantial evidence in the record that would support a change in segmentation. *Id.* at 13. JP11 and PNGC argue that BPA has an established segmentation methodology pursuant to which BPA has determined the Eastern Intertie to be a separate segment. *Id.* at 11-12; PNGC Br., BP-12-B-PN-01, at 5. Those parties argue that the sole purpose of the Montana Intertie is to import generation from Montana to the Pacific Northwest, and that the usage, function, and voltage of and contracts concerning the Eastern Intertie facilities all counsel in favor of continued segmentation. JP11 Br., BP-12-B-JP11-01, at 12; PNGC Br., BP-12-B-PN-01, at 5.

JP11 argues that to “justify rolling in the IM rate for FY 2012-2013, and shifting those costs to BPA’s Network transmission customers, proponents would have to provide substantial evidence in the Record showing that the Eastern Intertie now confers a benefit on BPA’s Network transmission customers.” JP11 Br., BP-12-B-JP11-01, at 4. In its brief on exceptions, PPC “requests that BPA revise its final decision on this issue to acknowledge that ... the cost-causation principle ... demands a demonstration of a benefit to the class charged with a cost that is roughly commensurate to a benefit received.” PPC Br. Ex., BP-12-R-PP-01, at 13-14.

WPAG argues that since the 1983 rate case BPA has separately segmented the Eastern Intertie as a line built by BPA primarily to transmit Colstrip generation to BPA’s Network. WPAG Br., BP-12-B-WG-01, at 60-61. WPAG argues that during the FY 2012–2013 rate period, the Eastern Intertie will still be used for the primary purpose of transmitting Colstrip generation, and that it does not appear that new wind generation will interconnect to the Eastern Intertie during the rate period. *Id.* Therefore, WPAG argues, there is no change in circumstances that would justify a change from the current segmentation. *Id.*

NWG argues that BPA’s segmentation methodology is irrelevant to the decision to end the IM rate. NWG Br., BP-12-B-NG-01, at 84. NWG asserts that the segmentation study that originally formed the basis for segmenting the Eastern Intertie was based on the Montana Intertie Agreement and the integration of the output from one single coal plant. *Id.* at 84-85. NWG further states that the segmentation study is outdated: the potential for use of those facilities has changed dramatically in recent years because of the availability of OATT service on BPA’s share of the Eastern Intertie capacity. *Id.* at 85. In addition, NWG states, the original segmentation study did not consider the question of the capacity associated with the IM Rate between Townsend and Garrison. *Id.* Although NWG maintains that BPA’s segmentation policy does not apply to the Townsend to Garrison segment, to the extent it does, NWG supports Staff’s interpretation of BPA’s segmentation policy stated in BPA’s rebuttal testimony. *Id.*, citing Fredrickson *et al.*, BP-12-E-BPA-48, at 7. NWG summarizes that interpretation as stating that the Administrator has discretion to consider the language in section 9 of the Federal Columbia River Transmission System Act that provides that rates shall be established “with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates consistent with sound business principles.” *Id.* NWG states that such language supports BPA ending the IM Rate in order to generate revenues from the Townsend-Garrison segment. *Id.*

PacifiCorp asserts that removal of the Montana Intertie “rate pancake” would support regional development of the greatest potential wind resources in the Western United States and help BPA’s customers meet the requirements of Renewable Portfolio Standards. PacifiCorp Br., BP-12-B-PC-01, at 4-5.

BPA Staff’s Position

Staff testifies that rolling in the Eastern Intertie costs that would otherwise be recovered through the IM rate during the FY 2012-2013 rate period would have a negligible impact on Network rates. Fredrickson *et al.*, BP-12-E-BPA-48, at 4. Staff testifies that BPA has discretion to accommodate conflicting policies that are committed to BPA’s care by statute and is not required to focus exclusively on cost causation. *Id.*, at 6-7, citing 1996 ROD, WP-96-A-02, at 45. For example, in the 1996 rate proceeding, BPA considered language of section 9 of the Federal Columbia River Transmission System Act providing that rates “shall be fixed and established: (1) with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates consistent with sound business principles ...” to roll the Fringe segment into the Integrated Network. *Id.* The Fringe segment had previously been a separate segment under a cost causation approach. *Id.*

Evaluation of Positions

Regarding JP11’s and PPC’s assertions that roll-in requires BPA to find, based on substantial evidence, a benefit commensurate to costs, because BPA has decided not to roll-in its share of Eastern Intertie costs, it is not necessary for BPA to address the factors that it would consider in a future rate case, including what conflicting policies might apply at that time and how it would balance any conflicting policies, and any benefits to the Network customers as a class.

BPA is expected to exercise its discretion to change its policies when circumstances change. *See Chevron, U.S.A., Inc. v. Natural Resources Defense Council*, 467 U.S. 837, 863-64 (1984). As WPAG notes, when BPA established the segmentation of the Eastern Intertie in the 1983 rate case, the line was expected to transmit Colstrip generation. Saleba *et al.*, BP-12-E-WG-04, at 7. In recent years, the area served by the Eastern Intertie has been identified as a high-quality wind generation area, Apperson, BP-12-E-PC-01, at 2, and Federal policy and state renewable portfolio standards in the Pacific Northwest and California promote the development and transmission of new renewable generation such as Montana wind. Mainzer *et al.*, BP-12-E-BPA-42, at 11; Fredrickson *et al.*, BP-12-E-BPA-48, at 9-10. Congress directed BPA to use its discretion to provide transmission service for non-Federal generating units. Transmission System Act § 4(a); *see Hearing on S. 3362 before the Subcomm. on Water and Power Resources of the Senate Comm. on Interior and Insular Affairs*, 93d Cong., 2d Sess. 125 (June 6, 1974) (BPA transmission of eastern Montana generation, Colstrip, was contemplated in the legislative history of the Transmission System Act).

Extending BPA's Integrated Network to include BPA's share of capacity on the Eastern Intertie could encourage the development of renewable generation resources in Montana, Fredrickson *et al.*, BP-12-E-BPA-48, at 7, and could encourage construction of new transmission facilities to export the renewables from Montana, as noted by JP10 and NWG. Baker *et al.*, BP-12-E-JP10-01, at 5-6, 8-9; Williams, BP-12-E-NG-03, at 4-5. NWG states that the IM rate pancake increases the cost to transmit Montana wind to loads on BPA's system. Williams, BP-12-E-NG-03, at 5. NWG adds that eliminating the IM rate could reduce the per-unit cost of integrating Montana wind generation. *Id.* at 6. Staff and several parties agree that if other significant cost issues could be adequately addressed, eliminating the IM rate pancake could reduce the cost to BPA's customers of meeting renewable portfolio standards with a combination of diverse Montana and Pacific Northwest wind. *See PacifiCorp Br.*, BP-12-B-PC-01, at 5; Fredrickson *et al.*, BP-12-E-BPA-48, at 7-9; Williams, BP-12-E-NG-03, at 5-6.

As discussed below under Issue 4.3.1.6, the impact on Network transmission rates of the roll-in would be negligible. However, as discussed under Issues 4.3.1.4, 4.3.1.9, 4.3.1.11, and 4.3.1.12, the record is inadequate for BPA to determine that roll-in would not have significant adverse cost impacts that would offset the potential benefits of rolling in the Eastern Intertie costs. As detailed in the discussion of Issue 4.3.1.4, more information is needed about the costs and benefits related to diversity of Montana wind with respect to wind in the Columbia Gorge area. As indicated in the discussion of Issue 4.3.1.9, additional information is needed with respect to whether roll-in of BPA's share of costs of the Eastern Intertie would be a precedent for roll-in of other segments, such as the Southern Intertie. In Issue 4.3.1.11, BPA explains that insufficient information has been provided to support the proposition that rolling in the IM rate capacity without roll-in of the TGT rate capacity would be discriminatory under BPA's statutes. Finally, as stated in Issue 4.3.1.12, more information is needed about the issue of whether roll-in of BPA's share of Eastern Intertie costs would discourage joint participation with BPA in new transmission projects. In the face of this uncertainty, making a change to BPA's longstanding segmentation policy regarding the Eastern Intertie is not warranted at this time.

NWG argues that BPA's segmentation methodology is irrelevant to a BPA decision whether to roll in BPA's share of Eastern Intertie costs. NWG Br., BP-12-B-NG-01, at 84. BPA disagrees that its segmentation methodology is irrelevant. Changing the allocation of costs of transmission facilities previously classified as a separate segment in rates is a segmentation decision that must be supported by an appropriate rate case record.

Decision

Issues 4.3.1.4, 4.3.1.9, 4.3.1.11, and 4.3.1.12 have not been adequately developed in this rate case so that BPA can determine cost impacts associated with those issues and could therefore determine, within its discretion, whether roll-in of BPA's share of Eastern Intertie costs or setting the IM rate to zero would better achieve an equitable allocation of transmission system costs and otherwise satisfy BPA's ratemaking standards. BPA and interested parties will have the opportunity to more fully address these and all other relevant issues in the upcoming workshops resulting from the Partial Transmission Settlement and in a future rate case where roll-in of BPA's share of Eastern Intertie costs or setting the IM rate at zero are considered.

Issue 4.3.1.2

Whether roll-in of BPA's share of the costs of the Eastern Intertie would result in additional utilization of the Eastern Intertie and therefore additional Network transmission revenues.

Parties' Positions

NWG argues that eliminating the IM Rate through roll-in would result in BPA generating revenues from the Townsend-Garrison line. NWG Br., BP-12-B-NG-01, at 86. NWG argues that the IM rate pancake, with termination of the exchange under the Montana Intertie Agreement, would increase transmission costs for Montana wind by 50 percent above BPA's Network rates, and that the IM rate pancake discourages new generation and transmission projects that would otherwise seek service from or interconnect with BPA at Townsend. *Id.* at 79-80. NWG states that ending the IM rate will lead to transmission service requests in BPA's network queue for transmission of Montana wind generation from Townsend, and that such requests are not contingent on the construction of Garrison-Ashe. *Id.* at 88. For example, NWG claims any requests for delivery east of the West of Hatwai cutplane would not require construction of Garrison-Ashe. *Id.* NWG states that there may be other options than Garrison-Ashe for developing capacity west of Garrison but does not want to speculate about they would be. *Id.* at 88-89. NWG argues that to attract the kind of development that will make use of the stranded capacity on the Townsend-Garrison line, BPA needs to make a long-term policy decision regarding eliminating the IM rate and not just a short-term solution that would apply to only the FY 2012–2013 rate period. *Id.* at 90.

NWG takes issue with BPA's draft decision that there is insufficient evidence in the record to determine whether rolling in BPA's share of Eastern Intertie costs would result in new transmission service on BPA's Network from Townsend. NWG Br. Ex., BP-12-R-NG-01, at 25-26. NWG points out that BPA's treatment of the Eastern Intertie as a separate segment for

over 20 years has resulted in only 16 MW of firm service using BPA's capacity on the line and that roll-in would send proper price signals and "could only serve to improve the use of the segment." *Id.* at 25. NWG argues that BPA's Draft ROD "gets sidetracked by the issue of whether and which transmission upgrades are needed"; that "the issues related to transmission upgrades are not before the Administrator in this proceeding"; that "BPA's arguments as to whether would-be users of this segment would be willing to pay an incremental cost rate for certain upgrades are speculative"; and that "[r]esolution of questions related to these upgrades is an unnecessary distraction to the fundamental issue of whether there is value to BPA and its customers in eliminating the rate pancake." *Id.* at 25-26.

PacifiCorp argues in favor of roll-in for the FY 2012–2013 rate period and that BPA could simply declare that roll-in would not be precedential for future rate periods. PacifiCorp Br., BP-12-B-PC-01, at 3-4. PacifiCorp argues that there is insufficient information on the record for it to take a position on the issue of whether rolling in or setting the IM-12 rate at zero would result in additional transmission service requests. *Id.* at 5.

PNGC states that it is unaware of any such service requests with or without the construction of Garrison-Ashe. PNGC Br., BP-12-B-PN-01, at 7. PNGC states that it does not intend to make such a request. *Id.*

WPAG states that elimination of the IM rate for the FY 2012–2013 rate period will not provide wind developers with sufficient certainty to make investments, and that they will need certainty regarding adequate capacity west of Garrison, such as from construction of Garrison-Ashe, to justify investment. WPAG Br., BP-12-B-GW-01, at 59-60.

JP11 argues that new wind generation will be developed in Montana regardless of whether the IM rate is rolled in. JP11 Br., BP-12-E-B-JP11-01, at 5.

NWE argues that while it is aware that wind projects are being planned in Montana, it is unclear at this time when such projects would be built and the amount of transmission capacity that would be required for such projects. NWE Br., BP-12-B-NC-01, at 5. NWE requests that BPA provide a redline of proposed tariff changes, rate schedules, or business practices through which BPA would offer rolled-in transmission service so that NWE could better respond to the question. *Id.*

BPA Staff's Position

The proposed IM rate of \$0.598/ kW per month at a 35 percent capacity factor results in a cost of about \$2.34 per megawatt-hour. Fredrickson *et al.*, BP-12-E-BPA-48, at 7. Staff agrees that eliminating the IM rate could encourage development of renewables in Montana "in a situation where the costs and revenues are close." *Id.*

At the April 20, 2011, rate case workshop, Staff asked parties to address the following question in their initial briefs:

Would rolling in BPA's share of Montana Intertie capacity or setting the IM rate at zero result in any transmission service requests in BPA's network queue for transmission of Montana wind generation from Townsend, for delivery either between Garrison and West of Hatwai or west of West of Hatwai? Or are any such requests contingent on the construction of Garrison-Ashe? (new request) Please be as specific as possible.

See the PowerPoint presentation titled "BP-12 (Transmission) Workshop on Montana Intertie REVISED" located on BPA's transmission Web site for NOS 2010 under customer meetings, for the April 20, 2011, meeting (Workshop Presentation), slide 12.

Evaluation of Positions

At the April 20, 2011, rate workshop, which was noticed to rate case parties, Staff disclosed that in the 2010 Network Open Season (NOS), BPA had 31 signed Precedent Transmission Service Agreements (PTSA) for 1,074 MW of service from Garrison to the west on BPA's Network but no transmission service requests for service on the Eastern Intertie. See Workshop Presentation, slide 9; see also Baker *et al.*, BP-12-E-JP11-01, at 6-7. BPA expects that the Colstrip Upgrade Project West (CUP West project) described in the Workshop Presentation at slide 7, which would increase capacity on BPA's Network west of Garrison, could allow transmission service for a maximum of 530 MW of Montana generation on the BPA Network from Garrison to the west at embedded cost transmission rates. See BPA Rolled-in Rate Decision Letter for the 2010 Network Open Season, at 2, and Attachment A, at 3 (May 31, 2011). Any additional Montana generation would face the need for a Network upgrade from Garrison to the west (the Garrison-Ashe, or "GASH" project), which would cost nearly \$1 billion and likely require BPA to charge incremental cost rates. *Id.* Staff understood from the discussion at the workshop that the 530 MW utilizing the CUP West project would be delivering power to BPA's system at Garrison, not Townsend. This is consistent with the fact that there are no requests in BPA's transmission queue for use of the Eastern Intertie. Thus, any use of BPA's 184 MWs of ATC on the Eastern Intertie would probably require the GASH project to deliver the power over the Network west of Garrison.

While it may be possible to deliver some amount of Montana wind generation on BPA's Network between Garrison and the West of Hatwai cutplane, as argued by NWG, there is no evidence in the record that there is any demand for Montana wind generation in that area.

As a result of decisions made in this rate case, BPA's IM rate for Eastern Intertie service will decrease by 54 percent. Although 184 MW is a small amount of the potential wind generation in Montana, the market response to this decrease may provide some evidence as to the impact of price on demand.

Staff agrees with NWG that elimination of the IM rate pancake could make a difference in whether new generation seeks service on BPA's Network from Townsend. Fredrickson *et al.*, BP-12-E-BPA-48, at 7; Williams, BP-12-E-NG-05, at 10. JP10 notes that significant new investments, such as GASH, will be needed for BPA to transmit wind generation on its Network west of Garrison, at a possible cost of \$1 billion. Baker *et al.*, BP-12-E-JP10-01, at 9. There is

no estimate in the record of the costs of a new transmission line from Townsend, and, since there is only 184 MW of capacity available on the Townsend to Garrison line, Williams, BP-12-E-NG-03, at 7, a new facility may be needed. Because new BPA Network facilities would be needed both west and east of Garrison to transmit significant new generation from eastern Montana, generators seeking service on BPA's Network would be expected to compare the costs of packages from a local transmission provider to transmit power to either Townsend or Garrison plus any incremental costs under BPA's Network rate for expansion of BPA facilities for service from either Townsend or Garrison. If the package cost for (1) service from the generation over the local transmission system to BPA's system and (2) from that point on BPA's system to the point of delivery outside of BPA's system would be less for BPA service from Garrison than from Townsend, generation developers would be expected to choose to access BPA's Network at Garrison rather than Townsend, as they have apparently done during the 2010 NOS. There is no evidence in the record of any such comparison, so it is unclear whether roll-in of BPA's share of Eastern Intertie costs would result in any more service on BPA's Network or would promote development of additional wind in Montana.

NWG argues that the Draft ROD's discussion of the costs of new lines and service over upgraded facilities is speculative or not relevant to the rate case. NWG Br. Ex., BP-12-R-NG-01, at 25-26. BPA disagrees. There is no dispute that to serve all existing requests in BPA's Network transmission queue for service from Garrison substation a facility costing nearly \$1 billion will be needed. There is also no dispute that BPA has only 184 MW of existing westbound capacity on the Eastern Intertie. The discussion in the previous paragraphs is based on the results of BPA's 2010 NOS, and it is relevant to the issue raised by NWG of whether roll-in would result in additional utilization of the Eastern Intertie and therefore additional BPA transmission revenues.

Because there is only 184 MW of available capacity on the Eastern Intertie, if roll-in of BPA's share of the costs of the Eastern Intertie is to significantly encourage development of new wind generation and new service on BPA's Network, upgrades to the Townsend-Garrison line will be needed. Because much of the Townsend-Garrison line is outside BPA's service area, congressional approval may be required before BPA may build major upgrades. NWG claims that the Eastern Intertie is in BPA's service area because BPA sells power to Vigilante Electric Cooperative, Williams, BP-12-E-NG-03, at 2, but JP11 notes that BPA's service to Vigilante is irrelevant. Baker *et al.*, BP-12-E-JP11-01, at 6. With the exception of certain customer service facilities that are not relevant to this proceeding, BPA must receive congressional approval to commence construction of a new transmission facility outside the Pacific Northwest, which, in this case, is east of the Continental Divide in Montana. Transmission System Act, § 4. Congress previously approved "the construction of facilities to integrate new generating facilities at Colstrip, Montana, and the Bonneville Power Administration transmission grid." The foregoing language was in Title I of the Energy and Water Appropriations Act for FY 1979 (H.R. 12928), which passed, but was vetoed on October 5, 1978. A continuing resolution was passed that approved:

[s]uch amounts as may be necessary, notwithstanding any other provision of this joint resolution, for the fiscal year ending September 30, 1979, for programs, projects, and activities to the extent and in the manner provided for in the Energy

and Water Development Appropriation Act, 1979 (H.R. 12928) as enacted by the Congress

HJR 1139, Public Law 95-482, § 101(b) (October 18, 1978). Because Congress approved construction of the Townsend-Garrison line, it is not a new facility under Transmission System Act section 4, and BPA has discretion to modify that facility without additional congressional approval. *See Hearing, supra*, at 158. However, if BPA needs to expand its system between Townsend and Garrison, and it is necessary to build a different line to provide more than the 184 MW of transmission now available from Townsend, BPA may need congressional approval. Any proposed congressional approval for new extraregional facilities would have a greater chance of success with unified support from the Pacific Northwest, and the opposition to roll-in of the Eastern Intertie expressed in this rate case indicates that unified support is not certain.

Decision

Further facts need to be developed for BPA to fully and fairly determine whether rolling in BPA's share of Eastern Intertie costs would result in greater transmission utilization.

Expensive projects may be needed to satisfy additional transmission requests on the Eastern Intertie. The incremental costs of expansion may exceed, and thus outweigh, the cost benefit of roll-in in a wind developer's decision to request service. There is insufficient evidence in the record regarding whether transmission customers would be willing to pay an incremental cost rate.

Issue 4.3.1.3

Whether roll-in of BPA's share of the costs of the Eastern Intertie, or setting the IM rate at zero, would result in additional wind generation development in Montana.

Parties' Positions

NWG argues that wind generation and transmission facility developers in Montana will consider the IM rate pancake when deciding whether to make generation and transmission investments, and that the pancake will make such projects less likely. NWG Br., BP-12-B-NG-01, at 79-81. NWG argues, however, that setting the IM Rate at zero for the FY 2012–2013 rate period will not be for a sufficient term to attract the investment needed to put the unused capacity on the Townsend–Garrison infrastructure to use. *Id.* at 89-90.

NWG argues that its testimony and other comments from the Governor of Montana in Participant Comments (*see* ROD section 5.2), and statements from wind developers outside the record, are substantial evidence of additional Montana wind generation that would result from roll-in of the IM rate sufficient for BPA to determine that roll-in would result in additional Montana wind generation development. NWG Br. Ex., BP-12-R-NG-01, at 26-27. NWG argues that short of confidential and proprietary information about the economics of particular projects, which NWG asserts seems unlikely and unnecessary, it is unclear what additional information BPA needs. *Id.* at 27.

PacifiCorp argues that removal of the Montana Intertie rate pancake would support the regional development of wind resources—including from the wind-rich area of Montana—without negatively impacting transmission rates for other users. PacifiCorp Br., BP-12-B-PC-01, at 4-5.

WPAG states that elimination of the IM rate for the FY 2012–2013 rate period will not provide wind developers with sufficient certainty to make investments, and that they will need certainty regarding adequate capacity west of Garrison, such as from construction of Garrison-Ashe, to justify investment. WPAG Br., BP-12-B-PG-01, at 59. WPAG argues that “[t]his is particularly true given that the settlement agreement pushes any permanent policy decision on this issue until the 2014 rate case.” *Id.* at 59-60.

JP11 argues that “there is simply no basis to conclude that wind developers will forego developing additional wind power in Montana unless the IM rate is rolled in. To the contrary, the Record indicates that such development will eventually occur regardless of whether the IM rate is rolled in or not.” JP11 Br., BP-12-B-JP11, at 5.

BPA Staff’s Position

The proposed IM rate of \$0.598/ kW per month at a 35 percent capacity factor results in a cost of about \$2.34 per megawatthour. Fredrickson *et al.*, BP-12-E-BPA-48, at 7. Staff agrees that eliminating the IM Rate could encourage development of renewables in Montana “in a situation where the costs and revenues are close.” *Id.*

Evaluation of Positions

The evaluation of positions for Issue 4.3.1.2, above, also applies to this issue.

Because there is no evidence in the record of any comparison of the costs of obtaining transmission service to and on BPA’s Network from Townsend and Garrison, BPA cannot determine whether roll-in would make development of Montana wind more likely. BPA is not necessarily asking for confidential or proprietary information, but some evidence comparing such costs is needed given the facts. This could also be an appropriate issue for discussion in the upcoming workshops regarding the future of the IM, IE, and TGT rates.

Decision

Although BPA expects that eliminating the IM rate and extending BPA’s Integrated Network to Townsend may eventually encourage development of new wind generation that would seek access to BPA’s Network at Townsend, for the reasons discussed in Issue 4.3.1.2, above, there is insufficient evidence in the record to determine that roll-in or setting the IM rate at zero during the FY 2012–2013 rate period would have that result. Based on evidence in the record, it appears that the impact of either of these decisions on the delivered cost of power would be in the range of \$2.34 per MWh, which in and of itself seems unlikely to be dispositive as to the development of new wind in Montana. Further, such reduction would apply only to the 184 MW of available capacity on the Townsend-Garrison line.

Issue 4.3.1.4

Whether the Pacific Northwest would receive wind generation diversity benefits if wind generation from eastern Montana were exported to the Pacific Northwest.

Parties' Positions

NWG argues that “BPA customers would ... benefit from the increased diversity through the interconnection of Montana wind energy projects, which would lower the per-unit costs of integrating variable resources into the grid.” NWG Br., BP-12-B-NG-01, at 83.

NWG asserts that, contrary to the conclusion in the Draft ROD, there is substantial evidence in the record demonstrating seasonal and diurnal diversity between Montana wind and wind on BPA’s system. NWG Br. Ex., BP-12-R-NG-01, at 27-28, *citing* Draft ROD, BP-12-A-01, at 419. NWG also disagrees with the evaluation of this issue in the Draft ROD that Montana wind would need to be in BPA’s balancing authority area for there to be balancing reserve capacity benefits to BPA from Montana wind because diverse wind in one area improves the efficiency and costs of balancing reserves to the region as a whole, particularly given the increasing use of dynamic transfer capability. *Id.* at 28-29, *citing* Draft ROD, BP-12-A-01, at 418-419. NWG also asserts that “using the federal transmission system to promote renewable energy development in other Pacific Northwest balancing areas is an appropriate way for BPA to fulfill its statutory requirement to facilitate new renewable energy development in the [Pacific Northwest] and does so without increasing BPA’s balancing requirements.” *Id.*

JP11 argues that NWG’s claim of seasonal diversity benefits is flawed because Montana wind is not negatively correlated with Columbia Gorge wind, and that, “at best ... any diversity would only be realized if BPA were to be the balancing authority providing reserves to balance the wind output and would only serve to mitigate BPA’s burden of integrating that wind into the Network—but it certainly could not be said to be a ‘benefit’ to Network reliability.” JP11 Br., BP-12-B-JP11-01, at 6. JP11 points out that NWG’s evidence of diversity indicates that there could be significant Montana wind energy produced during the Pacific Northwest runoff season. Baker *et al.*, BP-12-E-JP11-01, at 10-11.

PNGC states that NWG’s argument about diversity benefits is flawed because “any such Montana wind resources would not be negatively correlated with existing wind resources.” PNGC Br., BP-12-B-PN-01, at 4.

BPA Staff’s Position

Because Montana wind patterns are different from those of Columbia Gorge wind, there would be less incremental balancing requirements for adding Montana wind to BPA’s fleet of Columbia Gorge wind than for adding more Columbia Gorge wind, but there would nevertheless be additional balancing required. Fredrickson *et al.*, BP-12-B-BPA-48, at 8. Additional balancing reserves would be needed because Montana wind is not negatively correlated with Columbia Gorge wind. *Id.* Further, there could be months when the swings in Montana wind would not

produce diversity benefits. *Id.* Any diversity benefits would arise for Montana wind in BPA’s balancing authority area. *Id.* at 9.

Evaluation of Positions

Although Montana wind may be seasonally and diurnally diverse with wind in the vicinity of the Columbia Gorge, *see* Williams, BP-12-E-NG-03, Attachment 1, NWG’s testimony on whether Montana wind would provide wind generation diversity benefits on BPA’s system does not address whether the Montana wind would be in BPA’s balancing authority area. Williams, BP-12-E-NG-03, at 5-6. Unless the wind were in BPA’s balancing authority area, it would not provide any balancing reserve capacity diversity benefits. *See* Fredrickson *et al.*, BP-12-E-BPA-48, at 7-8. As noted by JP11, the weight of the evidence is that Montana wind would not be in BPA’s balancing authority area. *See* Baker *et al.*, BP-12-E-JP11-01, at 11. Even if the Montana wind were added to the BPA balancing authority area, although the incremental balancing reserves would be less than those required for adding more wind near the Columbia Gorge, additional balancing reserve capacity would be needed because the Montana wind is not negatively correlated with Columbia Gorge wind. Fredrickson *et al.*, BP-12-E-BPA-48, at 7-8. There is no analysis in the record of the amounts of costs or benefits for BPA’s balancing reserves needs of adding Montana wind to BPA’s balancing authority area.

Regarding NWG’s arguments on this issue in its brief on exceptions, in the previous paragraph immediately above, the Draft ROD acknowledges, as BPA does here, the seasonal and diurnal diversity between Montana wind and wind near the Columbia Gorge. However, in response to the argument made for the first time in NWG’s brief on exceptions that wind need not be in BPA’s balancing authority area to benefit BPA’s balancing reserve costs, NWG Br. Ex., BP-12-R-NG-01, at 27-28, BPA disagrees. Staff testifies that:

[w]hen wind patterns are significantly different from one wind project to another, the total amount of in-hour balancing reserve needed for the projects in a single Balancing Authority Area will be less than the sum of the in-hour balancing reserve needed for each project. This "diversity benefit" results because the change in wind output occurs at one of the projects in a certain hour and at the other project in a different hour.

Fredrickson *et al.*, BP-12-E-BPA-48, at 7-8. However, any balancing reserve diversity benefits would occur “if the Montana wind generation was in BPA’s Balancing Authority Area.” *Id.* at 9. Further, NWG cites no evidence in the record, and BPA is not aware of any such evidence, that wind in a non-BPA balancing authority area would benefit BPA’s balancing reserve costs.

Decision

The estimated diversity benefits and costs of transmitting Montana wind generation on BPA’s Network have not been quantified in the record. Furthermore, at present, wind in Montana is not in BPA’s balancing authority area, and there is no evidence that it will be in BPA’s balancing authority area at any time in the future.

It would be helpful for BPA to hear from additional existing wind transmission customers as to their views of these impacts, because those customers will incur the costs or benefits through BPA's rates for wind integration.

Issue 4.3.1.5

Whether BPA is authorized to support development of wind resources in eastern Montana through its segmentation policy.

Parties' Positions

Benton County PUD and WPAG argue that because section 2(1)(B) of the Northwest Power Act applies to development of renewable resources only in the Pacific Northwest and that the proposed wind projects that would benefit from rolling in the Montana Intertie or setting the IM rate at zero are outside the Pacific Northwest, BPA has no authority or responsibility to encourage the development of such resources. Benton Br., BP-12-B-BC-01, at 4; WPAG Br., BP-12-E-WG-01, at 55-57. WPAG also argues that because NWG expects BPA to provide integration and balancing services to the Montana wind fleet, WPAG Br., BP-12-B-WG-01, at 58, *citing* Williams, BP-12-E-NG-03, at 5-6, roll-in will accelerate the day when BPA's system capability will be insufficient to provide integration and balancing services to the wind fleet, while simultaneously fulfilling BPA's environmental and load service obligations. *Id.* This would raise the question of whether wind in the Pacific Northwest would be asked to pay higher rates for the incremental capacity needed to integrate and balance Montana wind projects. *Id.*

PNGC argues that BPA has no statutory mandate to encourage the development of such resources and that BPA's success in encouraging renewable generation in the Pacific Northwest shows that BPA has met any statutory obligation to encourage renewables. PNGC Br., BP-12-B-PN-01, at 6-7.

JP11 argues that BPA has no statutory directive to encourage wind development in eastern Montana, and that even if BPA did have such an obligation, BPA's statutory obligations must be considered together, to avoid shifting costs to other customers. JP11 Br., BP-12-B-JP11-01, at 8-9.

NWG asserts that the entire Townsend-Garrison line is in BPA's service area. NWG Br., BP-12-B-NG-01, at 91.

BPA Staff's Position

Since this issue is not raised until parties' initial briefs, Staff did not submit testimony on this issue. However, Staff acknowledges in rebuttal testimony that BPA has discretion "to apply 'a reasonable accommodation of conflicting policies that are committed to [its] care by statute.'" Fredrickson *et al.*, BP-12-E-BPA-48, at 7.

Evaluation of Positions

Section 2(1)(B) of the Northwest Power Act states that a purpose of the Act is to encourage, “through the unique opportunity provided by the Federal Columbia River Power System ... the development of renewable resources within the Pacific Northwest” The plain language of Northwest Power Act section 2(1)(B) states that the section applies to renewable generation only in the Pacific Northwest, which is defined in the Northwest Power Act section 3(14), 16 U.S.C. § 839a(14). That definition excludes the parts of Montana east of the Continental Divide, except for purposes of serving BPA’s rural electric cooperative customers with service areas that extend beyond the Continental Divide. The Montana wind generation that would benefit from roll-in of BPA’s Eastern Intertie costs is east of the Continental Divide and thus is not relevant to Northwest Power Act section 2(1)(B). PNGC Br., BP-12-B-PN-01, at 6; *see* Williams, BP-12-E-NG-03, at 5.

Because Northwest Power Act section 2(1)(B) does not preclude BPA from transmitting renewable generation that is located outside the Pacific Northwest, as discussed in Issue 4.3.1.1, above, and because BPA is authorized to transmit non-Federal generation and to provide interregional transmission facilities, *see* 16 U.S.C. §§ 838b(a) and (c), BPA may consider whether statutory policies other than Northwest Power Act section 2(1)(B) would support roll-in of BPA’s share of costs of the Eastern Intertie. For example, in the 1996 rate case, BPA considered whether its segmentation decision would encourage the widest possible diversified use of electric power at the lowest possible rates consistent with sound business principles. Fredrickson *et al.*, BP-12-E-BPA-48, at 6-7, *citing* 1996 ROD, WP-96-A-02, at 42-45.

Just as BPA considered Transmission System Act section 9 in the 1996 rate case, and, in appropriate circumstances, could consider Northwest Power Act section 2(1)(B), BPA may also consider other statutory directives in deciding segmentation. For example, BPA may consider the policy in Transmission System Act section 4(a) that the Administrator exercise discretion to build and operate the BPA transmission system to transmit non-Federal generation, including generation that is outside the Pacific Northwest. *See Hearing, supra*, at 125 (BPA transmission of eastern Montana generation, Colstrip, was contemplated in the legislative history of the Transmission System Act). Under appropriate facts, BPA could implement the policy of Transmission System Act section 4(a) and other applicable statutes by rolling in BPA’s share of the costs of the Eastern Intertie.

Further, section 6(l)(1) of the Northwest Power Act provides as follows:

The Administrator is authorized and directed to investigate opportunities for adding to the region's resources or reducing the region's power costs through the accelerated or cooperative development of resources located outside the States of Idaho, Montana, Oregon, and Washington if such resources are renewable resources, and are now or in the future planned or considered for eventual development by nonregional agencies or authorities that will or would own, sponsor, or otherwise develop them. The Administrator shall keep the Council fully and currently informed of such investigations, and seek the Council's advice as to the desirability of pursuing such investigations.

16 U.S.C. § 839d(1)(1). Were BPA to determine that resources could be developed consistent with the criteria of the section, the impact of continuing to segment the Eastern Intertie would need to be assessed in light of the newly developed facts.

BPA may rely on any relevant statute in making a segmentation decision, including, with respect to possible roll-in of BPA's share of Eastern Intertie costs, Transmission System Act sections 4(a), 4(c), and 9.

Decision

Northwest Power Act section 2(1)(B), 16 U.S.C. § 839(1)(B), applies to renewable generation only within the Pacific Northwest. However, Northwest Power Act section 2(1)(B) does not preclude BPA from using other statutes and policies to support transmission of new generation outside the Pacific Northwest. As discussed in elsewhere in this section 4.3.1, BPA is not rolling in BPA's share of Eastern Intertie costs or setting the IM rate at zero.

Issue 4.3.1.6

Whether roll-in of BPA's share of the costs of the Eastern Intertie, or setting the IM rate at zero, would result in an unreasonable cost shift to BPA's Integrated Network.

Parties' Positions

Benton County PUD argues that the only party that would receive an immediate benefit from roll-in and setting the IM rate at zero is PacifiCorp, which would receive a \$115,000/year reduction in IM rate charges. Benton Br., BP-12-B-BC-01, at 3. Benton argues that over the long term such a decision would have Network customers subsidize wind development in eastern Montana to boost such generation's competitiveness in the market. *Id.* Benton asserts that this would distort the power market and hide from purchasers the true delivered cost of the product. *Id.*

JP11 argues that rolling in the IM rate would shift to the Network transmission customers costs that should be paid by the users of the Eastern Intertie, and that would be inconsistent with BPA's segmentation methodology. JP11 Br., BP-12-B-JP11-01, at 3-4. JP11 argues that roll-in would require a benefit to transmission customers on BPA's Network. *Id.* at 4. JP11 also states that there would be cost shifts to such customers from use of financial reserves during the FY 2012–2013 rate period. *Id.* at 15. JP11 states that there also would be cost shifts to such customers later due to projected costs of new facilities at Townsend and on BPA's Network that would be needed for transmitting wind from Montana to points on BPA's Network. *Id.* at 6-7. JP11 adds that those customers also would face operation and maintenance costs of the Eastern Intertie facilities that would be included in the Network. *Id.* at 16. JP11 argues that there would be no benefit to Network customers from such costs. *Id.* at 7. JP11 argues that regardless of the size of the cost shift, it would not be justified. *Id.* at 7-8. JP11 also argues that there would be no substantive difference between roll-in and temporarily reducing the IM rate to zero, that such

a reduction is not supported by the record, and that it would be inconsistent with sound business principles because it would set rates below costs. *Id.* at 14-18.

JP11 argues that NWG's claims that including BPA's share of the Eastern Intertie in BPA's Network would provide significant benefits to the Montana economy, would stimulate development of wind in Montana, and would provide access to the Alberta market are all based on speculation and not on substantial evidence, and none of the asserted benefits would redound to BPA's Network transmission customers as a class. *Id.* at 5.

JP11 argues that roll-in would create an unreasonable subsidy for Montana wind generation because it would hide the true costs of wind from purchasers. *Id.* at 19-20. JP11 asserts that there is no basis for BPA to offer preferential transmission rates to one type of generating facility over another. *Id.* at 12. JP11 argues that rolling in or eliminating the IM rate, if it successfully results in wind generation being transmitted from Montana to the Northwest, would also exacerbate problems of overgeneration in the Pacific Northwest, which would disadvantage BPA's other transmission customers. *Id.* at 20.

NWG argues that ending the IM rate will not increase Network rates in the short term and is likely to reduce Network rates in the long term because ending the pancake would encourage new energy projects in the area, which will lead to additional revenues, a lower Network rate, and a lower TGT rate. NWG Br., BP-12-B-NG-01, at 81. NWG argues that because the facilities associated with the IM rate are not a separate intertie, including their costs in the Network would not violate cost causation. *Id.* at 82. NWG argues that JP10's concern about costs of future upgrades is based on speculation, and BPA's NOS process has a good track record of distinguishing between projects that should or should not qualify for embedded rate treatment. *Id.* at 86-87.

PacifiCorp argues that removal of the IM-12 pancake for the FY 2012–2013 rate period would have no impact on BPA's Network rates because of the Partial Transmission Settlement. PacifiCorp Br., BP-12-B-PC-01, at 3.

PNGC argues that because the Eastern Intertie facilities were built for a discrete set of generators for the sole purpose of importing power to the Pacific Northwest, generators importing power on those facilities must bear the cost of those facilities, and Network transmission customers should not bear such costs. PNGC Br., BP-12-B-PN-01, at 3. PNGC argues that there is no evidence in the record that Network transmission customers as a class would benefit from roll in. *Id.*

Snohomish County PUD states concern about the potential for greatly increased costs in future rate periods due to the need to expand the transmission system to accommodate future uses. Snohomish Br., BP-12-B-SN-01, at 24.

Tacoma Power argues that elimination of the Eastern Intertie as a separate segment and rolling its costs into the Network segment could substantially increase the costs of those parties that do not use the Eastern Intertie while providing a subsidy to those parties currently using or planning to use the Eastern Intertie. Tacoma Br., BP-12-B-TA-01, at 2.

WPAG argues that BPA is currently struggling with how to handle problems arising from large amounts of wind generation located in the Pacific Northwest that are already integrated, and that additional amounts of wind generation will seek to be integrated onto its system during the rate period. WPAG Br., BP-12-B-WG-01, at 57. WPAG submits that BPA and its customers need to focus on resolving those problems before taking on any additional burdens with Montana wind generation. *Id.*

BPA Staff's Position

Staff testifies that roll-in of BPA's share of the Eastern Intertie costs would result in only a 0.018 percent increase in Network rates, a negligible impact, Fredrickson *et al.*, BP-12-E-BPA-48, at 4, although Staff is also concerned about other cost issues. *Id.* at 10 and Workshop Presentation. With respect to the costs of new transmission facilities that might be needed to transmit wind from Montana, BPA's Network Open Season embedded cost rate test and incremental cost rates would substantially reduce or eliminate the risk of cost shift. *Id.* at 5.

Staff is concerned about the possibility of Montana Intertie roll-in as a precedent for roll-in of other non-integrated Network segments, especially the Southern Intertie. *Id.* at 9. If Montana Intertie roll-in led to roll-in of other non-Integrated Network segments, that could lead to significant cost shifts. *Id.* at 10.

Evaluation of Positions

JP11, and presumably PNGC, rely on Federal Power Act precedent in arguing that BPA must demonstrate benefits to Network customers as a class. JP11 Br., BP-12-B-JP11-01, at 4; PNGC Br., BP-12-B-PN-01, at 3. BPA is not subject to Federal Power Act cost causation standards. Nonetheless, an equitable allocation of costs is one that would certainly consider the issue of cost causation. BPA's expressed policy is to avoid significant cost shifts, Fredrickson *et al.*, BP-12-E-BPA-48, at 8-9, and roll-in of BPA's share of Eastern Intertie costs, in itself, would have a negligible impact on Network rates. *Id.* at 4. That is not to say, however, that it would be without any impact.

Regarding the cost impact on Network rates of future upgrades necessary to transmit wind from eastern Montana, BPA's Network Open Season process and incremental cost rates substantially reduce or eliminate increases to embedded cost rates. *Id.* at 5. Under BPA's Network Open Season process, if a cluster study indicates a need for a new transmission facility to satisfy a cluster of transmission service requests on BPA's Network, BPA will analyze whether there is sufficient demand in the cluster to build the facilities so that the new requested service would provide enough revenue to offset the added annual cost of the facility. *See* 2010 Precedent Transmission Service Agreement (PTSA), § 5(b); *see also Bonneville Power Administration*, 123 FERC ¶ 61,264, P 11 (2008). For example, in BPA's 2010 Network Open Season, the two new projects that BPA determined passed the embedded cost rate test are, in combination, expected to reduce Network rates because the new service would more than offset the expected costs of the facilities. BPA Rolled-in Rate Decision Letter for the 2010 Network Open Season, *supra*, Attachment A, at 8. Any facility that does not pass the embedded cost rate test in PTSA section 5(b) is subject to an incremental cost rate. Fredrickson *et al.*, BP-12-E-BPA-48, at 5.

Under an incremental cost rate, BPA would charge the customer for the new service at the higher of (1) the embedded cost of BPA's Network with the costs of the new facilities included or (2) the costs of the new facilities. *Id.*

However, the record does not include sufficient evidence regarding several other possible cost impacts, discussed in Issues 4.3.1.4, 4.3.1.9, 4.3.1.11, and 4.3.1.12, of rolling in BPA's share of Eastern Intertie costs or setting the IM rate at zero.

Decision

Currently, BPA provides 16 MW of firm service under the IM rate, and, as discussed above in Issue 4.3.1.2, it is not clear whether BPA will receive additional requests for service on the Eastern Intertie. The impact on BPA's Network rates of roll-in of the 16 MW of service on the Eastern Intertie would amount to 0.018 percent, a negligible impact. The availability of incremental cost rates, and the embedded cost rate test and other protections in the Precedent Transmission Service Agreement in BPA's Network Open Season process, would eliminate the risks of significant cost shifts when any new facilities would be required for service on a rolled-in BPA share of the Townsend-Garrison line capacity. As discussed elsewhere in this section 4.3.1, however, there has not been sufficient consideration in this case of other potential cost impacts of roll-in of BPA's share of the Eastern Intertie costs or setting the IM rate at zero. Until those impacts are better developed and understood, it is premature to conclude that BPA should abandon its current policy of segmenting the Eastern Intertie.

Issue 4.3.1.7

Whether roll-in of BPA's share of the costs of the Eastern Intertie, or setting the IM rate at zero, would send artificially low transmission price signals to future wind developers and hide the true delivered cost from purchasers.

Parties' Positions

JP11 argues that rolling in BPA's share of the costs of the Eastern Intertie or setting the IM rate at zero would send artificially low transmission price signals to future wind developers and be harmful to power consumers because it would be a subsidy to generators taking service on the Eastern Intertie that would distort the market and hide the true delivered cost of the product from purchasers. JP11 Br., BP-12-E-JP11-01, at 19-20.

BPA Staff's Position

Any new service on a rolled-in share of BPA's capacity on the Eastern Intertie would pay a higher rate than the proposed IM-12 rate, which would more than offset the Eastern Intertie costs included in the Network. Fredrickson *et al.*, BP-12-E-BPA-48, at 4. Cost shifts to the Network for any new facilities resulting from new service on the newly rolled-in part of BPA's system would be substantially reduced or eliminated because of the embedded cost rate test in the Network Open Season and incremental cost rates. *Id.* at 4-5.

Evaluation of Positions

As discussed under Issue 4.3.1.2, above, new service on the Eastern Intertie will likely face an incremental cost rate because of new facilities needed on either the Eastern Intertie, the existing Network, or both. Thus, roll-in of BPA's share of Eastern Intertie costs or setting the IM rate at zero will not send inappropriate price signals to wind developers.

Decision

As discussed under Issue 4.3.1.2, above, new service on the Eastern Intertie will likely face an incremental cost rate because of new facilities needed on the Eastern Intertie, the existing Network, or both. Therefore, roll-in of BPA's share of the costs of the Eastern Intertie, or setting the IM rate at zero, would not send artificially low transmission price signals to future wind developers or hide the true delivered cost from purchasers.

Issue 4.3.1.8

Whether roll-in of BPA's share of the costs of the Eastern Intertie, or setting the IM rate at zero, would exacerbate overgeneration events.

Parties' Positions

JP11 argues that there is a significant probability that increased Montana wind generation would exacerbate overgeneration events in the BPA balancing authority area. JP11 Br., BP-12-B-JP11-01, at 20. JP11 also states that the same would be true of any future wind development that does not have a long-term power purchase agreement. *Id.*

BPA Staff's Position

Because JP11 raises this issue in rebuttal testimony, Staff does not state a position.

Evaluation of Positions

BPA has adopted policies related to overgeneration in separate, non-rate case, processes. For example, after a separate public process, BPA adopted its Final Record of Decision on Interim Environmental Redispatch and Negative Pricing Policies in May 2011. Overgeneration involves operational and marketing issues that are best considered outside a BPA rate case, and JP11 has not argued that non-rate case processes are ineffective for dealing with such issues. Furthermore, as discussed in Issues 4.3.1.2 and 4.3.1.3 above, it is not clear that roll-in would result in additional Montana wind generation being transmitted on BPA's system.

Decision

Overgeneration policies are better suited to development in separate, non-rate case, processes. However, even if overgeneration events were relevant to segmentation decisions, there is insufficient evidence in the record regarding the potential costs or benefits of overgeneration

resulting from Montana wind that would be exported on BPA's Network due to roll-in of BPA's share of Eastern Intertie costs or setting the IM rate at zero.

Issue 4.3.1.9

Whether roll-in of BPA's share of the costs of the Eastern Intertie could be a precedent for roll-in of other non-Network segments of BPA's transmission system.

Parties' Positions

JP11 argues that Issue 4.3.1.9 is not the appropriate legal question. JP11 Br., BP-12-B-JP11-01, at 18-19. JP11 argues that the appropriate question is whether rolling in or eliminating the IM rate for FY 2012–2013 is justified in light of BPA's longstanding segmentation methodology and is supported by substantial evidence in the record, which, JP11 argues, it is not. *Id.* JP11 states that "BPA should be wary of rolling in the Eastern Intertie based on the facts before it as it could cause other parties to question the basis for retaining these other segments." *Id.* at 18.

Benton County PUD argues that rolling in the Montana Intertie could be precedential and that the costs of rolling in other non-integrated segments would have a significant impact on the rates of BPA's Network transmission customers. Benton Br., BP-12-B-BC-01, at 2. Benton argues that the rationale of roll-in proponents, *i.e.*, that it would encourage wind and economic development in the area, could be used to justify the roll-in of other non-integrated Network segments. *Id.* at 2.

WPAG argues that rolling in the Montana Intertie could set a potential precedent. WPAG Br., BP-12-B-WG-01, at 54. WPAG states that it is unclear what principles BPA would use to roll in the Montana Intertie, but that if the principles include encouraging wind generation development and economic development outside BPA's balancing authority area, such principles could also apply to other non-integrated Network segments, including the Southern Intertie or the full Eastern Intertie. *Id.* at 54-55.

NWE states that Montana Intertie roll-in would establish a precedent that would affect other segments. NWE Br., BP-12-B-NC-01, at 8. NWE states that it is not currently in a position to opine on the distinguishing characteristics of other interties or segments that may be impacted by Montana Intertie roll-in and that such characteristics should be considered on a case-by-case basis in any proceeding directly implicating that intertie or segment. *Id.*

NWG asserts that BPA's share of Eastern Intertie capacity is not an intertie, but that it is a part of BPA's integrated network. NWG Br., BP-12-B-NG-01, at 79. NWG states that roll-in of BPA's share of Townsend-Garrison capacity will not or should not have any precedential effect on the Southern Intertie or other non-integrated Network segments. *Id.* at 91. NWG submits evidence that, unlike the Southern Intertie, BPA's 200 MW Eastern Intertie capacity does not directly connect two different markets. Motion to Admit Data Responses, BP-12-M-NG-02, Attachment 1, Data Response to BPA-NG-62.

NWG argues that “there are sufficient facts in the record demonstrating that rolling in BPA’s share of the Eastern Intertie costs would not set a precedent for eliminating the Southern Intertie Rate or any other non-integrated Network segment.” NWG Br. Ex., BP-12-R-NG-01, at 29. NWG refers to statements in its initial brief and in the Draft ROD that the Network rate impacts of Eastern Intertie and Southern Intertie roll-in are much different, with the impact of Southern Intertie roll-in much greater and that the uses of those interties are different; and to NWG testimony that the Eastern Intertie is an “artificial segmentation.” *Id.* at 29-30. NWG also agrees with PacifiCorp that “BPA could make clear in the Final Record of Decision that it does not intend to create a precedent with respect to the IM Rate treatment.” *Id.* at 30, *citing* PacifiCorp Br., BP-12-B-PC-01, at 4.

PacifiCorp disagrees that rolling in the Montana Intertie cost is precedential. PacifiCorp Br., BP-12-B-PC-01, at 4. PacifiCorp states that BPA can make clear in its final decision that it does not intend to create a precedent and that it will evaluate its treatment of the Montana Intertie rate, as well as the potential impacts to other rates, in the FY 2014–2015 rate case. *Id.*

PNGC states that whether rolling in the Montana Intertie would set a precedent would depend on the specific facts and nature of future proposals to roll in other segments. PNGC Br., BP-12-B-PN-01, at 8. Even so, PNGC argues, if parties were willing to use the Montana Intertie roll-in as a precedent for roll-in of other segments, then BPA would face additional cost causation problems, and Network transmission customers could face significant rate increases from roll-in of those other segments. *Id.*

Puget argues that the record in this proceeding has not been adequately developed on the question of whether or to what extent rolling in any portion of the Eastern Intertie capacity into the Network could be argued to constitute a precedent with respect to rolling in the Southern Intertie. Puget Br., BP-12-B-PS-01, at 8. Puget argues that it is appropriate for BPA to be concerned about potential precedential effects, cost shifts, and other effects of any decisions to roll the Montana Intertie into the BPA Network.

BPA Staff’s Position

Staff expresses concern that a decision to roll in the Montana Intertie could lead to rolling in of other non-Integrated Network segments, particularly the Southern Intertie, in which case there could be significant cost shifts. Fredrickson *et al.*, BP-12-E-BPA-48, at 9-10. As a result, Staff asked parties to address this issue in their briefs. *Id.*

Evaluation of Positions

Roll-in of BPA’s share of the costs of the Eastern Intertie may, as NWG claims, be distinguishable from roll-in of Southern Intertie costs. The Southern Intertie connects two areas, the Pacific Northwest and California, which have sizeable markets and a history of transactions in both directions, while the Eastern Intertie has been a path to bring generation to the Pacific Northwest. *See* NWG Br., BP-12-B-NG-01, at 79, 91. Further, roll-in of BPA’s share of Eastern Intertie costs, in itself, would have a negligible impact on Network rates, Fredrickson *et al.*,

BP-12-E-BPA-48, at 4, while roll-in of the Southern Intertie would have a major impact on Network rates. *Id.* at 9.

BPA has considered roll-in of interties separately based on the factors applicable to each. For example, when BPA rolled in the Northern Intertie, BPA distinguished the Eastern and Southern Interties from the Northern Intertie. 1996 ROD, WP-96-A-02, at 423-425. In the 1996 rate case, BPA distinguished roll-in of the Southern Intertie from roll-in of the Northern Intertie partly on the basis of rate impacts. In that case, evidence was submitted that roll-in of the Northern Intertie would result in less than a 1 percent increase in Network rates, while roll-in of the Southern Intertie would result in an 18 percent increase. *Id.* at 423-424. Thus, roll-in of the Eastern Intertie could, but would not necessarily, be a precedent for roll-in of the Southern Intertie.

Whether roll-in of BPA's share of the costs of the Eastern Intertie would set a precedent for roll-in of other non-Integrated network segments depends, as PNGC states, on the relevant facts of each segment. Although intervenors have submitted evidence concerning the segmentation of the Eastern Intertie, little evidence has been submitted about other non-Integrated Network segments. BPA agrees with Puget that the record in this proceeding has not been adequately developed regarding the question of whether or to what extent rolling in any portion of the Eastern Intertie capacity into the Network could be argued to constitute a precedent with respect to rolling in the Southern Intertie. In that regard, BPA notes that the testimony submitted in this proceeding regarding the Montana Intertie rates used the term "Southern Intertie" only twice, once by JP10 in a sentence referring to all non-Integrated Network segments, Baker *et al.*, BP-12-E-JP10-01, at 10, and once by BPA Staff when it asked parties to address in briefs whether roll-in of the Montana Intertie could be used to argue for roll-in of other non-Integrated Network segments, Fredrickson, *et al.*, BP-12-E-BPA-48, at 9.

Although NWG's argument, NWG Br. Ex., BP-12-R-NG-01, at 29-30, may have merit, there has not been sufficient evidence presented in this proceeding regarding whether roll-in of BPA's share of Eastern Intertie costs would set a precedent for Southern Intertie roll-in. Further, because BPA is deciding not to roll in BPA's share of Eastern Intertie costs, it is not necessary for BPA to decide this issue. In the future rate case workshops regarding the IM, IE, and TGT rates, BPA would encourage the customers to develop a regional solution in which customers would agree that roll-in of the Eastern Intertie would not create a precedent for rolling in the Southern Intertie.

Decision

Whether roll-in of BPA's share of the Eastern Intertie costs would be precedential depends on the relevant facts, which have not been adequately developed in this proceeding. Regardless of the other distinguishing features between the Eastern and Southern Interties, a significant, and perhaps deciding, distinguishing factor between the two is that Eastern Intertie roll-in may have a de minimis impact on Network rates, while roll-in of the Southern Intertie would have a much greater impact. However, BPA encourages customers to come to an explicit agreement that they will not argue in future rate cases that rolling in the Eastern Intertie would create a precedent for rolling in the Southern Intertie.

Issue 4.3.1.10

Whether NWE's proposal to set the firm long-term and short-term IM rate to \$0 for the FY 2012–2013 rate period would indirectly result in allocation of reduced Eastern Intertie costs to the proposed TGT-12 rate without offsetting revenues from other rates.

Parties' Positions

NWE proposes that BPA set the proposed IM-12 rate at zero for the FY 2012–2013 rate period. Brush, BP-12-E-NC-01, at 2-3. NWE states that to the extent customers take service at a \$0 rate, BPA will not be compensated for the service, but that if such customers also take new service from BPA west of Garrison, BPA would receive additional new revenue. NWE Br., BP-12-B-NC-01, at 6.

NWG states that it does not have an independent basis to evaluate Staff's concern that NWE's proposal would reduce TGT rate revenues without offsetting revenues from other rates, and that although it recognizes that was not NWE's intent, to the extent such issue exists, it may present legitimate concerns about the viability of NWE's proposal. NWG Br., BP-12-B-NG-01, at 90.

PNGC states that it has no independent knowledge of how NWE's proposal might affect allocation of reduced Eastern Intertie costs. PNGC Br., BP-12-B-PN-01, at 7.

BPA Staff's Position

Because NWE raises this proposal in its rebuttal testimony, Staff does not state its position.

However, Staff recognizes the need to engage rate case parties on this issue and held a rate case workshop on April 20, 2011. At that time, Staff raised the following issue and asked parties to address it in their briefs:

Would NWE's proposal to set the firm long-term and short-term IM rate to \$0 for the FY-12-13 rate period indirectly result in allocation of reduced Eastern Intertie costs to the TGT rate without offsetting revenues from other rates?

Evaluation of Positions

The TGT rate formula increases BPA's share of Eastern Intertie costs and reduces the TGT rate customers' share of those costs as BPA makes additional firm transmission sales on the Eastern Intertie. Fredrickson *et al.*, BP-12-E-BPA-48, at 2-3. NWE and NWG both admit that it is possible that customers taking Eastern Intertie service at a zero IM rate might not take additional Network service, thus resulting in the TGT customers paying less Eastern Intertie costs but BPA not recovering those costs from additional Network service. NWE Br., BP-12-B-NC-01, at 6; NWG Br., BP-12-B-NG-01, at 90. Further, as discussed above regarding Issue 4.3.1.2, it appears there is no capacity available on the Network west of Garrison without a costly upgrade, and customers have not requested service on the Eastern Intertie because of both the costs of possible required Network upgrades and the costs of possible required upgrades on the Eastern

Intertie. This reduces the likelihood of additional Network service that would offset TGT rate revenue loss by setting the IM rate at zero.

Therefore, as JP10 notes, setting the long- and short-term firm IM rate at zero during the FY 2012–2013 rate period would likely result in use of financial reserves to offset Eastern Intertie costs that would not be recovered from the other parties to the Montana Intertie Agreement under the TGT-12 rate formula, for the 16 MW of IM rate service currently taken by PacifiCorp, and for any additional IM rate service that would find the zero rate attractive. Baker *et al.*, BP-12-E-JP10-01, at 6-7.

Decision

It is possible that setting the IM rate at zero would result in reduced TGT revenues without offsetting revenues from other rates. Therefore, BPA will not set the proposed IM-12 rate at zero.

Issue 4.3.1.11

Whether roll-in of BPA's share of the costs of the Eastern Intertie without roll-in of the Eastern Intertie capacity of the other parties to the Montana Intertie Agreement would be discriminatory.

Parties' Positions

NWE argues that if BPA rolls in Eastern Intertie capacity, NWE expects a capacity credit in the TGT rate corresponding to the amount of the rolled in capacity. NWE Br., BP-12-B-NC-01, at 10. NWE claims that if BPA does not provide such a credit, BPA would recover those costs twice from TGT rate customers, which, NWE alleges, would not be fair and nondiscriminatory. *Id.* NWE also argues that if BPA rolls in the IM rate, BPA would create several classes of customers taking service across the Eastern Intertie pursuant to two different rate methodologies, one class paying only a BPA Network rate and one paying both the TGT rate and a Network rate for the leg of service on BPA's Network. *Id.* at 10-11. NWE argues that such an arrangement is not fair and nondiscriminatory. *Id.*

Puget also states that it expects BPA to provide an immediate credit in the denominator of the TGT rate formula for the rolled-in capacity to avoid a result that is unfair or discriminatory. Puget Br., BP-12-B-PS-01, at 9.

JP11 argues that rolling in the IM Rate would create disparate treatment for wind and coal generators, with wind generators allegedly paying a subsidized rate and coal generators paying the unsubsidized TGT Rate. JP11 Br., BP-12-B-JP11-01, at 12. On the other hand, JP11 argues that the Eastern Intertie is used to connect Colstrip to the BPA Network. *Id.* at 3.

WPAG argues that BPA and the utilities that originally owned the Colstrip projects agreed that BPA would build the Eastern Intertie primarily to transmit Colstrip generation and that BPA

would recover the costs of the facility as a separate segment. WPAG Br., BP-12-B-WG-01, at 60-61.

NWG argues that there have been more than enough opportunities throughout the rate proceeding for parties to raise and address any TGT Rate-related issues, citing the dates of workshops as well as testimony and discovery opportunities. NWG Br. Ex., BP-12-R-NG-01, at 31. NWG argues that “[n]o party really developed the arguments about TGT Rate-related issues until the briefing stage from this proceeding.” *Id.* NWG “disagrees with the notion that all parties seeking service over the Eastern Intertie should continue to be charged duplicative rates when the rates of a handful of parties were entered into pursuant to a separate agreement.” *Id.*

BPA Staff's Position

Because this issue is raised after other parties raise it in rebuttal testimony and in briefs, Staff does not state a position.

Evaluation of Positions

The TGT rate customers would not pay Eastern Intertie costs twice, once in their Network rates and once in their TGT rates, because any new transmission service on the Eastern Intertie at BPA's Point-to-Point rate would recover more than the additional costs of service added to the Network by providing that service. Fredrickson *et al.*, BP-12-E-BPA-48, at 4.

Because BPA agreed with the other parties to the Montana Intertie Agreement to build the Eastern Intertie, and the parties to the Montana Intertie Agreement agreed to pay the costs of those facilities in accordance with the TGT rate and the Montana Intertie Agreement, BPA believes that roll-in of BPA's share of Eastern Intertie costs without roll-in of the costs allocated to the TGT rate customers would not be discriminatory.

However, this issue is raised late in the proceeding with no opportunity for parties to address it in subsequent testimony, and it could have significant cost implications for roll-in of BPA's share of Eastern Intertie costs. If BPA were required to roll in all the Eastern Intertie costs instead of rolling in only BPA's share of Eastern Intertie costs because of a successful challenge by TGT rate customers, Network rates could increase by 1.8 percent. Baker *et al.*, BP-12-E-JP10-01, Attachment 4.

In response to NWG's arguments, BPA notes that NWE did raise the discrimination issue prior to the briefing stage, in NWE's rebuttal testimony, Brush, BP-12-E-NC-01, at 4. Although BPA agrees with NWG that the TGT rate parties' agreement to the TGT rate in the Montana Intertie Agreement may be a sufficient basis for a determination that roll-in of BPA's share of the Eastern Intertie costs would not be unfair or discriminatory, it is not necessary for BPA to decide this issue in this proceeding. Further, the issue was addressed in testimony only by NWE; thus parties have not adequately addressed the issue in this proceeding.

Decision

There has been insufficient opportunity for parties to address this issue for BPA to decide the issue in this proceeding. Given that BPA is proposing not to roll in its share of Eastern Intertie costs in this rate proceeding, it is unnecessary to resolve this issue here. Because of the potential rate impact, this is an important issue to discuss in future workshops.

Issue 4.3.1.12

Whether roll-in of BPA's share of the costs of the Eastern Intertie would be a disincentive to potential joint participants in BPA transmission projects such as new intertie facilities.

Parties' Positions

JP11 argues that in order to support renewable resource development and ensure reliable operations, it may be necessary for BPA and other private entities to engage in joint transmission projects, and that in such case the private participants would need to be able to recover their individual capital and operating costs. JP11 Br., BP-12-B-JP11-01, at 19. JP11 states that cost recovery would be made difficult or impossible if BPA were to take its share of project capacity and essentially provide it for free to Network transmission customers by rolling the costs into BPA's Network rates at a time of BPA's choosing. *Id.* JP11 argues that BPA should avoid setting a policy that would materially increase the difficulty of or risk associated with making such investments. *Id.*

NWE argues that rolling in the Montana Intertie could create a significant disincentive for other parties to initiate joint transmission projects because a future roll-in may decrease a party's expected return on its investment, making such party less inclined to fund or build such a project. NWE Br., BP-12-B-NC-01, at 8.

PNGC argues that roll-in of the Montana Intertie could serve as a disincentive to build new needed transmission segments if future roll-in might decrease a party's expected return on its investment. PNGC Br., BP-12-B-PN-01, at 8.

Puget states that “[a]nother question that has not been adequately explored and developed in this proceeding is whether any roll-in of the Montana Intertie would interfere with or discourage participation by other parties in joint transmission projects to expand BPA's interties.” Puget Br., BP-12-B-PS-01, at 8.

BPA Staff's Position

Because this issue is raised by parties in their briefs, Staff does not state a position.

Evaluation of Positions

While the parties' arguments may be plausible, it is not clear what effect BPA's roll-in policies would necessarily have on other transmission providers' investment decisions. This is also an important issue to discuss in future workshops.

Decision

There is insufficient evidence in the record to decide whether roll-in of BPA's share of the costs of the Eastern Intertie would be a disincentive to potential joint participants in BPA transmission projects such as new intertie facilities.

Issue 4.3.1.13

Whether the record is adequate for BPA to roll in BPA's share of the costs of the Eastern Intertie or set the IM rate to zero.

Parties' Positions

NWG argues that BPA may decide to roll in BPA's IM rate capacity on the Townsend-Garrison line because that would be consistent with section 9 of the Federal Columbia River Transmission System Act. NWG Br., BP-12-B-NG-01, at 85-86. NWG argues that roll-in will result in BPA receiving revenues for service on a segment "that has not earned a nickel in over twenty years." *Id.* NWG says this should be a long-term policy decision. *Id.* at 90. NWG argues that there is currently significant interest in interconnecting new high-voltage transmission lines and energy generation projects in the Townsend area and that roll-in would make such projects more likely. *Id.* at 79. If such projects are built, NWG argues, there would be benefits to BPA in access to other markets in WECC, which could result in the ability to sell surplus hydro in such markets. *Id.* at 80. NWG argues that the IM rate capacity is not a separate segment in the same sense as the rest of the Townsend to Garrison capacity, and that the IM rate capacity is appropriately part of the Network. *Id.* at 85.

NWG maintains that there is sufficient evidence in the record for BPA to decide to roll in BPA's share of Eastern Intertie costs. NWG Br. Ex., BP-12-R-NG-12, at 26-27; 32. NWG quotes Staff that eliminating the IM Rate could encourage renewable energy development in Montana "in a situation where the costs and revenues are close." *Id.* at 26. NWG also argues that the expertise of its members as witnesses or workshop participants in this proceeding, and the participant comment of the Governor of Montana (*see* section 5.2), all provide substantial evidence on which BPA could rely to decide to roll in BPA's share of Eastern Intertie costs. *Id.* at 26-27. NWG also argues that there were "plenty of opportunities to raise issues." *Id.* at 32.

JP11 argues that the rate case record does not contain substantial evidence that the Eastern Intertie confers a benefit on BPA's Network transmission customers. JP11 Br., BP-12-B-JP11-01, at 4. According to JP11, such benefits must be "roughly commensurate or proportionate with the costs incurred." *Id.* at 5. Instead, according to JP11, the record shows that there will be a cost shift to Network transmission customers. *Id.* at 7. JP11 also argues that

there is no evidence in the record that a change in rate treatment during the FY 2012–2013 rate period would result in additional transmission requests for wind generation. *Id.* at 9-10. JP11 alleges that for BPA to change its longstanding practice of treating the Eastern Intertie as a separate segment, BPA must provide a cogent explanation supported by substantial evidence in the record of a change in the voltage, usage, or function of the Eastern Intertie, but the record does not support such a decision. *Id.* at 13.

PNGC also argues that there is no evidence in the record to support a cogent explanation for a change in the segmentation, arguing that none of the factors that support segmentation (usage, voltage, function) is different from when BPA determined that the Eastern Intertie was a separate segment. PNGC Br., BP-12-B-PN-01, at 5.

NWE argues that roll-in has significant economic, legal, and policy implications that have not been adequately assessed and addressed in this rate proceeding. NWE Br., BP-12-B-NC-01, at 9. For example, NWE argues, BPA has not addressed how roll-in of Eastern Intertie capacity and costs will impact the Montana Intertie Agreement and the TGT rate that BPA charges the Colstrip Parties. *Id.* NWE objects to BPA deciding to roll in such capacity and costs on the grounds that BPA has not provided appropriate notice under the Northwest Power Act, section 7(i)(1), and the Administrative Procedure Act. *Id.* at 11. NWE suggests that BPA hold workshops on the issue during the FY 2012–2013 rate period to fully develop a proposal. *Id.*

Puget also argues that “[b]ecause the significant economic, legal and policy implications and effects of any roll-in of the Montana Intertie in this rate proceeding have not been fully identified, explained and considered, BPA should not roll any portion of the Montana Intertie into the Network in this proceeding.” Puget Br., BP-12-B-PS-01, at 8. Puget also notes the Partial Transmission Settlement Agreement provision regarding public discussions of these issues during the FY 2012–2013 rate period. *Id.* at 8-9.

WPAG argues that rolling the Montana Intertie into the Network or setting the IM rate at zero would have significant long-term economic, policy, and operational implications that cannot be adequately considered in this rate proceeding. WPAG Br., BP-12-B-WG-01, at 53. WPAG states that these issues should be taken up in a policy process in which all of these matters can receive the appropriate consideration. *Id.* WPAG argues that implementing either roll-in or setting the IM rate at zero would irretrievably prejudice these discussions, to the detriment of all. *Id.*

BPA Staff’s Position

BPA Staff requested additional information from parties on certain issues related to rolling in BPA’s share of the costs of the Eastern Intertie and setting the IM rate to zero. Fredrickson *et al.*, BP-12-E-BPA-48, at 9-10; Workshop Presentation, slide 12.

Evaluation of Positions

Because the Eastern Intertie is presently a separate segment, a decision to roll in BPA’s share of the costs of the segment would be, by definition, a new segmentation decision.

Staff does not propose to roll in BPA's share of the costs of the Eastern Intertie or to set the IM rate at zero, and Staff does not take a position on this issue in testimony. Although NWG, PacifiCorp, and Staff provide evidence that could support roll-in, the evidence indicates that roll-in during only the FY 2012–2013 rate period would not result in additional use of BPA's Network. See NWG Br., BP-12-B-NG-01, at 89-90 ("Short-term rate decisions will not attract long-term investments. In order to attract the kind of development that will make use of that stranded capacity, the Administrator needs to make a long-term policy decision."). BPA has already committed to conduct workshops during the FY 2012–2013 rate period in preparation for a proposal on the future of the IM, IE, and TGT rates in the next rate case. Such workshops will likely consider many of the issues described above, and such workshops might or might not result in a different proposal or decision in a future rate case regarding those rates. Therefore it is unlikely that a wind generation developer could rely on a decision to roll in BPA's share of the costs of the Eastern Intertie in this rate case.

In response to NWG's arguments, NWG Br. Ex., BP-12-R-NG-12, at 26-27, as discussed in the Evaluation of Positions for Issues 4.3.1.2 and 4.3.1.3 above, because there are transmission requests currently in BPA's transmission request queue for service from Garrison substation in Montana, but no requests for service from Townsend, it is apparent that Montana wind is using paths for accessing BPA's Network other than BPA's capacity on the Eastern Intertie. Given those facts, the conclusory statements cited by NWG about the effects of roll-in are not enough for BPA to determine that roll-in of BPA's share of Eastern Intertie costs would result in additional transmission requests or additional development of wind in Montana. It would be helpful if participants in the upcoming workshops on the future of the IE, IM, and TGT rates could develop additional facts regarding the cost comparison between use of BPA's share of capacity on the Eastern Intertie and use of other paths to move generation to the west on BPA's Network.

Further, there is no evidence that roll-in during the FY 2012–2013 rate period would result in additional transmission requests on BPA's share of Townsend-Garrison capacity for only the duration of that rate period.

For the reasons just discussed, it appears that roll-in during the FY 2012–2013 rate period would be unlikely to result in any change in development or transmission of wind generation in Montana.

As discussed above regarding those issues, there is insufficient evidence regarding or consideration of Issues 4.3.1.4, 4.3.1.9, 4.3.1.11, and 4.3.1.12 for BPA to decide that those issues do not present significant cost risks to BPA.

Decision

Because it appears that roll-in of BPA's share of Eastern Intertie costs for the FY 2012–2013 rate period would not result in transmission on BPA's system of additional wind generation from Montana, and because there is insufficient evidence in the record regarding issues that could result in significant cost impacts on BPA, the record is inadequate to decide to roll in BPA's

share of Eastern Intertie costs. As stated in the decision under Issue 4.3.1.10, the record is adequate to decide not to set the IM rate at zero.

Issue 4.3.1.14

Whether BPA should roll in BPA's share of the costs of the Eastern Intertie.

Parties' Positions

The following parties support roll-in of BPA's share of the costs of the Eastern Intertie:

- NWG, BP-12-B-NG-01, at 77 (BPA should end the Montana Intertie Rate)
- PacifiCorp, BP-12-B-PC-01, at 3 (remove the unnecessary IM-12 rate pancake for the FY 2012–2013 rate period)

The following parties either favor delay or oppose roll-in of BPA's share of the costs of the Eastern Intertie:

- MSR, BP-12-B-MS-01, at 1 (delay)
- NWE, BP-12-B-NC-01, at 2 (roll-in is premature)
- PGE, BP-12-B-PG-01, at 3 (should not roll any portion of the Montana Intertie into the Network in this proceeding)
- Puget, BP-12-B-PS-01, at 8 (should not roll any portion of the Montana Intertie into the Network in this proceeding)
- WPAG, BP-12-B-WG-01, at 53 (should not be implemented in this rate proceeding); WPAG Br. Ex., BP-12-R-WG-01, at 27
- Benton County PUD, BP-12-B-BC-01, at 1 (oppose)
- JP01, BP-12-B-JP01-01, at 39 (oppose)
- Franklin County PUD, BP-12-B-FR-01, at 2 (oppose)
- PNGC and its members, BP-12-B-PN-01, at 3 (oppose)
- JP11, BP-12-B-JP11-01, at 1 (oppose)
- Seattle, BP-12-B-SE-01, at 1 (oppose)
- Snohomish, BP-12-B-SN-01, at 24 (oppose)
- Tacoma, BP-12-B-TA-01, at 2 (oppose)

BPA Staff's Position

Staff takes no position on this issue.

Evaluation of Positions

For the reasons stated in the Evaluation of Positions for Issue 4.3.1.13, the record does not support a decision to roll in BPA's share of Eastern Intertie costs.

Decision

As discussed above under Issues 4.3.1.2 and 4.3.1.3, there is insufficient evidence in the record for BPA to determine that roll-in of BPA's share of the Eastern Intertie during the FY 2012-2013 rate period would result in either new transmission requests on BPA's Network or development of new wind generation. Further, there is insufficient evidence for BPA to determine whether roll-in of BPA's share of Eastern Intertie costs would result in impacts on wind balancing costs (Issue 4.3.1.4), would have precedential value for roll-in of other non-Integrated Network segments (Issue 4.3.1.9), would discriminate against TGT rate customers (Issue 4.3.1.11), or would discourage other parties from participating in transmission projects with BPA (Issue 4.3.1.12). For those reasons, BPA will not roll in BPA's share of costs of the Eastern Intertie in this rate case. BPA will, however, discuss these issues in workshops that BPA agreed in the Partial Transmission Settlement Agreement to hold during the upcoming rate period. It is also worth noting that as a result of decisions made in this rate proceeding, BPA is reducing the proposed IM-12 rate by approximately half (see section 4.3.2 below).

4.3.2 Changes to the Proposed Townsend-to-Garrison (TGT-12) Rate, the Eastern Intertie (IE-12) Rate, and the Montana Intertie (IM-12) Rate

Issue 4.3.2.1

Whether BPA should set the level of the proposed long-term firm IM-12 rate at \$0.598 per kilowatt per month.

Parties' Positions

Except for those parties favoring roll-in, no party explicitly takes a position with respect to the level of the proposed IM-12 rate.

BPA Staff's Position

Staff proposes to set the level of the long-term firm IM-12 rate at \$0.598 per kilowatt per month to reflect termination of the exchange in the Montana Intertie Agreement. Fredrickson *et al.*, BP-12-E-BPA-48, at 1-2.

Evaluation of Positions

Because BPA terminated the exchange in the Montana Intertie Agreement effective October 1, 2011, reducing the proposed IM-12 rate from \$1.312 per kW per month to \$0.598 per kW per month accurately reflects BPA's share of the costs of the Eastern Intertie.

Decision

The proposed IM-12 long-term firm rate is reduced to \$0.598 per kW per month, a 54 percent reduction.

Issue 4.3.2.2

Whether the proposed TGT-12 rate should be clarified.

Parties' Positions

NWE supports the intent of Staff's rebuttal testimony proposal to revise the TGT rate to account for non-firm transmission sales under the IM rate, but suggests the following change:

~~This charge will be filed as a separate rate schedule, the Eastern Intertie (IE) rate and the Montana Intertie (IM) rate for non-firm transmission service on the Eastern Intertie, and revenues received there under and revenues received for non-firm transmission service on the Eastern Intertie under other rate schedules will reduce the amount of revenue to be collected under the Intertie Charge below.~~

NWE Br., BP-12-B-NC-01, at 4.

NWE argues that BPA's proposed revision to the NFR factor in section III.B of the TGT rate in the Draft ROD incorrectly credits only monthly non-firm revenue for sales under the IE rate instead of all non-firm revenue under such rate. NWE Br. Ex., BP-12-R-NC-01, at 1.

Puget also supports the intent of BPA's proposed change, but suggested a different change:

A. NON-FIRM TRANSMISSION CHARGE:

~~This charge will be filed as a separate rate schedule, the Eastern Intertie (IE) rate, the Montana Intertie (IM) rate for non-firm transmission service on the Eastern Intertie, and revenues received there under and revenues received any other rate for non-firm transmission service on the Eastern Intertie under other rate schedules will reduce the amount of revenue to be collected under the Intertie Charge below.~~

Puget Br., BP-12-B-PS-01, at 5. Regarding BPA's firm transmission service on the Eastern Intertie, Puget argues that "firm transmission service under the IM-12 Rate in either direction must be included in the BPA firm capacity requirement under the TGT-12 Rate." *Id.* at 6. Because of the termination of the exchange under the Montana Intertie Agreement, Puget argues that the firm transmission service under the IM-12 rate in either direction must be included in the BPA firm capacity requirement under the TGT-12 Rate. *Id.*

BPA Staff's Position

Staff proposes a change to the TGT-12 Rate formula to clarify that any non-firm transmission BPA provides on the Eastern Intertie would reduce the amount to be collected from the TGT rate:

A. NON-FIRM TRANSMISSION CHARGE:

This charge will be filed as a separate rate schedule, the Eastern Intertie (IE) rate, and revenues received there under and revenues received for non-firm transmission service on the Eastern Intertie under other rate schedules will reduce the amount of revenue to be collected under the Intertie Charge below.

Fredrickson *et al.*, BP-12-E-BPA-48, at 2.

Staff did not submit testimony on whether the proposed TGT-12 rate should be changed to reflect firm service under the proposed IM-12 rate.

Evaluation of Positions

With respect to non-firm revenues (NFR), all the parties that comment on the issue agree that, with termination of the exchange, the TGT rate schedule should be modified so that it is clear that all non-firm revenues collected by BPA for service over the Eastern Intertie, regardless of which rate schedule was charged, are credited in the calculation of the TGT rate.

However, section II.A. of the TGT rate schedule is not the proper place for clarifying the non-firm revenue credit. Section II.A. states what the Nonfirm Transmission Rate Charge is for service under the TGT rate. That charge is the Eastern Intertie rate. It is unnecessary and potentially confusing to try to list all the potential sources of non-firm revenue in this section.

The nonfirm revenue credit is contained in section III.B of the TGT rate schedule, which defines the term “NFR” in the formula for determining the Intertie Charge For Firm Transmission Service. This definition should be revised to clarify that all non-firm revenue collected by BPA for service over the Eastern Intertie, regardless of which rate schedule was charged, is credited in the calculation of the TGT rate.

NWE’s argument apparently does not fully explain its position, since the argument does not address the fact that the proposed definition of “NFR” in section III.B of the TGT rate for revenues from non-firm transmission service under rates other than the IE rate also uses the phrase “for such month.” BPA will not speculate why NWE does not include the other rates in its argument. However, after reviewing the proposed IE rate and the proposed rates for non-firm transmission service under the IM and PTP rates, it appears that non-firm service under the IM and PTP rates may be interpreted as monthly, weekly, daily, or hourly, while IE rate service is clearly only hourly. That would seem to make it even more important to clarify that all non-firm transmission service under rates other than the IE rate, as well as the IE rate, include all non-firm service, not just monthly service. The credit for non-firm revenues in the TGT rate is to be applied to TGT rate charges, separately, for the revenues received each month in which non-firm service is provided, which is why BPA included the phrase in the Draft ROD. However, for avoidance of doubt, in the definition of “NFR,” BPA changes the phrase “for such month” wherever it appears to “during such month.”

The proposed TGT-12 rate formula includes the factors “Capacity Requirement” (CR) and “Total Capacity Requirement” (TCR). Both definitions state that they include the capacity

requirements specified in firm transmission agreements. That language does not distinguish between short and long-term firm capacity requirements, and thus may be interpreted as inclusive of both, in either direction. Because of the general language regarding firm requirements in the TGT rate formula, BPA may interpret the formula to reflect short-term firm requirements in proportion to their duration.

Decision

Section II.A of the TGT-12 rate schedule is revised to read:

A. NON-FIRM TRANSMISSION CHARGE:

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

Section III.B. of the TGT-12 rate schedule is revised to read:

- 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.**

No revision is made to sections III.C. and D. of the TGT rate schedule, which defines the terms “Capacity Requirement” and “Total Capacity Requirements” in the formula for determining the Intertie Charge For Firm Transmission Service. The existing language is clear that such terms include all the megawatts of firm sales on the Montana Intertie regardless of the rate schedule they are sold under and regardless of whether the sales are short-term firm or long-term firm. Short-term firm requirements will be reflected in proportion to their duration. With the termination of the exchange, included firm sales would be in both directions on the Eastern Intertie.

Issue 4.3.2.3

Whether the proposed IM-12 rate should be clarified.

Parties’ Positions

Puget argues that, because of the termination of the exchange under the Montana Intertie Agreement, the second sentence of the proposed IM-12 rate schedule should be clarified as follows to remove any inference that the rate schedule is limited to transmission by BPA across the entire Montana Intertie:

It [IM-12 Rate] is available to Transmission Customers taking Point-to-Point (PTP) Transmission Service on BPA’s share of ~~Montana Intertie~~ transmission capacity on the Montana Intertie (or any portion thereof).

Puget Br., BP-12-B-PS-01, at 6.

BPA Staff's Position

Staff does not take a position on this issue.

Evaluation of Positions

Puget is correct that with termination of the exchange, the IM rate schedule needs to be clarified that it is available for service over the Eastern Intertie. Puget's proposed reference to the Montana Intertie or any portion thereof could be confusing, and the term "Eastern Intertie" accurately reflects the portion of the Montana Intertie over which BPA would provide IM rate service.

Decision

In the IM-12 rate schedule the second sentence of Section I. Availability: is revised to read:

It is available to Transmission Customers taking Point-to-Point (PTP) Transmission Service on the Eastern Intertie transmission capacity.

Issue 4.3.2.4

Whether BPA should make any changes to the proposed IE-12 rate.

Parties' Positions

No party raises any issue with respect to changes to the proposed IE-12 rate.

BPA Staff's Position

Staff proposes no changes to the IE-12 rate. Fredrickson *et al.*, BP-12-E-BPA-32, at 4.

Evaluation of Positions

There are no issues that would require a change to the proposed IE-12 rate.

Decision

BPA adopts the proposed IE-12 rate without changes.

5.0 PARTICIPANT COMMENTS

This chapter summarizes and evaluates the comments of participants in BPA’s BP-12 rate case. “Participants” are persons and organizations that comment on BPA’s rate proposal but do not take part in the formal rate case hearings with the responsibilities of “parties.” Parties to the case cannot submit comments as participants because parties can participate through the filing of testimony and briefs. Participant comments are part of the official record of the rate case and are considered when the Administrator makes his final decisions.

On November 18, 2010, BPA published in the Federal Register a Notice of “Fiscal Year (FY) 2012–2013 Proposed Power Rate Adjustments Public Hearing and Opportunities for Public Review and Comment,” 75 Fed. Reg. 70744 (2010). On December 16, 2010, BPA published in the Federal Register a Notice of “Fiscal Year (FY) 2012–2013 Proposed Transmission Rate Adjustments Public Hearing and Opportunities for Public Review and Comment,” 75 Fed. Reg. 78690 (2010). Those Federal Register notices may be viewed at the following Web site: <http://www.bpa.gov/corporate/ratecase/2012/>. The Federal Register notices set deadlines for participant comments of February 18, 2011, for power issues and March 15, 2011, for transmission issues.

Springfield Utility Board, which intervened in this proceeding as a member of a customer group, also submitted two comments as a participant (comment numbers BPR100005 and RPT110003). As stated in both Federal Register notices, “BPA customers whose rates are subject to this proceeding, or their affiliated customer groups, may not submit participant comments.” 75 Fed. Reg. 70744, 70748 (Nov. 18, 2010); 75 Fed. Reg. 78690, 78693 (Dec. 16, 2010). Therefore, Springfield Utility Board may not file participant comments, and its comments will not be addressed in the Record of Decision. Springfield’s comment BPR100005 addressed the Transmission Partial Settlement Agreement; the PF Public demand rate, demand billing determinant, and energy billing determinant; and generation inputs policy and resource integration. Comment RPT110003 addressed the Transmission Partial Settlement Agreement. Allowing Springfield to use the participant comment process to address substantive issues puts rate case parties taking positions adverse to Springfield at a disadvantage by denying them an opportunity to question Springfield’s position and offer rebuttal and refutation. Springfield cannot escape the duties of a rate case party by using the participant comment process as a means of subverting the due process of rate case parties. In contrast, Weyerhaeuser, a member of ICNU, a rate case party, submitted general comments, which are allowed. BPA Rules of Procedure, 1010.5. No rate case party is denied due process by Weyerhaeuser’s comment. Thus the comments submitted by Weyerhaeuser will be considered.

Including the above comments, BPA received six comments related to power issues and three comments related to transmission issues. Summaries of the participant comments, and BPA’s responses, are provided below.

5.1 Power Participant Comments

BPR100004

Comment. A member of the Spokane Tribe, Donald Kieffer, raises several issues in comment BPR100004. The first is a procedural issue related to the time between the publication of the Federal Register notice and the time for intervening in the rate case. The comment stated, “Allowing six days for a tribe to intervene is not enough time to allow the Spokane Tribal Business Council to make a reasoned decision on how best to protect the interests of its members.”

Response. The Tribe’s concern is fashioned as one of not having adequate time as opposed to not knowing BPA’s rate case was beginning. The six days referenced in the comment is the time between the publication of the Federal Register notice on November 18, 2010, and the date for interventions, November 24, 2010. Even assuming six days is not sufficient time for the Tribe to make a decision, the Tribe could have filed for late intervention after that date, as several other parties did.

In addition, there are two material factors Mr. Kieffer ignores. First, the initiation of the rate case was announced regionally well before the publication of the Federal Register notice. BPA held public workshops and meetings with stakeholders to discuss the issues in the upcoming rate case. Also, the date of the pre-hearing conference was shared more than a month before publication of that date in the Federal Register notice. Consequently, the Tribe had the necessary information or had access to the information to begin internal discussion regarding any decision to intervene well before the publication of the Federal Register notice.

If the Tribe decided that there was even a remote possibility that it had a material interest in the case, the prudent course of action would have been to intervene. If it subsequently determined that it did not have a sufficient interest in the case to merit active participation, the Tribe could remain silent and monitor the case. Intervention does not create any obligation on the part of any party to actively participate in the case.

Comment. Mr. Kieffer of the Spokane Tribe further states that the studies and documentation BPA released as part of the Initial Proposal do not include revenues to cover the annual payment that will be made from the Bonneville Fund to the Spokane Tribe in the event the U.S. Congress enacts settlement legislation.

Response. This is correct: the BP-12 rates do not contain any dollars for the Spokane settlement because Congress has not passed legislation mandating the payment, and thus BPA is not currently obligated to make such a payment during the rate period for which rates are currently being developed. This is not a value judgment on BPA’s part; BPA is required by law to recover its costs through rates, but it is not required to set rates to recover potential costs.

While the payment is not accounted for in the revenue requirement on which the rates are based, the possibility that Congress could pass legislation during the rate period obligating BPA to make a payment to the Spokane Tribe is factored into the risk analysis. As noted in the Power

Risk and Market Price Study, risk is the same as uncertainty and does not imply a negative connotation. Power Risk and Market Price Study, BP-12-FS-BPA-04, at 1. Because this potential amount is not included in rates, the possibility that Congress could enact such a settlement represents a risk or uncertainty to BPA's ratepayers. If Congress passes legislation mandating the payment during the upcoming rate period, BPA would be obligated to pay that amount even though rates were not set based on that assumption.

The Non-Operating Risk Model (NORM) simulates uncertainty in Power Services' net revenue caused by variability in BPA's non-operating risks. BPA relies upon its subject matter experts for the probability distributions in NORM. Currently, Federal law does not authorize BPA to make payments to the Spokane Tribe, although, as the Power Risk and Market Price Study states, "Within the rate period, legislation enacting a . . . settlement with the Spokane Tribe could go into effect." Power Risk and Market Price Study, BP-12-FS-BPA-04, at 55. The subject matter expert consulted for the Spokane Settlement Payments stated that, in his judgment, there was a 30 percent probability that Congress would pass a law authorizing BPA to make payments to the Spokane Tribe. It is important to note that this probability reflects the uncertainty that BPA faces over possible actions of Congress; in contrast, BPA assumes a 100 percent probability that it will meet its obligation to the Spokane Tribe as this obligation is defined by Congress. The 30 percent probability is incorporated into the random simulations of NORM. The model includes payments to the Spokane Tribe in approximately 30 percent of the 3,500 games (simulations) generated by the model when the model is run.

Comment. Referring to the above explanation, Mr. Kieffer concludes, "Apparently, this statement is inserted [in the Power Risk and Market Price Study] so that, in the event that the Spokane Tribe is able to get legislation in front of Congress sometime between October 1, 2011, and September 30, 2013, the Congressional Budget Office will assume that the Bonneville Fund cannot be used to make annual payments because, in the assessment of non-operating risk, it has already incurred such costs and cannot charge ratepayers twice for the same thing."

Response. The conclusion drawn by Mr. Kieffer is incorrect. The statement in the risk study was made to explain how BPA factored into its consideration of uncertainties the possibility that Congress could pass legislation that would obligate BPA to pay the Spokane Tribe a certain amount of money. Any cost associated with a payment to the Spokane Tribe has not actually been incurred and will not be incurred until such time as Congress authorizes a payment. The statement in the risk study addresses only how the uncertainty of such a payment was factored into the risk analysis and was not intended to mislead Congress, the Congressional Budget Office, or the Spokane Tribe regarding the use of the Bonneville Fund or any obligation on the part of ratepayers to pay for some future obligation to the Spokane Tribe. Finally, in the event that Congress authorize a payment, certain rates are subject to a Cost Recovery Adjustment Clause (CRAC) that would allow BPA to increase rates in the event the settlement payment created an unacceptable financial burden.

BPR100001, BPR100003, BPR100007

Comment. Several participants expressed concern about BPA's proposal to increase rates for the rate period, fiscal years 2012 and 2013. A participant, self-identified as "oulman," stated that

he/she is tired of rate increases and that the burden of such increases is “getting very very bad.” BPR100001. Another participant, Ms. Noreen Ramsey, noted that power customers “are already hanging on by a thread” and the economy is fragile; she stated that BPA should reconsider its proposal to increase rates. BPR100007. A third participant, Weyerhaeuser, stated that it “encourages BPA to find ways to minimize rate increases.” Weyerhaeuser also stated that “[c]ost minimization is critical to protecting, preserving, and increasing Northwest manufacturing jobs.” BPR100003.

Response. As noted in BPA Staff’s direct testimony, BPA has competing objectives when setting its rates, and these objectives must be balanced against each other. Bliven *et al.*, BP-12-E-BPA-11, at 8. One of the most important objectives is to respond to the economic difficulties in the region by reducing spending levels for the rate period as low as possible without jeopardizing the reliability of the system. *Id.* at 9. At the same time, the “reliability” aspect of that objective means that BPA must maintain and operate generation resources and transmission facilities so the demand for power is met at all times.

As described in the testimony, *id.*, and in more detail in section 1.2.1 of this Record of Decision, BPA’s spending levels are set after a lengthy public process called the Integrated Program Review. The ratesetting process takes those forecast spending levels and turns them into rates as BPA is directed by the Northwest Power Act and other statutes. The result of this balancing of interests, and the fact that BPA cannot ignore its statutory mandate to set rates that are sufficient to meet its repayment and cost obligations, is that BPA cannot completely eliminate the rate increase. *See also* ROD section 2.1.2.

BPR100006

Comment. Dr. Charles Pace stated that the scope of the BP-12 rate case excludes many key issues. BPR100006 at 5. Dr. Pace stated that the Administrator’s definition of scope for the BP-12 rate case is “... arbitrary and capricious, an abuse of discretion, inconsistent with sound business principles, and injurious to regional preference customers’ interests.” *Id.* Dr. Pace states particular concern with BPA’s costs due to entering into the 2008 Fish Accords and continues that the public utilities from whom he purchases power are not able to “... question, in a ratemaking context, whether the expenses and investments [BPA] proposes to adjust rates to cover should or should not be included in its revenue requirement” *Id.* at 7.

Response. The Federal Register notices for the power and transmission portions of the BP-12 rate case, 75 Fed. Reg. 70744 (2010) and 75 Fed. Reg. 78690 (2010), stated that the Integrated Program Review, where BPA’s costs are evaluated, is outside the scope of the formal ratemaking process. This decision, in effect for multiple rate cases, is by design and is not “arbitrary and capricious.” Having costs discussed preceding the start of the formal 7(i) case allows interested persons to meet and freely share ideas and opinions about BPA’s spending levels in a relatively informal process before the strict requirements regarding communications during rate cases take effect. BPA thus is able to consider the comments received, update analyses, and set spending levels to incorporate in ratesetting.

BPA's decision to participate in the 2008 Columbia Basin Fish Accords was made thoughtfully, after consideration of many factors, and only after soliciting and analyzing comments from interested persons and organizations. BPA is proud to be part of the Accords, which brought together Federal agencies, States, and Tribes to achieve desirable and statutorily required biological objectives for fish.

Comment. Dr. Charles Pace also stated concern about BPA conducting the power rate case separate from the transmission rate case. BPR100006 at 7.

Response. This concern is misplaced—the BP-12 rate case considers power and transmission rates in one process.

Comment. Dr. Pace stated concern about the BP-12 case being separate from the REP-12 case. *Id.*

Response. Procedurally, this decision arose out of necessity and scope. The timing of the REP Settlement discussions and the time needed to prepare for the REP-12 case did not allow the two cases to begin at the same time. They are concluding at the same time, however. The REP-12 case is limited in scope: consideration of the 2012 REP Settlement, the conduct of the section 7(b)(2) rate test in the absence of the Settlement, and Lookback issues. For purposes of economy of effort, this limited set of issues was reserved to the REP-12 case. In addition, on January 18, 2011, the Hearing Officer in the BP-12 case granted BPA's motion to amend the Special Rules of Practice to Govern These Proceedings to include the following provision:

Citations to Evidence Presented in REP-12. In this BP-12 proceeding, parties may cite to evidence or arguments from the REP-12 proceeding if and to the extent such evidence or arguments are relevant and within the scope of this proceeding.

The Hearing Officer noted that the amendment will prevent the filing of duplicative arguments and evidence in the REP-12 and BP-12 cases, while still allowing the development of a full and complete record. All information related to the BP-12 and REP-12 cases is available on BPA's Web site, and both cases included participant comment periods (Dr. Pace filed comments in the power portion of the BP-12 case, the transmission portion of the BP-12 case, and the REP-12 case).

Comment. Dr. Charles Pace also stated concern with the exclusion of evidence and argument addressing potential environmental impacts of the BP-12 rate case from the hearing record for the rate case. *Id.* at 12.

Response. As discussed in the Federal Register notices for this rate case, the Hearings Officer was directed to exclude from the hearing record all argument, testimony, or other evidence that seeks in any way to address the potential environmental impacts of the rates being developed in this case because these environmental issues are being addressed in a separate but concurrent NEPA process. *See* 75 Fed. Reg. 70744 (2010) and 75 Fed. Reg. 78690 (2010). Accordingly, this exclusion does not mean that comments concerning potential environmental impacts are *entirely* excluded from consideration by BPA; instead, any such comments are considered in the

environmentally focused NEPA process, which is more appropriate than considering them in the 7(i) rate case. Conducting a separate but concurrent NEPA process also allows for broader public participation and ability for the public to comment on potential environmental impacts, since NEPA processes are open to the public at large and 7(i) cases are limited in their participation. The Federal Register notices for the rate cases included information concerning how the public could participate and submit comments in the separate NEPA process for the BP-12 rates. Finally, BPA's NEPA analysis of the BP-12 rates is considered by the Administrator before making his decisions concerning the rate case, and this consideration is included in this Final Record of Decision.

As discussed in Chapter 6 of this ROD, BPA considered potential environmental effects associated with the BP-12 rate case under NEPA. All of Dr. Pace's comments concerning NEPA compliance and potential environmental impacts were provided to BPA's NEPA compliance staff for consideration in this NEPA process. No party or other participant filed comments regarding BPA's NEPA analysis.

Comment. Dr. Charles Pace decries the Administrator's "... unbridled discretion without regard to sound business principles and without the benefit or support of any sound business analyses" *Id.* at 13.

Response. Sections 1.1.2 and 1.1.3 of this ROD discuss the many statutory and regulatory constraints on the Administrator's discretion. Section 1.1.2.2 discusses the Administrator's broad ratemaking discretion, which has been upheld by myriad court decisions.

BPA takes very seriously its mandate to set rates based on sound business principles. As discussed in ROD section 1.1.2.1, section 5 of the Flood Control Act of 1944 directs that rate schedules should encourage the most widespread use of power at the lowest possible rates to consumers consistent with sound business principles. Section 5 of the Flood Control Act also provides that rate schedules should be drawn having regard to the recovery of the cost of producing and transmitting electric energy, including the amortization of the Federal investment over a reasonable number of years. Section 7(a)(1) of the Northwest Power Act reaffirms the applicability of section 5 of the Flood Control Act of 1944 and directs the Administrator to set rates to recover, in accordance with sound business principles, the costs of acquiring, conserving, and transmitting electric power.

As far as Dr. Pace's claim regarding "...without the benefit or support of any sound business analyses ...," one need only visit the BP-12 rate case Web site to see how wrong this claim is. Performing a search for BPA Exhibits, Studies, Testimony, Affidavits (one of the choices in the drop-down box for Designation Code) yields 16 pages of listings, with 10 documents listed on each of the first 15 pages and 4 documents on the final page (search conducted May 11, 2011). Certainly 154 documents cannot be considered a lack of analysis. BPA Staff has confidence that its analysis is sound. At the same time, however, BPA Staff has confidence that parties and participants to the BP-12 rate case will provide detailed comments and analysis to refute parts of Staff's analysis. All this material on the official record is helpful to the Administrator as he

makes his decisions in this Final Record of Decision. Unfortunately, Dr. Pace provided no examples of the type of analysis he finds lacking in the record.

5.2 Transmission Participant Comments

RPT 110005

Comment. Dr. Charles Pace commented that the decision to enter into the Partial Transmission Settlement Agreement was arbitrary and capricious and not in accord with law. Dr. Pace stated that the agreement was inappropriate because BPA would be using some of its financial reserves to maintain current transmission rates, and therefore would fail to collect sufficient revenue to cover the increasing costs of new transmission lines and physical and cyber security measures.

Response. As BPA Staff testified, for several years revenues from transmission rates have provided funds in excess of cash requirements. Therefore, BPA can use financial reserves to keep transmission rates at current levels without jeopardizing Transmission Services' Treasury Payment Probability. Homenick *et al.*, BP-12-E-BPA-31, at 3. Transmission Services' Treasury Payment Probability for the rate period is 98.89 percent, well above BPA's standard of 95 percent. *Id.* at 13. The transmission risk analysis is discussed in section 4.2.4 of this Record of Decision.

Under the Partial Settlement Agreement, Appendix A to this ROD, Transmission Services is able to meet all its expected expenses while maintaining a very high probability of making its Treasury payments in full and on time during both years of the rate period. BPA fully anticipates collecting sufficient revenue to cover all costs. In addition, many of the costs cited by Dr. Pace will occur in future rate periods, and BPA will set rates to recover those costs at that time. BPA is setting its Fiscal Year 2012-2013 rates to recover all costs it will incur during that rate period.

Comment. Dr. Pace commented that the Partial Settlement Agreement does not shelter customers from the possibility that they will experience rate increases to cover the increasing costs of coming into compliance with various environmental laws and laws protecting regional preference customers, which Dr. Pace accused BPA of violating.

Response. BPA does not agree that it has failed to comply with applicable law, and notes that Dr. Pace makes a general statement but does not specify any particular violations of law. Therefore, he has cited no violations to which BPA can respond. In addition, the rates being established in this rate case are adequate to recover the costs BPA expects it will incur during the rate period. If costs do increase in the future, rates will be established to recover those costs.

Comment. Dr. Pace stated that he is adversely affected by BPA's failure to comply with environmental laws, and that as a consumer of electricity sold by two of BPA's preference customers he faces higher costs because BPA allocates virtually all fish mitigation costs to the power business line. Dr. Pace also noted that "hundreds of millions of dollars" of fish and wildlife costs are "impermissible."

Response. This comment largely repeats Dr. Pace’s second comment and similarly includes no specific allegations of legal violations or an explanation of how BPA is violating any environmental laws. As to the fish mitigation costs, they are allocated to rates and to generation inputs because they are mitigation for the presence and operation of the power projects. Their allocation is based on cost causation. When BPA allocates costs to each project, it ensures that electric power consumers bear no greater share of the costs of fish and wildlife mitigation than the power portion of the project. Power Revenue Requirement Study, BP-12-FS-BPA-02, at 11.

Comment. Dr. Pace commented that BPA arbitrarily limited the scope of the rate case by excluding from the record argument and evidence on program cost estimates, Federal and non-Federal debt service and debt management, and environmental impacts. Dr. Pace stated that this exclusion is especially inappropriate because BPA agreed to fund fish and wildlife measures as part of the Fish Accords. Dr. Pace challenged the appropriateness of the Fish Accords and accuses BPA of avoiding compliance with laws protecting listed species.

Response. As stated in the Federal Register notice announcing the transmission segment of the rate case, BPA excluded the above matters from the rate case because decisions on those matters are made in other forums. 75 Fed. Reg. at 78692. Interested parties, including Dr. Pace, had an opportunity to participate in these forums. Moreover, the appropriateness of the Fish Accords is not a rate case issue (nor is BPA’s alleged violation of environmental laws), and again Dr. Pace offers no rationale for his assertion.

In any case, BPA believes that the Fish Accords are appropriate and beneficial to the region, and reiterates that it believes it is in compliance with applicable environmental laws, including those protecting listed species.

BPR 110004

Comment. The Governor of Montana, the Honorable Brian Schweitzer, suggested that BPA should eliminate the Montana Intertie rate. Governor Schweitzer said that eliminating this rate will spur development of renewable resources in Montana and could decrease the balancing needs of variable energy generators in the Pacific Northwest.

Response. BPA has decided not to eliminate the Montana Intertie rate at this time. This issue is further discussed in section 4.3 of this ROD.

6.0 NATIONAL ENVIRONMENTAL POLICY ACT ANALYSIS

6.1 Introduction

BPA has assessed the potential environmental effects that could result from decisions being made through the 2012 Wholesale Power and Transmission Rate Adjustment Proceeding, consistent with the National Environmental Policy Act (NEPA), 42 U.S.C. § 4321, *et seq.* The NEPA analysis is conducted separately from the formal rate process.

BPA has previously prepared a policy-level Business Plan Final Environmental Impact Statement (Business Plan EIS), which evaluates the environmental impacts of a range of business structure alternatives that include, among other things, various rate designs for BPA's power and transmission products and services. DOE/EIS-0183, June 1995. The BPA Administrator also has issued a Record of Decision (Business Plan ROD, August 1995), which adopted the Market-Driven alternative from the Business Plan EIS. As discussed in more detail below, the BP-12 rate proposal falls within the scope of the Market-Driven alternative and is not expected to result in environmental impacts that are significantly different from those examined in the Business Plan EIS. The decision to implement the BP-12 rates thus is tiered to the Business Plan ROD.

Although BPA is electing to tier its decision to the Business Plan ROD, BPA notes that this rate proposal is the type of action typically excluded from NEPA pursuant to U.S. Department of Energy NEPA regulations, which are applicable to BPA. More specifically, this rate proposal falls within Categorical Exclusion B4.3, found at 10 CFR 1021, Subpart D, Appendix B, which provides for the categorical exclusion from NEPA documentation of "[r]ate changes for electric power, power transmission, and other products or services provided by a Power Marketing Administration that are based on a change in revenue requirements if the operations of generation projects would remain within normal operating limits." Nonetheless, BPA has laid out a strategy in the Business Plan EIS and ROD for NEPA compliance concerning future business-related decisions, and believes that a ROD tiered to the Business Plan ROD is an appropriate means for ensuring NEPA consideration of the BP-12 rates.

6.2 Business Plan EIS and ROD

The Business Plan EIS was prepared in response to a need for an adaptive business policy that would allow BPA to be more responsive to the evolving and increasingly competitive wholesale electricity market, while still meeting its business and public service missions. Accordingly, BPA designed the Business Plan EIS to support a wide array of business decisions, including decisions related to rates for products and services in rate cases in 1995 and thereafter. Business Plan EIS, section 1.4. BPA identified several purposes for consideration, including achieving strategic business objectives; competitively marketing BPA's products and services; providing for equitable treatment of Columbia River fish and wildlife; achieving BPA's share of the Northwest Power and Conservation Council's conservation goal; establishing rates that are easy to understand and administer, stable, and fair; recovering costs through rates; meeting legal mandates and contractual obligations; avoiding adverse environmental impacts; and establishing productive government-to-government relationships with Indian Tribes. *Id.*, section 1.2; Business Plan ROD, sections 5 and 6.

BPA's Business Plan EIS evaluates six alternative business directions: Status Quo (No Action); BPA Influence; Market-Driven; Maximize Financial Returns; Minimal BPA; and Short-Term Marketing. Each of the six alternatives provides policy direction for deciding 19 major policy issues that fall into five broad categories: Products and Services, Rates, Energy Resources, Transmission, and Fish and Wildlife Administration. Business Plan EIS, section 2.4. Table 2.4-1 of the Business Plan EIS shows how the alternatives evaluated in the Business Plan EIS treat these issues. Four policy options, or modules, were also developed in the Business Plan EIS to allow variations of the alternatives in key areas, including rate design.

The alternatives and modules are designed to cover the range of options for the important issues affecting BPA's business activities, as well as the impacts of those options. Variations can be assembled by matching issues and substituting modules among the six alternatives. *Id.*, section 2.1.2. All of the alternatives and modules are examined under two widely different hydrosystem operations strategies that served as "bookends" for reasonably possible operations of the FCRPS. These alternatives thus represent a range of reasonable alternatives for BPA's business activities and BPA's ability to balance costs and revenues.

The Business Plan EIS focuses on BPA relationships to the market. Business Plan EIS, section 2.1. BPA's business decisions, such as setting or revising rates, do not have a direct effect on the environment; rather, environmental impacts are determined indirectly by market responses to BPA's marketing actions and business decisions. *Id.*, sections 2.1.5 and 4.1.2. These market responses, discussed in detail in section 4.2 of the Business Plan EIS, are resource (including conservation) development; resource operation; transmission development and operation; and consumer behavior. These market responses can result in a variety of environmental impacts, including air, land, and water impacts, as well as socioeconomic impacts. *Id.*, Figures 2.1-1 and S-2. For wholesale power and transmission ratemaking, the Business Plan EIS describes how BPA rates can affect the environment through market responses. *Id.*, section 2.4.2 and Figure 2.4-1.

Thus, the Business Plan EIS is based on a "relationship analysis." BPA has quantitatively and qualitatively evaluated relationships between variables in the short run and assumed that these relationships will hold true in the long term. This relationship-based approach serves as the foundation for the environmental analyses of alternatives and modules in sections 4.4 and 4.5 of the Business Plan EIS.

To determine the potential environmental consequences of the various alternatives, the Business Plan EIS identifies general market responses to key policy issues. *Id.*, Table 4.2-1. The market responses for products and services are discussed for each of the alternative business directions, and the market responses for rates also are discussed. *Id.*, sections 4.2.1 and 4.2.2. The market responses and the environmental consequences are discussed both in general terms and in terms specific to each alternative. *Id.*, section 4.3. Table 4.3-1 details the typical environmental impacts from power generation and transmission. Section 4.4 presents the market responses and environmental impacts by alternative under each of the two bookend hydro operation scenarios. Section 4.4.3 also includes an illustrative numerical example. Table 4.4-19 summarizes the key environmental impacts by alternative. *Id.*, section 4.4.3.8. In addition, Appendix B to the

Business Plan EIS includes an extensive evaluation of rate design, including market response and environmental impacts. *Id.*, Appendix B. As can be seen from the environmental analyses summarized in Tables 4.4-19 and 4.4-20, differences in total environmental impacts among the alternatives are relatively small.

Each of the alternative business directions examined in the Business Plan EIS was also evaluated against the purposes for the action to determine how well each of the alternatives meets the need. *Id.*, section 2.6.5. Based on the evaluation of potential environmental impacts and the comparison of each alternative to the identified purposes, the Administrator adopted the Market-Driven alternative as the Agency's overall business policy in the Business Plan ROD. Business Plan ROD, section 6. The Market-Driven alternative strikes a balance between marketing and environmental concerns. It also assists BPA in maintaining the financial strength necessary to continue a relatively high level of support for public service benefits, such as energy conservation and fish and wildlife mitigation activities, while keeping BPA rates and the costs of other BPA products and services as low as possible.

Recognizing that the Administrator could select a variety of actions, BPA included many mitigation response strategies in the Business Plan EIS and ROD to address changed conditions and allow the Agency to balance costs and revenues. These response strategies include measures that BPA could implement to increase revenues (including rates), decrease spending, and/or transfer costs if its costs and revenues do not balance. Business Plan EIS, section 2.5; Business Plan ROD, section 7. These strategies enable BPA to best meet its financial, public service, and environmental obligations while remaining competitive. In the Business Plan ROD, the BPA Administrator decided to implement as many response strategies, or equivalents, as necessary to balance costs and revenues. Business Plan ROD, section 7.

The Business Plan EIS and ROD also document a decision strategy for tiering subsequent business decisions to the Business Plan ROD. Business Plan EIS, section 1.4; Business Plan ROD, section 8. For each such decision, as appropriate, the BPA Administrator reviews the Business Plan EIS and ROD to determine whether the proposed subsequent decision falls within the scope of the Market-Driven Alternative evaluated in the EIS and adopted in the ROD. If the proposed decision is found to be within the scope of this alternative, the Administrator may tier his decision under NEPA to the Business Plan ROD. Business Plan ROD, section 8. Tiering a ROD to the Business Plan ROD helps BPA delineate its business decisions clearly and provides a logical framework for connecting broad policy decisions to more specific actions. Business Plan EIS, section 1.4.

Since 1995, over 40 business decisions have been implemented by tiering RODs for each decision to the Business Plan ROD. RODs tiered to the Business Plan ROD have been completed for a broad array of BPA business decisions, such as rates for power products and services, rates for transmission products and services, power sales contracts, transmission agreements, power interconnection projects, power subscription, interconnection of energy development projects, and cost recovery adjustment clauses. Through these RODs, BPA also has evaluated the accuracy of its assumption, made in the Business Plan EIS, that the short-term

relationships among variables would hold true in the long term. BPA has found these relationships have stayed largely the same where relevant to environmental concerns.

In April 2007, BPA completed a review of the Business Plan EIS and ROD through a Supplement Analysis, as provided for in NEPA regulations applicable to BPA. The Supplement Analysis was prepared to assess whether the Business Plan EIS still provides an adequate evaluation, at a policy level, of environmental impacts that may result from BPA's current business practices, and whether these practices are still consistent with the Market-Driven alternative adopted in the Business Plan ROD. Changes that have occurred in the electric utility market and the existing environment were evaluated, and developments that have occurred in BPA's business practices and policies were considered. The Supplement Analysis found that the Business Plan EIS's relationship-based and policy-level analysis of potential environmental impacts from BPA's business practices remains valid, and that BPA's current business practices are still consistent with BPA's Market-Driven approach. The Business Plan EIS and ROD thus continue to provide a sound basis for making determinations under NEPA concerning BPA's policy-level decisions.

In 2007, BPA decided to adopt the Long-Term Regional Dialogue Final Policy (RD Policy) and Record of Decision (RD Policy ROD) (July 19, 2007), which describes the agency's long-term power supply role after FY 2011. This policy is the result of a Regional Dialogue process that began in April 2002 with the intent to define BPA's power supply and marketing role in a way that meets key regional and national energy goals in the short term and long term. Considering the depth and complexity of many issues, BPA determined that it would address the issues in two phases. The first phase of Regional Dialogue addressed issues that had to be resolved to replace power rates that expired in September 2006. *See* Bonneville Power Administration's Policy for Power Supply Role for Fiscal Years 2007-2011 (February 2005) (Short-Term Policy). The second phase addressed longer-term issues, culminating in BPA's RD Policy ROD. This policy provides BPA's customers with greater clarity about their Federal power supply so they can effectively plan for the future and, if they choose, make capital investments in long-term electricity infrastructure. It was during the Regional Dialogue processes that a tiered rate structure was introduced.

The Tiered Rate Methodology (TRM) rate proceeding (November 2008) represents the implementation of a policy for tiering Priority Firm Power (PF) rates that was established in BPA's Long-Term Regional Dialogue Policy and evaluated in the RD Policy ROD. The TRM is a rate design methodology that prescribes how BPA will design specific PF Public rates that will go into effect in FY 2012 and will remain in use through FY 2028. The TRM basic design and methodology components are consistent with the policy for tiering PF rates as described in the RD Policy, which included an evaluation of tiered rates and their potential environmental impacts. The Tiered Rate Methodology Supplemental Rate Proceeding (TRM Supplemental Proposal) (Sept 2, 2009) included eight revisions, administrative in nature, to the TRM (November 2008). Implementation of the TRM, with these revisions, continues to be consistent with the Market- Driven Alternative that was evaluated in the Business Plan EIS and adopted in the Business Plan ROD (August 15, 1995), as well as with the Long-Term Regional Dialogue Policy and its associated NEPA ROD.

6.3 Environmental Analysis

The Business Plan EIS and ROD were reviewed to determine whether the BP-12 rate proposal is adequately covered within the scope of the EIS and the Market-Driven alternative adopted in the Business Plan ROD. The Business Plan EIS includes analysis of the same rate-related issues associated with decisions being made through the BP-12 rate case. The key policy issues analyzed in the Business Plan EIS include several rates-related decisions, and the modules include a range of rate design options, including tiered rates, streamflow-based rates, seasonal rates, surcharges, market-based pricing, and elimination of existing rate discounts.

As discussed above, the Business Plan EIS identifies general market responses to BPA actions, such as establishing or revising rates, and these market responses are the source of environmental impacts. More specifically, the primary environmental impacts of power and transmission prices and rate attributes are through the choices customers make for generation resources and conservation and also in their preferred transmission provider. Business Plan EIS, sections 4.2.2.2 and 4.5.2. For example, increasing rates may cause more customers to seek energy on the market, may encourage customers to develop their own generation resources, or may cause more customers to seek alternative transmission providers or construct new transmission facilities. If this were to occur, customers may potentially develop or purchase energy from thermal generation, which in theory could be less expensive. Transmission and wheeling pricing could also influence customer decisions on resource siting, or the marketability of resource output based on the influence of wheeling costs on the total cost to the purchaser of power services offered by different suppliers. This market response could increase various environmental impacts, such as air pollution from nitrogen, sulfur and carbon emissions and water- and land-use impacts.

It is expected that these types of indirect environmental effects, as well as their potential to occur, from market responses to the BP-12 rates would be consistent with those effects identified in the Business Plan EIS. The relationships between BPA's rates-related actions and market responses have not changed significantly relative to environmental concerns since they were analyzed in the Business Plan EIS. In addition, hydrosystem operations will not be affected by the BP-12 rates. BPA already has mechanisms in place to serve its contractual obligations and market power and services with available resources consistent with the operating constraints that apply to the hydrosystem, consistent with the Business Plan EIS and ROD. Business Plan EIS, section 1.5.6; Business Plan ROD, page 4.

Based on the review of the Business Plan EIS and ROD, the BP-12 rates are a direct application of the Market-Driven alternative, and the rates remain consistent with the type of rate designs identified and evaluated in the Business Plan EIS. The issues related to this proposal are consistent with the analysis of key policy issues related to power and transmission products and services identified for the Market-Driven alternative. *Id.*, sections 2.2.3 and 2.6. In addition, the BP-12 rates do not differ substantially from the types of rate designs considered and evaluated in the Business Plan EIS. *Id.*, sections 2.4.1.6, 2.4.2.2, and 2.44, and Appendix B. Therefore, the specifics of the 2012 Wholesale Power and Transmission Rate Adjustment Proceeding fall within the scope of the Market-Driven Alternative that was evaluated in the Business Plan EIS

and adopted in the Business Plan ROD. Because of these consistencies, implementation of this rate proposal will not result in significantly different environmental impacts from those examined for the Market-Driven alternative in the Business Plan EIS.

Furthermore, the BP-12 rates will assist BPA in accomplishing the goals of the Market-Driven Alternative identified in the Business Plan ROD. This alternative was selected as BPA's business direction because it allows BPA to (1) recover costs through rates; (2) competitively market BPA's products and services; (3) develop rates that meet customer needs for clarity and simplicity; and (4) continue to meet BPA's legal mandates.

The BP-12 rates provide a competitive rate structure that includes various mechanisms to account for potential revenue shortfalls. The rate proposal thus allows BPA to continue to recover its costs through its rates while remaining competitive, and is consistent with the general approach to setting rates and managing and responding to risk that was developed in the Market-Driven alternative and continued through subsequent rate cases. In addition, the rate design has been made as clear and simple as possible, given the various types of products and services covered. Finally, BPA believes that the BP-12 rates will allow BPA to meet all of its applicable legal mandates. Accordingly, the BP-12 rates are consistent with these aspects of the Market-Driven Alternative.

6.4 Public Comments

The BP-12 public comment period for power rates ended February 18, 2011. The BP-12 public comment period for transmission rates ended March 15, 2011. Comments received relevant to BPA's environmental analysis of the BP-12 rate proposal under NEPA raised during the comment periods follow.

Comment. Failure to comply with NEPA and consider environmental impacts associated with the proposed rates, including impacts to plants, fish, and wildlife. Comments BPR100006 and RPT110005.

Response. As discussed above, BPA has assessed the potential environmental effects that could result from decisions being made through the 2012 Wholesale Power and Transmission Rate Adjustment Proceeding, consistent with the National Environmental Policy Act (NEPA), 42 U.S.C. § 4321, *et seq.* Specifically, BPA tiered this rate proposal to the Business Plan EIS and ROD. DOE/EIS-0183, June 1995. BPA reviewed the Business Plan EIS and ROD to determine whether the BP-12 rate proposal is adequately covered within the scope of the Business Plan EIS and the Market-Driven alternative adopted in the Business Plan ROD. The Business Plan EIS includes analysis of the same rate-related issues associated with decisions being made through the BP-12 rate case.

As described in the Business Plan EIS, sections 4.2.2.2 and 4.5.2, and in Chapter 6 of this ROD, the primary environmental impacts of power and transmission prices and rate attributes are through the choices customers make for generation resources and conservation and also in their preferred transmission provider. The relationships between BPA's rates-related actions and

market responses have not changed significantly relative to environmental concerns since they were analyzed in the Business Plan EIS. In addition, hydrosystem operations will not be affected by the BP-12 rate proposal. Furthermore, it is expected that these types of indirect environmental effects, as well as their potential to occur, from market responses to the BP-12 rates would be consistent with those effects identified in the Business Plan EIS.

6.5 NEPA Decision

Based on a review of the Business Plan EIS and ROD, BPA determines that the BP-12 rate proposal falls within the scope of the Market-Driven alternative evaluated in the Business Plan EIS and adopted in the Business Plan ROD. The BP-12 rates are not expected to result in environmental impacts that are significantly different from those examined in the Business Plan EIS, and will assist BPA in accomplishing the goals related to the Market-Driven alternative that are identified in the Business Plan ROD. Therefore, the decision to implement the BP-12 rates is tiered to the Business Plan ROD.

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7.0 CONCLUSION

As required by law, the rates established and adopted in this Final Record of Decision have been set to recover the costs associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the FCRPS (including irrigation costs required to be repaid out of power revenues) over a reasonable period of years and the other costs and expenses incurred by the Administrator in carrying out the requirements of the Northwest Power Act and other provisions of law. In addition, these rates have been designed to be as low as possible consistent with sound business principles, to encourage the widest possible use of BPA's power, and to satisfy BPA's other ratemaking obligations. The transmission and ancillary services rates have been designed to equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing such system. Finally, the Hearing Officer has assured me that all interested parties and participants were afforded the opportunity for a full and fair evidentiary hearing, as required by law.

BPA must establish its rates pursuant to section 7(i) of the Northwest Power Act. BPA must also evaluate the potential environmental impacts of the proposed rates and alternatives thereto, as required by NEPA. In this instance, the environmental analysis provided by the Business Plan Final EIS details the environmental impacts of BPA's FY 2012-2013 final power and transmission rate proposals. The environmental analysis contained in the Business Plan Final EIS has been considered in making the decisions in this ROD.

Based upon the record compiled in this proceeding, the decisions expressed herein, and all requirements of law, I hereby adopt the accompanying Power Rate Schedules and Transmission Rate Schedules as final Bonneville Power Administration rates. In accordance with Federal Energy Regulatory Commission Requirements, 18 C.F.R. § 300.10(g), the Administrator hereby certifies that the Power and Transmission Rate Schedules adopted herein are consistent with applicable laws and are the lowest possible rates consistent with sound business principles.

Issued at Portland, Oregon, this 26th day of July, 2011.

/s/ Stephen J. Wright

Stephen J. Wright

Administrator and Chief Executive Officer

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**2012 Wholesale Power and Transmission Rate
Adjustment Proceeding (BP-12)**

**ADMINISTRATOR'S FINAL
RECORD OF DECISION**

Appendix A: Partial Transmission Settlement Agreement

July 2011

BP-12-A-02A



PARTIAL TRANSMISSION SETTLEMENT AGREEMENT
Bonneville Power Administration 2012 Rate Case
Revised 12/7/10

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

1. In the Bonneville Power Administration (BPA) 2012 rate case, BPA will submit a proposal (Settlement Proposal) to establish rates for transmission services for fiscal years 2012-2013 (Rate Period) (including alternatives for the Montana Intertie rate depending on whether BPA terminates the exchange in the Montana Intertie agreement) as shown in Attachment 1. The Settlement Proposal will also include the following changes to existing rate schedules, all shown on Attachment 2, and no other changes:
 - a. A change in the rate for the Failure to Comply Penalty Charge from 1000 mills per kilowatthour to the greater of 500 mills per kilowatthour or 150% of an hourly energy index.
 - b. Deletion of Customer-Served Load provisions from the Network Integration rate schedule and addition of a short-distance discount to such rate schedule.
 - c. Modification of section E of the Integration of Resources rate schedule, Ratchet Demand Relief, to provide that Ratchet Demand relief is not available in the month in which the Ratchet Demand was established and that for such month the customer will be assessed charges based upon its highest hourly Scheduled Demand for the month.
 - d. Modification of the definitions of Dynamic Schedule and Dynamic Transfer to be identical to the definitions that are adopted in the Dynamic Transfer Operating and Scheduling Business Practice.
 - e. Removal of the words "Short-Term Firm and Non-Firm PTP Transmission" from the definitions of Daily Service and Weekly Service; and replacement of the definitions for Monthly Firm Service and Monthly Non-Firm Service with a definition of Monthly Service that reads as follows: "*Monthly Service* is service that starts at 00:00 of any date and stops at 00:00 at least 28 days later, but less than or equal to 364 days later."
2. a) The Administrator will establish the IM and IE rates, and address possible revisions to the TGT rate that are consistent with the Montana Intertie Agreement, BPA contract number DE-MS79-81BP90210, in a contested process in the 2012 rate case. As part of the Settlement Proposal, BPA staff will propose that the Administrator establish IM and IE rates that are no higher than the rates shown in Attachment 3, and the signatories agree not to present evidence or argument in the 2012 rate case, or before FERC or in any judicial forum, that either the IM or IE rate should be higher than the rates shown in Attachment 3. However, BPA staff will propose that the Administrator adopt all of the rates shown on Attachment 1 regardless of his decisions on the level of the IM, IE, and TGT rates.

- b) In addition, during the Rate Period BPA will hold a public process to discuss with all interested parties the future of the IM, IE, and TGT rates. The workshops will include discussion of the then-existing rate treatment and potential alternative rate treatments of the costs of BPA's share of Montana Intertie transmission capacity and the costs of the Eastern Intertie. BPA will include in its initial proposal in the 2014 rate case a proposal for the rate treatment of the above costs, including proposals regarding the existence and level of the IM, IE, and TGT rates
3. The ancillary services Regulation and Frequency Response Service, Energy Imbalance Service, Operating Reserve – Spinning Reserve Service, Operating Reserve – Supplemental Reserve Service, and Generation Imbalance Service, and all control area services, are not included in this settlement. All rates issues concerning these services will be litigated in the 2012 rate case. BPA reserves the right to propose changes to the rates, rate schedules, and associated general rate schedule provisions for these services, and the signatories to this settlement preserve the right to litigate all issues concerning these services.
4. The signatories acknowledge that BPA expects the costs of transmission service to increase in future rate periods because of, among other things, additional cyber and physical security requirements, repairs to aging equipment, and construction of new lines. The signatories do not waive the right to challenge proposed rate increases in future rate cases, and agree to collaborate with BPA in exploring ways to reduce rate pressures in future rate periods.
5. a) During the Rate Period, BPA will engage the signatories in discussions, request and respond to written comments, and take the following actions regarding the following issues:
- i. BPA will adopt commercial practices under which BPA allocates dynamic transfer capability (DTC) on BPA's transmission system, including DTC for both imports and exports, taking into account the technical and operational requirements and the DTC needed for self-supply and other regional initiatives;
 - ii. BPA will further develop methodologies to determine the availability of DTC;
 - iii. BPA will adopt ways to secure reliable and reasonable operational certainty for generators given the operational limits on the amount of DTC that BPA can make available;
 - iv. BPA will develop and adopt methodologies for determining the infrastructure requirements and cost allocations for increasing DTC;
 - v. BPA will determine the appropriate use and terms of dynamic transfer agreements to govern access to and use of DTC; and

- vi. To the extent, if any, that BPA has the unilateral authority to do so, BPA will determine the appropriate use, if any, of the Northwest Power Pool Firm Contingent product code for wind.
 - b) During the Rate Period, BPA will hold discussions with interested parties and accept and respond to written comments regarding ways that generators can operate to prevent or mitigate cumulative imbalances and patterns of under-delivery or over-use of energy. These discussions will not include discussions of the Persistent Deviation charge or the criteria for Persistent Deviation.
 - c) By April 15, 2011, BPA will allocate available DTC for the Rate Period.
6. Before the start of the 2014 rate case, BPA will (a) work with interested transmission customers in an open and collaborative forum to define the parameters of a cost of service study that includes consideration of alternative methodologies for allocating demand-related costs and that determines the costs of BPA's major transmission services, (b) complete an illustrative cost of service study using forecasted data from a recent fiscal year, and (c) share the cost of service model with customers to ensure clear and transparent cost of service determinations. BPA will use the methodology from the study in the initial proposal for the 2014 rate case to prepare rate designs and allocate costs among rate classes.
7. If BPA submits a rate proposal consistent with the terms of this Partial Settlement Agreement, the signatories agree not to contest in the 2012 rate case, or before FERC or in any judicial forum, any aspect of the Settlement Proposal or of the rates or rate schedules included in the Settlement Proposal, or any of the elements thereof or the methodologies and principles used to derive such rates. The signatories further agree to waive their rights to cross-examination and discovery with respect thereto, except in response to issues raised by any party in such proceeding that is not a signatory to this Partial Settlement Agreement. Execution of the Partial Settlement Agreement by any signatory does not constitute consent or agreement in any future rate proceeding to the transmission rates or rate schedule modifications included herein or to any underlying principle or methodology.
8. The signatories will move the Hearing Officer to specify a date, within a reasonable time of the prehearing conference in the rate case, by which any party to the rate case that has not executed this Partial Settlement Agreement must object to the settlement proposed in this Partial Settlement Agreement and identify each issue included in the Settlement Proposal that such rate case party chooses to preserve for hearing. If no rate case party objects to the Settlement Proposal and preserves issues for hearing, BPA shall propose to the Administrator that he adopt the Settlement Proposal in its entirety. If any rate case party does object to the Settlement Proposal, BPA may, but shall not be required to, revise the Settlement Proposal as it believes appropriate, either after such rate case party states its objection or after parties file their direct testimony. If BPA decides to revise the Settlement Proposal, the signatories, together with any other interested rate case parties, will meet promptly to discuss a new procedural schedule that they will propose to the Hearing Officer, allowing BPA a reasonable time in which to present a revised proposal and the parties a reasonable time to respond to

such revised proposal. In that event, the signatories may contest any aspect of the revised proposal.

- 9.I f the Administrator establishes transmission rates in accordance with the Settlement Proposal and submits such rates to FERC for confirmation and approval under the applicable standards of the Northwest Power Act, the signatories will not challenge the confirmation and approval of the rates or any element thereof, including the methodologies and principles used to establish the rates, or support or join any such challenge, and will not challenge the rates or any element thereof, including the methodologies and principles used to establish the rates, in any judicial forum.
10. The signatories will not assert in any forum that anything in this Partial Settlement Agreement or any action with regard to this Partial Settlement Agreement taken or not taken by any signatory, the Hearing Officer, the Administrator, FERC, or a court, creates or implies any procedural or substantive precedent or creates or implies agreement to any underlying principle or methodology, or creates any precedent under any contract between BPA and any signatory.
11. By executing this Partial Settlement Agreement, no signatory waives any of its rights under the Federal Power Act or any right to pursue BPA tariff dispute resolution procedures consistent with BPA's tariff (including without limitation any complaint concerning implementation of BPA's tariff) or any claim that a particular charge, methodology, practice or rate schedule has been improperly applied.
12. Nothing in this Partial Settlement Agreement amends any contract or modifies rights or obligations or limits the remedies available thereunder.

This Partial Settlement Agreement may be executed in counterparts.

_____ for
_____ Date _____
Party

Attachment 1

Summary of Transmission Rate Levels

	Units	Proposed 2012 Rates	
		FPT-12.1	FPT-12.3
FPT-12.1 and FPT-12.3			
M-G Distance.....	\$/kW-mi-yr	0.0587	0.0587
M-G Miscellaneous Facilities.....	\$/kW-yr	3.35	3.35
M-G Terminal.....	\$/kW-yr	0.68	0.68
M-G Interconnection Terminal.....	\$/kW-yr	0.61	0.61
S-S Transformation.....	\$/kW-yr	6.31	6.31
S-S Interconnection Terminal.....	\$/kW-yr	1.73	1.73
S-S Intermediate Terminal.....	\$/kW-yr	2.44	2.44
S-S Distance.....	\$/kW-mi-yr	0.5772	0.5772
Overall FPT Rate.....	\$/kW-yr	15.93	15.93
Overall FPT Rate.....	\$/kW-mo	1.327	1.327
IR-12			
Demand.....	\$/kW-mo	1.498	
NT-12			
Base Rate (\$/kW-mo).....	\$/kW-mo	1.298	
Load Shaping (\$/kW-mo).....	\$/kW-mo	0.367	
Base plus Load Shaping.....	\$/kW-mo	1.665	
PTP-12			
Demand.....	\$/kW-mo	1.298	
Daily Block 1 (day 1 thru 5).....	\$/kW-day	0.060	
Daily Block 2 (day 6 and beyond).....	\$/kW-day	0.046	
Hourly.....	mills/kWh	3.74	
Utility Delivery			
Demand.....	\$/kW-mo	1.119	
IS-12			
Demand.....	\$/kW-mo	1.293	
Daily Block 1 (day 1 thru 5).....	\$/kW-day	0.060	
Daily Block 2 (day 6 and beyond).....	\$/kW-day	0.045	
Hourly.....	mills/kWh	3.72	

Attachment 1

Summary of Transmission Rate Levels

	Units	Proposed 2012 Rates
Power Factor Penalty Charge		
Demand -- Lagging.....	\$/kVAr-mo	0.28
Demand -- Leading.....	\$/kVAr-mo	0.24
Scheduling Control and Dispatch ('12)		
Demand.....	\$/kW-mo	0.203
Daily Block 1 (day 1 thru 5).....	\$/kW-day	0.010
Daily Block 2 (day 6 and beyond).	\$/kW-day	0.006
Hourly.....	mills/kWh	0.59
Generation Supplied Reactive ('12)		
Demand.....	\$/kW-mo	0.000
Daily Block 1 (day 1 thru 5).....	\$/kW-day	0.000
Daily Block 2 (day 6 and beyond).	\$/kW-day	0.000
Hourly.....	mills/kWh	0.00

Attachment 2

SECTION II. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

B. FAILURE TO COMPLY PENALTY CHARGE AND ASSESSMENT OF OTHER COSTS RESULTING FROM THE FAILURE TO COMPLY

1. RATE FOR FAILURE TO COMPLY PENALTY CHARGE

If a party fails to comply with the BPA-TS's dispatch, curtailment, redispatch, or load shedding orders, the party will be assessed the Failure to Comply Penalty Charge. The Failure to Comply Penalty Charge shall be ~~1000 mills per kilowatthour~~ the greater of 500 mills per kilowatthour or 150% of an hourly energy index in the Pacific Northwest.

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

Parties who 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 the BPA-TS of the situation upon occurrence of the force majeure.

2. BILLING FACTORS

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 minutes after issuance of the order in any of the following situations:

- a. Failure to shed load when directed to do so by BPA-TS 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 the BPA-TS 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 the BPA-TS 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-TS 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.

Attachment 2

1.1 NT-12 Network Integration Rate

SECTION I. AVAILABILITY

This schedule supersedes Schedule NT-10. It is available to Transmission Customers taking Network Integration Transmission (NT) Service over Federal Columbia River Transmission System Network and Delivery facilities and to Transmission Customers taking Conditional Firm 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 BPA-TS's General Rate Schedule Provisions (GRSPs).

SECTION II. RATES

The monthly charge will be the sum of A and B.

A. BASE CHARGE

\$1.298 per kilowatt per month

B. LOAD SHAPING CHARGE

\$0.367 per kilowatt per month

SECTION III. BILLING FACTORS

A. BASE CHARGE

~~If no Declared Customer Served Load (CSL) is specified in the customer's NT Service Agreement, the~~ The monthly Billing Factor for the Base Charge specified in section II.A. shall be the customer's Network Load on the hour of the Monthly Transmission Peak Load.

- ~~a. For the billing month, if the sum of the Actual CSLs occurring during Heavy Load Hours (HLH) is greater than or equal to 60 percent of the Declared CSL multiplied by the number of HLHs in the billing month, the monthly Billing Factor shall be the customer's Network Load on the hour of the Monthly Transmission Peak Load, less Declared CSL.~~

~~b. For the billing month, if the sum of the Actual CSLs occurring during HLH is less than 60 percent of the Declared CSL multiplied by the number of HLHs in the billing month, the monthly Billing Factor shall be the customer's Network Load on the hour of the Monthly Transmission Peak Load. The Billing Factor will be reduced by any megawatts charged the NT Unauthorized Increase Charge under section IV.F. for the month.~~

~~Where:~~

~~“Declared Customer Served Load (CSL)” is the monthly amount in megawatts of the Transmission Customer's Network Load that the Transmission Customer elects to serve on a firm basis from sources internal to its system or over non-Federal transmission facilities or pursuant to contracts other than the Network Integration Service Agreement. The customer's Declared CSL is contractually specified for each month. Declared Customer Served Load shall not exceed the annual amounts and shall be limited to the resources and contracts specified in the Service Agreement on October 1, 2005.~~

~~“Actual Customer Served Load (CSL)” is the actual hourly amount in megawatts of the Network Load that the customer serves on a firm basis from sources internal to its system or over non-Federal transmission facilities or pursuant to contracts other than the Network Integration Service Agreement.~~

B. LOAD SHAPING CHARGE

The monthly Billing Factor for the Load Shaping Charge specified in section II.B. shall be the Network Load on the hour of the Monthly Transmission 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 section II.A. of the GRSPs.

C. FAILURE TO COMPLY PENALTY

Customers taking NT Service are subject to the Failure to Comply Penalty specified in section II.B. of the GRSPs.

D. METERING ADJUSTMENT

At those Points of Delivery that do not have meters capable of determining the demand on the hour of the Monthly Transmission Peak Load, the Billing Demand shall be calculated by substituting 1) the sum of the highest hourly demand that occurs during the billing month at all Points of Delivery multiplied by 0.79 for 2) Network Load on the hour of the Monthly Transmission Peak Load.

E. POWER FACTOR PENALTY

Customers taking service under this rate are subject to the Power Factor Penalty Charge specified in section II.C. of the GRSPs.

~~F. UNAUTHORIZED INCREASE CHARGE~~

~~If the Network Customer's Actual CSL is less than its Declared CSL, the Unauthorized Increase Charge specified in section II.G of the GRSPs shall be assessed.~~

F. 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: (i) is designated as a Network Resource (DNR) in the customer's NT Service Agreement for at least 12 months, and (ii) 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:

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

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 POD(s) to the total DNR SD designated capacity. The output serving Network Load is:

- i) in the case of a scheduled DNR SD, the sum of firm schedules to Network Load; and
- ii) in the case of Behind the Meter Resources, the metered output of the resource.

NT Rate = NT Base Charge

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

i) 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 ii 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.

ii) The amount of designated capacity from all DNR SD allocated to any POD may not exceed the POD’s peak load.

iii) 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.

G. DIRECT ASSIGNMENT FACILITIES

BPA-TS 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.

H. 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-TS 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.

I. 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 section II.D. of the GRSPs.

Attachment 2

1.2 IR-12 Integration of Resources Rate

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

E. RATCHET DEMAND RELIEF

Under appropriate circumstances, BPA-TS 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 which 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-TS's transmission system or transmission services, or to any other Transmission Customer; or

2. The event which 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-TS'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-TS 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-TS 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.

Attachment 2

1.3 Section III. Definitions

1.3.1 8. Dynamic Schedule

Add definition adopted in Dynamic Transfer Operating and Scheduling Business Practice. ~~A *Dynamic Schedule* is a telemeter reading or value which is updated in real time and which is used as a schedule in the Automatic Generation Control (AGC) and Area Control Error (ACE) equation of the BPA-TS and the integrated value of which is treated as a schedule for interchange accounting purposes. One-way Dynamic Schedules are commonly used for scheduling remote generation or remote load to or from another Control Area. Two-way Dynamic Schedules are commonly used to provide supplemental regulation or operating reserve support from one entity to another, usually between Control Areas. The Receiving Party sends the Delivering Party a requested Dynamic Schedule (the first part of the two-way schedule). The Delivering Party then responds with the official Dynamic Schedule of what actually is delivered to the Receiving Party (the second part of the two-way schedule).~~

1.3.2 12. Dynamic Transfer

Add definition adopted in Dynamic Transfer Operating and Scheduling Business Practice. ~~*Dynamic Transfer* is the provision of real-time monitoring, telemetering, computer software, hardware, communications, engineering, transmission capacity and energy accounting (including inadvertent interchange), and administration, including transmission scheduling, required to electronically move all or a portion of the real energy services associated with a generator or load out of one Control Area into another Control Area.~~

1.3.3 7. 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. ~~*Daily Service* is Short-Term Firm and Non-Firm PTP Transmission 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.~~

1.3.4 31. ~~Monthly Non-Firm Service~~

~~*Monthly Non-Firm Service* is Non-Firm PTP Transmission Service that starts at 00:00 of any date and stops at 00:00 at least 28 days later, but less than or equal to 31 days later.~~

1.3.5 33. ~~Monthly Firm Service~~

~~*Monthly Firm Service* is Short-Term Firm PTP Transmission Service that starts at 00:00 of any date and stops at 00:00 at least 28 days later, but less than or equal to 364 days later.~~

1.3.6 73. ~~Weekly Service~~

~~*Weekly Service* is Short-Term Firm and Non-Firm PTP Transmission service that starts at 00:00 of any date and stops at 00:00 at least seven (7) days later, but less than or equal to 27 days later.~~

Attachment 3

Summary of Transmission Rate Levels

		Exchange Terminated	Exchange Not Terminated
IM-12¹			
Demand.....	\$/kW-mo	0.598	1.312
Daily Block 1 (day 1 thru 5).....	\$/kW-day	0.028	0.061
Daily Block 2 (day 6 and beyond).	\$/kW-day	0.020	0.043
Hourly.....	mills/kWh	1.72	3.78
 Intertie East			
IE-12.....	mills/kWh	1.13	1.13

¹ Only one set of IM rates will appear in the final rate schedules, depending on whether BPA has terminated the exchange.

**SIGNATORIES TO THE
2012 TRANSMISSION RATE CASE
PARTIAL SETTLEMENT AGREEMENT**

Alcoa Inc.
Asotin County PUD
Central Lincoln PUD
Chelan County Public Utility District No. 1
Emerald People's Utility District
Eugene Water & Electric Board
Grant County Public Utility District
Idaho Falls Power
Idaho Power Company
Klickitat PUD
Northwest Requirements Utilities

Signing for:

Ashland, City of
Benton Rural Electric Association
Big Bend Electric Co-Op
Bonners Ferry, City of
Burley, City of
Cascade Locks, City of
Centralia, City of
Central Lincoln PUD
Cheney, City of
Columbia Basin Electric Co-op
Columbia Power Cooperative
Columbia Rural Electric Association
Columbia River PUD
East End Mutual Electric Co.
Ferry County PUD #1
Flathead Electric Cooperative
Forest Grove, City of
Harney Electric Cooperative
Hermiston Energy Services
Heyburn, City of
Hood River Electric Co-op
United Electric Cooperative
Idaho County Light & Power
Inland Power & Light
Kootenai Electric Cooperative
Lower Valley Energy
McMinnville Water & Light
Midstate Electric Cooperative

Milton-Freewater City Light & Power
Mission Valley Power
Modern Electric Water Company
Monmouth, City of
Nespelem Valley Cooperative
Northern Wasco County PUD
Orcas Power & Light Coop
Oregon Trail Electric Co-op
Peninsula Light
Ravalli County Electric Coop
Richland, City of
Rupert, City of
Salem Electric
Skamania County PUD
South Side Electric, Inc.
Surprise Valley Electric
Tanner Electric Cooperative
Tillamook PUD
Vera Water & Power
Vigilante Electric Coop
Wasco Electric Cooperative
Wells Rural Electric
NorthWestern Energy
Pend Oreille County Public Utility District
PNGC Power
Signing For:
Pacific Northwest Generating Cooperative
Blachly-Lane County Cooperative Electric Association
Central Electric Cooperative, Inc.
Clearwater Power Company
Consumers Power, Inc.
Coos-Curry Electric Cooperative, Inc.
Douglas Electric Cooperative, Inc.
Fall River Rural Electric Cooperative, Inc.
Lane Electric Cooperative, Inc.
Lincoln Electric Cooperative, Inc.
Lost River Electric Cooperative, Inc.
Northern Lights, Inc.
Okanogan County Electric Cooperative, Inc.
Raft River Rural Electric Cooperative, Inc.
Salmon River Electric Cooperative, Inc.
Umatilla Electric Cooperative Association
West Oregon Electric Cooperative, Inc.
Public Power Council
Seattle City Light
Snohomish PUD

Southern California Edison Company
Springfield Utility Board
Tacoma Power
TransAlta
Turlock Irrigation District
Western Montana Electric G&T

Signing For:

Flathead Electric Cooperative
Glacier Electric Cooperative
Mission Valley Power
Missoula Electric Cooperative
Ravalli County Electric Cooperative
Vigilante Electric Cooperative

Western Public Agencies Group

Signing For:

Alder Mutual Light Company
Benton Rural Electric Association
Eatonville, Town of
Ellensburg, City of
Elmhurst Mutual Power and Light Company
Lakeview Light and Power Company
Milton, City of
Parkland Light and Water Company
Peninsula Light Company
Port Angeles, City of
Public Utility District No. 1 of Clallam County
Public Utility District No. 1 of Clark County
Public Utility District No. 1 of Grays Harbor County
Public Utility District No. 1 of Kittitas County
Public Utility District No. 1 of Lewis County
Public Utility District No. 1 of Mason County
Public Utility District No. 1 of Clallam County
Public Utility District No. 3 of Mason County
Public Utility District No. 2 of Pacific County
Public Utility District No. 1 of Skamania County
Public Utility District No. 1 of Wahkiakum County
Tanner Electric Cooperative

**2012 Wholesale Power and Transmission Rate
Adjustment Proceeding (BP-12)**

**ADMINISTRATOR'S FINAL
RECORD OF DECISION**

Appendix B: Power Rate Schedules

July 2011

BP-12-A-02B



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BONNEVILLE POWER ADMINISTRATION
POWER RATE SCHEDULES

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COMMONLY USED ACRONYMS AND SHORT FORMS

AGC	Automatic Generation Control
ALF	Agency Load Forecast (computer model)
aMW	average megawatt(s)
AMNR	Accumulated Modified Net Revenues
ANR	Accumulated Net Revenues
ASC	Average System Cost
BiOp	Biological Opinion
BPA	Bonneville Power Administration
Btu	British thermal unit
CDD	cooling degree day(s)
CDQ	Contract Demand Quantity
CGS	Columbia Generating Station
CHWM	Contract High Water Mark
Commission	Federal Energy Regulatory Commission
Corps or USACE	U.S. Army Corps of Engineers
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council	Northwest Power and Conservation Council
CRAC	Cost Recovery Adjustment Clause
CSP	Customer System Peak
CT	combustion turbine
CY	calendar year (January through December)
DDC	Dividend Distribution Clause
<i>dec</i>	decrease, decrement, or decremental
DERBS	Dispatchable Energy Resource Balancing Service
DFS	Diurnal Flattening Service
DOE	Department of Energy
DSI	direct-service industrial customer or direct-service industry
DSO	Dispatcher Standing Order
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.
EPP	Environmentally Preferred Power
ESA	Endangered Species Act
e-Tag	electronic interchange transaction information
FBS	Federal base system
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FELCC	firm energy load carrying capability
FORS	Forced Outage Reserve Service
FPS	Firm Power Products and Services (rate)
FY	fiscal year (October through September)
GARD	Generation and Reserves Dispatch (computer model)
GEP	Green Energy Premium

GRSPs	General Rate Schedule Provisions
GTA	General Transfer Agreement
GWh	gigawatthour
HDD	heating degree day(s)
HLH	Heavy Load Hour(s)
HOSS	Hourly Operating and Scheduling Simulator (computer model)
HYDSIM	Hydro Simulation (computer model)
ICE	Intercontinental Exchange
<i>inc</i>	increase, increment, or incremental
IOU	investor-owned utility
IP	Industrial Firm Power (rate)
IPR	Integrated Program Review
IRD	Irrigation Rate Discount
JOE	Joint Operating Entity
kW	kilowatt (1000 watts)
kWh	kilowatthour
LDD	Low Density Discount
LLH	Light Load Hour(s)
LRA	Load Reduction Agreement
Maf	million acre-feet
Mid-C	Mid-Columbia
MMBtu	million British thermal units
MNR	Modified Net Revenues
MRNR	Minimum Required Net Revenue
MW	megawatt (1 million watts)
MWh	megawatthour
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NFB	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NORM	Non-Operating Risk Model (computer model)
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPV	net present value
NR	New Resource Firm Power (rate)
NT	Network Transmission
NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation
NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff
O&M	operation and maintenance
OMB	Office of Management and Budget
OY	operating year (August through July)

PF	Priority Firm Power (rate)
PFp	Priority Firm Public (rate)
PFx	Priority Firm Exchange (rate)
PNCA	Pacific Northwest Coordination Agreement
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration or Point of Interconnection
POM	Point of Metering
POR	Point of Receipt
Project Act	Bonneville Project Act
PRS	Power Rates Study
PS	BPA Power Services
PSW	Pacific Southwest
PTP	Point to Point Transmission (rate)
PUD	public or people's utility district
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
RD	Regional Dialogue
REC	Renewable Energy Certificate
Reclamation or USBR	U.S. Bureau of Reclamation
REP	Residential Exchange Program
RevSim	Revenue Simulation Model (component of RiskMod)
RFA	Revenue Forecast Application (database)
RHWM	Rate Period High Water Mark
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model (component of RiskMod)
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RR	Resource Replacement (rate)
RSS	Resource Support Services
RT1SC	RHWM Tier 1 System Capability
RTO	Regional Transmission Operator
SCADA	Supervisory Control and Data Acquisition
SCS	Secondary Crediting Service
Slice	Slice of the System (product)
T1SFCO	Tier 1 System Firm Critical Output
TCMS	Transmission Curtailment Management Service
TOCA	Tier 1 Cost Allocator
TPP	Treasury Payment Probability
Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load
TRM	Tiered Rate Methodology
TS	BPA Transmission Services
TSS	Transmission Scheduling Service
UAI	Unauthorized Increase

ULS	Unanticipated Load Service
USACE or Corps	U.S. Army Corps of Engineers
USBR or Reclamation	U.S. Bureau of Reclamation
USFWS	U.S. Fish and Wildlife Service
VERBS	Variable Energy Resources Balancing Service (rate)
VOR	Value of Reserves
WECC	Western Electricity Coordinating Council (formerly WSCC)
WIT	Wind Integration Team
WSPP	Western Systems Power Pool

POWER RATE SCHEDULES

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SCHEDULE PF-12 PRIORITY FIRM POWER RATE

1 Availability

This schedule is available for the contract purchase of Firm Requirements Power pursuant to section 5(b) of the Northwest Power Act. Firm Requirements Power may be purchased for use within the Pacific Northwest by public bodies, cooperatives, and Federal agencies for resale to ultimate consumers, for direct consumption, and for Construction, Test and Start-Up, and Station Service.

Utilities participating in the Residential Exchange Program under section 5(c) of the Northwest Power Act may purchase Residential Exchange Program Power pursuant to a Residential Purchase and Sale Agreement or Residential Exchange Program Settlement Implementation Agreement.

With the exception of sales under the Residential Exchange Program, transmission and ancillary services for use of the Federal Columbia River Transmission System facilities shall be charged separately under the applicable rate schedules.

Effective October 1, 2011, this rate schedule supersedes the PF-10 rate schedule, which went into effect October 1, 2009. Sales under the PF-12 rate schedule are subject to the General Rate Schedule Provisions (GRSPs). For sales under this rate schedule, bills shall be rendered and payments due pursuant to the GRSPs and billing process.

2 Priority Firm Public Rate

The PF Public Rate is applicable to the sale of Firm Requirements Power under CHWM Contracts for Load Following, Block, and Slice/Block power products.

2.1 Tier 1 Charges

Tier 1 charges for each customer consist of two of three Customer charges, a Demand charge, and a Load Shaping charge.

2.1.1 Customer Charges

The Customer Charges are applicable to Customers that purchase the following products: Load Following, Block, and Slice/Block.

2.1.1.1 Customer Rates

The monthly Composite, Non-Slice and Slice Customer rates are specified in the following table:

	<i>Customer Charge</i>		
	<i>Rate per percentage point of billing determinant</i>		
	<i>Composite</i>	<i>Non-Slice</i>	<i>Slice</i>
Customer Rate	\$1,952,169	(\$388,748)	\$0

2.1.1.2 Customer Billing Determinants

The Composite, Non-Slice and Slice Customer billing determinants are specified in the following table:

	<i>Customer Charge</i>		
	<i>Billing determinant for each rate</i>		
	<i>Composite</i>	<i>Non-Slice</i>	<i>Slice</i>
Load Following	TOCA	TOCA	N/A
Block only	TOCA	TOCA	N/A
Block portion of Slice/Block	Non-Slice TOCA	Non-Slice TOCA	N/A
Slice portion of Slice/Block	Slice %	N/A	Slice %

N/A = Not Applicable

Where:

TOCA = Tier 1 Cost Allocator, expressed as a percent

For each Customer for each Fiscal Year of the Rate Period, the TOCA shall be calculated according to the following formula:

$$\frac{\text{Minimum of the Customer's:}}{\text{Sum of all Customers' RHWMs}} \times 100$$

a) RHWM, or
b) Forecast Net Requirement for each Fiscal Year

The TOCA for a Joint Operating Entity (JOE) is the sum of the TOCAs of the individual members of the JOE.

All Customer TOCAs will be posted on the BPA Web site. A Customer's TOCA may be revised pursuant to the TOCA Adjustment, GRSP II.T.

Slice % = The Slice percentage for the relevant Fiscal Year as specified in Exhibit K of the Slice Customer's CHWM Contract.

Non-Slice TOCA = TOCA minus Slice %, expressed as a percent

A Customer's Non-Slice TOCA may be revised pursuant to the TOCA Adjustment, GRSP II.T.

2.1.2 Demand Charge

The Demand Charge is applicable to Customers that purchase the following products: Load Following and Block with Shaping.

2.1.2.1 Demand Rate

<i>Month</i>	<i>Rate in \$/kW</i>
October	9.18
November	9.31
December	9.97
January	9.70
February	9.92
March	9.60
April	9.10
May	8.50
June	8.72
July	10.20
August	10.75
September	10.53

2.1.2.2 Demand Billing Determinant

The Demand billing determinant for each billing month equals:

Tier 1 CSP – aHLH – CDQ – SuperPeak

Where:

Tier 1 CSP = The Tier 1 Customer System Peak is the Customer's maximum Actual Hourly Tier 1 Load during the Heavy Load Hours of the month, in kilowatts.

aHLH = Average of the Customer's Actual Hourly Tier 1 Loads during the HLH, in kilowatts

CDQ = Contract Demand Quantity specified in the Customer's CHWM Contract, Exhibit B, section 2, in kilowatts

SuperPeak = Super Peak Credit, if any, specified in the Customer's CHWM Contract, Exhibit A, section 9, in kilowatts

If the Demand Charge billing determinant calculation results in a value less than zero, the billing determinant is deemed to be zero.

If a Customer purchases Secondary Crediting Service, the Demand billing determinant may be adjusted pursuant to GRSP II.P.2.

2.1.3 Load Shaping Charge

The Load Shaping Charge is applicable to Customers that purchase the following products: Load Following, Block, and the Block portion of Slice/Block. In any diurnal period, the Load Shaping Charge may be a charge or a credit, depending upon whether the Load Shaping billing determinant is positive or negative.

2.1.3.1 Load Shaping Rate

<i>Month</i>	<i>Rate in mills/kWh</i>	
	<i>Diurnal Period:</i>	
	<i>HLH</i>	<i>LLH</i>
October	37.86	31.20
November	38.37	31.40
December	41.10	33.39
January	40.03	31.70
February	40.93	33.17
March	39.57	32.33
April	37.53	30.41
May	35.06	24.40
June	35.97	23.02
July	42.07	29.91
August	44.35	32.15
September	43.45	33.59

2.1.3.2 Load Shaping Billing Determinant

The Load Shaping billing determinant for each of the two diurnal periods, HLH and LLH, for each month equals:

$$\begin{aligned}
 &\text{Customer's Actual Monthly/Diurnal Tier 1 Load,} \\
 &\quad \text{in kilowatthours} \\
 &\quad \textit{Minus} \\
 &\text{Customer's System Shaped Load for the relevant diurnal period,} \\
 &\quad \text{in kilowatthours}
 \end{aligned}$$

If a Customer purchases Secondary Crediting Service (SCS), the Load Shaping billing determinant may be adjusted pursuant to GRSP II.P.2.

2.1.3.2.1 System Shaped Load

A System Shaped Load is calculated for each diurnal period of each month. The Customer's System Shaped Load for each diurnal period equals:

$$RT1SC \times TOCA$$

Where:

RT1SC = RHWMTier 1 System Capability for the relevant diurnal period, in kilowatthours. The RT1SC for each diurnal period of the Rate Period is specified in GRSP II.Q.

TOCA = The effective TOCA for a Load Following or Block Customer, or the effective Non-Slice TOCA for a Slice/Block Customer, expressed as a percent. The TOCA used in this System Shaped Load calculation shall reflect a Customer's Adjusted TOCA pursuant to GRSP II.T.

2.1.3.2.2 Joint Operating Entity (JOE)

For calculating the Load Shaping Charge billing determinant for a Joint Operating Entity (JOE), the sum of the Actual Monthly/Diurnal Tier 1 Loads of the JOE's individual members and the sum of System Shaped Loads of the JOE's individual members shall be used.

2.2 Tier 2 Charges

2.2.1 Short-Term Charge

The Short-Term Charge is applicable to Customers that have elected to purchase power at the Tier 2 Short-Term Rate, as specified in the Customer's CHWM Contract, Exhibit C, section 2.5.2.

2.2.1.1 Short-Term Rate

<i>FY</i>	<i>Rate in mills/kWh</i>
2012	46.48
2013	48.69

2.2.1.2 Short-Term Billing Determinant

The billing determinant is the annual amount of power specified in the Customer's CHWM Contract. For the relevant billing month, the contract amount shall be converted from average megawatts to kilowatthours assuming a Flat Annual Shape.

2.2.2 Load Growth Charge

The Load Growth Charge is applicable to Customers that have elected to purchase power at the Tier 2 Load Growth Rate, as specified in the Customer's CHWM Contract, Exhibit C, section 2.5.2.

2.2.2.1 Load Growth Rate

<i>FY</i>	<i>Rate in mills/kWh</i>
2012	N/A
2013	48.63

N/A = Not Applicable

2.2.2.2 Load Growth Billing Determinant

The billing determinant is the annual amount of power specified in the Customer's CHWM Contract. For the relevant billing month, the contract amount shall be converted from average megawatts to kilowatthours assuming a Flat Annual Shape.

3 Priority Firm Melded Rate

The PF Melded Rate is applicable to the sale of Firm Requirements Power under contracts other than CHWM Contracts.

Rates under contracts that contain charges that escalate based on BPA's PF rate shall be based on the rates listed in this section in addition to any applicable transmission and ancillary service charges.

The PF Melded Rate is not available to loads that are considered unanticipated loads as defined in Unanticipated Load Service, GRSP II.U.1.

3.1 Energy Charge

3.1.1 Energy Rate

<i>Month</i>	<i>Rate in mills/kWh</i>	
	<i>Diurnal Period:</i>	
	<i>HLH</i>	<i>LLH</i>
October	31.04	24.38
November	31.55	24.58
December	34.28	26.57
January	33.21	24.88
February	34.11	26.35
March	32.75	25.51
April	30.71	23.59
May	28.24	17.58
June	29.15	16.2
July	35.25	23.09
August	37.53	25.33
September	36.63	26.77

3.1.2 Energy Billing Determinant

The Energy billing determinant is the total of the hourly loads, as specified in the Customer's contract, for each diurnal period, in kilowatthours.

3.2 Demand Charge

3.2.1 Demand Rate

<i>Month</i>	<i>Rate in \$/kW</i>
October	9.18
November	9.31
December	9.97
January	9.70
February	9.92
March	9.60
April	9.10
May	8.50
June	8.72
July	10.20
August	10.75
September	10.53

3.2.2 Demand Billing Determinant

The Demand billing determinant is the maximum hourly load, as specified in the Customer's contract, during the HLH of the month, in kilowatts, less the average of the hourly loads during the HLH of the month, in kilowatts.

4 Unanticipated Load Rate

The Unanticipated Load Rate is applicable to the sale of Firm Requirements Power to serve unanticipated loads. The billing determinant for an unanticipated load and the applicable rates are specified in Unanticipated Load Service, GRSP II.U.1.

5 Resource Support Services Rates

Resource Support Services rates are applicable to Customers that elect to take Diurnal Flattening Service or Secondary Crediting Service for non-Federal resources. The Resource Shaping Charge and Adjustment are applicable to Customers that elect this option to financially convert the output of certain types of non-Federal resources to a flat annual block of power as specified in their CHWM Contract.

5.1 Diurnal Flattening Service (DFS)

Customers that have elected to take DFS for their non-Federal resources are subject to the DFS Energy and Capacity Charges, specified in GRSP II.P.1.

5.2 Resource Shaping Charge and Adjustment

Customers that have elected to take this option for their new resources, other than small non-dispatchable resources, are subject to the Resource Shaping Charge and Adjustment, specified in GRSP II.P.1.

5.3 Secondary Crediting Service (SCS)

Customers that have elected to take SCS for their non-Federal resources are subject to the SCS Shortfall Energy Charge, SCS Secondary Energy Charge, and SCS Administrative Charge, specified in GRSP II.P.2.

6 Priority Firm Exchange Rate

The PF Exchange Rate applies to sales of Residential Exchange Program Power under a Residential Purchase and Sale Agreement or Residential Exchange Program Settlement Implementation Agreement.

6.1. Energy Rate

A utility-specific PF Exchange rate is calculated for each utility purchasing Residential Exchange Program Power. For investor-owned utilities, the PF Exchange rate equals the Base PF Exchange Rate plus a utility-specific 7(b)(3) Surcharge. For consumer-

owned utilities, the PF Exchange rate equals the Base Tier 1 PF Exchange Rate plus a utility-specific 7(b)(3) Surcharge.

	<i>Rates in mills/kWh</i>		
	<i>Base PF Exchange Rates</i>	<i>7(b)(3) Surcharge</i>	<i>PF Exchange Rates</i>
<i>Investor-Owned Utilities</i>			
Avista	43.06	11.37	54.429
Idaho Power	43.06	3.23	46.282
NorthWestern	43.06	7.75	50.809
PacifiCorp	43.06	13.80	56.858
Portland General	43.06	18.79	61.842
Puget Sound Energy	43.06	16.78	59.833
<i>Consumer-Owned Utilities</i>	<i>Base Tier 1 PF Exchange Rates</i>	<i>7(b)(3) Surcharge</i>	<i>PF Exchange Rates</i>
Clark Public Utilities	43.03	10.73	53.76
Snohomish PUD	43.03	2.38	45.41

6.1.1 7(b)(3) Surcharge for Non-Listed Utilities

For eligible Customers not listed in section 6.1, the applicable 7(b)(3) Surcharge will equal the Customer’s Average System Cost minus the applicable Base PF Exchange rate. The Customer’s Average System Cost will be determined pursuant to BPA’s 2008 Average System Cost Methodology.

6.2 Energy Billing Determinant

The billing determinant for the PF Exchange Power charge is the Customer’s Residential Load specified in GRSP II.N.

7 Adjustments, Charges and Special Rate Provisions

Adjustments, charges and special rate provisions are applicable to PF rates as shown in the following table.

<i>GRSP II.</i>	<i>Adjustments, Charges and Special Rate Provisions</i>	<i>Applicable to:</i>				<i>REP</i>
		<i>Firm Requirements</i>				
		<i>Load Following</i>	<i>Block only and Block Portion of Slice/Block</i>	<i>Slice Portion of Slice/Block</i>		
<i>A</i>	Conservation Surcharge	X	X	X		
<i>B</i>	Cost Contributions	X	X			
<i>C</i>	Cost Recovery Adjustment Clause (CRAC)	X	X			
<i>D</i>	Dividend Distribution Clause (DDC)	X	X			
<i>G</i>	Flexible Priority Firm Power (PF) Rate Option	X	X			
<i>H</i>	Irrigation Rate Discount	X	X	X		
<i>I</i>	Load Shaping Charge Adjustment	X	X			
<i>J</i>	Low Density Discount (LDD)	X	X	X		
<i>K</i>	NFB Mechanisms	X	X			
<i>L</i>	Priority Firm Power (PF) Shaping Option	X	X			
<i>N</i>	Residential Load				X	
<i>O</i>	7(b)(3) Surcharge Adjustment				X	
<i>P</i>	Resource Support Services and Transmission Scheduling Service	X	X	X		
<i>Q</i>	RHWM Tier 1 System Capability (RT1SC)	X	X			
<i>R</i>	Slice True-Up Adjustment			X		
<i>S</i>	Tier 2 Rate TCMS Adjustment	X				
<i>T</i>	TOCA Adjustment	X	X			
<i>U</i>	Unanticipated Load Service	X	X			
<i>V</i>	Unauthorized Increase (UAI) Charge	X	X	X	X	

SCHEDULE NR-12 NEW RESOURCE FIRM POWER RATE

1 Availability

This schedule is available for the contract purchase of firm power to be used within the Pacific Northwest. New Resource Firm Power (NR) is available to investor-owned utilities under Northwest Power Act section 5(b) requirements contracts for resale to ultimate consumers, for direct consumption, and for Construction, Test and Start-Up, and Station Service. New Resources Firm Power also is available to any public body, cooperative, or Federal agency to the extent such power is used to serve any new large single load (NLSL), as defined by the Northwest Power Act.

Transmission and ancillary services for use of the Federal Columbia River Transmission System facilities shall be charged separately under the applicable rate schedules.

Effective October 1, 2011, this rate schedule supersedes the NR-10 rate schedule. Sales under the NR-12 rate schedule are subject to the General Rate Schedule Provisions (GRSPs). For sales under this rate schedule, bills shall be rendered and payments due pursuant to the GRSPs and billing process.

2 New Resource Rates

2.1 Energy Charge

2.1.1 Energy Rate

<i>Month</i>	<i>Rate in mills/kWh</i>	
	<i>Diurnal Period:</i>	
	<i>HLH</i>	<i>LLH</i>
October	71.70	65.04
November	72.21	65.24
December	74.94	67.23
January	73.87	65.54
February	74.77	67.01
March	73.41	66.17
April	71.37	64.25
May	68.90	58.24
June	69.81	56.86
July	75.91	63.75
August	78.19	65.99
September	77.29	67.43

2.1.1.1 REP Surcharge

Each energy rate in the table above reflects a REP Surcharge of 7.72 mills/kWh.

2.1.2 Energy Billing Determinant

The billing determinant is the total of NR Hourly Loads for each diurnal period.

2.2 Demand Charge

2.2.1 Demand Rate

<i>Month</i>	<i>Rate in \$/kW</i>
October	9.18
November	9.31
December	9.97
January	9.70
February	9.92
March	9.60
April	9.10
May	8.50
June	8.72
July	10.20
August	10.75
September	10.53

2.2.2 Demand Billing Determinant

The billing determinant is the highest NR Hourly Load during HLH, in kilowatts, for the billing period minus the average of the NR Hourly Load during the HLH, in kilowatts.

3 Unanticipated Load Rate

The Unanticipated Load Rate is applicable to the sale of Firm Requirements Power to serve unanticipated loads. The billing determinant for an unanticipated load and the applicable rates are specified in GRSP II.U.3.

4 Adjustments, Charges, and Special Rate Provisions

Adjustments, charges, and special rate provisions are applicable as shown in the following table.

<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>GRSP II.</i>
Conservation Surcharge	A
Cost Contributions	B
Cost Recovery Adjustment Clause (CRAC)	C
Dividend Distribution Clause (DDC)	D
Flexible New Resource Firm Power (NR) Rate Option	F
Low Density Discount (LDD)	J
NFB Mechanisms	K
Unanticipated Load Service	U
Unauthorized Increase (UAI) Charge	V

SCHEDULE IP-12 INDUSTRIAL FIRM POWER RATE

1 Availability

This schedule is available to BPA’s direct service industrial Customers (DSIs), as defined by the Northwest Power Act, for firm power to be used in their industrial operations in the Pacific Northwest. Industrial Firm Power (IP) is available under Northwest Power Act section 5(d) contracts to DSIs for direct consumption.

Transmission and ancillary services for use of the Federal Columbia River Transmission System facilities shall be charged separately under the applicable rate schedules.

Effective October 1, 2011, this rate schedule supersedes the IP-10 rate schedule. Sales under the IP-12 rate schedule are subject to the General Rate Schedule Provisions (GRSPs). For sales under this rate schedule, bills shall be rendered and payments due pursuant to the GRSPs and billing process.

DSIs purchasing power pursuant to the IP-12 rate schedule shall be required to provide the Minimum DSI Operating Reserve – Supplemental.

2 Industrial Firm Rates

2.1 Energy Charge

2.1.1 Energy Rates

<i>Month</i>	<i>Rate in mills/kWh</i>	
	<i>Diurnal Period:</i>	
	<i>HLH</i>	<i>LLH</i>
October	38.51	31.85
November	39.02	32.05
December	41.75	34.04
January	40.68	32.35
February	41.58	33.82
March	40.22	32.98
April	38.18	31.06
May	35.71	25.05
June	36.62	23.67
July	42.72	30.56
August	45.00	32.80
September	44.10	34.24

2.1.1.1 REP Surcharge

Each energy rate in the table above reflects a REP Surcharge of 7.72 mills/kWh.

2.1.1.2 Value of Reserves Credit

Each energy rate in the table above reflects a 0.94 mill/kWh credit for the value of the Minimum DSI Operating Reserve – Supplemental.

2.1.2 Energy Billing Determinant

The energy billing is the Energy Entitlement that is specified in the Customer's contract.

2.2 Demand Charge

2.2.1 Demand Rate

<i>Month</i>	<i>Rate in \$/kW</i>
October	9.18
November	9.31
December	9.97
January	9.70
February	9.92
March	9.60
April	9.10
May	8.50
June	8.72
July	10.20
August	10.75
September	10.53

2.2.2 Demand Billing Determinant

The billing determinant is the Customer's maximum schedule amount during HLH, in kilowatts, for the billing period minus the average of the Customer's monthly schedule amount during the HLH, minus the Industrial Demand Adjuster, if any, in kilowatts.

Port Townsend Paper Corporation's Industrial Demand Adjuster values are specified in the table below.

<i>Month</i>	<i>Industrial Demand Adjuster (kW)</i>
October	3,495
November	2,811
December	1,982
January	1,741
February	1,905
March	2,730
April	1,358
May	1,916
June	1,304
July	1,354
August	1,542
September	1,249

In the event Port Townsend’s historical Contract Demand (20.5 MW) is reduced in part or in all by BPA due to the transfer of service to a BPA preference customer the Industrial Demand Adjuster values in the above table will be reduced proportionally.

3 Adjustments, Charges and Special Rate Provisions

Adjustments, charges, and special rate provisions are applicable as shown in the following table.

<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>GRSP II.</i>
Conservation Surcharge	A
Cost Contributions	B
Cost Recovery Adjustment Clause (CRAC)	C
Dividend Distribution Clause (DDC)	D
DSI Reserves Adjustment	E
NFB Mechanisms	K
Unauthorized Increase (UAI) Charge	V

FPS-12

FIRM POWER PRODUCTS AND SERVICES RATE

1 Availability

This rate schedule is available for the purchase of Firm Power, Capacity Without Energy, Supplemental Control Area Services, Shaping Services, Reservation and Rights to Change Services, Reassignment or Remarketing of Surplus Transmission Capacity, Services for Non-Federal Resources, and Unanticipated Load Service for use inside and outside the Pacific Northwest.

Sales under this rate schedule are discretionary. BPA is not obligated to sell any of these products, even if such sales will not displace PF, NR, or IP sales. Ancillary Services needed for transmission service over Federal Columbia River Transmission System facilities shall be charged separately under the applicable transmission rate schedule.

Effective October 1, 2011, this rate schedule supersedes the FPS-10 rate schedule. Sales under the FPS-12 rate schedule are subject to the General Rate Schedule Provisions (GRSPs). For sales under this rate schedule, bills shall be rendered and payments due pursuant to the GRSPs and billing process.

2 Firm Power and Capacity Without Energy

2.1 Flexible Rate

Demand and/or energy charges shall be as specified by BPA or as mutually agreed by BPA and the Customer. Billing determinants shall be Contract Demand and Contract Energy unless otherwise agreed by BPA and the Customer.

2.2 Adjustments, Charges, and Special Rate Provisions

Adjustments, charges, and special rate provisions are described in the 2012 GRSPs. Relevant sections are identified below.

<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>GRSP II.</i>
Cost Contributions	B
Unauthorized Increase (UAI) Charge	V

3 Supplemental Control Area Services

3.1 Rates and Billing Determinants

The charge for Supplemental Control Area Services shall be the applicable rate(s) times the applicable billing determinant(s), pursuant to the agreement between BPA and the Customer.

The rate(s) and billing determinant(s) for Supplemental Control Area Services shall be as established by BPA or as mutually agreed by BPA and the Customer.

3.2 Adjustments, Charges, and Special Rate Provisions

Adjustments, charges, and special rate provisions are described in the 2012 GRSPs. Relevant sections are identified below.

<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>GRSP II.</i>
Cost Contributions	B
Unauthorized Increase (UAI) Charge	V

4 Shaping Services

4.1 Rates and Billing Determinants

The charge for Shaping Services shall be the applicable rate(s) times the applicable billing determinant(s), pursuant to the agreement between BPA and the Customer.

The rate(s) and billing determinant(s) for use of Shaping Services shall be as established by BPA or as mutually agreed by BPA and the Customer.

4.2 Adjustments, Charges, and Special Rate Provisions

Adjustments, charges, and special rate provisions are described in the 2012 GRSPs. Relevant sections are identified below.

<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>GRSP II.</i>
Cost Contributions	B
Unauthorized Increase (UAI) Charge	V

5 Reservations and Rights to Change Services

5.1 Rates and Billing Determinants

The charge for Reservation and Rights to Change Services shall be the applicable rate(s) times the applicable billing determinant(s), pursuant to the agreement between BPA and the Customer.

The rate(s) and billing determinant(s) for Reservation and Rights to Change Services shall be as established by BPA or as mutually agreed by BPA and the Customer.

5.2 Adjustments, Charges, and Special Rate Provisions

There are no additional adjustments, charges, or special rate provisions for the Reservation and Rights to Change Services.

6 Reassignment or Remarketing of Surplus Transmission Capacity

Power Services may reassign or remarket surplus transmission capacity that it has reserved for its own use consistent with the terms of the transmission provider's Open Access Transmission Tariff (OATT).

6.1 Rates and Billing Determinants

The charges for Reassignment or Remarketing of Surplus Transmission Capacity shall be the applicable rate(s) times the applicable billing determinant(s), pursuant to the agreement between BPA and the Customer.

The rate(s) and billing determinant(s) for Reassignment or Remarketing of Surplus Transmission Capacity shall be as established by BPA or as mutually agreed to by BPA and the Customer.

6.2 Adjustments, Charges, and Special Rate Provisions

There are no additional adjustments, charges, or special rate provisions for the Reassignment or Remarketing of Surplus Transmission Capacity.

7 Services for Non-Federal Resources

7.1 Transmission Scheduling Service/Transmission Curtailment Management Service (TSS/TCMS)

Customers that have elected to take TSS/TCMS for their non-Federal resources are subject to the TSS and TCMS Charges specified in GRSP II.P.4, Resource Support Services and Transmission Scheduling Service.

7.2 Forced Outage Reserve Service (FORS)

Customers that have elected to take FORS for their non-Federal resources are subject to the FORS Energy and Capacity Charges specified in GRSP II.P.3.

8 Unanticipated Load Service

The Unanticipated Load Service is applicable to the sale of firm power to serve unanticipated loads resulting from a request for service under section 9(i) of the Northwest Power Act. The billing determinant for an unanticipated load and the applicable rates are specified in GRSP II.U.4.

GTA-12
GENERAL TRANSFER AGREEMENT SERVICE RATE

1 Availability

This schedule applies to BPA Power Service Customers that are served under General Transfer Agreements (GTAs) or other non-Federal transmission service agreements.

2 GTA Delivery Charge

The GTA Delivery Charge is a BPA Power Services charge for low-voltage delivery service of Federal power provided under General Transfer Agreements (GTAs) or other non-Federal transmission service agreements. The GTA Delivery Charge shall apply to Customers that purchase Federal power that is delivered over non-Federal low-voltage transmission facilities.

1.1 Rate

	<i>Rate in \$/kW</i>
All months	1.119

1.2 Billing Determinant

The monthly billing determinant for the GTA Delivery rate shall be the total load on the hour of the Monthly Transmission Peak Load at the low voltage Points of Delivery provided for in GTA and other non-Federal transmission service arrangements.

At those Points of Delivery that do not have meters capable of determining the demand on the hour of the Monthly Transmission Peak Load, the billing determinant shall equal the highest hourly demand that occurs during the billing month at the Point of Delivery, multiplied by 0.79.

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 (also known as Balancing Authority Area) and metered flow into BPA’s Control Area.

3 Transfer Service Operating Reserve Charge

Power Services Customers served by GTAs or other non-Federal transmission service agreements (hereafter “by transfer”) will be subject to the Transfer Service Operating Reserve Charge at such time that Transmission Services implements the WECC proposed reliability standard, BAL-002-WECC-1, regarding operating reserve (hereafter “the 3 and 3 reliability standard”). At such time, the Transfer Service Operating Reserve Charge will apply to power Customers that meet the following criteria: (1) Power Services serves the

Customer by transfer; (2) the power Customer does not pay Transmission Services for operating reserve based on the 3 and 3 reliability standard for the Customer's load; and (3) Power Services is assessed operating reserve charges by a third-party transmission provider for service to the power Customer's load.

2.1 Rate

- 2.1.1 The rate for the Transfer Service Spinning Operating Reserve Charge shall be equal to the ACS-12 Operating Reserve – Spinning Reserve Service rate.
- 2.1.2 The rate for the Transfer Service Supplemental Operating Reserve Charge shall be equal to the ACS-12 Operating Reserve – Supplemental Reserve Service rate.

2.2 Billing Determinant

- 2.2.1 The monthly billing determinant for the Transfer Service Spinning Operating Reserve Charge shall be the same as that used for the ACS-12 Operating Reserve – Spinning Reserve Service except that the load used to calculate the billing determinant for Power Services charges will be the load of the Customer served by transfer.
- 2.2.2 The monthly billing determinant for the Transfer Service Supplemental Operating Reserve Charge shall be the same as that used for the ACS-12 Operating Reserve – Supplemental Reserve Service except that the load used to calculate the billing determinant for Power Services charges will be the load of the Customer served by transfer.

GENERAL RATE SCHEDULE PROVISIONS

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GENERAL RATE SCHEDULE PROVISIONS (GRSPs)

SECTION I. ADOPTION OF REVISED POWER RATE SCHEDULES AND GENERAL RATE SCHEDULE PROVISIONS

A. Approval of Rates

The Power Rate Schedules and these General Rate Schedule Provisions (GRSPs) shall become effective upon interim approval or upon final confirmation and approval by the Federal Energy Regulatory Commission (Commission). BPA will request that the Commission make these rates and GRSPs effective on October 1, 2011. All rate schedules shall remain in effect until they are replaced or expire on their own terms.

B. General Provisions

The Power Rate Schedules and GRSPs associated with the schedules supersede BPA's 2010 Power Rate Schedules, which became effective October 1, 2009, to the extent stated in the Availability Section of each rate schedule. The schedules and these GRSPs shall be applicable to all BPA contracts, including contracts executed 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, the Regional Preference Act (P.L. 88-552), the Transmission System Act (P.L. 93-454), the Northwest Power Act (P.L. 96-501), and the Energy Policy Act of 1992 (P.L. 102-486).

The 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. Payment Provisions

Payment must be received by the 20th day after the issue date of the bill (Due Date). If the 20th day is a Saturday, Sunday, or Federal holiday, the Due Date is the next business day. After the Due Date, a late payment charge equal to the higher of (1) the Prime Rate (as reported in the Wall Street Journal or successor publication in the first issue published during the month in which payment was due) plus four percent, divided by 365; or (2) the Prime Rate times 1.5, divided by 365, shall be applied each day to any unpaid balance. The applicable "Prime Rate" shall be the rate reported on the first day of the month in which payment is received. The Customer shall pay by electronic funds transfer using BPA's established procedures.

D. 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.

E. Supplemental Guidelines for Direct Assignment of Facilities Costs Incurred Under Transfer Agreements

BPA will use this set of Supplemental Guidelines to assign costs to Transfer Service customers. Such costs are comparable to the costs purchasers of Transfer Services would incur if such purchasers were directly connected to the BPA transmission system.

This set of Supplemental Guidelines augments the BPA Transmission Services “Direct Assignment Facilities Guidelines,” as amended or superseded (Transmission Services Guidelines), currently posted at:

http://transmission.bpa.gov/ts_business_practices/

In determining whether to directly assign to a Transfer Customer costs incurred by BPA in providing transfer service to the customer, BPA will apply the current Transmission Services Guidelines and these Supplemental Guidelines. The Supplemental Guidelines apply only to transfer service acquired by BPA from third-party transmission providers for service to Preference Customers. The Supplemental Guidelines use some terms defined in the 20-year Agreement Regarding Transfer Service (ARTS). Also, Direct Assignment Facilities, as defined in most pro forma Open-Access Transmission Tariffs (OATT), are:

Facilities or portions of facilities that are constructed by the Transmission Provider for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer....

These Supplemental Guidelines are designed to supplement, not replace, the Transmission Service Guidelines and to assist in predicting how BPA, as the default transmission customer for transfer arrangements, will recover costs for Direct Assignment Facilities assessed by third-party transmission providers. Unless otherwise specifically excluded in the Transmission Services Guidelines or below, the cost of Direct Assignment Facilities will be passed through to the customer.

Supplemental Guideline Regarding Voltages below 34.5 kV

For new facilities or new service over existing third-party transmission provider facilities at voltages below 34.5 kV that meet the definition of Direct Assignment Facilities, metered quantities for customer deliveries will be adjusted for losses to the point where the voltage is at or above 34.5 kV, such that BPA is not responsible for losses across such facilities. Loss calculations should be similar whether the customer

or the transmission provider owns the delivery facilities. *Note:* The cut-off voltage of 34.5 kV is used in the Transmission Services Guidelines. If this voltage level is changed in the Transmission Services Guidelines, these Supplemental Guidelines will be deemed modified.

Supplemental Guidelines Regarding Replacement with Higher Capacity Facility or Addition of a Transformer in Parallel

Pursuant to the Transmission Services Guidelines, for a new transmission provider-owned facility that also adds capacity, the costs that exceed the cost of replacing the previous capacity may be directly assigned to the benefiting customer. Alternatively, BPA and the customer may agree to full direct assignment in lieu of payment of the GTA Delivery Charge. Similarly, when a parallel transformer is added, BPA and the customer may agree to a simplified direct assignment of all delivery costs in lieu of some combination of Delivery Charge and direct assignment.

Supplemental Guidelines Regarding Construction Option

The customer may work directly with the third-party transmission provider to develop and select among options regarding construction, cost sharing, and ownership. BPA will work with the customer and the transmission provider to arrive at the best one-utility plan, workable cost-sharing options, equitable ownership, and interconnection arrangements. Due to regulatory issues, it is Power Services' policy not to own facilities.

Additional Guidelines:

Rolled-in Rate Treatment by Transmission Provider

If a customer receives new Transfer Service over new or pre-existing facilities below 34.5 kV offered by the transfer provider under a rolled-in rate or revenue requirement, BPA reserves the right to assess the GTA Delivery Charge. BPA will not assess the GTA Delivery Charge for a new point of delivery (POD) if specific facilities' costs are not rolled in but are directly assigned to BPA and in turn passed through to the customer.

Wholesale Distribution Facilities Beyond the Step-Down Substation

On any new arrangement for delivery below 34.5 kV (new or pre-existing facilities), the incremental cost for use of any facilities (other than potential transformers or current transformers for revenue metering) beyond the fence of the corresponding step-down transformer substation (or beyond a 20-foot radius of the step-down, for pole-top substations) shall be passed through to the customer, whether such costs are directly assigned to BPA or are imposed pursuant to a discrete wholesale distribution rate or Load Ratio Share of a discrete wholesale distribution revenue requirement.

Customer Arrangements Directly with the Third-Party Transmission Provider

A customer may, in lieu of paying the GTA Delivery Charge, choose to contract directly with the third-party transmission provider for delivery below 34.5 kV for an existing POD, but must then do so for all similar PODs with that transmission provider. The customer must take delivery from BPA at or above 34.5 kV for these PODs such that the customer is responsible for costs of and losses through the delivering facilities. A customer contracting with the third party for a new POD does not create a requirement that the customer contract with the third party for its pre-existing low voltage PODs.

F. Metering Usage Data Estimation Provision

Pursuant to section 15.1 of the CHWM Contract for the Load Following product, BPA shall apply the Meter Usage Data Estimations procedures posted on the BPA Metering Web site.

SECTION II. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

A. Conservation Surcharge

The Conservation Surcharge, if implemented, shall be applied in accordance with relevant provisions of the Northwest Power Act, BPA's current Conservation Surcharge policy, and the Customer's power sales contract with BPA. The Conservation Surcharge applies to the PF-12 (including Slice purchasers), IP-12, and NR-12 rate schedules.

B. Cost Contributions

Pursuant to section 7(j) of the Northwest Power Act, BPA has made the following resource cost determinations:

1. The approximate cost contribution of different resource categories to each rate schedule is:

Table A
Resource Cost Contribution

<i>Rate Schedule</i>	<i>Federal Base System</i>	<i>Exchange Resources</i>	<i>New Resources</i>
PF	44.77%	55.23%	0%
IP	0%	67.89%	32.11%
NR	0%	67.89%	32.11%
FPS	0%	67.89%	32.11%

2. The cost of resources acquired to meet load growth within the region is estimated to be 47.93 mills/kWh, and the forecast average cost of resources available to BPA under average water conditions is 42.52 mills/kWh.

C. Cost Recovery Adjustment Clause (CRAC)

The CRAC is an upward adjustment to certain rates that can apply to rates during FY 2012 or FY 2013 or both. It applies to these Power rates:

- Non-Slice Customer rate (PF-12);
- PF Melded rate (PF-12);
- Industrial Firm Power rate (IP-12); and
- New Resource Firm Power rate (NR-12).

The CRAC also applies to these Transmission rates:

- Reserves-based Ancillary and Control Area Services (ACS-12) rates.

1. Calculations for the Cost Recovery Adjustment Clause

Prior to the beginning of each fiscal year of the rate period (that is, each “applicable year”), BPA will forecast the end-of-year Accumulated Net Revenue (ANR) for the fiscal year preceding the applicable year. If the forecast ANR is less than the CRAC Threshold for that applicable year by at least \$5 million, the CRAC will trigger, and a rate increase will go into effect beginning on October 1 of the applicable year.

(a) Calculating the CRAC Amount

The CRAC Amount is based on the Underrun, which is equal to the CRAC Threshold minus forecast ANR. There are four possibilities:

- (1) If the Underrun is less \$5 million there is no CRAC.
- (2) If the Underrun is greater than or equal to \$5 million and less than or equal to \$100 million, the CRAC Amount is equal to the Underrun.
- (3) If the Underrun is greater than \$100 million and less than \$500 million, the CRAC Amount is equal to \$100 million plus one-half of the difference between \$100 million and the Underrun.
- (4) If the Underrun is greater than or equal to \$500 million, the CRAC Amount is equal to \$300 million.

NOTE: In cases 3 and 4 above, if an NFB Adjustment increases the CRAC Cap from \$300 million to a higher number, the terms will be adjusted. In cases 3 and 4, the “\$500 million” figure will be replaced by \$500 million plus twice the difference between the new Cap and \$300 million. In case 4, the “\$300 million” figure will be replaced by the new Cap.

The CRAC Cap and thresholds are shown in Table B.

Table B: CRAC Annual Thresholds and Caps
(dollars in millions)

<i>ANR Calculated near End of Fiscal Year</i>	<i>CRAC Applied to Fiscal Year</i>	<i>CRAC Threshold Measured in ANR</i>	<i>Approx. Threshold as Measured in Power Services Reserves for Risk</i>	<i>Maximum CRAC Recovery Amount (Cap)*</i>
2011	2012	(\$187.6)	\$0	\$300
2012	2013	(\$143.4)	\$0	\$300

* The Maximum CRAC Recovery Amount (Cap) may be modified by the NFB Adjustment (if triggered).

Where:

CRAC Amount is the additional net revenue that an increase in rates, due to the CRAC, is intended to generate during the year of application.

CRAC Threshold is the “trigger point” for invoking a rate increase under the CRAC.

ANR is Accumulated Net Revenue for the generation function, as accumulated since the end of FY 2010. A forecast of ANR is used to determine whether the CRAC Threshold has been reached, and if so, the required CRAC Amount to be collected. The forecast of ANR for use in determining the CRAC that will apply to FY 2012 rates will be the forecast of PS Net Revenue for FY 2011. The forecast of ANR for use in determining the CRAC that will apply to FY 2013 rates will be the sum of the PS Net Revenue for FY 2011 plus the forecast of PS Net Revenue for FY 2012.

PS Net Revenue for any given fiscal year is defined as generation function accrued revenue less accrued expenses (in accordance with Generally Accepted Accounting Principles).

Maximum CRAC Recovery Amount (Cap) is the maximum annual amount that is allowed to be recovered through the CRAC.

(b) Calculating the PF/IP/NR CRAC Amount and the ACS CRAC Amount

The PF/IP/NR CRAC Amount is 96.4% times the CRAC Amount.

The ACS CRAC Amount is 3.6% times the CRAC Amount.

(c) Converting the PF/IP/NR CRAC Amount to the PF/IP/NR CRAC Surcharge

Once the PF/IP/NR CRAC Amount is determined, that amount will be converted to a mills per kilowatthour Surcharge rate added to each of the monthly/diurnal PF Melded, IP, and NR energy rates. The Surcharge rate will be converted to a monthly dollars per one percentage point of Non-Slice TOCA value and added to the Non-Slice Customer Rate.

The PF/IP/NR CRAC Surcharge rate is calculated by dividing the PF/IP/NR CRAC Amount by the most current forecast of kilowatthours of service under PF Melded, IP, and NR rates and the sum of PF System Shaped Loads for the applicable year.

The PF/IP/NR CRAC Surcharge rate is converted to a monthly dollars per one percentage point of Non-Slice TOCA by:

- (1) Multiplying the sum of PF System Shaped Loads by the PF/IP/NR CRAC Surcharge rate. The product of this calculation is the annual dollar amount to be collected through the Non-Slice TOCA billing determinant.

- (2) The annual dollar amount to be collected through the Non-Slice TOCA billing determinant will be divided by the sum of the Non-Slice TOCAs and divided again by 12.

The result of this calculation is a monthly dollars per one percentage point of Non-Slice TOCA rate adjustment.

(d) CRAC Charges for the PF, IP, and NR Rates

For service under PF Melded, IP, or NR rate: A line item will be added to the bills for the service during the 12 months of the applicable year showing additional charges calculated by multiplying the PF/IP/NR CRAC Surcharge by the applicable kilowatthours of service.

For service under Non-Slice Customer rate: A line item will be added to the bills for the service during the 12 months of the applicable year showing an additional charge calculated by multiplying the monthly dollars per one percentage point of Non-Slice TOCA rate adjustment by the Non-Slice TOCA.

(e) Converting the ACS CRAC Amount to Charges on Customers' Bills

Once the ACS CRAC Amount is determined, that amount will be passed to Transmission Services. See Transmission GRSP II.H. for details of how those Transmission rates subject to the CRAC will be modified.

(f) Other Rate Adjustments

The Surcharge rate, calculated pursuant to section 1(c), will be subtracted from the Load Shaping Charge True-up rate to create the CRAC-Adjusted Load Shaping True-up rate. See GRSP II.I.

The Surcharge rate, calculated pursuant to section 1(c), will be subtracted from the PF Melded Equivalent Energy Scalar to create the CRAC-Adjusted PF Melded Equivalent Energy Scalar. See GRSP II.R.

The Surcharge rate, calculated pursuant to section 1(c), will also be added to each of the monthly/diurnal PF Tier 1 Equivalent energy rates. See GRSP II.M.

2. CRAC Adjustment Timing

Prior to the beginning of each fiscal year in the rate period, the Administrator will calculate the ANR forecast for the end of that year; if that amount is below the CRAC Threshold, a CRAC rate adjustment will be made for the next fiscal year.

3. CRAC Notification Process

BPA shall follow these notification procedures:

(a) Financial Performance Status Reports

Each quarter, BPA shall post to its external Web site (www.bpa.gov) preliminary, unaudited, *year-to-date* aggregate financial results for the generation function, including ANR.

For the Second and Third Quarter Reviews, BPA shall post to its external Web site (www.bpa.gov) the preliminary, unaudited, *end-of-year* forecast of ANR attributable to the generation function.

(b) Notification of CRAC Trigger

BPA shall complete a forecast of end-of-year ANR in July of 2011 for use in calculating the CRAC applicable to rates in FY 2012 and in September 2012 for use in calculating the CRAC applicable to rates in FY 2013. If the forecast value of ANR is below the CRAC Threshold applicable to the following year by at least \$5 million, then BPA shall notify all Customers and rate case parties by late July 2011 of the amount by which BPA intends to adjust rates for FY 2012 due to the CRAC, and by late September 2012 of the amount by which BPA intends to adjust rates for FY 2013.

Notification will be posted on BPA's Web site and will include the forecast of ANR for the current fiscal year, the audited ANR for FY 2011 in the case of the CRAC applicable to FY 2013 rates, the CRAC Amount, the PF/IP/NR CRAC Amount, the PF/IP/NR Surcharge, the monthly dollars per one percentage point of Non-Slice TOCA rate adjustment, the CRAC-adjusted Load Shaping True-up rate, the CRAC-adjusted PF Melded Equivalent Energy Scalar, the ACS CRAC Amount, and details about how the ACS CRAC Amount has been used to modify Transmission rates for the subsequent fiscal year. The notification shall also describe the data and assumptions relied upon by BPA for all ANR determinations. BPA shall make such data, assumptions, and documentation, if non-proprietary and non-privileged, available for review upon request.

Associated with any notification as described above of CRAC calculations, BPA shall conduct a workshop(s) to explain the ANR calculations, describe the calculation of the CRAC Amount and allocations to various rates, and demonstrate that the CRAC has been implemented in accordance with these GRSPs. The workshop(s) will provide an opportunity for public comment.

The Administrator may exercise discretion and elect to reduce the CRAC rate adjustment provided (1) the resulting TPP for the remainder of the rate period is greater than or equal to BPA's TPP standard (95 percent for the FY 2012-2013 period in the case of the CRAC applicable to FY 2012 rates; 97.5 percent in the

case of the CRAC applicable to FY 2013 rates); and (2) the reduced CRAC will recover in the following year the first \$100 million of any use by BPA to pay Power bills of the Treasury Facility or reserves attributed to Transmission Services plus one-half of any use of the Treasury Facility or reserves attributed to Transmission Services beyond \$100 million, up to a maximum of the CRAC Cap as described above. In the case of the CRAC applicable to the FY 2012 rates, the Administrator may modify the parameters for the CRAC applicable to FY 2013 rates to meet the one-year TPP standard for FY 2013; criterion (2) above must still be met. If the Administrator so elects, the Customers shall be informed during the workshop.

If the CRAC applicable to FY 2012 rates triggers, then on or about July 31, 2011, BPA will post to the BPA Web site the final CRAC calculations, including any NFB Adjustment (see GRSP II.K) to the CRAC Cap. If the CRAC applicable to FY 2013 rates triggers, then on or about September 30, 2012, BPA will post to the BPA Web site the final CRAC calculations, including any NFB Adjustment (see GRSP II.K) to the CRAC Cap.

D. Dividend Distribution Clause (DDC)

The DDC is a downward adjustment to certain rates that can apply to rates during FY 2012 or FY 2013 or both. It applies to these Power rates:

- Non-Slice Customer rate (PF-12);
- PF Melded rate (PF-12);
- Industrial Firm Power rate (IP-12); and
- New Resource Firm Power rate (NR-12).

The DDC also applies to these Transmission rates:

- Reserves-based Ancillary and Control Area Services (ACS-12) rates.

1. Calculations for the Dividend Distribution Clause

Prior to the beginning of each fiscal year of the rate period (that is, each “applicable year”), BPA will forecast the end-of-year Accumulated Net Revenue (ANR) for the fiscal year preceding the applicable year. If the forecast ANR is greater than the DDC Threshold for that applicable year by at least \$5 million, the DDC will trigger, and a rate decrease will go into effect beginning on October 1 of the applicable year.

(a) Calculating the DDC Amount

The DDC Amount will be equal to either the forecast ANR less the DDC Threshold or \$1,000 million, whichever is smaller.

Table C: DDC Annual Thresholds and Cap
(Dollars in Millions)

<i>ANR Calculated near End of Fiscal Year</i>	<i>DDC Applied to Fiscal Year</i>	<i>DDC Threshold Measured in ANR</i>	<i>Approx. Threshold as Measured in Power Services Reserves for Risk</i>	<i>Maximum DDC Amount (Cap)</i>
2011	2012	\$562.4	\$750	\$1,000
2012	2013	\$606.6	\$750	\$1,000

Where:

DDC Amount is the reduction in net revenue that a decrease in rates, due to the DDC, is intended to generate during the year of application.

DDC Threshold is the “trigger point” for invoking a rate decrease under the DDC.

ANR is Accumulated Net Revenue for the generation function, as accumulated since the end of FY 2010. A forecast of ANR is used to determine whether the DDC Threshold has been reached, and if so, the required DDC Amount to be collected. The forecast of ANR for use in determining the DDC that will apply to FY 2012 rates will be the forecast of PS Net Revenue for FY 2011. The forecast of ANR for use in determining the DDC that will apply to FY 2013 rates will be the sum of the PS Net Revenue for FY 2011 plus the forecast of PS Net Revenue for FY 2012.

PS Net Revenue for any given fiscal year is defined as generation function accrued revenue less accrued expenses (in accordance with Generally Accepted Accounting Principles).

Maximum DDC Recovery Amount (Cap) is the maximum annual amount that is allowed to be distributed through the DDC.

(b) Calculating the PF/IP/NR DDC Amount and the ACS DDC Amount

The PF/IP/NR DDC Amount is 96.4% times the DDC Amount.

The ACS DDC Amount is 3.6% times the DDC Amount.

(c) Converting the PF/IP/NR DDC Amount to the PF/IP/NR DDC Credit

Once the PF/IP/NR DDC Amount is determined, that amount will be converted to a mills per kilowatthour PF/IP/NR DDC Credit rate and subtracted from each of the monthly/diurnal PF Melded, IP, and NR energy rates. The mills per kilowatthour PF/IP/NR DDC Credit will be converted to a monthly dollars per one percentage point of Non-Slice TOCA value and subtracted from the Non-Slice Customer Rate.

The PF/IP/NR DDC Credit rate is calculated by dividing the PF/IP/NR DDC Amount by the most current forecast of kilowatthours of service under PF Melded, IP, and NR rates and the sum of PF System Shaped Loads for the applicable year.

The PF/IP/NR DDC Credit rate is converted to a monthly dollars per one percentage point of Non-Slice TOCA by:

- (1) Multiplying the sum of PF System Shaped Loads by the PF/IP/NR DDC Credit rate. The product of this calculation is the annual dollar amount to be distributed through the Non-Slice TOCA billing determinant.
- (2) The annual dollar amount to be distributed through the Non-Slice TOCA billing determinant will be divided by the sum of the Non-Slice TOCAs and divided again by 12.

The result of this calculation is a monthly dollars per one percentage point of Non-Slice TOCA rate adjustment.

(d) DDC Credits for the PF, IP, and NR Rates

For service under PF Melded, IP, or NR rates: A line item will be added to the bills for the service during the 12 months of the applicable year showing credits calculated by multiplying the PF/IP/NR DDC Credit by the applicable kilowatthours of service.

For service under the PF Non-Slice Customer rate: A line item will be added to the bills for the service during the 12 months of the applicable year showing a credit calculated by multiplying the monthly dollars per one percentage point of Non-Slice TOCA rate adjustment by the Non-Slice TOCA.

(e) Converting the ACS DDC Amount to Charges on Customers' Bills

Once the ACS DDC Amount is determined, that amount will be passed to Transmission Services. See Transmission GRSP II.H for details of how those Transmission rates subject to the DDC will be modified.

(f) Other Rate Adjustments

The Credit rate, calculated pursuant to section 1(c), will be added to the Load Shaping True-up Rate to create the DDC-Adjusted Load Shaping True-up Rate. See GRSP II.I.

The Credit rate, calculated pursuant to section 1(c), will be added to the PFp Melded Equivalent Energy Scalar to create the DDC-Adjusted PF Melded Equivalent Energy Scalar. See GRSP II.R.

The Credit rate, calculated pursuant to section 1(c), will also be subtracted from each of the monthly/diurnal PF Tier 1 Equivalent energy rates. See GRSP II.M.

2. DDC Adjustment Timing

Prior to the beginning of each fiscal year in the rate period, the Administrator will calculate the ANR forecast for the end of that year; if that amount is above the DDC Threshold, a DDC rate adjustment will be made for the next fiscal year.

(a) DDC Notification Process

BPA shall follow these notification procedures:

(1) Financial Performance Status Reports

Each quarter, BPA shall post to its external Web site (www.bpa.gov) preliminary, unaudited, *year-to-date* aggregate financial results for the generation function, including ANR.

For the Second and Third Quarter Reviews, BPA shall post to its external Web site (www.bpa.gov) the preliminary, unaudited, *end-of-year* forecast of ANR attributable to the generation function.

(2) Notification of DDC Trigger

BPA shall complete a forecast of end-of-year ANR in July of 2011 for use in calculating the DDC applicable to rates in FY 2012 and in September 2012 for use in calculating the DDC applicable to rates in FY 2013. If the forecast value of ANR is above the DDC Threshold applicable to the following year by at least \$5 million, then BPA shall notify all Customers and rate case parties by late July 2011 of the amount by which BPA intends to adjust rates for FY 2012 due to the DDC, and by late September 2012 of the amount by which BPA intends to adjust rates for FY 2013.

Notification will be posted on BPA's Web site and will include the forecast of ANR for the current fiscal year, the audited ANR for FY 2011 in the case of the DDC applicable to FY 2013 rates, the DDC Amount, the PF/IP/NR DDC Amount, the PF/IP/NR Surcharge, the monthly dollars per one percentage point of Non-Slice TOCA rate adjustment, the DDC-adjusted Load Shaping True-up rate, the DDC-adjusted PF Melded Equivalent Energy Scalar, the ACS DDC Amount, and details about how the ACS DDC Amount has been used to modify Transmission rates for the subsequent fiscal year. The notification shall also describe the data and assumptions relied upon by BPA for all ANR determinations. BPA shall make such data, assumptions, and documentation, if non-proprietary and non-privileged, available for review upon request.

Associated with any notification as described above of DDC calculations, BPA shall conduct a workshop(s) to explain the ANR calculations, describe the calculation of the DDC Amount and allocations to various rates, and demonstrate that the DDC has been implemented in accordance with these GRSPs. The workshop(s) will provide an opportunity for public comment.

If the DDC applicable to FY 2012 rates triggers, then on or about July 31, 2011, BPA will post to the BPA Web site the final DDC calculations. If the DDC applicable to FY 2013 rates triggers, then on or about September 30, 2012, BPA will post to the BPA Web site the final DDC calculations.

E. DSI Reserves Adjustment

A DSI Customer's Wholesale Power bill may be adjusted to reflect a DSI Reserves Adjustment. BPA Power Services is not obligated to purchase any DSI Reserve(s) beyond the Minimum DSI Operating Reserve – Supplemental, but is willing to negotiate with any DSI interested in providing additional DSI Reserves. A DSI Reserve is provided through an ability for BPA to interrupt, curtail, or otherwise reduce DSI load when such a right is made available to Power Services in addition to the Minimum DSI Operating Reserve – Supplemental.

This optional DSI Reserves Adjustment is designed to provide flexibility that will allow BPA to negotiate company-specific interruption rights, with the rate based on the characteristics of the DSI Reserve(s) provided. To ensure that any such purchases by BPA are cost effective, the maximum amount Power Services may pay a DSI for DSI Reserve(s) is \$6.96 per kW per month.

The availability of DSI Reserve(s) purchased by Power Services must be consistent with North American Electric Reliability Corporation, Western Electricity Coordinating Council, and Northwest Power Pool standards and criteria specific to balancing authority area Operating Reserve requirements, including the two characteristics below:

1. The interruptible load must be off-line or the increased generation on-line within the period specified for the applicable DSI Reserve purchased; and
2. The interruptible load or increased generation must be accessible prior to a request for reserves from other Northwest Power Pool parties.

In addition to these two required characteristics, the issues identified below will help define when Power Services may pay the maximum value for DSI Reserves:

1. The extent to which Power Services has the discretion when and how to use all reserves and to determine what resources to call on in the event of a system disturbance, or for some other purpose specified in the negotiated arrangement.

2. Whether there are limitations on the number of times or total minutes the reserves may be utilized.
3. Duration of time the interruptible load is available to be off-line or increased generation is available to be on-line.

Even in the event that a DSI is willing to provide reserves meeting all of the criteria established above, the Administrator is not obligated to purchase reserves in any amount beyond the Minimum DSI Operating Reserve – Supplemental.

F. Flexible New Resource Firm Power (NR) Rate Option

The Flexible NR rate option will be offered at BPA's discretion to a Customer that makes a contractual commitment to purchase under this option. The rates and billing determinants under this option shall be specified by BPA at the time the Administrator offers to make power available to a Customer under this option. The Customer under the Flexible NR rate option shall purchase the same set of power products and services that it would otherwise purchase under the NR-12 rate schedule. The flexible rates and billing determinants will be mutually agreed to by BPA and the Customer, subject to satisfying the following conditions:

Equivalent NPV Revenue: Forecast revenue from a Customer under the Flexible NR rate option must be equivalent, on a net present value basis, to the revenue BPA would have received had the appropriate rates specified in the sections 2 and 3 of the NR-12 rate schedule been applied to the same sales.

The Flexible NR rate contract may establish a limit on the amount of power purchased at the Flexible NR rate. In this case, purchases beyond the contractual limit will be billed at the rates specified in sections 2 and 3 of the NR-12 rate schedule, unless such power would be charged as an Unauthorized Increase.

Notwithstanding the effective dates of the NR-12 rate and associated GRSPs, any rights and obligations of BPA and a Customer arising out of the Customer's election to participate in the Flexible NR Rate program by purchasing under the Flexible NR Rate Option shall survive and be fully enforceable until such time as they are fully satisfied.

G. Flexible Priority Firm Power (PF) Rate Option

The Flexible PF rate option will be offered at BPA's discretion to a Customer that makes a contractual commitment to purchase under this option. The rates and billing determinants under this option shall be specified by BPA at the time the Administrator offers to make power available to a Customer under this option. The Customer under the Flexible PF rate option shall purchase the same set of power products and services that it would otherwise purchase under the PF-12 rate schedule. The flexible rates and billing determinants will be mutually agreed to by BPA and the Customer, subject to satisfying the following conditions:

Equivalent NPV Revenue: Forecast revenue from a Customer under the Flexible PF rate option must be equivalent, on a net present value basis, to the revenue BPA would have received had the appropriate rates specified in sections 2, 3, 4, and 5 of the PF-12 rate schedule been applied to the same sales.

The Flexible PF rate contract may establish a limit on the amount of power purchased at the Flexible PF rate. In this case, purchases beyond the contractual limit will be billed at the rates specified in sections 2, 3, 4, and 5 of the PF-12 rate schedule, unless such power would be charged as an Unauthorized Increase.

Notwithstanding the effective dates of the PF-12 rate and associated GRSPs, any rights and obligations of BPA and a Customer arising out of the Customer's election to participate in the Flexible PF Rate program by purchasing under the Flexible PF Rate Option shall survive and be fully enforceable until such time as they are fully satisfied.

H. Irrigation Rate Discount

1. Discount for Eligible Customers

In May, June, July, August, and September, an eligible Customer shall have the Irrigation Rate Discount of 10.26 mills/kWh applied to the lesser of the amount of energy purchased at Tier 1 rates in the month or the irrigation load amounts listed in Exhibit D of its CHWM Contract.

For a Load Following or Block Customer, the energy purchased at Tier 1 rates will be equal to its Actual Monthly/Diurnal Tier 1 Load used to calculate its Load Shaping billing determinant. For a Slice/Block Customer, the energy purchased at Tier 1 rates will be equal to the sum of its monthly Block purchase at Tier 1 rates plus its Slice Percentage multiplied by the monthly/diurnal RHWMTier 1 System Capability.

The Irrigation Rate Discount for a Joint Operating Entity (JOE) will be calculated based on individual utility members and billed to the JOE and designated for each eligible utility.

2. Irrigation Rate Discount True-Up and Reimbursement

There will be an assessment of the Irrigation Rate Discount each November to ensure the Customer served the full amount of irrigation load for which it received an Irrigation Rate Discount. If the sum of a Customer's May to September measured irrigation load is greater than or equal to the sum of the May through September billed irrigation load amounts, a true-up calculation is not applicable. However, if the sum of a Customer's May to September measured irrigation load is less the sum of the May through September billed irrigation load amounts, a true-up calculation is required. The actual metered irrigation kilowatthour (kWh) amounts submitted by the Customer each year will be increased by 7 percent to account for losses (measured irrigation load) before they are compared to the billed irrigation load amounts. The true-up calculation

determines the amount of excess Irrigation Rate Discount that a Customer shall reimburse to BPA.

If a true-up calculation is needed, an adjustment shall be determined following each Fiscal Year of the Rate Period and will appear as a charge on the Customer’s power bill.

If applicable, the true-up is calculated as follows: The measured irrigation load for the May through September period will be subtracted from the sum of the May through September billed irrigation load amounts. The result, if positive, will be multiplied by the Irrigation Rate Discount to determine the true-up reimbursement.

To ensure the timeliness of a true-up reimbursement each eligible Customer must send its May to September measured irrigation load amounts to BPA by October 31 following each May to September irrigation season.

I. Load Shaping Charge True-up Adjustment

The Load Shaping Charge True-up Adjustment is applicable to Customers purchasing the Load Following product in specific circumstances. The Adjustment shall be determined following each fiscal year of the rate period and will appear on the Customer’s power bill.

1. Load Shaping Charge True-up Rate

<i>FY</i>	<i>Rate in mills/kWh</i>
2012	6.45
2013	6.45

2. Load Shaping Charge True-up Billing Determinants

(a) Annual Deviation

The Annual Deviation for each Customer determines whether the Customer may be eligible for a True-up charge or credit.

$$\text{Annual Deviation} = \frac{\text{Actual Annual Tier 1 Load (measured)}}{\text{TOCA Load (calculated)}} \text{ minus}$$

TOCA Load is the annual amount of energy that is used to calculate the Customer’s TOCA. If the Customer’s TOCA is modified pursuant to the TOCA Adjustment, GRSP II.T, TOCA Load will reflect the Adjusted TOCA. If Annual Deviation is zero, there may be no True-up; see Special Implementation Provision, section 3 below.

(b) True-up Credit

If Annual Deviation is positive, the Customer is eligible for a True-up credit if Above-Forecast Amount is positive (greater than zero).

$$\text{Above-Forecast Amount} = \frac{\text{RHWM (calculated)}}{\text{TOCA Load (calculated)}} \text{ minus}$$

If Above-Forecast Amount is positive, the True-up Credit billing determinant equals the lesser of:

- (1) Annual Deviation multiplied by a negative one (-1), or
- (2) Above-Forecast Amount multiplied by a negative one (-1).

There is no True-up if Above-Forecast Amount equals zero (0).

(c) True-up Charge

If Annual Deviation is negative, the Customer may be subject to a True-up charge. If Above-RHWM Load is less than the absolute value of the Annual Deviation ($< | \text{Annual Deviation} |$), the Customer is subject to a True-up charge.

$$\text{True-up Charge billing determinant} = \frac{\text{Absolute value of the Annual Deviation (} | \text{Annual Deviation} | \text{)}}{\text{Above-RHWM Load}} \text{ minus}$$

The True-up Charge billing determinant cannot be less than zero.

3. Special Implementation Provision

Special implementation provisions apply if two conditions are met:

- (a) the Customer has Above-RHWM load
and
- (b) the Customer has an Above-Forecast Amount greater than zero.

If these conditions are met, the Customer may be eligible for an additional Load Shaping True-up credit.

If the Annual Deviation is negative or equal to zero and the absolute value of the Annual Deviation is less than the Customer's Above-RHWM load, then the Special True-up Credit billing determinant is the smallest of: i) the Customer's Above-RHWM load; ii) the Above-RHWM load minus the absolute value of the Annual Deviation; or iii) the Above-Forecast Amount.

If the Annual Deviation is positive and the Annual Deviation amount is less than the Above-Forecast amount, then the Special True-up Credit billing determinant is negative one (-1) multiplied by the lesser of i) the Customer's Above-RHWM load; or ii) the Above-Forecast amount minus the Annual Deviation.

4. Load Shaping Charge True-up Adjustment

The Load Shaping Charge True-up Adjustment is equal to the Load Shaping Charge True-up rate multiplied by the sum of i) the True-up Credit billing determinant; ii) the True-up Charge billing determinant; and iii) the Special True-up Credit billing determinant.

J. Low Density Discount (LDD)

1. Application and Definitions

For eligible Customers, as defined in section 2 below, a Low Density Discount (LDD) shall be applied each billing month to the PF-12 Composite Customer charge, PF-12 Non-Slice Customer charge, PF-12 Load Shaping charge, and PF-12 Demand charge. It also applies to eligible Customers under the PF-12 Melded rate schedule and the NR-12 rate schedule. The LDD shall be applied to only those charges listed in this GRSP II.J.

For Load Following purchases, the applicable discount percentage will apply to all charges for purchases by the Customer under the Tier 1 rates (Composite Customer charge, Non-Slice Customer charge, Load Shaping charge, and Demand charge). The applicable discount percentage will be adjusted for Above-High Water Mark load, as described in section 6 below.

For Slice/Block purchases, an LDD dollar benefit will be calculated by BPA as though it was a Load Following Customer. BPA will use the Customer's previous fiscal year's load data to calculate an annual LDD dollar benefit amount. This amount will be divided by 12 to derive a monthly LDD dollar credit, which will be applied to the Customer's monthly power bills over the next 12 months. There will be no separate Slice and Block LDD benefits calculated. The applicable discount percentage will be adjusted for Above-High Water Mark load, as described in section 6 below.

The eligible and applicable discount percentages shall be revised annually based on data supplied by June 30 of each calendar year (CY) for the previous calendar year and shall become effective on the following October 1.

The calculation of the ratios below shall be based on calendar year data the Customer provides from its annual financial and operating reports (Rural Utility Services Form 7, similar Cooperative Finance Corporation form, or audited financial report) and its annual 861 report to the Energy Information Administration. The annual financial and operating reports and Energy Information Administration reports are to be enclosed

with the Customer's calendar year data. The Customer shall certify that the data submitted is true and correct.

Load acquired by a Customer as a direct result of retail access rights established by Federal, state, or local legislation, and that would not otherwise have been acquired absent such legislation, is not eligible to receive the benefits provided by the LDD. The Customer shall certify that the data submitted does not include such load. The Customer shall not pass the benefits of the LDD to such acquired consumers.

In calculating the ratios below, BPA shall compile the data submitted by the Customer based on the Customer's entire electric utility system in the Pacific Northwest. For Customers with service territories that include any areas outside the PNW, BPA shall compile data submitted by the Customer separately on the Customer's system in the PNW and on the Customer's entire electric system, both inside and outside the PNW. BPA shall apply the eligibility criteria and discount percentages to the Customer's system within the PNW and, where applicable, also to its entire system inside and outside the PNW. The Customer's eligibility for the LDD shall be determined by the lesser amount of discount applicable to its PNW system or to its combined system inside and outside the PNW. BPA, in its sole discretion, may waive the requirement to submit separate data for the Customer with a small amount of its system outside the PNW. Results of the calculations shall not be rounded.

If a Customer does not provide BPA with the requisite information and reports by June 30 of each year for BPA to calculate the K/I and C/M ratios, the Customer shall be ineligible for the LDD effective the following October 1. The Customer may reapply for the LDD in any subsequent year.

If a Customer's data and reports are submitted prior to the June 30 deadline, and a revision is necessary, the Customer must submit the revised data within 12 months of the original submission date to be considered for an adjustment.

(a) The Kilowatthour/Investment Ratio

The Kilowatthour/Investment (K/I) ratio is calculated annually based on the data the Customer supplies by June 30 of each calendar year. The K/I ratio is calculated by dividing the Customer's Total Retail Load during the previous calendar year by the value of the Customer's depreciated electric plant (excluding generation plant) at the end of the previous calendar year.

(b) The Consumers/Mile of Line Ratio

The Consumers/Mile of Line (C/M) ratio is calculated annually based on the data the Customer supplies by June 30 of each calendar year. The C/M ratio is calculated by dividing the Customer's number of consumers within the distribution system, as defined below, by the end-of-CY number of pole miles of distribution lines at the end of the previous calendar year.

Consumers will be the number of consumers, by classification, having a current service connection in December of each year. Residential consumers (seasonal and non-seasonal) should be counted on the basis of the number of residences served. If one meter serves two residences, then two consumers should be counted. If a water heater is metered separately from other appliances on the same premises, the water heater load will not count as a separate consumer.

Security or safety lights billed to a residential Customer will not be counted as an additional consumer.

Seasonal consumers expected to resume service during the next seasonal period will be counted during off-season periods as well.

A residence and commercial establishment on the same premises receiving service through the same meter and being billed under the same rate schedule would be classified as one consumer based on the rate schedule. If the same rate schedule applies to both the residential and the commercial class, the consumer should be classified according to the principal use.

Consumers for Public Street and Highway Lighting should be counted by the number of billings, regardless of the number of lights per billing.

Distribution lines are defined as lines that deliver electric energy from a substation or metering point at a voltage of 34.5kV or below to the point of attachment to the consumer's wiring and include primary, secondary, and service facilities. (Service drops are considered service facilities.)

2. Eligibility Criteria

To qualify for a discount, the Customer must meet all five of the following eligibility criteria:

- (a) The Customer must serve as an electric utility offering power for resale to retail consumers.
- (b) The Customer must agree to pass the benefits of the discount through to its eligible Consumers within the region served by BPA.
- (c) The Customer's average retail rate for the reporting year must exceed BPA's average Priority Firm Power rate for the most closely corresponding fiscal year by at least 25 percent, which is 35.96 mills/kWh for FY 2012 and FY 2013.
- (d) The Customer's K/I ratio must be less than 100.
- (e) The Customer's C/M ratio must be less than 12.

Each year BPA shall determine whether a Customer is eligible for a discount. Such determination shall not be dependent on whether the Customer was determined to be eligible in the previous year.

3. Determination of Eligible Discount Percentage

For each Customer, an eligible discount percentage will be determined using Table D below. The eligible discount percentage will be the sum of the two potential discount percentages for which the Customer qualifies, based on Table D. The total eligible discount percentage shall not exceed 7 percent and may be adjusted pursuant to sections 4, 5, and 6 below.

Table D
LDD Percentage Eligible Discount Percentage Table

<i>Percentage Discount</i>	<i>Applicable Range for kWh/Investment (K/I) Ratio</i>	<i>Applicable Range for Consumers/Mile (C/M) Ratio</i>
0.0%	$35.0 < X$	$12.0 < X$
0.5%	$31.5 < X < 35.0$	$10.8 < X < 12.0$
1.0%	$28.0 < X < 31.5$	$9.6 < X < 10.8$
1.5%	$24.5 < X < 28.0$	$8.4 < X < 9.6$
2.0%	$21.0 < X < 24.5$	$7.2 < X < 8.4$
2.5%	$17.5 < X < 21.0$	$6.0 < X < 7.2$
3.0%	$14.0 < X < 17.5$	$4.8 < X < 6.0$
3.5%	$10.5 < X < 14.0$	$3.6 < X < 4.8$
4.0%	$7.0 < X < 10.5$	$2.4 < X < 3.6$
4.5%	$3.5 < X < 7.0$	$1.2 < X < 2.4$
5.0%	$X < 3.5$	$X < 1.2$

4. LDD Phase-In Adjustment

If the Customer satisfies the eligibility criteria (2.a. through e.) and the calculated eligible discount percentage differs from the existing eligible discount percentage by more than one-half of 1 percentage point, the applicable eligible discount percentage will be one of the following amounts:

- (a) the existing eligible discount percentage plus a maximum of one-half percent if the calculated eligible discount percentage exceeds the existing discount.
- (b) the existing eligible discount percentage minus a maximum of one-half percentage if the calculated eligible discount percentage is less than the existing discount.

The foregoing formula will be applied each October 1 until the existing eligible discount percentage is equal to the calculated eligible discount percentage.

The Customer is not eligible to receive any discount, effective each October, if the Customer fails to meet the eligibility criteria in section 2.(a) through (e) above. If the Customer is eligible to receive a discount in a year following a year in which the

Customer was not eligible to receive the discount, then the one-half percent phase-in adjustment described above will apply to the most-recent eligible discount.

5. Additional Adjustment for Very Low Densities

If a Customer's C/M ratio is 3 or less and its K/I ratio is 26 or less, after determination of the eligible discount percentage pursuant to sections 3 and 4 above, an additional one-half percentage shall be added to the Customer's eligible discount percentage, not to exceed a total eligible discount of 7 percent. In subsequent years, the one-half percentage added to the eligible discount percentage pursuant to this section shall not be included when determining the applicable discount percentage pursuant to section 4 above.

6. Applicable Discount for Customers with Above-RHWM Load

A discount is not provided for the costs of power used to serve the Customer's Above-RHWM load; however, the LDD benefit will be adjusted to be approximately the same as if the Above-RHWM load was included. This adjustment modifies the Customer's eligible discount percentage. The formula used to calculate the applicable discount percentage for eligible purchases on the Customer's power bill during the rate period is:

$$\text{applicableLDD} = \text{eligibleLDD} \times \max \left(\frac{\text{adjTRL}}{\text{RHWM}}, 1.0 \right)$$

Where:

applicableLDD = the discount percentage to be applied to the Tier 1 charges on a Customer's bill

eligibleLDD = the Customer's eligible discount percentage as computed according to sections 2 through 5 above.

adjTRL = the Customer's Total Retail Load less output of Existing Resources and NLSLs, as determined in the BP-12 Final Proposal for the applicable fiscal year

RHWM = the Customer's Rate Period High Water Mark

Any Customer with *adjTRL* less than its *RHWM* will have its applicable discount percentage set equal to its eligible discount percentage.

7. Treatment for Joint Operating Entity

The LDD benefit to a JOE will be equivalent to the sum of LDD benefits for all eligible individual members of the JOE. Except for LDD benefits for Tier 1 Demand, the LDD benefits for the JOE will be based on each such individual utility member's applicable discount percentage applied to all charges for purchases by the individual utility

member under the Tier 1 rates according to section 1 above. The monthly LDD benefit for Demand for a JOE is calculated as follows:

- (a) each individual utility member's Demand billing determinant is calculated as if such member were not a member of a JOE;
- (b) the Demand billing determinants for all individual utility members are summed;
- (c) the individual utility members' calculated Demand billing determinants are scaled (up or down) such that the sum of all individual utility members' calculated Demand billing determinants equals the JOE's Demand billing determinant;
- (d) the Demand LDD benefit attributable to each eligible individual member of the JOE is equal to the member's scaled Demand billing determinant multiplied by the member's applicable discount percentage and the applicable monthly Tier 1 Demand charge; and
- (e) the Demand LDD benefits of the eligible individual members of the JOE are summed to yield the Demand LDD benefit to the JOE.

K. NFB Mechanisms

The two NFB mechanisms described here are rate features that allow BPA to recover additional revenue if financial impacts ("Financial Effects") from a specified set of circumstances ("Trigger Events") in the fish and wildlife arena cause a reduction in Power Services' forecast Net Revenue. The first mechanism, the NFB Adjustment, would increase the CRAC Cap applicable to the fiscal year(s) following the fiscal year in which an NFB Trigger Event (see below) occurs. The second mechanism, the Emergency NFB Surcharge, would increase rates within the fiscal year in which an NFB Trigger Event resulting in Financial Effects occurs. The latter situation would apply if waiting until the next year for additional cost recovery would be imprudent because BPA is in a "cash crunch" (defined in section 3 below).

1. Definitions

- (a) An NFB *Trigger Event* is one of the following events that results in changes to BPA's FCRPS Endangered Species Act (ESA) obligations compared to those adopted in the most recent wholesale power rate proceeding as modified prior to this Trigger Event:
 - (1) A court order in *National Wildlife Federation vs. National Marine Fisheries Service*, CV 01-640-RE, or any other case filed regarding an FCRPS Biological Opinion (BiOp) issued by NMFS (also known as NOAA Fisheries Service), or any appeal thereof ("Litigation").

- (2) An agreement (whether or not approved by the Court) that results in the resolution of issues in, or the withdrawal of parties from, the Litigation.
 - (3) A new FCRPS BiOp.
 - (4) A BPA commitment to implement Recovery Plans under the ESA that results in the resolution of issues in, or the withdrawal of parties from, the Litigation.
 - (5) Actions or measures required under the Adaptive Management Implementation Plan associated with the FCRPS BiOp that reduce BPA's forecast net revenue.
- (b) Financial Effects of a Trigger Event are net reductions in estimated Power Net Revenue within the fiscal year due to a Trigger Event that affects power sales revenues, fish and wildlife credits, power purchases, direct program expenses of the anadromous fish component of BPA's fish and wildlife program, USACE and Reclamation O&M expenses, direct program expenses of the USFWS, or amortization of capital costs when compared with the estimate of the foregoing revenues, credits, costs, and obligations adopted in the most recent wholesale power rate proceeding, as modified prior to this Trigger Event. These effects are the total effects on the BPA System, excluding the operational or expense effects borne by Slice Customers.
- (c) The *Agency Within-Year TPP* is the probability that the Agency (including both Power and Transmission) will be able to meet all Agency financial obligations to the Treasury for the fiscal year in which a Trigger Event occurs. Agency Within-Year TPP takes into account, for the remainder of such fiscal year: (i) all funds reasonably expected to be available to the Agency to repay the Treasury, including but not limited to financial reserves (including deferred borrowing), any expense reductions and revenue increases, short-term borrowing available through the Treasury Facility (which availability may be limited by constraints on BPA's remaining borrowing authority), and BPA's then-current best estimate of 4(h)(10)(C) credits for that year; and (ii) all financial obligations reasonably expected to require payment, including but not limited to Treasury payments scheduled in the BP-12 rate proceeding, repayments to Treasury required pursuant to the previous exercise of liquidity tools, and updated forecasts of other reasonably necessary expenses and reasonably necessary uses of cash.
- (d) *Surcharge Amount* is the amount of money to be collected under the Emergency NFB Surcharge.
- (e) *Revenue Basis* is the 12-month totals of revenue from Power rates subject to the Emergency NFB Surcharge for a specific fiscal year.

- (f) *Customer Percentage* is the Revenue Basis associated with each Customer divided by the total Revenue Basis. Each Customer Percentage will be rounded to four decimal places.

2. The NFB Adjustment

The NFB Adjustment results in an upward adjustment to the CRAC Cap for a fiscal year in the rate period if Financial Effects from an NFB Trigger Event(s) occur. For the BP-12 rates, the NFB Adjustment calculation can result in an increase in the annual CRAC Cap set forth in Table B in GRSP II.C if an NFB Trigger Event occurs prior to the fiscal year to which a CRAC is applied.

$$\text{NFB Adjustment} = \text{Financial Effects of Trigger Event(s)}$$

$$\text{Adjusted CRAC Cap} = \text{CRAC Cap from Table B} + \text{NFB Adjustment}$$

3. The Emergency NFB Surcharge

The Emergency NFB Surcharge (Surcharge) results in an upward adjustment to specified rates during a year in which (a) Financial Effect(s) occur from a Trigger Event(s) and (b) the Agency Within-Year TPP is below 80 percent (also referred to as a “cash crunch”). A “cash crunch” means the Agency Within-Year TPP is calculated to be below 80 percent including (1) the Financial Effects of all Trigger Events and (2) all revenues from those, but only those, CRACs and Emergency NFB Surcharges that have already been implemented (*i.e.*, calculated, and scheduled to be affecting rates). The Emergency NFB Surcharge is a separate adjustment from the NFB Adjustment.

For the BP-12 rates, the Surcharge may be implemented in FY 2012 if the (a) and (b) events required to impose the Surcharge occur in that fiscal year, or in FY 2013 if the requisite (a) and (b) events occur in that year.

The Surcharge is an upward adjustment to certain rates for FY 2012 or FY 2013 or both. It applies to these Power rates:

- Non-Slice Customer rate (PF-12);
- PF Melded rate (PF-12);
- Industrial Firm Power rate (IP-12); and
- New Resource Firm Power rate (NR-12).

The CRAC also applies to these Transmission rates:

- Reserves-based Ancillary and Control Area Services (ACS-12) rates.

There can be more than one Trigger Event in a year, and therefore there could be more than one Surcharge implemented in a fiscal year.

At the discretion of the Administrator, BPA may collect the Surcharge Amount by modifying the Monthly Surcharge to collect less in earlier months and more in later months of the fiscal year.

No Surcharge will be levied if the Surcharge Amount described below is calculated to be less than \$10 million. If the first month in which the Surcharge bill is sent out occurs during the last quarter of the fiscal year in which the Trigger Event occurred, then the Surcharge Amount in each such month shall not exceed \$25 million.

If Surcharge revenues total less than the total Financial Effects for Trigger Events in that year, the remaining balance of Financial Effects will be included in an NFB Adjustment to the CRAC Cap for the subsequent year.

4. Calculations for the NFB Emergency Surcharge

(a) Calculating the NFB Surcharge Amount

NFB Surcharge Amount = Financial Effects of Trigger Event

(b) Calculating the PF/IP/NR Surcharge Amount and the ACS Surcharge Amount

The PF/IP/NR Surcharge Amount is 96.4% times the Surcharge Amount.

The ACS Surcharge Amount is 3.6% times the Surcharge Amount.

(c) Converting the PF/IP/NR Surcharge Amount to the PF/IP/NR Surcharge

Once the PF/IP/NR Surcharge Amount is determined, that amount will be converted to a mills per kilowatthour Surcharge rate added to the IP and NR rates. The Surcharge rate will be converted to a monthly dollars per one percentage point of Non-Slice TOCA value and added to the Non-Slice Customer rate (making a negative Non-Slice Customer rate less negative).

The PF/IP/NR Surcharge rate is calculated by dividing the PF/IP/NR Surcharge Amount by the most current forecast of kilowatthours of service under PF Melded, IP, and NR rates and the sum of PF System Shaped Loads for the applicable months of the applicable year.

The PF/IP/NR Surcharge rate is converted to a monthly dollars per one percentage point of Non-Slice TOCA by multiplying the sum of PF System Shaped Loads for the applicable months by the PF/IP/NR Surcharge rate. The product of this calculation is the dollar amount to be collected through the Non-Slice TOCA billing determinant. The dollar amount to be collected through the Non-Slice TOCA billing determinant will be divided by the sum of the Non-Slice TOCAs and divided again by the applicable months in the fiscal year. The result of this

calculation is a monthly dollars per one percentage point of Non-Slice TOCA rate adjustment.

(d) Customer Charges for the PF/IP/NR Surcharge

Line items will be added to the bills during the applicable months of the applicable year for service under PF Melded, IP, and NR rates showing additional charges calculated by multiplying the PF/IP/NR Surcharge rate by the applicable kilowatthours of service.

A line item will be added to the bills during the applicable months of the applicable year for service under PF rates showing an additional charge calculated by multiplying the monthly dollars per one percentage point of Non-Slice TOCA rate adjustment by the Non-Slice TOCA.

(e) Converting the ACS Surcharge Amount to Charges on Customers' Bills

Once the ACS Surcharge Amount is determined, that amount will be passed to Transmission Services. See Transmission GRSP II.H for details of how those Transmission rates subject to the Surcharge will be modified.

(f) Other Rate Adjustments

The PF/IP/NR Surcharge rate will be converted to an annual Surcharge rate. This annual Surcharge rate is calculated as the PF/IP/NR Surcharge rate multiplied by the quotient of the sum of PF System Shaped Loads for the applicable surcharge months divided by the annual sum of PF System Shaped Loads.

The annual Surcharge rate will be applied to the Load Shaping True-up Rate to create the Surcharge-Adjusted Load Shaping True-up Rate. The annual Surcharge rate will be applied to the PF Melded Equivalent Energy Scalar, see GRSP II.R., to create the Surcharge-adjusted PF Melded Equivalent Energy Scalar.

The PF/IP/NR Surcharge will also be applied to the applicable months of the PF Tier 1 Equivalent energy rates. See GRSP II.M.

5. Criteria for Applying the NFB Adjustment or Assessing the Surcharge

NFB Trigger Events that have Financial Effects can lead to NFB Adjustments or Surcharges according to these GRSPs if they occur in fiscal years 2011, 2012, or 2013. Whether such Trigger Events lead to NFB Adjustments or to Surcharges depends on whether BPA is in a "cash crunch" in the year in which the Trigger Event occurs.

If a Trigger Event occurs in FY 2011, it may result in a Surcharge for FY 2011 if BPA is in a cash crunch in FY 2011. Such a Surcharge would be governed by the WP-10 GRSPs. If BPA is not in a cash crunch, or if a Surcharge implemented pursuant to the

WP-10 GRSPs during FY 2011 collects less than the full amount of the FY 2011 Financial Effects, such a Trigger Event could lead to an NFB Adjustment to the CRAC Cap applicable to FY 2012 and 2013, as governed by these GRSPs.

If a Trigger Event occurs in FY 2012, it may result in either a Surcharge applicable to FY 2012 rates or an NFB Adjustment to the CRAC Cap applicable to FY 2013 rates. Such a Trigger Event may result in both NFB mechanisms being used if some but not all of the Financial Effects were recoverable from a Surcharge in FY 2012. All of these possibilities will be governed by these GRSPs.

If a Trigger Event occurs in FY 2013 and BPA is in a cash crunch, the Surcharge procedures defined in these GRSPs will apply. If BPA is not in a cash crunch in FY 2013, these GRSPs are silent on the implications. Any NFB Adjustment that might apply to FY 2014 rates based on Trigger Events occurring in FY 2013 will be defined by the 2014 GRSPs.

If a Trigger Event occurs that has Financial Effects in the year of its occurrence and also in later years, the Trigger Event will be deemed to have occurred on the first day of all subsequent years in which it has Financial Effects (*i.e.*, Financial Effects that have not been incorporated into the general rates applicable to that year). If there are, or are deemed to be, multiple Trigger Events in any fiscal year, the Financial Effects of those events will be the net effect for that fiscal year of all Trigger Events combined.

6. NFB Adjustment and Surcharge Notification Processes

BPA shall use the following procedures following a Trigger Event:

(a) Notification of Trigger Event and Related Workshops

BPA will notify Customers within 30 days of the occurrence of an NFB Trigger Event in FY 2012 or 2013, as defined above, if BPA estimates the Financial Effects of the Trigger Event to be \$10 million or more. This initial notification, posted to BPA's Web site and provided by e-mail to those listed on the service list for the BP-12 rate proceeding, will include a description of the Trigger Event. BPA may elect not to notify Customers of the Trigger Event if BPA estimates the Financial Effects of a Trigger Event to be less than \$10 million or BPA expects that neither a CRAC applicable to the subsequent year nor a Surcharge resulting from the Trigger Event applicable to the current year will be implemented.

If BPA does not determine that the Agency Within-Year TPP is below 80 percent at any later time in the fiscal year, a Trigger Event with Financial Effects will result in an NFB Adjustment. The Financial Effects of the Trigger Event will be presented along with the forecast of the end-of-year ANR calculation in July 2011 or September 2012. There can be more than one NFB Adjustment Trigger Event in a year. There will be only one, if any, calculation of the NFB Adjustment to the CRAC Cap applicable to the next year.

If the ANR is forecast to fall below the CRAC Threshold applicable to the next year, BPA shall conduct a workshop(s) as called for by the CRAC procedures in GRSP II.C. At the workshop(s), BPA will explain the Trigger Event and the estimated Financial Effects. BPA will provide and explain the data, models, and assumptions used to calculate the Surcharge Amount. BPA will respond to reasonable requests for data and calculations and will accept comments on any of the foregoing topics. At the Customers' request, BPA Account Executives shall provide Customers details of their charges under the Surcharge.

If the CRAC applicable to FY 2012 rates triggers, then on or about July 31, 2011, BPA will post to the BPA Web site the final CRAC calculations, including any NFB Adjustment (see section 2 above) to the CRAC Cap. If the CRAC applicable to FY 2013 rates triggers, then on or about September 30, 2012, BPA will post to the BPA Web site the final CRAC calculations, including any NFB Adjustment (see section 2 above) to the CRAC Cap.

(b) Notification of Agency Within-Year TPP Falling Below 80 Percent Following a Trigger Event, and Related Workshops

If, during a fiscal year in which a Trigger Event has occurred, BPA determines that the Agency Within-Year TPP is below 80 percent, BPA will notify Customers within seven (7) days of such a determination. In addition, this notification will be posted to BPA's Web site and provided by e-mail to parties on the service list for the BP-12 rate proceeding.

This notification will include the time and location of a public workshop to be conducted no later than seven (7) days after the issuance of the notification. This notification will also include updated calculations of the Financial Effects of the Trigger Event(s) and the Agency Within-Year TPP. Concurrently, BPA's Account Executives will inform Customers of their charges under the Surcharge.

At this workshop, BPA will explain the calculation of the Agency Within-Year TPP and the Surcharge Amount, including the monthly shape of payments.

BPA will provide data and assumptions used in these calculations. BPA will respond to relevant requests for data and calculations and will accept comments on any of the foregoing topics.

(1) Final Notification Procedures for Monthly Surcharge and Fiscal Year Surcharge Amount to Be Paid By Customers

BPA will provide written Final Notification to each Customer in accordance with the notification provisions of the Customer's BPA contract no later than seven (7) days following the conclusion of the workshop described above. Such Final Notification will state the monthly Surcharge Amount and the total Surcharge Amount to be recovered from each Customer by September 30 of the fiscal year in which the Surcharge is in effect.

The monthly Surcharge Amount will be included on bills to Customers and will be payable in accordance with the applicable payment provisions of the Customers' contracts. The first monthly Surcharge Amount will be billed no sooner than 30 days following the Final Notification.

(2) Process Following Implementation of Surcharge

Within thirty (30) days of the Final Notification of implementation of a Surcharge described above, BPA will convene two or more meetings within sixty (60) days of the Final Notification.

At the first meeting, Customers and interested persons may request additional information and explanations about the Trigger Event, its Financial Effects, and the updated Agency Within-Year TPP. Customers and interested persons may also request information regarding BPA's financial performance to date, revenue and expense forecasts for the remainder of the fiscal year, the calculation of the Surcharge Amount, and any other materials related to the Surcharge then in effect. BPA will provide responses to relevant information requests as promptly as possible, but in any case no later than 48 hours prior to the final meeting. Subsequent meetings may be held as necessary.

At the final meeting, Customers and interested persons may ask questions of and present their views to the Administrator. Customers and interested persons may also submit their views in writing to the Administrator within seven days after the meeting.

Based on the information and views presented during the process provided for in this section, and not later than twenty (20) days after the final meeting, the Administrator will issue a close-out letter that addresses the issues raised in the meetings, the need for the Surcharge, and whether the Surcharge is set at the appropriate level, all in accordance with these GRSPs. If the Administrator determines that the Surcharge Amount needs to be adjusted, the close-out letter will establish the refund or credit amount to Customers for the amounts over-collected, or adjust the Surcharge then in effect for the remainder of the year. The Administrator may remove the Surcharge entirely if one or both of the following occurs:

- (a) the Agency Within-Year TPP, not including future surcharge payments, is determined at the time of the close-out letter to be greater than 90 percent; or
- (b) an updated calculation indicates that the Financial Effects of the Trigger Event(s) are less than \$10 million for that fiscal year.

L. Priority Firm Power (PF) Shaping Option

Prior to the beginning of the rate period, BPA and a Customer purchasing Firm Requirements Power charged under section 2.1 of the PF-12 rate schedule may agree to a PF-12 Tier 1 Customer charge payment schedule for the rate period that differs from the flat monthly charge specified in the PF-12 rate schedule. BPA will, to the maximum extent practicable while ensuring timely BPA cost recovery, accommodate individual Customer requests to “shape” certain PF-12 Tier 1 Customer charges within the fiscal year to mitigate adverse cash flow effects on the Customer. The shaped payments at PF-12 Tier 1 Customer rates will be mutually agreed to by BPA and the Customer. Requests to shape Customer charges during the rate period must be received by BPA no later than September 1, 2011.

This Shaping Option analysis will take into account the cash-flow impacts to the Customer of the Tier 1 charges: the Customer charges; a forecast of monthly Load Shaping charges; a forecast of monthly Demand charges; and any applicable rate discounts. BPA and the Customer may agree to 12 monthly Composite Customer charges that the Customer shall pay in each year of the rate period. If further shaping is requested to mitigate a Customer’s cash-flow impacts, BPA may also agree to shape the Non-Slice Customer charge.

BPA will accommodate requests to shape Customer charges if the following conditions are met:

1. Equivalent Net Present Value: Forecast revenue from the shaped charges must be equivalent, on a net present value basis, to the revenue BPA would have received for each fiscal year without shaping; and
2. The aggregate shaping requests do not have a material adverse impact on BPA’s overall cash flow, as determined solely by BPA. In order to accommodate multiple shaping requests, BPA will take into account the potential offsetting impacts of all shaping requests. If BPA is not able to accommodate all requests in total due to material adverse impacts on BPA’s cash flow, BPA may limit the shaping for individual requests.

M. Priority Firm Power (PF) Tier 1 Equivalent Rates

The PF Tier 1 Equivalent rates are an expression of the Non-Slice PF Public Tier 1 rates in a traditional HLH and LLH energy form. These rates can be used as a reference when a need arises for Tier 1 rates to be expressed in this manner.

<i>Month</i>	<i>Rate in mills/kWh Diurnal Period:</i>		<i>Rate in \$/kW Demand</i>
	<i>HLH</i>	<i>LLH</i>	<i>HLH</i>
October	31.41	24.75	9.18
November	31.92	24.95	9.31
December	34.65	26.94	9.97
January	33.58	25.25	9.70
February	34.48	26.72	9.92
March	33.12	25.88	9.60
April	31.08	23.96	9.10
May	28.61	17.95	8.50
June	29.52	16.57	8.72
July	35.62	23.46	10.20
August	37.90	25.70	10.75
September	37.00	27.14	10.53

N. Residential Exchange Program Residential Load

Residential Loads of investor-owned utilities for the rate period are determined pursuant to the definition of Residential Load in section 2 of the 2012 REP Settlement.

**Table E
Residential Load (in kWh)**

<i>Month</i>	<i>Avista</i>	<i>Idaho</i>	<i>North-Western</i>
October	249,810,193	411,752,689	45,053,181
November	294,369,391	374,139,148	53,013,504
December	405,249,003	526,501,227	65,750,872
January	482,235,005	621,920,898	68,951,808
February	411,828,020	529,646,938	62,445,641
March	373,871,167	480,243,730	55,550,599
April	332,605,442	432,185,665	52,102,953
May	284,929,919	382,203,401	47,304,632
June	257,297,251	408,844,581	45,721,951
July	249,682,902	434,734,263	47,222,571
August	293,905,738	543,959,182	50,200,574
September	269,747,266	486,753,325	46,956,133

<i>Month</i>	<i>PacifiCorp</i>	<i>Portland General</i>	<i>Puget Sound</i>
October	623,530,820	590,678,816	793,638,840
November	693,870,052	673,821,224	989,756,383
December	993,780,172	916,232,241	1,318,881,901
January	1,086,985,340	1,027,721,506	1,447,513,479
February	867,207,780	856,740,142	1,254,203,500
March	792,566,054	804,371,890	1,174,450,000

<i>Month</i>	<i>PacifiCorp</i>	<i>Portland General</i>	<i>Puget Sound</i>
April	720,239,821	721,054,615	1,054,412,000
May	666,108,174	626,117,293	910,425,000
June	674,308,730	609,842,075	806,213,894
July	790,781,448	618,801,197	755,651,416
August	852,923,496	698,783,779	762,008,380
September	706,512,592	632,179,453	776,977,227

These loads are applicable to each year of the rate period, FY 2012-2013, and will be revised pursuant to the 2012 REP Settlement.

O. Residential Exchange Program 7(b)(3) Surcharge Adjustment

1. ASC Adjustment

The 7(b)(3) Surcharge is a utility-specific addition to the Base PF Exchange rate that recovers each REP participant's allocated share of the rate protection provided pursuant to the 2012 REP Settlement. As determined in the BP-12 7(i) process, each REP participant's 7(b)(3) Surcharge is based on its Base PF Exchange rate, its Average System Cost (ASC), and its contract exchange loads. Each REP participant's 7(b)(3) Surcharge is displayed in the table in section 6.1 of the PF-12 rate schedule and is subject to modification under this GRSP.

Under the 2008 Average System Cost Methodology, when a participating utility files an ASC with BPA, the utility may request an ASC modification based on the expectation that its set of resources will change during BPA's rate period. The participating utility must file the expected changes to its ASC with its ASC filing. Subject to limitations in the 2008 ASC Methodology, BPA will establish a modified ASC for a utility during BPA's rate period effective with the operational date of the new resource. Therefore, if a participating utility's ASC differs from the ASC used in establishing rates in section 6.1 of the PF-12 rate schedule, BPA will adjust the 7(b)(3) Surcharges of all participating utilities to reflect the new ASC.

Such adjustment of 7(b)(3) Surcharges will be accomplished by substituting all modified ASCs and recomputing the rates in section 6.1 of the PF-12 rate schedule. This recomputation will be accomplished by:

- Inserting the participating utility's revised Average System Cost, expressed in mills/kWh (equivalent to \$/MWh).
- Retaining the forecast exchange load for the participating utility, expressed in gigawatthours, as adopted in the BP-12 7(i) proceeding.
- Multiplying the difference between the ASC and the applicable Base PF Exchange rate by the forecast exchange load to compute the unconstrained benefits for each participant.

- Summing the unconstrained benefits for each participant to compute total unconstrained benefits.
- Computing the difference between the total unconstrained benefits and \$403,320,000 (the total REP benefits adopted for the 2-year rate period in the BP-12 7(i) proceeding).
- Allocate the computed difference to participants such that \$153,075,234 is allocated to the IOU participants and the remainder is allocated to all participants on a pro rata basis referenced to unconstrained benefits.
- Recompute the IOU adjustments specified in section 6.2 of the 2012 REP Settlement.
- Divide the recomputed allocated dollars by exchange loads to determine the revised 7(b)(3) Surcharge and add each revised 7(b)(3) Surcharge to the appropriate Base PF Exchange rate to compute the revised utility-specific PF Exchange rates.

The specific computations that will be performed are displayed on Table 2.4.12 of the Power Rates Study Documentation, BP-12-FS-BPA-01A. This table will be updated as specified above to perform the actual 7(b)(3) Surcharge adjustments. The adjusted 7(b)(3) Surcharges will take effect on the day that the utility's modified ASC takes effect. This adjustment will occur as frequently as ASCs are modified during the 2-year rate period the PF Exchange rate herein is in effect.

The adjustment of 7(b)(3) Surcharges will be updated and published as ASCs are modified. The table can be accessed through BPA's Residential Exchange Program Web site.

2. Change in Service Territory due to Annexation or Load Transfer

Should an REP-participating utility lose or gain load through an annexation or other transfer of load, the total REP benefits of \$403,320,000 used in the 7(b)(3) Surcharge calculation in section 1 above will be subject to change. If load is transferred from a participating utility to a preference Customer, resulting in an increase in PF preference load on BPA, and thereby increasing BPA's expenses, then the reduction in REP benefits to the REP-participating IOU will reduce the \$403,320,000 by the same amount. If the load is transferred from a participating utility to another Customer such that BPA expenses are not increased due to the transferred load, then the \$403,320,000 will not be reduced. The \$403,320,000 cannot be increased through a transfer of load.

P. Resource Support Services and Transmission Scheduling Service

Resource-specific RSS rates will be posted on the BPA Web site.

1. Diurnal Flattening Service Charges, Resource Shaping Charge, and Resource Shaping Charge Adjustment

DFS financially converts the output of a variable, non-dispatchable generating resource into output that is equivalent to a flat amount of power within each diurnal period of a month. Generally, DFS does not apply to small, non-dispatchable resources as such resources are defined in the Customer's CHWM Contract. When DFS charges are coupled with the Resource Shaping Charges, the variable generating resource is financially converted to one that is equivalent to a flat annual block of power. These charges are applied to each resource that is receiving this service. Unless stated otherwise, the resource amounts used in these calculations are either 1) generation amounts specified in the Customer's CHWM Contract Exhibit A (Exhibit A amounts); or 2) planned generation amounts based on hourly generation from the most recent historical year specified in Exhibit D (Exhibit D amounts).

(a) DFS Energy Charge

(1) DFS Energy Rate

The RSS module of BPA's Rate Analysis Model calculates the DFS Energy rate for each resource. Generally, for each monthly/diurnal period, the sum of planned generation in excess of average monthly/diurnal Exhibit D amounts is multiplied by 25 percent. The result is multiplied by the applicable monthly/diurnal Resource Shaping rate in section 1(c) below. The monthly/diurnal results are summed for the year and divided by the total planned energy from the Exhibit D amounts to calculate the DFS Energy rate.

(2) DFS Energy Billing Determinant

The DFS Energy billing determinant is the actual generation for the particular resource during the billing month. The actual generation amounts will be either the resource meter readings or resource transmission schedules if the resource requires an e-Tag.

(3) DFS Energy Charge

For each resource, the DFS Energy charge is the product of multiplying the DFS Energy rate by the DFS Energy billing determinant for each month.

(b) DFS Capacity Charge

(1) DFS Capacity Rate

The rates are the monthly PF Tier 1 Demand rates shown in section 2.1.2.1 of the PF-12 rate schedule.

(2) DFS Capacity Billing Determinant

The billing determinant is the difference between the resource's monthly average HLH Exhibit D amounts in one year and the calculated monthly firm capacity of the resource.

The RSS module of BPA's Rate Analysis Model calculates monthly firm capacity amounts for each resource. Generally, the firm capacity calculation represents the lowest level of historical generation in a HLH period of a month after accounting for planned outages and forced outages.

(3) DFS Capacity Charge

For each resource, the DFS Capacity charge is the lesser of:

- 1) the annual sum of i) the monthly DFS Capacity rates multiplied by ii) the monthly DFS billing determinants.
- or
- 2) the annual average Exhibit D amount multiplied by the sum of the monthly PF Tier 1 Demand rates.

The result is then divided by 12 to calculate a flat monthly charge that will be specified in Exhibit D of the Customer's CHWM Contract.

(c) Resource Shaping Charge

(1) Resource Shaping Rate

The monthly/diurnal Resource Shaping rates are equal to the PF Tier 1 Load Shaping rates shown in section 2.1.3.1 of the PF-12 rate schedule.

(2) Resource Shaping Billing Determinant

The billing determinant for each resource is the difference between the planned monthly/diurnal generation from Exhibit D amounts and the annual average Exhibit A amounts for the same year. Generally, the Resource Shaping charge does not apply to small, non-dispatchable resources as such resources are defined in the Customer's CHWM Contract.

(3) Resource Shaping Charge

For each resource, the Resource Shaping charge is the product of multiplying the Resource Shaping rate by the Resource Shaping billing determinant for each monthly/diurnal period. The sum of the values is divided by 24 (or 12 if the service applies only in FY 2013) to calculate a flat monthly charge.

(d) Resource Shaping Charge Adjustment

(1) Resource Shaping Charge Adjustment Rate

The rates are the monthly/diurnal Resource Shaping rates described in section 1(c) above.

(2) Resource Shaping Charge Adjustment Billing Determinant

For each resource, the billing determinant is the difference between the planned monthly/diurnal generation from Exhibit D amounts and the actual monthly/diurnal generation. The actual generation amounts will be either the resource meter readings or resource transmission schedules if the resource requires an e-Tag. The calculation of the Resource Shaping Charge Adjustment billing determinant will also include energy provided through FORS, TCMS, planned outage replacement, economic dispatch, and UAIs in the determination of actual generation.

(3) Resource Shaping Charge Adjustment

For each resource, the Resource Shaping Charge Adjustment is the product of multiplying the Resource Shaping rate by the Resource Shaping Charge Adjustment billing determinant for each monthly/diurnal period. On a monthly/diurnal basis this calculation can result in either a charge or a credit.

2. Secondary Crediting Service (SCS) Charges

SCS provides a Load Following Customer that dedicates the entire output of a hydroelectric Existing Resource with a credit for the energy produced by that resource that is in excess of the amounts specified in the CHWM Contract Exhibit A (Exhibit A amounts) and a charge for any energy shortfall by the resource from the Exhibit A amounts. There is also an SCS Administrative Charge for providing this service.

When a resource has SCS applied to it, the PF Tier 1 Demand and Load Shaping billing determinants will be calculated using the applicable monthly/diurnal Exhibit A amounts instead of either the actual, metered values or annual average Exhibit A amounts.

(a) SCS Shortfall Energy Charges and Secondary Energy Credits

(1) SCS Energy Rate

The rates are the monthly/diurnal Resource Shaping rates described in section 1(c) above.

(2) SCS Energy Billing Determinant

For each resource, the billing determinant is the difference between the actual monthly/diurnal generation and monthly/diurnal generation from Exhibit A amounts. The actual generation amounts will be either the resource meter readings or resource transmission schedules if the resource requires an e-Tag. The actual generation shall include energy amounts provided through TCMS.

(3) SCS Shortfall Energy Charge/Secondary Energy Credit

For each resource, the charge or credit is the product of multiplying the SCS Energy rate by the SCS Energy billing determinant for each monthly/diurnal period. On a monthly/diurnal basis, this calculation can result in a charge or a credit. If the actual generation exceeds the Exhibit A amount, the Customer will receive a credit. If the actual generation is less than the Exhibit A amount, the Customer will receive a charge.

(b) SCS Administrative Charge

(1) SCS Administrative Rate

The rate is the monthly PF Tier 1 Demand rate shown in section 2.1.2.1 of the PF-12 rate schedule.

(2) SCS Administrative Charge Billing Determinant

For each resource, the billing determinant is the monthly HLH Exhibit A amount multiplied by the forced outage rating.

(3) SCS Administrative Charge

For each resource, the SCS Administrative charge is the product of multiplying the SCS Administrative rate by the SCS Administrative billing determinant for each month. The sum of the values is divided by 12 to calculate a flat monthly charge. The SCS Administrative charge will be specified in Exhibit D of the Customer's CHWM Contract.

3. Forced Outage Reserve Service (FORS) Charges

FORS is an optional service to provide an agreed-upon amount of capacity and energy to Customers that have a qualifying resource that experiences a forced outage. Unless stated otherwise, the resource amounts used in these calculations are those specified in the Customer's CHWM Contract Exhibit D (Exhibit D amounts) and are planned generation amounts based on hourly generation from the most recent historical year.

(a) FORS Capacity Charge

(1) FORS Capacity Rate

<i>Month</i>	<i>Rate in \$/kW</i>
October	9.18
November	9.31
December	9.97
January	9.70
February	9.92
March	9.60
April	9.10
May	8.50
June	8.72
July	10.20
August	10.75
September	10.53

(2) FORS Capacity Billing Determinant

For each resource, the billing determinant is the monthly firm capacity multiplied by the forced outage rating. The monthly firm capacity is calculated in the manner described under the DFS Capacity Billing Determinant, section 1(b)(2).

(3) FORS Capacity Charge

For each resource, the FORS Capacity charge is the product of multiplying the FORS Capacity rate by the FORS Capacity billing determinant for each month. The sum of the values is divided by 12 to calculate a flat monthly charge. The FORS Capacity charge will be specified in Exhibit D of the Customer's CHWM Contract.

(b) FORS Energy Charge

(1) FORS Energy Rate

The rate for the energy provided during the first 24 hours of a forced outage will be the average of the Powerdex Mid-C hourly index prices (or its replacement) during hours of the forced outage. The rate for energy provided after the first 24 hours of a forced outage will be the diurnal Intercontinental Exchange (ICE) Mid-C Day Ahead Power Price Index (or its replacement) over the applicable diurnal period for which energy is provided. If any Mid-C price used in computing the average is less than zero, the average of the prices will be computed using a zero price for such hours.

(2) FORS Energy Billing Determinant

The FORS Energy billing determinant is the total actual replacement generation a resource requires to meet the planned generation amount specified in Exhibit D of the Customer’s CHWM Contract, subject to the FORS energy limits specified therein.

(3) FORS Energy Charge

For each resource, the monthly FORS Energy charge is the product of multiplying the FORS Energy rate by the FORS Energy billing determinant.

4. Transmission Scheduling Service Charge and Transmission Curtailment Management Service Charge

Transmission Scheduling Service (TSS) is a service provided by Power Services to undertake certain scheduling obligations on behalf of the Customer. Transmission Curtailment Management Service (TCMS) is a feature of TSS under which BPA provides either replacement transmission or power to Customers that have a qualifying resource that experiences a transmission event pursuant to the conditions specified in Exhibit F of the CHWM Contract.

(a) TSS Charge

(1) TSS Rate

<i>FY</i>	<i>Rate in mills/kWh</i>
2012	0.23
2013	0.23

(2) TSS Billing Determinant

The TSS billing determinant is the total kilowatthours of planned generation that the Customer has dedicated to load during the rate period, as specified in Exhibit A of the CHWM Contract.

(3) TSS Charge

For each eligible resource, the TSS charge is the product of multiplying the TSS rate by TSS billing determinant for each month of the rate period (or FY 2013 if this service applies only in FY 2013). The sum of the values is divided by 24 (or 12 if the service applies only in FY 2013) to calculate a flat monthly charge. The charge is subject to a cap such that if the annual cost to the Customer using the TSS rate exceeds \$1,080/month, then the monthly charge is capped at \$1,080/month.

(b) TCMS Charge if Replacement Power is Provided

(1) TCMS Rate

The TCMS rate will be the Powerdex Mid-C hourly index price (or its replacement) for the hour the event occurred. If any Mid-C price is less than zero, the TCMS Energy rate will be zero for that hour.

(2) TCMS Billing Determinant

The TCMS billing determinant is the total actual kilowatthours of replacement power BPA supplies.

(3) TCMS Charge

For each eligible resource, the TCMS charge is the product of multiplying the TCMS rate by the TCMS billing determinant for each hour of the month.

(c) TCMS Charge if Alternative Transmission is Provided

(1) TCMS Charge

When replacement Point-to-Point transmission is used to deliver the Customer's eligible resource to load using an alternate transmission path, for each resource the TCMS charge is the cost of the additional transmission BPA purchases plus any additional costs, including real power losses associated with using the replacement transmission.

Q. RHWMTier 1 System Capability (RT1SC)

The RT1SC is an element of the Tier 1 Load Shaping Charge billing determinant, described in section 2.1.3.2 of the PF-12 rate schedule. RT1SC is the Tier 1 System Firm Critical Output plus RHWMTier 1 Augmentation. The RT1SC values for the FY 2012-2013 rate period are shown in Table F below.

Table F
FY 2012-2013 RHWMTier 1 System Capability

<i>Month</i>	<i>RTISC in kWh</i> <i>Diurnal Period:</i>	
	<i>HLH</i>	<i>LLH</i>
October	2,961,235,239	1,678,579,553
November	3,502,848,559	2,177,926,566
December	3,481,759,080	2,182,731,814
January	3,426,187,607	2,261,397,688
February		
2012	2,903,311,798	1,828,509,446
2013	2,788,415,894	1,771,061,494
March	2,889,552,246	1,877,177,196
April	2,229,763,533	1,497,063,764
May	4,131,953,165	2,496,552,914
June	3,591,719,178	1,996,068,864
July	4,006,184,756	1,953,943,898
August	3,319,571,128	1,739,677,390
September	3,117,743,858	1,824,810,716

Note: Monthly values are the same for FY 2012 and FY 2013, except for February, due to the 2012 leap year.

R. Slice True-Up Adjustment

Slice Customers will have an annual Slice True-Up Adjustment for expenses, revenue credits, and adjustments allocated to the Composite cost pool and to the Slice cost pool. The annual Slice True-Up Adjustment will be calculated for each fiscal year as soon as BPA’s audited actual financial data are available (usually in November). See section 2.7 of the TRM, BP-12-A-03.

1. Calculation of the Annual Composite Cost Pool True-Up

Following the end of each fiscal year of the rate period, BPA will

- (a) subtract:
 - (i) the forecast annual expenses, revenue credits, and adjustments allocated to the Composite cost pool for the applicable fiscal year of the rate period, from
 - (ii) the actual expenses, revenue credits, and adjustments in the applicable fiscal year of the rate period that are allocable to the Composite cost pool;
- (b) divide the difference determined in (a) above by the sum of TOCAs for that fiscal year adjusted in accordance with TRM section 5.1.1, based on the Annual Net Requirement process for Slice Customers and the Load Shaping True-Up methodology set forth in TRM section 5.2.4.1 for Load Following Customers; and
- (c) multiply the dollar amount in (b) above by each Slice Customer’s Slice Percentage for the applicable fiscal year.

For each Slice Customer, the dollar amount calculated, which may be positive or negative, constitutes its Slice True-Up Adjustment charge for the Composite cost pool.

The Composite Cost Pool True-Up Table (Table G) contains the forecast expenses, revenue credits, and adjustments that will be the basis, when compared to actual expenses, revenue credits, and adjustments, for the Slice True-Up Adjustment calculation for the Composite cost pool for the applicable fiscal year.

(a) Calculation of the Actual Firm Surplus and Secondary Adjustment from Unused RHWM

For purposes of the annual Composite Cost Pool True-Up, the actual Firm Surplus and Secondary Adjustment from Unused RHWM for the applicable fiscal year will be calculated as the sum of:

- (1) the forecast Firm Surplus and Secondary Adjustment from Unused RHWM for the applicable fiscal year developed in the BP-12 7(i) process; and
- (2) the Change in PF Composite Customer Charge Revenue for the applicable fiscal year (change can be positive or negative);

Where:

Change in PF Composite Customer Charge Revenue = (sum of actual TOCAs – sum of forecast TOCAs) × monthly Composite Customer rate × 12 months.

TOCAs are expressed as a percentage, *e.g.*, 95 percent.

Sum of actual TOCAs is calculated after the fiscal year, and is equal to the forecast sum of TOCAs for Slice Customers, adjusted based on the Annual Net Requirement process in accordance with TRM section 5.1.1, and for Load Following Customers, adjusted based on TRM section 2.7.1 using information from the Load Shaping True-Up methodology set forth in TRM section 5.2.4.1.

Sum of forecast TOCAs is the sum of TOCAs used to set the PF-12 Composite Customer rate.

and

- (3) the Change in Unused RHWM Revenue for the applicable fiscal year (change can be positive or negative).

Where:

Change in Unused RHWM Revenue = (Actual Unused RHWM – Forecast Unused RHWM) × 45.74 mills/kWh.

Actual Unused RHWM = (1.00 – sum of actual TOCAs, expressed as a decimal) × RHWM Tier 1 System Capability for the applicable fiscal year (expressed in aMW) × 8,760 hours (8,784 hours if a leap year)

Forecast Unused RHW = (1.00 – sum of forecast TOCAs, expressed as a decimal) × RHW Tier 1 System Capability for the applicable FY (expressed in aMW) × 8,760 hours (8,784 hours if a leap year).

(b) Calculation of the Actual DSI Revenue Credit

For purposes of the annual Composite Cost Pool True-Up, the Actual DSI Revenue Credit for the applicable fiscal year will be calculated as the sum of:

- (1) the forecast DSI Revenue Credit for the applicable fiscal year developed in the BP-12 7(i) process;
 - (2) i) the forecast MWh amount used to calculate (1) above for the applicable fiscal year *minus* ii) the actual MWh amount of DSI sales for the applicable fiscal year, the result multiplied by -1.59 mills/kWh;
- and
- (3) DSI Take-or-Pay revenues

Where:

Actual kWh amount of DSI sales and DSI Take-or-Pay revenues will be obtained from BPA data sources

-1.59 mills/kWh is calculated by the equation:
PFMEES – 8.41 mills/kWh

Where:

PFMEES is the PF Melded Equivalent Energy Scalar of 6.82 mills/kWh and is subject to the CRAC, the DDC, and the NFB Emergency Surcharge.

2. Calculation of the Annual Slice Cost Pool True-Up

The Slice Cost Pool True-Up Table (Table H) contains the forecast expenses, revenue credits, and adjustments that will be the basis, when compared to actual expenses, revenue credits, and adjustments, for the Slice True-Up Adjustment calculation for the Slice cost pool for the applicable fiscal year.

Following the end of each fiscal year and pursuant to TRM section 2.7.2, BPA will:

- (a) subtract:
 - (1) the forecast annual expenses, revenue credits, and adjustments allocated to the Slice cost pool for the applicable fiscal year of the rate period
from
 - (2) the actual expenses, revenue credits, and adjustments that are allocated to the Slice cost pool for the applicable fiscal year of the rate period;
- and
- (b) for each Slice Customer, multiply the resulting difference from (1) above by the ratio of (i) the Customer’s Slice Percentage for the fiscal year in Exhibit K of the

Slice/Block Contract to (ii) the sum of all Customers' Slice Percentages for the fiscal year in all Exhibit K of the Slice/Block CHWM Contracts.

For each Slice Customer, the dollar amount calculated, which may be positive or negative, constitutes its Slice True-Up Adjustment charge for the Slice cost pool.

Table G
Composite Cost Pool True-Up Table

	Audited Actual Data (\$000)	FY 2012 forecast (\$000)	FY 2013 forecast (\$000)
1	Operating Expenses		
2	Power System Generation Resources		
3	Operating Generation		
4	COLUMBIA GENERATING STATION (WNP-2)	\$ 306,366	\$ 345,945
5	BUREAU OF RECLAMATION	\$ 111,972	\$ 119,891
6	CORPS OF ENGINEERS	\$ 208,700	\$ 215,700
8	LONG-TERM CONTRACT GENERATING PROJECTS	\$ 25,079	\$ 25,832
9	Sub-Total	\$ 652,117	\$ 707,368
10	Operating Generation Settlement Payment and Other Payments		
11	COLVILLE GENERATION SETTLEMENT	\$ 21,928	\$ 22,148
12	SPOKANE LEGISLATION SETTLEMENT	\$ -	\$ -
13	Sub-Total	\$ 21,928	\$ 22,148
14	Non-Operating Generation		
15	TROJAN DECOMMISSIONING	\$ 1,500	\$ 1,500
16	WNP-1&3 DECOMMISSIONING	\$ 438	\$ 448
17	Sub-Total	\$ 1,938	\$ 1,948
18	Gross Contracted Power Purchases		
19	PNCA HEADWATER BENEFITS	\$ 2,452	\$ 2,704
20	HEDGING/MITIGATION (omit except for those assoc. with augmentation)	\$ -	\$ -
21	GROSS OTHER POWER PURCHASES (omit, except for those assoc. with Designated BPA System Obligations or Designated BPA Contract Purchases)	\$ -	\$ -
22	Sub-Total	\$ 2,452	\$ 2,704
23	Bookout Adjustment to Power Purchases (omit)		
24	Augmentation Power Purchases (omit - calculated below)		
25	AUGMENTATION POWER PURCHASES		
26	Sub-Total	\$ -	\$ -
27	Exchanges and Settlements		
28	RESIDENTIAL EXCHANGE PROGRAM (REP)	\$ 210,490	\$ 192,656
29	REP ADMINISTRATION COSTS	\$ 1,446	\$ 885
30	OTHER SETTLEMENTS	\$ -	\$ -
31	Sub-Total	\$ 211,935	\$ 193,541
32	Renewable Generation		
33	RENEWABLES R&D	\$ 5,622	\$ 5,939
34	Contra expense for unspent GEP revenues remaining at end of FY 2011	\$ (2,625)	\$ (2,625)
35	RENEWABLES (excludes KIII)	\$ 27,670	\$ 28,145
36	Sub-Total	\$ 30,667	\$ 31,459
37	Generation Conservation		
38	GENERATION CONSERVATION R&D	\$ -	\$ -
39	DSM TECHNOLOGY	\$ -	\$ -
40	CONSERVATION ACQUISITION	\$ 15,950	\$ 15,950
41	LOW INCOME WEATHERIZATION & TRIBAL	\$ 5,000	\$ 5,000
42	ENERGY EFFICIENCY DEVELOPMENT	\$ 11,500	\$ 11,500
43	LEGACY	\$ 1,000	\$ 900
44	MARKET TRANSFORMATION	\$ 13,500	\$ 14,500
45	Sub-Total	\$ 46,950	\$ 47,850
46	Conservation Rate credit (CRC)	\$ -	\$ -
47	Power System Generation Sub-Total	\$ 967,988	\$ 1,007,017
48			
49	Power Non-Generation Operations		
50	Power Services System Operations		
51	EFFICIENCIES PROGRAM	\$ -	\$ -
52	PS SYSTEM OPERATIONS R&D	\$ -	\$ -
53	INFORMATION TECHNOLOGY	\$ 7,143	\$ 7,316
54	GENERATION PROJECT COORDINATION	\$ 5,895	\$ 5,919
55	SLICE IMPLEMENTATION	\$ 2,322	\$ 2,394
56	Sub-Total	\$ 15,360	\$ 15,629
57	Power Services Scheduling		
58	OPERATIONS SCHEDULING	\$ 10,041	\$ 10,010
59	PS SCHEDULING R&D	\$ -	\$ -
60	OPERATIONS PLANNING	\$ 6,744	\$ 6,709
61	Sub-Total	\$ 16,785	\$ 16,719
62	Power Services Marketing and Business Support		
63	SALES & SUPPORT	\$ 19,745	\$ 20,130
64	STRATEGY, FINANCE & RISK MGMT	\$ 16,469	\$ 17,412
65	EXECUTIVE AND ADMINISTRATIVE SERVICES	\$ 3,480	\$ 3,550
66	CONSERVATION SUPPORT	\$ 9,555	\$ 9,686
67	Sub-Total	\$ 49,249	\$ 50,778
68	Power Non-Generation Operations Sub-Total	\$ 81,393	\$ 83,126
69	Power Services Transmission Acquisition and Ancillary Services		
70	PS Transmission Acquisition and Ancillary Services		
71	POWER SERVICES TRANSMISSION & ANCILLARY SERVICES		
72	Transmission costs for Designated BPA System Obligations	\$ 31,707	\$ 31,707
73	3RD PARTY GTA WHEELING	\$ 52,263	\$ 52,891
74	POWER SERVICES - 3RD PARTY TRANS & ANCILLARY SVCS (omit)		
75	GENERATION INTEGRATION	\$ 8,865	\$ 8,709
76	WIND INTEGRATION TEAM	\$ 4,170	\$ 4,259
77	TELEMETERING/EQUIP REPLACEMT	\$ 50	\$ 51
78	Power Services Trans Acquisition and Ancillary Serv Sub-Total	\$ 97,056	\$ 97,617
79	Fish and Wildlife/USF&W/Planning Council/Environmental Req		
80	BPA Fish and Wildlife (includes F&W Shared Services)		
81	Fish & Wildlife	\$ 237,394	\$ 241,384
82	USF&W Lower Snake Hatcheries	\$ 28,800	\$ 29,900
83	Planning Council	\$ 10,114	\$ 10,355
84	Environmental Requirements	\$ 302	\$ 305
85	Fish and Wildlife/USF&W/Planning Council Sub-Total	\$ 276,610	\$ 281,944

**Table G, continued
Composite Cost Pool True-Up Table**

	Audited Actual Data (\$000)	FY 2012 forecast (\$000)	FY 2013 forecast (\$000)
86	BPA Internal Support		
87	Additional Post-Retirement Contribution	\$ 17,243	\$ 17,821
88	Agency Services G&A (excludes direct project support)	\$ 51,735	\$ 52,662
89	BPA Internal Support Sub-Total	\$ 68,978	\$ 70,483
90	Bad Debt Expense	\$ -	\$ -
91	Other Income, Expenses, Adjustments	\$ -	\$ -
92	Non-Federal Debt Service		
93	Energy Northwest Debt Service		
94	COLUMBIA GENERATING STATION DEBT SVC	\$ 115,553	\$ 100,172
95	WNP-1 DEBT SVC	\$ 282,802	\$ 249,288
96	WNP-3 DEBT SVC	\$ 156,299	\$ 175,817
97	EN RETIRED DEBT	\$ -	\$ -
98	EN LIBOR INTEREST RATE SWAP	\$ -	\$ -
99	Sub-Total	\$ 554,654	\$ 525,277
100	Non-Energy Northwest Debt Service		
101	TROJAN DEBT SVC	\$ -	\$ -
102	CONSERVATION DEBT SVC	\$ 2,379	\$ 2,377
103	COWLITZ FALLS DEBT SVC	\$ 11,715	\$ 11,709
104	NORTHERN WASCO DEBT SVC	\$ 2,223	\$ 2,224
105	Sub-Total	\$ 16,316	\$ 16,309
106	Non-Federal Debt Service Sub-Total	\$ 570,970	\$ 541,586
107	Depreciation	\$ 122,169	\$ 127,560
108	Amortization	\$ 81,029	\$ 86,767
109	Total Operating Expenses	\$ 2,266,193	\$ 2,296,100
110			
111	Other Expenses		
112	Net Interest Expense	\$ 208,802	\$ 221,546
113	Interest credit adjustment (to remove nonSlice cost pool interest credit)	\$ 1,362	\$ (1,216)
114	LDD	\$ 31,768	\$ 32,944
115	Irrigation Rate Discount Costs	\$ 19,305	\$ 19,305
116	Sub-Total	\$ 261,237	\$ 272,579
117	Total Expenses	\$ 2,527,430	\$ 2,568,680
118			
119	Revenue Credits		
120	Generation Inputs for Ancillary, Control Area, and Other Services Revenues	\$ 127,449	\$ 131,078
121	Downstream Benefits and Pumping Power revenues	\$ 14,338	\$ 14,438
122	4(h)(10)(c) credit	\$ 91,062	\$ 95,847
123	Colville and Spokane Settlements	\$ 4,600	\$ 4,600
124	Energy Efficiency Revenues	\$ 11,500	\$ 11,500
125	Miscellaneous revenues	\$ 3,420	\$ 3,420
126	Renewable Energy Certificates	\$ 2,658	\$ 2,836
127	Pre-Subscription Revenues	\$ 1,716	\$ 1,778
128	Net Revenues from other Designated BPA System Obligations	\$ 360	\$ 397
129	WNP-3 Settlement revenues	\$ 29,516	\$ 29,163
130	RSS Revenues	\$ 2,532	\$ 2,611
131	Firm Surplus and Secondary Adjustment (from Unused RHWM)	\$ 19,469	\$ 5,827
132	Balancing Augmentation Adjustment	\$ (7,957)	\$ (6,268)
133	Transmission Loss Adjustment	\$ 24,835	\$ 25,266
134	Tier 2 Rate Adjustment	\$ 215	\$ 645
135	NR Revenues	\$ 1	\$ 1
136	Total Revenue Credits	\$ 325,712	\$ 323,139
137			
138	Augmentation Costs (not subject to True-Up)		
139	Tier 1 Augmentation Resources (includes Augmentation RSS and Augmentation RSC adders)	\$ 12,740	\$ 12,737
140	Augmentation Purchases	\$ -	\$ 66,155
141	Total Augmentation Costs	\$ 12,740	\$ 78,892
142			
143	DSI Revenue Credit		
144	Revenues 340 aMW, 340 aMW @ IP rate	\$ 108,606	\$ 108,309
145	Total DSI revenues	\$ 108,606	\$ 108,309
146			
147	Minimum Required Net Revenue Calculation		
148	Principal Payment of Fed Debt for Power	\$ 193,000	\$ 122,800
149	Irrigation assistance	\$ 1,182	\$ 58,822
150	Depreciation	\$ 122,169	\$ 127,560
151	Amortization	\$ 81,029	\$ 86,767
152	Capitalization Adjustment	\$ (45,937)	\$ (45,937)
153	Bond Premium Amortization	\$ 185	\$ 185
154	Principal Payment of Fed Debt exceeds non cash expenses	\$ 36,736	\$ 13,047
155	Minimum Required Net Revenues	\$ 36,736	\$ 13,047
156			
157	Annual Composite Cost Pool (Amounts for each FY)	\$ 2,142,588	\$ 2,229,172
158			
159	SLICE TRUE-UP ADJUSTMENT CALCULATION FOR COMPOSITE COST POOL		
160	TRUE UP AMOUNT (Diff. between actual Comp. Cost Pool and forecast Comp. Cost Pool for applicable FY)		
161	Adjustment of True-Up Amount when actual TOCAs < 100 percent (divide by sum of TOCAs, expressed as a decimal, 100 percent = 1.0)		
162	TRUE-UP ADJUSTMENT CHARGE BILLED (26.85407 percent)		

**Table H
Slice Cost Pool True-Up Table**

	Audited Actual Data (\$000)	FY 2012 forecast (\$000)	FY 2013 forecast (\$000)
1 Slice Expenses			
2			
3			
4 Total Slice Expenses		\$ -	\$ -
5			
6 Slice Credits			
7			
8 Total Slice Credits		\$ -	\$ -
9			
10 Annual Slice Cost Pool (Amounts for each FY)		\$ -	\$ -
11			
12 SLICE TRUE-UP ADJUSTMENT CALCULATION FOR SLICE COST POOL			
13 TRUE UP AMOUNT (Diff. between actual Comp. Cost Pool and forecast Comp. Cost Pool for applicable FY)			
14			
15 TRUE-UP ADJUSTMENT CHARGE BILLED (100 percent)			

S. Tier 2 Rate TCMS Adjustment

When BPA provides replacement power during a transmission event, a TCMS adjustment will be applied to Customers' bills if they purchase power at the applicable Tier 2 rate. The megawatthours of replacement power will be multiplied by the applicable Powerdex Mid-C hourly index price (or its replacement) for the hour(s) the event occurred. If a Mid-C price is less than zero, the TCMS Adjustment rate will be zero for that hour. The sum of this calculation every month is the Tier 2-related TCMS cost. Each Tier 2 rate Customer's TCMS Adjustment will be the Customer's share of the Tier 2-related TCMS cost allocated by total applicable Tier 2 rate sales.

T. TOCA Adjustment

For each Customer purchasing Firm Requirements Power service under a CHWM Contract, a TOCA for each year of the rate period is calculated in the BP-12 7(i) process and will be made available to the Customer prior to October 1, 2011. A Customer's TOCA for a fiscal year will be revised only as specified below. Any adjustment of a Customer's TOCA must be made prior to each October 1 and is effective for the following fiscal year only.

1. Load Following Customers

If there is substantial reason for BPA to believe that the Customer's Actual Annual Tier 1 Load will differ from its Forecast Net Requirement determined in the 2011 CHWM Process, BPA will calculate an Adjusted TOCA for that Load Following Customer using an updated estimate of the Customer's Actual Annual Tier 1 Load in place of the Customer's Forecast Net Requirement, as follows:

$$\frac{\text{Updated estimate of Customer's Actual Annual Tier 1 Load}}{\text{Sum of all Customers' RHWs}} \times 100$$

If the resulting TOCA differs from the TOCA calculated in the BP-12 7(i) process by at least 20 percent, this Adjusted TOCA will be used in the place of the TOCA calculated in the BP-12 7(i) process.

A Load Following Customer and BPA may agree to revise a TOCA for a difference of less than 20 percent.

The Customer's Adjusted TOCA will be the billing determinant for the Composite and Non-Slice Customer charges for the relevant fiscal year. No other Customer's TOCA shall be affected by this TOCA adjustment.

2. Slice/Block Customers

BPA will revise the TOCA of a Slice/Block Customer in two circumstances:

- (a) If the Customer's Annual Net Requirement is less than its RHWM and differs from the Forecast Net Requirement used in the BP-12 7(i) process, the Customer's TOCA shall be recalculated for that fiscal year using the Customer's Annual Net Requirement.
- (b) If the Customer's Annual Net Requirement equals or exceeds its RHWM, and its Forecast Net Requirement used in the BP-12 7(i) process is less than its RHWM, then the Customer's TOCA shall be recalculated for that fiscal year using the Customer's RHWM.

The adjusted TOCA will be used to determine an adjusted Non-Slice TOCA for the relevant fiscal year. No other Customer's TOCA shall be affected by this TOCA adjustment.

U. Unanticipated Load Service

1. Availability

Unanticipated Load Service (ULS) applies to any request for Firm Requirements Power received after February 1, 2011, that results in an unanticipated increase in a Customer's load placed on BPA during the FY 2012-2013 rate period. Contractual obligations that result from a request for service under section 9(i) of the Northwest Power Act also will be considered ULS. ULS also may apply to a Customer that adds load through retail access, including load that was once served by the customer and returns under retail access. When ULS is used for replacement of a customer's new Specified Resource, ULS is available only on a temporary basis for the FY 2012-2013 rate period and only when requested pursuant to the required notice.

The following list includes the only sources of unanticipated load that will be served by BPA along with the applicable rate schedule under which each type of unanticipated load will be served.

Under PF-12, unanticipated load is:

- Load of a New Public (Load Following customers only)
- Load annexed from investor-owned utilities by a Public (Load Following customers only)

Under NR-12, unanticipated load is:

- New Large Single Loads
- Requirements service requested by investor-owned utilities

Under FPS-12, unanticipated load is:

- Delays in the on-line date of a Customer's specified resource for Above-RHWM service (Load Following customers only)
- New Specified Resources that are 10 aMW or less and either experience permanent failure during the rate period or fail to come online (Load Following customers only)
- Transfer customers that both 1) cannot secure Firm Network Transmission (NT) from source to sink for their Dedicated Non-Federal Resource to their Above-RHWM Load by the time power deliveries are to begin under the Regional Dialogue contract and 2) are expected to face high TCMS charges due to their reliance on Secondary Network Transmission, while they pursue Firm Network Transmission (Load Following customers only)

BPA also will review annexations of load between public utility Customers to assess if there will be an increase in BPA's Firm Requirements Power that will be considered unanticipated load.

To start service for unanticipated load, a Customer must notify BPA three months in advance of the requested service date for load amounts between 1 and 50 aMW and six months in advance of the requested service date for load amounts greater than 50 aMW. To stop service for unanticipated load, a Customer must notify BPA three months in advance of the requested stop date.

ULS will apply for the length of the Customer's contract for unanticipated load service or the conclusion of the rate period on September 30, 2013, whichever occurs first. ULS is a temporary service and may be adjusted annually. Any unanticipated load service in a future rate period must comply with the provisions for ULS for that rate period.

2. Unanticipated Load Rate Under PF-12 Rate Schedule

(a) Energy Charge

(1) Energy Rate

The energy rate may be adjusted each Fiscal Year and will be the greater of (1) the rate for the applicable diurnal period from the table below, or (2) the

applicable diurnal period forecast market price for purchased power plus any additional costs incurred by BPA in purchasing power from other entities.

<i>Month</i>	<i>Rate in mills/kWh</i>	
	<i>Diurnal Period:</i>	
	<i>HLH</i>	<i>LLH</i>
October	37.86	31.20
November	38.37	31.40
December	41.10	33.39
January	40.03	31.70
February	40.93	33.17
March	39.57	32.33
April	37.53	30.41
May	35.06	24.40
June	35.97	23.02
July	42.07	29.91
August	44.35	32.15
September	43.45	33.59

(2) Energy Billing Determinant

The energy billing determinant will be the total amount of unanticipated load for each diurnal period, measured in kilowatthours.

(b) Demand Charge

(1) Demand Rate

The demand rate is equal to the demand rate included in section 2.1.2.1 of the PF-12 rate schedule.

(2) Demand Billing Determinant

The demand billing determinant will be the lesser of (1) the maximum unanticipated hourly load in a month during the HLH minus the average HLH load amount for the month or (2) 20 percent of the highest unanticipated hourly load amount in a month during the HLH.

3. Unanticipated Load Rate Under the NR-12 Rate Schedule

(a) Energy Charge

(1) Energy Rate

The energy rate may be adjusted each Fiscal Year and will be the greater of (1) the rate for the applicable diurnal period from the table below, or (2) the

applicable diurnal period forecast market price for purchased power plus any additional costs incurred by BPA in purchasing power from other entities.

<i>Month</i>	<i>Rate in mills/kWh</i>	
	<i>Diurnal Period:</i>	
	<i>HLH</i>	<i>LLH</i>
October	71.70	65.04
November	72.21	65.24
December	74.94	67.23
January	73.87	65.54
February	74.77	67.01
March	73.41	66.17
April	71.37	64.25
May	68.90	58.24
June	69.81	56.86
July	75.91	63.75
August	78.19	65.99
September	77.29	67.43

(2) Energy Billing Determinant

The energy billing determinant is the total of unanticipated NR Hourly Load for each diurnal period, measured in kilowatthours.

(b) Demand Charge

(1) Demand Rate

The demand rate is equal to the demand rate included in section 2.2 of the NR-12 rate schedule.

(2) Demand Billing Determinant

The billing determinant is the maximum unanticipated NR Hourly Load in a month during HLH, in kilowatts, for the billing period minus the average of the unanticipated NR Hourly Load in a month during the HLH.

4. Unanticipated Load Rate Under the FPS-12 Rate Schedule

(a) Energy Charge

(1) Energy Rate

The energy rate may be adjusted each Fiscal Year and will be the greater of (1) the Resource Replacement rate for the applicable diurnal period (shown in the table below), or (2) the applicable diurnal period forecast market price

for purchased power plus any additional costs incurred by BPA in purchasing power from other entities.

<i>Month</i>	<i>Resource Replacement Rate in mills/kWh Diurnal Period:</i>	
	<i>HLH</i>	<i>LLH</i>
October	37.86	31.20
November	38.37	31.40
December	41.10	33.39
January	40.03	31.70
February	40.93	33.17
March	39.57	32.33
April	37.53	30.41
May	35.06	24.40
June	35.97	23.02
July	42.07	29.91
August	44.35	32.15
September	43.45	33.59

(2) Energy Billing Determinant

The energy billing determinant is the total of unanticipated load for each diurnal period, measured in kilowatthours.

(b) Demand Charge

(1) Demand Rate

<i>Month</i>	<i>Rate in \$/kW</i>
October	9.18
November	9.31
December	9.97
January	9.70
February	9.92
March	9.60
April	9.10
May	8.50
June	8.72
July	10.20
August	10.75
September	10.53

(2) Demand Billing Determinant

The billing determinant is the highest maximum unanticipated resource replacement load in a month during HLH, in kilowatts, for the billing period minus the average of the unanticipated resource replacement load in a month during the HLH.

V. Unauthorized Increase (UAI) Charge

The Unauthorized Increase Charge is a charge to any Customer taking more power from BPA than it is contractually entitled to take.

1. Charge for Unauthorized Increase in Demand

The amount of measured demand during a HLH billing hour that exceeds the amount of demand the Customer is contractually entitled to take during that hour shall be billed at 1.25 times the applicable monthly demand charge.

The billing determinant for the UAI demand charge will be equal to the Customer's single highest HLH demand that is in excess of the Customer's contractual demand entitlement.

For a Load Following Customer, the demand in excess of its demand entitlement will be the shortfall of its dedicated resources delivered to load on the hour of its Customer System Peak as compared to the Customer's CHWM Contract Exhibit A amount or Exhibit D amount, whichever is applicable.

For a Slice Customer, the demand in excess of its demand entitlement is any excess Slice delivered amount on the highest Slice delivery hour during the HLH period of the month.

2. Charge for Unauthorized Increase in Energy

The amount of measured energy or Residential Exchange Program contract load that exceeds the amount of energy the Customer is contractually entitled to take during a diurnal billing period shall be billed the greater of:

- (a) 150 mills/kWh; or
- (b) Two times the highest hourly Powerdex Mid-C Index price for firm power for the month in which the unauthorized increase occurs.

In the event the hourly Powerdex Mid-C price index expires, the index will be replaced for purposes of the Unauthorized Increase charge for energy by the highest price for the month from any applicable new hourly or diurnal energy index at a hub at which Northwest parties can trade, established between October 1, 2011, and September 30, 2013.

SECTION III. DEFINITIONS

A. Power Products and Services Offered By BPA Power Services

1. Block Product

As defined in the TRM, the Block Product is BPA's power product defined in section 4 of the Block and Slice/Block CHWM Contracts.

2. Capacity Without Energy

Capacity Without Energy is the stand-ready obligation whereby BPA will deliver a contract-specific amount of power upon contract-specific notice provisions. The notice provision may be automated, such as Automatic Generation Control automatic deliveries, phone call schedules, or any other standard utility notice provisions. The notice provision and duration of delivery is contract-specific and will affect the value of the capacity product. No energy is sold with Capacity Without Energy; any energy delivered when the capacity contract is exercised will be returned or paid for under contract terms. The terms of the contract will define all parameters of the required notice provisions and all parameters of the return or payment of any energy delivered when capacity rights are exercised.

3. Construction, Test and Start-Up, and Station Service

Power for the purpose of Construction, Test and Start-Up, and Station Service for a generating resource or transmission facility shall be made available to eligible Customers under the Priority Firm Power (PF-12), New Resources Firm Power (NR-12), and Firm Power Products and Services (FPS-12) rate schedules. Such power is not available under the PF Exchange rate.

Construction, Test and Start-Up, and Station Service power must be used in the manner specified below:

- (a) Power sold for construction is to be used in the construction of the project.
- (b) Power sold for test and start-up may be used prior to commercial operation, both to bring the project online and to ensure that the project is working properly.
- (c) Power sold for station service may be purchased at any time following commercial operation of the project. Once the project has been energized for commercial operation, the Customer may use station service power for start-up, shutdown, normal operations, and operations during a shutdown period.
- (d) Power sold for Construction, Test and Start-Up, and Station Service is not available for replacement of lost generation for forced or planned outages or resource underperformance.

4. Firm Requirements Power

Firm Requirements Power is Federal power that BPA makes continuously available to a Customer to meet BPA's obligations to the Customer under section 5(b) of the Northwest Power Act.

5. Forced Outage Reserve Service (FORS)

As defined in the TRM, FORS is a service that provides an agreed-to amount of capacity and energy to load during the forced outages of a qualifying resource.

6. Industrial Firm Power (IP)

Industrial Firm Power (IP) is electric power that BPA will make available to a DSI Customer subject to the terms of the DSI Customer's power sales contract with BPA.

7. Load Following Product

As defined in the TRM, the Load Following Product is the BPA firm power service under the Load Following CHWM Contract that meets the Customer's Total Retail Load less its Non-Federal Resources obligation on a real-time basis.

8. Load Shaping

BPA provides Load Shaping to Customers with CHWM Contracts purchasing either the Load Following Product or the Block portion of the Slice/Block Product. Load Shaping shapes the Tier 1 System Capability to the monthly/diurnal shape of a Customer's Actual Monthly/Diurnal Tier 1 Load.

9. New Resource Firm Power (NR)

New Resource Firm Power (NR) is electric power (capacity and energy) that BPA will make continuously available:

- (a) for any NLSL, as defined in the Northwest Power Act
- (b) for Firm Power purchased by IOUs pursuant to power sales contracts with BPA

NR is to be used to meet the Customer's firm power load within the PNW. Deliveries of NR may be reduced or interrupted as permitted by the terms of the Customer's power sales contract with BPA.

NR is guaranteed to be continuously available to the Customer during the period covered by its contractual commitment, except for reasons of certain uncontrollable forces and force majeure events.

10. Priority Firm Power (PF)

Priority Firm Power (PF) is electric power (capacity and energy) that BPA will make continuously available for direct consumption or resale by public bodies, cooperatives, and Federal agencies. Utilities participating in the Residential Exchange Program (REP) may purchase PF pursuant to their RPSA or REPSIA with BPA. PF is not available to serve NLSLs. Deliveries of PF may be reduced or interrupted as permitted by the terms of the Customer's power sales contract with BPA.

PF is guaranteed to be continuously available to the Customer during the period covered by its contractual commitment, except for reasons of certain uncontrollable forces and force majeure events.

11. Residential Exchange Program Power

Residential Exchange Program Power is power BPA sells to a Customer pursuant to the REP. Under Section 5(c) of the Northwest Power Act, BPA "purchases" power from eligible PNW utilities at a utility's Average System Cost (ASC). BPA then offers, in exchange, to "sell" an equivalent amount of electric power to that Customer at BPA's PF rate applicable to exchanging utilities (PF Exchange rate). The amount of power purchased and sold are both equal to the utility's eligible residential and small farm load. Benefits must be passed directly to the utility's residential and small farm Customers.

12. Resource Support Services (RSS)

Resource Support Services are used to make resources, either non-Federal or Federal resource acquisitions, financially equivalent to a flat block. RSS are available for all specified non-Federal resources that Load Following Customers contractually dedicate to serve their Total Retail Load and for specified new renewable resources Slice/Block Customers contractually dedicate to serving their Total Retail Load. RSS include Diurnal Flattening Service, Forced Outage Reserve Service, Secondary Crediting Service, and Transmission Curtailment Management Service.

13. Secondary Crediting Service (SCS)

As defined in the TRM, Secondary Crediting Service (SCS) is the optional service offered by BPA that provides a monetary credit for the secondary output from an existing resource that has a firm critical energy component and a secondary energy component. There are two different options for SCS. Under SCS Option 1, the customer exchanges power generated by its resource with Federal deliveries. Under SCS Option 2, the customer applies its resource directly to load and Federal deliveries cover the net load

14. Slice/Block Product

The Slice/Block Product is the Customer's purchase obligation under the Slice product and the Block Product to meet its regional consumer load obligation under section 3.1 of the Slice/Block CHWM Contract.

B. Definition of Rate Schedule Terms

1. Above-RHWM Load

As defined in the TRM, Above-RHWM Load is the forecast annual Total Retail Load, less Existing Resources, NLSLs, and the Customer's RHWM, as determined in the RHWM Process. For the Transition Period, FY 2012-2014, Above-RHWM Load will be established as described in TRM section 4.3.2.2.

2. Actual Monthly/Diurnal Tier 1 Load

As defined in the TRM, the Actual Monthly/Diurnal Tier 1 Load is the amount of the Customer's electric load (measured in kilowatthours) that was served at Tier 1 rates during the relevant monthly/diurnal period.

3. Billing Determinant

- (a) A measure of electric power usage at a Customer's metered point of delivery used in the computation of a Customer's bill;
- (b) as defined in the TRM, a unit of measure for sales of a product or service for which a Customer is billed by BPA.

4. Charge

A charge is the product of a Billing Determinant and a Rate.

5. Contract Demand

The Customer's Contract Demand is the maximum amount of capacity that the Customer agrees to purchase and BPA agrees to make available, subject to any limitations included in the applicable contract between BPA and the Customer.

6. Contract Demand Quantity (CDQ)

As defined in the TRM, the Contract Demand Quantity is the monthly quantity of demand (expressed in kilowatts) included in each Customer's CHWM Contract that is subtracted from the Customer System Peak (CSP) as part of the process of determining the Customer's Demand charge billing determinant, as calculated in accordance with TRM section 5.3.5.

7. Contract Energy

Contract Energy is the maximum amount of energy that the Customer agrees to purchase and BPA agrees to make available, subject to any limitations included in the applicable contract between BPA and the Customer.

8. Contract High Water Mark (CHWM)

As defined in the TRM, the Contract High Water Mark is the amount (expressed in average megawatts) computed for each Customer in accordance with TRM section 4. For each Customer with a CHWM Contract, the CHWM is used to calculate each Customer's RHW in the RHW Process for each applicable rate period. The CHWM Contract specifies the CHWM for each Customer.

9. CHWM Contract

As defined in the TRM, the CHWM Contract is the power sales contract between a Customer and BPA that contains a Contract High Water Mark (CHWM), and under which the Customer purchases power from BPA at rates established by BPA in accordance with the TRM.

10. Customer

Pursuant to the terms of an agreement and applicable rate schedule(s), a Customer is the entity that contracts to pay BPA for providing a product or service.

11. DSI Reserve

A DSI Reserve is any interruption right in addition to the Minimum DSI Operating Reserve – Supplemental, consistent with the DSI Reserves Adjustment standards and criteria described in GRSP II.E, that is provided by a DSI in a contract with BPA.

12. Flat Annual Shape

As defined in the CHWM Contracts, Flat Annual Shape means a distribution of energy having the same average megawatt value of energy in each month of the year.

13. Heavy Load Hours (HLH)

Heavy Load Hours (HLH) are all hours in the on-peak period – the hour ending 7 a.m. through the hour ending 10 p.m., Monday through Saturday, Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable). BPA recognizes NERC Standards in classifying six holidays as Light Load Hours.

14. IntercontinentalExchange (ICE) Mid-C Day Ahead Power Price Index

Average HLH (or on-peak) and average LLH (or off-peak) price indices for firm power sales of electricity at delivery points along the Mid-Columbia River, as published by IntercontinentalExchange, Inc.

15. Light Load Hours (LLH)

Light Load Hours (LLH) are all those hours in the off-peak period – the hour ending 11 p.m. through the 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 recognizes six holidays classified according to NERC Standards as LLH. Memorial Day, Labor Day, and Thanksgiving Day 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 the predetermined dates fall on a Sunday, the holiday is recognized as the Monday immediately following that Sunday, so that Monday is also LLH all day. If the predetermined dates fall on a Saturday, the holiday is recognized as that Saturday, and that Saturday is classified as LLH.

16. Metered Demand

The Metered Demand, in kilowatts, shall be the largest of the 60-minute clock hour integrated demands at which electric energy is delivered to a Customer:

- (a) at each point of delivery for which the Metered Demand is the basis for 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 accordance 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.

17. Metered Energy

The Metered Energy for a Customer shall be the amount of kilowatthours that are recorded on the appropriate metering equipment, adjusted as specified in the applicable agreement and delivered to a Customer:

- (a) at all points of delivery for which metered energy is the basis for determination of the measured energy; and

- (b) during any billing period.

18. Minimum DSI Operating Reserve – Supplemental

The Minimum DSI Operating Reserve – Supplemental is a right to interrupt DSI load made available by each DSI purchasing Industrial Firm Power in a megawatt amount equal to 10 percent of Net Industrial Firm Power. Net Industrial Firm Power shall equal the Industrial Firm Power less the sum of: (a) any power restricted by BPA under any other agreement, and (b) Wheel Turning Load. The availability of the Minimum DSI Operating Reserve – Supplemental must be consistent with North American Electric Reliability Corporation (NERC), Western Electricity Coordinating Council (WECC), or Northwest Power Pool (NWPP) standards and criteria:

- (a) The interruptible load must be off-line or the increased generation must be on-line within 10 minutes after a call from BPA;
- (b) In the event of a system disturbance, the interruptible load or increased generation must be accessible prior to a request for reserves from other NWPP parties;
- (c) The interruptible load must be available to be off-line for up to 105 minutes, or increased generation must be available to be on-line for up to 105 minutes.
- (d) There are no limitations on the number of times or aggregate minutes the Minimum DSI Operating Reserve – Supplemental may be utilized.

The energy charges stated in the IP-12 rate schedule reflect the credit for the value of the Minimum DSI Operating Reserve – Supplemental.

19. New Public

As defined in the TRM, a New Public is a Public that is not an Existing Customer.

As defined in the TRM, an Existing Customer is a Public that has a CHWM Contract at the time there is an annexation of some portion of its service territory.

20. NR Hourly Load

The actual hourly amount (measured in kilowatthours) of 1) a Customer's New Large Single Load that is recorded on the metering equipment and adjusted for any applicable resource amounts, as defined in the CHWM Contract; or 2) an investor-owned utility's NR Block amounts as specified in its NR Block Contract.

21. Powerdex Hourly Mid-C Price Index

Average hourly price index for hourly firm power sales of electricity at delivery points along the Mid-Columbia River, as published by Powerdex, Inc.

22. Public

As defined in the TRM, a Public is a public body or cooperative utility or Federal agency eligible to purchase requirements power from BPA pursuant to section 5(b) of the Northwest Power Act.

23. Rate Period High Water Mark (RHWM)

As defined in the TRM, the Rate Period High Water Mark is the amount, calculated by BPA in each RHWM Process pursuant to the formula in TRM section 4.2.1 and expressed in average megawatts, that BPA establishes for each Customer based on the Customer's CHWM and the RHWM Tier 1 System Capability. The maximum planned amount of power a Customer may purchase under Tier 1 rates each fiscal year of the rate period is the RHWM for Load Following Customers and the lesser of RHWM or Annual Net Requirement for Block and Slice/Block Customers.

24. Resource Shaping Charge

As defined in the TRM, the Resource Shaping Charge is the Customer-specific charge or credit as described in TRM section 8.5 that adjusts for the difference in value between a planned resource energy shape that is flat within each monthly/diurnal period (but not necessarily flat when comparing one monthly/diurnal period to another) and an equivalently sized flat annual block (flat for all hours of the fiscal year).

25. Resource Shaping Rate

As defined in the TRM, the Resource Shaping Rate is the rate that is set, as described in TRM section 8.5, equal to the Load Shaping Rate for each monthly/diurnal period.

26. Retail Access

Retail Access is non-discriminatory retail distribution access mandated either by Federal or state law that grants retail electric power consumers the right to choose their electricity supplier.

27. RHWM Tier 1 System Capability (RT1SC)

As defined in the TRM, RHWM Tier 1 System Capability means the Tier 1 System Firm Critical Output plus RHWM Augmentation. The RT1SC table of values may be found at GRSP II.Q.

28. Super Peak Credit

As defined in the TRM, the Super Peak Credit is the amount of additional HLH energy, as defined in TRM section 5.3.4, that a Customer contractually commits to provide with non-Federal resources during the Super Peak Period. Such notification must occur by October 31 of the Rate Case Year.

29. Super Peak Period

As defined in the TRM, the Super Peak Period is the hours defined pursuant to the CHWM Contract for each rate period into which a Customer must reshape its HLH energy from its Specified and Unspecified Resources to receive a Super Peak Credit. The hours BPA establishes for the Super Peak Period may vary by month and will be either two 3-hour periods each day or a single 6-hour period each day.

The Super Peak Period hours for FY 2012-2013 are as follows (HE = Hour Ending):

October – February	HE 8 through HE 10 and HE 18 through HE 20
March – May	HE 7 through HE 12
June – September	HE 14 through HE 19

30. System Shaped Load

As defined in the TRM, the System Shaped Load is the amount of energy a Load Following or Block Customer would receive from BPA under its Tier 1 rates in each of the monthly/diurnal periods in each fiscal year of the rate period if the Customer's TOCA Load was delivered in the shape of the RHWM Tier 1 System Capability through such periods.

31. Tier 1 Cost Allocator (TOCA)

As defined in the TRM, the TOCA is the billing determinant for the Customer charges for each Customer purchasing power at a Tier 1 rate under its CHWM Contract. TOCAs are expressed as percentages and are calculated as specified in TRM section 5.1.1. TOCAs are posted on BPA's Web site.

32. Tier 1 Customer System Peak (Tier 1 CSP)

Tier 1 Customer System Peak is equivalent to Customer System Peak as defined in the TRM. As defined in the TRM, Tier 1 CSP is the Customer's maximum Actual Hourly Tier 1 Load (measured in kilowatts) during the Heavy Load Hours of each month.

33. Total Customer System Peak (CSP or Total CSP)

Total Customer System Peak is the largest measured HLH Total Retail Load amount, in kilowatts, for the billing period.

34. Total Retail Load (TRL)

All retail electric power consumption, including electric system losses, within a customer's electrical system, excluding: (i) those loads BPA and the customer have agreed are nonfirm or interruptible loads; (ii) transfer loads of other utilities served by such customer; or (iii) any loads not on such customer's electrical system or not within such customer's service territory, unless specifically agreed to by BPA.

35. Unanticipated Load

Unanticipated Load is any request by a Customer for Firm Requirements Power received by BPA after February 1 of the ratesetting year that (1) results in an increase in the Customer's load placed on BPA during the ensuing rate period and (2) was not requested and thus not forecast when setting the rates for that rate period.

36. Wheel Turning Load

Wheel Turning Load is that portion of Total Plant Load that is not integral to a Customer's industrial process and is not a part of a technological allowance. A megawatt amount of Wheel Turning Load shall be defined in the Customer's power sales contract with BPA, unless such amount is self-supplied. Wheel Turning Load shall be exempt from reduction or interruption associated with providing Minimum DSI Operating Reserve – Supplemental.

Appendix A

Customer Refund Amounts in FY 2012-2013

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Customer Refund Amounts in FY 2012-2013

Section 1. Purpose

The Customer Refund Amount in FY 2012-2013 is a credit on a customer's power bill pursuant to the 2012 REP Settlement, Contract No. 11PB-12322 (Settlement). The individual customer credit is determined in part on the terms of the Settlement and in part on information developed in each rate case.

Section 2. Terms of the Customer Refund Amount

The Customer Refund Amount applies to customers listed in the table below.

A credit shall appear on the monthly power bills beginning with the month that the rates established in the BP-12 rate proceeding take effect. The total credit for a given fiscal year will be the fiscal year's Total Refund divided into 12 equal monthly amounts. Monthly amounts shall be rounded to the nearest whole dollar amount on the power bill.

Section 3. Definitions

PF-02 Refund is the portion of the Customer Refund Amount provided pursuant to Exhibit B of the Settlement.

Scaled TOCA is the customer specific percentage derived from a customer's BP-12 Final Proposal TOCA as adjusted pursuant to Section 3.4 of the REP Settlement Agreement.

TOCA Refund is the annual Refund Amount from Section 3.2 of the Settlement (\$76,537,617) minus the total annual Customer Specific PF-02 Refund Amount from Exhibit B of the Settlement (\$38,269,000) multiplied by the Scaled TOCA or $\$76,537,617 \text{ minus } \$38,269,000 \text{ equals } \$38,268,617 \text{ multiplied by the Scaled TOCA .}$

Total Refund is the sum of the PF-02 Refund Amount and the TOCA Refund Amount.

Section 4. Customer Refund Amounts

As displayed on the following table:

Customer Refund Amounts

BPA Customer ID Number	BPA Customer Name	PF-02 Refund (1)	FY 2012 Scaled TOCA (2)	FY 2013 Scaled TOCA (2)	FY 2012 TOCA Refund	FY 2013 TOCA Refund	FY 2012 Total Refund	FY 2013 Total Refund
10005	Alder Mutual	\$ 3,178	0.0080%	0.0079%	\$ 3,062	\$ 3,029	\$ 6,240	\$ 6,207
10015	Asotin County PUD #1	\$ -	0.0087%	0.0086%	\$ 3,321	\$ 3,305	\$ 3,321	\$ 3,305
10024	Benton County PUD #1	\$ 1,074,609	2.8284%	2.8274%	\$ 1,082,402	\$ 1,082,009	\$ 2,157,011	\$ 2,156,618
10025	Benton REA	\$ 365,914	0.9784%	0.9679%	\$ 374,437	\$ 370,409	\$ 740,351	\$ 736,323
10027	Big Bend Elec Coop	\$ 180,557	0.8823%	0.8846%	\$ 337,636	\$ 338,528	\$ 518,193	\$ 519,085
10029	Blachly Lane Elec Coop	\$ 102,877	0.2514%	0.2547%	\$ 96,195	\$ 97,454	\$ 199,072	\$ 200,331
10044	Canby, City of	\$ 146,793	0.2964%	0.2936%	\$ 113,439	\$ 112,348	\$ 260,232	\$ 259,141
10046	Central Electric Coop	\$ 400,537	1.1423%	1.1530%	\$ 437,128	\$ 441,226	\$ 837,664	\$ 841,762
10047	Central Lincoln PUD	\$ 483,285	2.2113%	2.2039%	\$ 846,231	\$ 843,394	\$ 1,329,515	\$ 1,326,679
10055	Albion, City of	\$ -	0.0058%	0.0058%	\$ 2,211	\$ 2,203	\$ 2,211	\$ 2,203
10057	Ashland, City of	\$ 161,518	0.2941%	0.2926%	\$ 112,560	\$ 111,959	\$ 274,078	\$ 273,477
10059	Bandon, City of	\$ 55,554	0.1058%	0.1053%	\$ 40,472	\$ 40,296	\$ 96,026	\$ 95,851
10061	Blaine, City of	\$ 60,506	0.1261%	0.1264%	\$ 48,251	\$ 48,377	\$ 108,757	\$ 108,883
10062	Bonnors Ferry, City of	\$ 45,589	0.0777%	0.0769%	\$ 29,747	\$ 29,427	\$ 75,335	\$ 75,015
10064	Burley, City of	\$ 105,386	0.2055%	0.2033%	\$ 78,649	\$ 77,803	\$ 184,035	\$ 183,189
10065	Cascade Locks, City of	\$ 17,913	0.0324%	0.0321%	\$ 12,396	\$ 12,270	\$ 30,309	\$ 30,183
10066	Centralia, City of	\$ 164,230	0.3516%	0.3523%	\$ 134,556	\$ 134,823	\$ 298,786	\$ 299,054
10067	Cheney, City of	\$ 108,606	0.2311%	0.2286%	\$ 88,452	\$ 87,501	\$ 197,058	\$ 196,107
10068	Chewelah, City of	\$ -	0.0401%	0.0411%	\$ 15,347	\$ 15,736	\$ 15,347	\$ 15,736
10070	Declo, City of	\$ -	0.0052%	0.0052%	\$ 2,004	\$ 1,983	\$ 2,004	\$ 1,983
10071	Drain, City of	\$ 19,088	0.0309%	0.0311%	\$ 11,835	\$ 11,893	\$ 30,923	\$ 30,981
10072	Ellensburg, City of	\$ 175,179	0.3505%	0.3467%	\$ 134,114	\$ 132,671	\$ 309,293	\$ 307,851
10074	Forest Grove, City of	\$ 169,141	0.3530%	0.3512%	\$ 135,088	\$ 134,395	\$ 304,229	\$ 303,535
10076	Heyburn, City of	\$ 50,558	0.0704%	0.0696%	\$ 26,939	\$ 26,649	\$ 77,497	\$ 77,207
10078	McCleary, City of	\$ 35,576	0.0610%	0.0603%	\$ 23,340	\$ 23,089	\$ 58,916	\$ 58,665
10079	McMinnville, City of	\$ 593,568	1.2488%	1.2751%	\$ 477,910	\$ 487,958	\$ 1,071,478	\$ 1,081,526
10080	Milton, Town of	\$ 53,707	0.1087%	0.1075%	\$ 41,590	\$ 41,142	\$ 95,297	\$ 94,849
10081	Milton-Freewater, City of	\$ 76,961	0.1375%	0.1374%	\$ 52,613	\$ 52,594	\$ 129,574	\$ 129,555
10082	Minidoka, City of	\$ -	0.0017%	0.0017%	\$ 660	\$ 653	\$ 660	\$ 653
10083	Monmouth, City of	\$ 59,603	0.1222%	0.1209%	\$ 46,767	\$ 46,264	\$ 106,370	\$ 105,867
10086	Plummer, City of	\$ 28,254	0.0577%	0.0570%	\$ 22,063	\$ 21,826	\$ 50,317	\$ 50,080
10087	Port Angeles, City of	\$ 517,172	1.1982%	1.1887%	\$ 458,539	\$ 454,892	\$ 975,711	\$ 972,065
10089	Richland, City of	\$ 623,657	1.4413%	1.4614%	\$ 551,561	\$ 559,243	\$ 1,175,218	\$ 1,182,900
10091	Rupert, City of	\$ 72,943	0.1304%	0.1290%	\$ 49,893	\$ 49,372	\$ 122,836	\$ 122,315
10094	Soda Springs, City of	\$ -	0.0434%	0.0428%	\$ 16,595	\$ 16,373	\$ 16,595	\$ 16,373
10095	Sumas, Town of	\$ 23,429	0.0532%	0.0527%	\$ 20,369	\$ 20,150	\$ 43,798	\$ 43,579
10097	Troy, City of	\$ -	0.0298%	0.0295%	\$ 11,394	\$ 11,271	\$ 11,394	\$ 11,271
10101	Clallam County PUD #1	\$ 520,583	1.1103%	1.0990%	\$ 424,907	\$ 420,588	\$ 945,490	\$ 941,171

Customer Refund Amounts

BPA Customer ID Number	BPA Customer Name	PF-02 Refund (1)	FY 2012 Scaled TOCA (2)	FY 2013 Scaled TOCA (2)	FY 2012 TOCA Refund	FY 2013 TOCA Refund	FY 2012 Total Refund	FY 2013 Total Refund
10103	Clark County PUD #1	\$ 2,370,948	4.4021%	4.4012%	\$ 1,684,623	\$ 1,684,286	\$ 4,055,572	\$ 4,055,235
10105	Clatskanie PUD	\$ 617,393	1.2971%	1.2884%	\$ 496,398	\$ 493,064	\$ 1,113,791	\$ 1,110,457
10106	Clearwater Power	\$ 125,833	0.3361%	0.3368%	\$ 128,610	\$ 128,887	\$ 254,443	\$ 254,720
10109	Columbia Basin Elec Coop	\$ -	0.1745%	0.1752%	\$ 66,791	\$ 67,040	\$ 66,791	\$ 67,040
10111	Columbia Power Coop	\$ -	0.0465%	0.0464%	\$ 17,804	\$ 17,758	\$ 17,804	\$ 17,758
10112	Columbia River PUD	\$ 265,444	0.8204%	0.8184%	\$ 313,942	\$ 313,189	\$ 579,386	\$ 578,633
10113	Columbia REA	\$ -	0.5508%	0.5449%	\$ 210,783	\$ 208,516	\$ 210,783	\$ 208,516
10116	Consol. Irrigation District	\$ 1,825	0.0033%	0.0033%	\$ 1,273	\$ 1,259	\$ 3,098	\$ 3,084
10118	Consumers Power	\$ 246,076	0.6298%	0.6288%	\$ 241,027	\$ 240,637	\$ 487,103	\$ 486,713
10121	Coos Curry Elec Coop	\$ 229,267	0.5861%	0.5834%	\$ 224,277	\$ 223,272	\$ 453,544	\$ 452,540
10123	Cowlitz County PUD #1	\$ 3,446,817	7.7193%	7.6630%	\$ 2,954,063	\$ 2,932,520	\$ 6,400,880	\$ 6,379,337
10136	Douglas Electric Cooperative	\$ 105,338	0.2607%	0.2586%	\$ 99,754	\$ 98,957	\$ 205,093	\$ 204,295
10142	East End Mutual Electric	\$ -	0.0393%	0.0388%	\$ 15,024	\$ 14,863	\$ 15,024	\$ 14,863
10144	Eatonville, City of	\$ 23,238	0.0492%	0.0487%	\$ 18,834	\$ 18,632	\$ 42,072	\$ 41,870
10156	Elmhurst Mutual P & L	\$ -	0.4658%	0.4657%	\$ 178,241	\$ 178,200	\$ 178,241	\$ 178,200
10157	Emerald PUD	\$ 376,548	0.7320%	0.7398%	\$ 280,135	\$ 283,105	\$ 656,683	\$ 659,653
10158	Energy Northwest	\$ 20,415	0.0384%	0.0379%	\$ 14,682	\$ 14,521	\$ 35,097	\$ 34,935
10170	Eugene Water & Electric Board	\$ 1,490,101	3.6391%	3.6298%	\$ 1,392,621	\$ 1,389,076	\$ 2,882,722	\$ 2,879,177
10172	U.S. Airforce Base, Fairchild	\$ 60,465	0.0871%	0.0872%	\$ 33,326	\$ 33,384	\$ 93,791	\$ 93,850
10173	Fall River Elec Coop	\$ 152,407	0.4841%	0.4789%	\$ 185,268	\$ 183,275	\$ 337,674	\$ 335,681
10174	Farmers Elec Coop	\$ -	0.0073%	0.0072%	\$ 2,784	\$ 2,770	\$ 2,784	\$ 2,770
10177	Ferry County PUD #1	\$ 67,875	0.1679%	0.1686%	\$ 64,269	\$ 64,530	\$ 132,144	\$ 132,405
10179	Flathead Elec Coop	\$ 608,080	2.3110%	2.3263%	\$ 884,380	\$ 890,233	\$ 1,492,460	\$ 1,498,312
10183	Franklin County PUD #1	\$ 471,954	1.6676%	1.6844%	\$ 638,172	\$ 644,584	\$ 1,110,125	\$ 1,116,537
10186	Glacier Elec Coop	\$ -	0.3032%	0.3052%	\$ 116,024	\$ 116,813	\$ 116,024	\$ 116,813
10190	Grant County PUD #2	\$ 1,146,092	0.6011%	0.5947%	\$ 230,043	\$ 227,568	\$ 1,376,135	\$ 1,373,660
10191	Grays Harbor PUD #1	\$ 736,828	1.9175%	1.8968%	\$ 733,786	\$ 725,892	\$ 1,470,614	\$ 1,462,720
10197	Harney Elec Coop	\$ 91,382	0.3228%	0.3236%	\$ 123,544	\$ 123,828	\$ 214,926	\$ 215,210
10202	Hood River Elec Coop	\$ 89,783	0.1864%	0.1864%	\$ 71,336	\$ 71,332	\$ 161,119	\$ 161,115
10203	Idaho County L & P	\$ 39,010	0.0908%	0.0898%	\$ 34,745	\$ 34,372	\$ 73,755	\$ 73,381
10204	Idaho Falls Power	\$ 435,271	1.1402%	1.1385%	\$ 436,348	\$ 435,698	\$ 871,619	\$ 870,969
10209	Inland P & L	\$ -	1.5108%	1.5217%	\$ 578,177	\$ 582,320	\$ 578,177	\$ 582,320
10230	Kititas County PUD #1	\$ 48,061	0.1343%	0.1329%	\$ 51,380	\$ 50,859	\$ 99,441	\$ 98,920
10231	Klickitat County PUD #1	\$ 219,238	0.5167%	0.5203%	\$ 197,719	\$ 199,125	\$ 416,957	\$ 418,363
10234	Kootenai Electric Coop	\$ -	0.7218%	0.7266%	\$ 276,206	\$ 278,058	\$ 276,206	\$ 278,058
10235	Lakeview L & P (WA)	\$ 261,953	0.4751%	0.4714%	\$ 181,808	\$ 180,387	\$ 443,761	\$ 442,340
10236	Lane County Elec Coop	\$ 154,159	0.4149%	0.4132%	\$ 158,782	\$ 158,140	\$ 312,941	\$ 312,299
10237	Lewis County PUD #1	\$ 720,554	1.5906%	1.5906%	\$ 608,684	\$ 608,690	\$ 1,329,238	\$ 1,329,244

Customer Refund Amounts

BPA Customer ID Number	BPA Customer Name	PF-02 Refund (1)	FY 2012 Scaled TOCA (2)	FY 2013 Scaled TOCA (2)	FY 2012 TOCA Refund	FY 2013 TOCA Refund	FY 2012 Total Refund	FY 2013 Total Refund
10239	Lincoln Elec Coop (MT)	\$ -	0.1947%	0.1956%	\$ 74,518	\$ 74,845	\$ 74,518	\$ 74,845
10242	Lost River Elec Coop	\$ 50,765	0.1370%	0.1372%	\$ 52,418	\$ 52,508	\$ 103,183	\$ 103,272
10244	Lower Valley Energy	\$ -	1.2573%	1.2437%	\$ 481,139	\$ 475,963	\$ 481,139	\$ 475,963
10246	Mason County PUD #1	\$ 52,092	0.1313%	0.1299%	\$ 50,255	\$ 49,714	\$ 102,347	\$ 101,807
10247	Mason County PUD #3	\$ 544,117	1.1477%	1.1474%	\$ 439,216	\$ 439,105	\$ 983,333	\$ 983,222
10256	Midstate Elec Coop	\$ 287,247	0.6681%	0.6691%	\$ 255,685	\$ 256,070	\$ 542,932	\$ 543,317
10258	Mission Valley	\$ -	0.5151%	0.5219%	\$ 197,135	\$ 199,715	\$ 197,135	\$ 199,715
10259	Missoula Elec Coop	\$ -	0.3819%	0.3845%	\$ 146,140	\$ 147,141	\$ 146,140	\$ 147,141
10260	Modern Elec Coop	\$ -	0.3754%	0.3780%	\$ 143,647	\$ 144,654	\$ 143,647	\$ 144,654
10273	Nespelem Valley Elec Coop	\$ 35,342	0.0859%	0.0850%	\$ 32,888	\$ 32,534	\$ 68,230	\$ 67,876
10278	Northern Lights	\$ 134,905	0.5250%	0.5194%	\$ 200,917	\$ 198,755	\$ 335,821	\$ 333,660
10279	Northern Wasco County PUD	\$ 169,186	0.8835%	0.8800%	\$ 338,093	\$ 336,749	\$ 507,279	\$ 505,935
10284	Ohop Mutual Light Company	\$ -	0.1484%	0.1469%	\$ 56,809	\$ 56,198	\$ 56,809	\$ 56,198
10285	Okanogan County Elec Coop	\$ 33,056	0.0954%	0.0944%	\$ 36,507	\$ 36,114	\$ 69,563	\$ 69,171
10286	Okanogan County PUD #1	\$ 302,445	0.7109%	0.7076%	\$ 272,062	\$ 270,780	\$ 574,507	\$ 573,224
10288	Orcas P & L	\$ -	0.3614%	0.3576%	\$ 138,318	\$ 136,830	\$ 138,318	\$ 136,830
10291	Oregon Trail Coop	\$ 535,684	1.0682%	1.0742%	\$ 408,793	\$ 411,075	\$ 944,477	\$ 946,760
10294	Pacific County PUD #2	\$ 263,432	0.4461%	0.5013%	\$ 170,729	\$ 191,859	\$ 434,160	\$ 455,291
10304	Parkland L & W	\$ -	0.2019%	0.2020%	\$ 77,281	\$ 77,320	\$ 77,281	\$ 77,320
10306	Pend Oreille County PUD #1	\$ 218,512	0.3035%	0.3434%	\$ 116,147	\$ 131,413	\$ 334,658	\$ 349,924
10307	Peninsula Light Company	\$ 484,256	1.0248%	1.0333%	\$ 392,174	\$ 395,426	\$ 876,430	\$ 879,682
10326	U.S. Naval Base, Bremerton	\$ 216,980	0.3926%	0.3884%	\$ 150,228	\$ 148,624	\$ 367,208	\$ 365,604
10331	Raft River Elec Coop	\$ 81,677	0.4844%	0.4828%	\$ 185,383	\$ 184,750	\$ 267,060	\$ 266,427
10333	Ravalli County Elec Coop	\$ -	0.2607%	0.2626%	\$ 99,754	\$ 100,499	\$ 99,754	\$ 100,499
10338	Riverside Elec Coop	\$ -	0.0327%	0.0324%	\$ 12,523	\$ 12,404	\$ 12,523	\$ 12,404
10342	Salem Elec Coop	\$ 342,469	0.5756%	0.5694%	\$ 220,268	\$ 217,898	\$ 562,737	\$ 560,367
10343	Salmon River Elec Coop	\$ 126,695	0.4447%	0.4389%	\$ 170,176	\$ 167,979	\$ 296,871	\$ 294,674
10349	Seattle City Light	\$ 2,806,762	7.6559%	7.5735%	\$ 2,929,808	\$ 2,898,290	\$ 5,736,570	\$ 5,705,052
10352	Skamania County PUD #1	\$ 110,458	0.2271%	0.2273%	\$ 86,921	\$ 86,982	\$ 197,380	\$ 197,440
10354	Snohomish County PUD #1	\$ 4,394,837	11.4873%	11.5471%	\$ 4,396,048	\$ 4,418,905	\$ 8,790,886	\$ 8,813,742
10360	Southside Elec Lines	\$ -	0.0933%	0.0947%	\$ 35,716	\$ 36,232	\$ 35,716	\$ 36,232
10363	Springfield Utility Board	\$ 490,736	1.4114%	1.4120%	\$ 540,127	\$ 540,355	\$ 1,030,864	\$ 1,031,092
10369	Surprise Valley Elec Coop	\$ 81,780	0.2261%	0.2267%	\$ 86,524	\$ 86,765	\$ 168,303	\$ 168,545
10370	Tacoma Public Utilities	\$ 2,979,021	5.7214%	5.7137%	\$ 2,189,512	\$ 2,186,556	\$ 5,168,533	\$ 5,165,577
10371	Tanner Elec Coop	\$ 59,409	0.1612%	0.1595%	\$ 61,696	\$ 61,033	\$ 121,106	\$ 120,442
10376	Tillamook PUD #1	\$ 287,525	0.7926%	0.7875%	\$ 303,312	\$ 301,382	\$ 590,837	\$ 588,908
10378	Coulee Dam, City of	\$ -	0.0296%	0.0293%	\$ 11,322	\$ 11,200	\$ 11,322	\$ 11,200
10379	Steilacoom, Town of	\$ 35,527	0.0696%	0.0695%	\$ 26,637	\$ 26,598	\$ 62,164	\$ 62,125

Customer Refund Amounts

BPA Customer ID Number	BPA Customer Name	PF-02 Refund (1)	FY 2012 Scaled TOCA (2)	FY 2013 Scaled TOCA (2)	FY 2012 TOCA Refund	FY 2013 TOCA Refund	FY 2012 Total Refund	FY 2013 Total Refund
10388	Umatilla Elec Coop	\$ 557,880	1.6382%	1.6367%	\$ 626,925	\$ 626,353	\$ 1,184,806	\$ 1,184,234
10391	United Electric Coop	\$ 144,156	0.4380%	0.4333%	\$ 167,635	\$ 165,831	\$ 311,790	\$ 309,987
10406	U.S. DOE Albany	\$ 3,304	0.0066%	0.0065%	\$ 2,533	\$ 2,506	\$ 5,838	\$ 5,810
10408	U.S. Navy, Jim Creek	\$ 10,783	0.0213%	0.0210%	\$ 8,133	\$ 8,045	\$ 18,915	\$ 18,828
10409	U.S. Navy, Bangor	\$ 151,547	0.2896%	0.2869%	\$ 110,810	\$ 109,811	\$ 262,357	\$ 261,358
10426	U.S. DOE Richland	\$ 193,387	0.3625%	0.3796%	\$ 138,707	\$ 145,268	\$ 332,094	\$ 338,655
10434	Vera Irrigation District	\$ 190,495	0.3808%	0.3834%	\$ 145,738	\$ 146,732	\$ 336,233	\$ 337,226
10436	Vigilante Elec Coop	\$ -	0.2642%	0.2661%	\$ 101,091	\$ 101,825	\$ 101,091	\$ 101,825
10440	Wahkiakum County PUD #1	\$ 32,517	0.0726%	0.0724%	\$ 27,794	\$ 27,688	\$ 60,311	\$ 60,205
10442	Wasco Elec Coop	\$ -	0.1958%	0.1937%	\$ 74,915	\$ 74,109	\$ 74,915	\$ 74,109
10446	Wells Rural Elec Coop	\$ 388,509	1.3821%	1.3844%	\$ 528,925	\$ 529,808	\$ 917,433	\$ 918,317
10448	West Oregon Elec Coop	\$ 48,959	0.1229%	0.1221%	\$ 47,018	\$ 46,717	\$ 95,977	\$ 95,676
10451	Whatcom County PUD #1	\$ 179,980	0.3707%	0.3879%	\$ 141,849	\$ 148,439	\$ 321,829	\$ 328,419
10482	Umpqua Indian Utility Coop	\$ 15,681	0.0477%	0.0510%	\$ 18,269	\$ 19,513	\$ 33,950	\$ 35,194
10502	Yakama Power	\$ 7,897	0.0917%	0.0919%	\$ 35,111	\$ 35,186	\$ 43,008	\$ 43,083
10597	Hermiston, City of	\$ 100,167	0.1812%	0.1801%	\$ 69,332	\$ 68,928	\$ 169,498	\$ 169,095
10706	Port of Seattle - SETAC	\$ -	0.2408%	0.2390%	\$ 92,167	\$ 91,470	\$ 92,167	\$ 91,470
11680	Weiser, City of	\$ -	0.0902%	0.0900%	\$ 34,503	\$ 34,423	\$ 34,503	\$ 34,423
Total		\$ 38,269,000	100.0000%	100.0000%	\$38,268,617	\$38,268,617	\$76,537,617	\$76,537,617

(1) See Exhibit B of REP Settlement Agreement, Contract No. 11PB-12322. US BIA Wapato was annexed by Yakama Power; therefore the PF-02 Refund Amount is included under Yakama Power.

(2) Reflects adjustment to the Exhibit A Existing Resource amounts for Cowlitz PUD to reflect loss of Priest Rapids contract rights. Adjusted TOCAs are recomputed with Grant CHWM equal to 41.75 aMW, pursuant to Section 3.4 of the REP Settlement Agreement. Final Scaled TOCAs reallocate headroom (when customers' net requirement is below their RHWM allocated share of the Tier 1 System) among all customers pro rata to Adjusted TOCA percentages.

**2012 Wholesale Power and Transmission Rate
Adjustment Proceeding (BP-12)**

**ADMINISTRATOR'S FINAL
RECORD OF DECISION**

**Appendix C: Transmission, Ancillary and Control Area
Service Rate Schedules**

July 2011

BP-12-A-02C



INDEX

2012 TRANSMISSION, ANCILLARY AND CONTROL AREA SERVICE

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COMMONLY USED ACRONYMS AND SHORT FORMS

AGC	Automatic Generation Control
ALF	Agency Load Forecast (computer model)
aMW	average megawatt(s)
AMNR	Accumulated Modified Net Revenues
ANR	Accumulated Net Revenues
ASC	Average System Cost
BiOp	Biological Opinion
BPA	Bonneville Power Administration
Btu	British thermal unit
CDD	cooling degree day(s)
CDQ	Contract Demand Quantity
CGS	Columbia Generating Station
CHWM	Contract High Water Mark
Commission	Federal Energy Regulatory Commission
COSA	Cost of Service Analysis
COU	consumer-owned utility
Corps or USACE	U.S. Army Corps of Engineers
Council	Northwest Power and Conservation Council
CRAC	Cost Recovery Adjustment Clause
CSP	Customer System Peak
CT	combustion turbine
CY	calendar year (January through December)
DDC	Dividend Distribution Clause
<i>dec</i>	decrease, decrement, or decremental
DERBS	Dispatchable Energy Resource Balancing Service
DFS	Diurnal Flattening Service
DOE	Department of Energy
DSI	direct-service industrial customer or direct-service industry
DSO	Dispatcher Standing Order
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.
EPP	Environmentally Preferred Power
ESA	Endangered Species Act
e-Tag	electronic interchange transaction information
FBS	Federal base system
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FELCC	firm energy load carrying capability
FORS	Forced Outage Reserve Service
FPS	Firm Power Products and Services (rate)
FY	fiscal year (October through September)
GARD	Generation and Reserves Dispatch (computer model)

GEP	Green Energy Premium
GRSPs	General Rate Schedule Provisions
GTA	General Transfer Agreement
GWh	gigawatthour
HDD	heating degree day(s)
HLH	Heavy Load Hour(s)
HOSS	Hourly Operating and Scheduling Simulator (computer model)
HYDSIM	Hydro Simulation (computer model)
ICE	IntercontinentalExchange
<i>inc</i>	increase, increment, or incremental
IOU	investor-owned utility
IP	Industrial Firm Power (rate)
IPR	Integrated Program Review
IRD	Irrigation Rate Discount
JOE	Joint Operating Entity
kW	kilowatt (1000 watts)
kWh	kilowatthour
LDD	Low Density Discount
LLH	Light Load Hour(s)
LRA	Load Reduction Agreement
Maf	million acre-feet
Mid-C	Mid-Columbia
MMBtu	million British thermal units
MNR	Modified Net Revenues
MRNR	Minimum Required Net Revenue
MW	megawatt (1 million watts)
MWh	megawatthour
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NFB	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NORM	Non-Operating Risk Model (computer model)
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPV	net present value
NR	New Resource Firm Power (rate)
NT	Network Transmission
NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation
NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff

O&M	operation and maintenance
OMB	Office of Management and Budget
OY	operating year (August through July)
PF	Priority Firm Power (rate)
PFp	Priority Firm Public (rate)
PFx	Priority Firm Exchange (rate)
PNCA	Pacific Northwest Coordination Agreement
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration or Point of Interconnection
POM	Point of Metering
POR	Point of Receipt
Project Act	Bonneville Project Act
PRS	Power Rates Study
PS	BPA Power Services
PSW	Pacific Southwest
PTP	Point to Point Transmission (rate)
PUD	public or people's utility district
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
RD	Regional Dialogue
REC	Renewable Energy Certificate
Reclamation or USBR	U.S. Bureau of Reclamation
REP	Residential Exchange Program
RevSim	Revenue Simulation Model (component of RiskMod)
RFA	Revenue Forecast Application (database)
RHWM	Rate Period High Water Mark
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model (component of RiskMod)
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RR	Resource Replacement (rate)
RSS	Resource Support Services
RT1SC	RHWM Tier 1 System Capability
RTO	Regional Transmission Operator
SCADA	Supervisory Control and Data Acquisition
SCS	Secondary Crediting Service
Slice	Slice of the System (product)
T1SFCO	Tier 1 System Firm Critical Output
TCMS	Transmission Curtailment Management Service
TOCA	Tier 1 Cost Allocator
TPP	Treasury Payment Probability
Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load

TRM	Tiered Rate Methodology
TS	BPA Transmission Services
TSS	Transmission Scheduling Service
UAI	Unauthorized Increase
ULS	Unanticipated Load Service
USACE or Corps	U.S. Army Corps of Engineers
USBR or Reclamation	U.S. Bureau of Reclamation
USFWS	U.S. Fish and Wildlife Service
VERBS	Variable Energy Resources Balancing Service (rate)
VOR	Value of Reserves
WECC	Western Electricity Coordinating Council (formerly WSCC)
WIT	Wind Integration Team
WSPP	Western Systems Power Pool

RATE SCHEDULES

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FPT-12.1
FORMULA POWER TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes Schedule FPT-10.1 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 BPA-TS's General Rate Schedule Provisions (GRSPs).

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 beginning October 2007 according to the following formula:

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

Where:

GSR_q = The ACS-12 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	\$0.0587 per mile
2. Main Grid Interconnection Terminal	\$0.61/kW
3. Main Grid Terminal	\$0.68/kW
4. Main Grid Miscellaneous Facilities	\$3.35/kW
SECONDARY SYSTEM CHARGES	
1. Secondary System Distance	\$0.5772 per mile
2. Secondary System Transformation	\$6.31/kW
3. Secondary System Intermediate Terminal	\$2.44/kW
4. Secondary System Interconnection Terminal	\$1.73/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 section II.B. of the GRSPs.

C. POWER FACTOR PENALTY

Customers taking service under this rate schedule are subject to the Power Factor Penalty Charge, specified in section II.C. of the GRSPs.

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FPT-12.3 FORMULA POWER TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes Schedule FPT-10.3 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 BPA-TS's General Rate Schedule Provisions (GRSPs).

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 beginning October 2007 according to the following formula:

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

Where:

GSR_q = The ACS-12 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	\$0.0587 per mile
2.	Main Grid Interconnection Terminal	\$0.61/kW
3.	Main Grid Terminal	\$0.68/kW
4.	Main Grid Miscellaneous Facilities	\$3.35/kW
SECONDARY SYSTEM CHARGES		
1.	Secondary System Distance	\$0.5772 per mile
2.	Secondary System Transformation	\$6.31/kW
3.	Secondary System Intermediate Terminal	\$2.44/kW
4.	Secondary System Interconnection Terminal	\$1.73/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 section II.B. of the GRSPs.

C. POWER FACTOR PENALTY

Customers taking transmission service under FPT agreements are subject to the Power Factor Penalty Charge, specified in section II.C. of the GRSPs.

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IR-12 INTEGRATION OF RESOURCES RATE

SECTION I. AVAILABILITY

This schedule supersedes Schedule IR-10 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 BPA-TS's General Rate Schedule Provisions (GRSPs).

SECTION II. RATES

The IR rates in sections A and B, below, are calculated each quarter beginning October 2007. These rates shall be calculated to three decimal places. The monthly IR rate shall be as provided in section A or section B.

A. BASE RATE

The Base Rate shall be the sum of:

1. \$1.498 per kilowatt per month (\$/kW/mo); and
2. ACS-12 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. \$0.203/kW/mo; and
2. ACS-12 Reactive Supply and Voltage Control From Generation Sources Service Rate for Long-Term Firm PTP Transmission Service and NT Service, section II.B.1.a., effective for the quarter for which the IR rate is being calculated, in \$/kW/mo; and

3. $(0.6 + (0.4 \times \text{transmission distance}/75)) \times \$1.295/\text{kW}/\text{mo}$

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-TS 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-TS 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-12) for Hourly Non-Firm Service.

When the Scheduled Demand or Ratchet Demand is the Billing Factor, short-distance POIs shall be charged the Base 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 section II.A. of the GRSPs.

C. FAILURE TO COMPLY PENALTY

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

D. POWER FACTOR PENALTY

Customers taking service under this rate schedule are subject to the Power Factor Penalty Charge, specified in section II.C. of the GRSPs.

E. RATCHET DEMAND RELIEF

Under appropriate circumstances, BPA-TS 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-TS 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-TS 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.

F. 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 an equivalent basis to the credit for PTP Transmission Customers.

NT-12 NETWORK INTEGRATION RATE

SECTION I. AVAILABILITY

This schedule supersedes Schedule NT-10. It is available to Transmission Customers taking Network Integration Transmission (NT) Service over Federal Columbia River Transmission System Network and Delivery facilities and to Transmission Customers taking Conditional Firm 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 BPA-TS's General Rate Schedule Provisions (GRSPs).

SECTION II. RATES

The monthly charge will be the sum of A and B.

A. BASE CHARGE

\$1.298 per kilowatt per month

B. LOAD SHAPING CHARGE

\$0.367 per kilowatt per month

SECTION III. BILLING FACTORS

A. BASE CHARGE

The monthly Billing Factor for the Base Charge specified in section II.A. shall be the customer's Network Load on the hour of the Monthly Transmission Peak Load.

B. LOAD SHAPING CHARGE

The monthly Billing Factor for the Load Shaping Charge specified in section II.B. shall be the customer's Network Load on the hour of the Monthly Transmission 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 section II.A. of the GRSPs.

C. FAILURE TO COMPLY PENALTY

Customers taking NT Service are subject to the Failure to Comply Penalty Charge, specified in section II.B. of the GRSPs.

D. METERING ADJUSTMENT

At those Points of Delivery that do not have meters capable of determining the demand on the hour of the Monthly Transmission Peak Load, the Billing Demand shall be calculated by substituting 1) the sum of the highest hourly demand that occurs during the billing month at all Points of Delivery multiplied by 0.79 for 2) Network Load on the hour of the Monthly Transmission Peak Load.

E. POWER FACTOR PENALTY

Customers taking service under this rate are subject to the Power Factor Penalty Charge, specified in section II.C. of the GRSPs.

F. 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:

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

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 POD(s) 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; and
2. in the case of Behind the Meter Resources, the metered output of the resource.

NT Rate = NT Base Charge

Tx Distance = The contractually specified distance measured in circuit miles between the DNR SD 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.

G. DIRECT ASSIGNMENT FACILITIES

BPA-TS 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.

H. 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-TS 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.

I. 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 section II.D. of the GRSPs.

**PTP-12
POINT-TO-POINT RATE**

SECTION I. AVAILABILITY

This schedule supersedes Schedule PTP-10. It is available to Transmission Customers taking Point-to-Point (PTP) Transmission Service over Federal Columbia River Transmission System (FCRTS) Network and Delivery facilities, for hourly non-firm service over such FCRTS facilities for customers with Integration of Resources agreements, and to customers taking Conditional Firm (CF) Transmission Service, if BPA adopts CF Transmission Service. 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 BPA-TS's General Rate Schedule Provisions (GRSPs).

SECTION II. RATES

A. LONG-TERM FIRM PTP TRANSMISSION SERVICE

\$1.298 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** \$0.060 per kilowatt per day
- b. Day 6 and beyond** \$0.046 per kilowatt per day

2. Hourly Firm and Non-Firm Service

3.74 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 service 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.

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 section II.A. of the GRSPs.

C. FAILURE TO COMPLY PENALTY

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

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.

When Reserved Capacity becomes the Billing Factor for Hourly Non-Firm Service, the following shall apply:

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. POWER FACTOR PENALTY

Customers taking service under this rate schedule are subject to the Power Factor Penalty Charge, specified in section II.C. of the GRSPs.

F. 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 section II.E. of the GRSPs.

G. SHORT-DISTANCE DISCOUNT (SDD)

When a Point of Receipt (POR) and Point of Delivery (POD) 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:

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

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. 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.

H. UNAUTHORIZED INCREASE CHARGE

Customers that exceed their capacity reservations at any Point of Receipt (POR) or Point of Delivery (POD) shall be subject to the Unauthorized Increase Charge, specified in section II.G. of the GRSPs.

I. DIRECT ASSIGNMENT FACILITIES

BPA-TS 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.

J. 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-TS 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.

K. 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 section II.D. of the GRSPs.

IS-12
SOUTHERN INTERTIE RATE

SECTION I. AVAILABILITY

This schedule supersedes Schedule IS-10. It is available to Transmission Customers taking Point-to-Point Transmission Service over 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 BPA-TS's General Rate Schedule Provisions (GRSPs).

SECTION II. RATES

A. LONG-TERM FIRM PTP TRANSMISSION SERVICE

\$1.293 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 \$0.060 per kilowatt per day

b. Day 6 and beyond \$0.045 per kilowatt per day

2. Hourly Firm and Non-Firm Service

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

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 section II.B. of the GRSPs.

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.

When Reserved Capacity becomes the Billing Factor for Hourly Non-Firm Service, 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.

D. POWER FACTOR PENALTY

Customers taking service under this rate schedule are subject to the Power Factor Penalty Charge specified in section II.C. of the GRSPs.

E. 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 section II.E of the GRSPs.

F. UNAUTHORIZED INCREASE CHARGE

Customers that exceed their capacity reservations at any Point of Receipt (POR) or Point of Delivery (POD) shall be subject to the Unauthorized Increase Charge, specified in section II.G. in the GRSPs.

G. DIRECT ASSIGNMENT FACILITIES

BPA-TS 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.

H. 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-TS 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.

I. 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 section II.D. of the GRSPs.

IM-12
MONTANA INTERTIE RATE

SECTION I. AVAILABILITY

This schedule supersedes Schedule IM-10. 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 BPA-TS's General Rate Schedule Provisions (GRSPs).

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 service 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.

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 section II.B. of the GRSPs.

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.

When Reserved Capacity becomes the Billing Factor for Hourly Non-Firm Service, 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.

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 section II.E. of the GRSPs.

E. UNAUTHORIZED INCREASE CHARGE

Customers that exceed their capacity reservations at any Point of Receipt (POR) or Point of Delivery (POD) shall be subject to the Unauthorized Increase Charge, specified in section II.G. of the GRSPs.

F. DIRECT ASSIGNMENT FACILITIES

BPA-TS 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-TS 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 section II.D. of the GRSPs.

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UFT-12

USE-OF-FACILITIES TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes Schedule UFT-10 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 BPA-TS's General Rate Schedule Provisions (GRSPs).

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-TS shall determine the following data for the facilities that have been constructed or otherwise acquired by BPA-TS 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-TS for making deliveries to the transferee shall be determined from the costs specified in the agreement between BPA-TS 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-TS 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-TS 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-TS 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 section II.B. of the GRSPs.

C. POWER FACTOR PENALTY CHARGE

Customers taking service under this rate schedule are subject to the Power Factor Penalty Charge, specified in section II.C. of the GRSPs.

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AF-12
ADVANCE FUNDING RATE

SECTION I. AVAILABILITY

This schedule supersedes Schedule AF-10 and is available to customers that execute an agreement that provides for BPA-TS 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-TS.

Service under this schedule is subject to BPA-TS's General Rate Schedule Provisions (GRSPs).

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 an 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-TS shall be specified in the agreement as either:

- 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-TS.

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-TS 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-TS. The customer will either receive a refund from BPA-TS or be billed for additional payment for the difference between the advance payment and the actual capital and related costs.

TGT-12

TOWNSEND-GARRISON TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes Schedule TGT-10 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 BPA-TS's General Rate Schedule Provisions (GRSPs).

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 either a surplus or a deficit. Such surpluses or deficits 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 will be the unit rate.

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. During an estimated 1- to 3-year period following the commercial operation of the third generating unit at the Colstrip Thermal Generating Plant at Colstrip, Montana, the capability of the Federal Transmission System west of Garrison Substation may be different from the long-term situation. It may not be possible to complete the extension of the 500-kV portion of the Federal Transmission System to Garrison by such commercial operation date. In such event, the 500/230 kV transformer will be an essential extension of the Townsend-Garrison Intertie facilities, and the annual costs of such transformer will be included in the calculation of the Intertie Charge.

However, starting 1 month after extension to Garrison of the 500-kV portion of the Federal Transmission System, the annual costs of such transformer will no longer be included in the calculation of the Intertie Charge.

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:

$$\text{Intertie Charge} = \frac{((\text{TAC}/12) - \text{NFR}) \times (\text{CR} - \text{EC})}{\text{TCR}}$$

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.

IE-12
EASTERN INTERTIE RATE

SECTION I. AVAILABILITY

This schedule supersedes IE-10 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 above BPA's firm transmission rights. Service under this schedule is subject to BPA-TS's General Rate Schedule Provisions (GRSPs).

SECTION II. RATE

The rate shall not exceed 1.13 mills per kilowatthour.

SECTION III. BILLING FACTORS

The Billing Factor shall be the scheduled kilowatthours, unless otherwise specified in the 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 section II.B. of the GRSPs.

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ACS-12

ANCILLARY AND CONTROL AREA SERVICES RATES

SECTION I. AVAILABILITY

This schedule supersedes Schedule ACS-10. It is available to all Transmission Customers taking service under the Open Access Transmission Tariff and other contractual arrangements. 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 BPA-TS's General Rate Schedule Provisions (GRSPs).

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 a transmission agreement 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-TS. 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. Long-Term Firm PTP Transmission Service and NT Service

The rate shall not exceed \$0.203 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 \$0.010 per kilowatt per day

(b) Day 6 and beyond \$0.006 per kilowatt per day

(2) Hourly Firm and Non-Firm Service

The rate shall not exceed 0.59 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 section 1.a., 1.b.(1), and for the Hourly Firm PTP Transmission Service rate specified in 1.b.(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 Base Charge Billing Factor determined pursuant to section III.A. of the Network Integration Rate Schedule (NT-12).

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 under section II.G.2.a. of the GRSPs.

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

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-TS. 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 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 2011, 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 = 470,532 MW-mo = Average of forecasted FY 2010 and FY 2011 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-TS 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-TS 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, 2011, U_{q-1} is zero. (\$)

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

Z_{q-1} = A dollar true-up for under- or overstatement of reactive self-supply in rate calculations for the preceding quarter(s). For calculating the GSR rate effective October 1, 2011, 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)

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

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

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

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

The rate shall not exceed:

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

Where:

The “Long-Term Service Rate” specified in the formulas in sections 1.b.(1)(a) and (b), and 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 section 1.a., 1.b.(1) and for Hourly Firm PTP Transmission Service specified in 1.b.(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 Base Charge Billing Factor determined pursuant to section III.A. of the Network Integration Rate Schedule (NT-12).

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-TS'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 under section II.G.2.a. of the GRSPs.

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

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 0.13 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-TS. 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 same basis as the intra-hour scheduling period.

1. RATES

a. Imbalances Within Deviation Band 1

Deviation Band 1 applies to deviations that are less than or equal to:
i) $\pm 1.5\%$ of the scheduled amount of energy, or ii) ± 2 MW, whichever is larger in absolute value. BPA-TS 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-TS 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:

- (i) 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.
- (ii) 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 $\pm 1.5\%$ of the scheduled amount of energy or ± 2 MW,

whichever is larger in absolute value, ii) up to and including $\pm 7.5\%$ of the scheduled amount of energy or ± 10 MW, whichever is larger in absolute value.

- (i) When energy taken by the Transmission Customer in a schedule period is greater than the energy scheduled, the charge is 110% of BPA's incremental cost.
- (ii) When energy taken by the Transmission Customer in a schedule period is less than the scheduled amount, the credit is 90% of BPA's incremental cost.

c. Imbalances Within Deviation Band 3

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

- (i) When energy taken by the Transmission Customer in a schedule period is greater than the energy scheduled, the charge is 125% of BPA's highest incremental cost that occurs during that day. The highest daily incremental cost shall be determined separately for HLH and LLH.
- (ii) When energy taken by the Transmission Customer in a schedule period is less than the scheduled amount, the credit is 75% 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-TS will post the name of the index to be used on the OASIS at least 30 days prior to its use. BPA-TS will not change the index more often than once per year unless BPA-TS 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:

- (i) For negative deviations (energy taken is less than the scheduled energy) within Band 1, no credit will be given.
- (ii) For negative deviations (energy taken is less than the scheduled energy) within Band 2, the charge is the energy index for that hour.
- (iii) 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:

- (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% 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-TS determines to be a Persistent Deviation, the charge is the energy index for that hour.

If BPA-TS assesses a persistent deviation penalty charge in any scheduled period for a positive deviation, BPA-TS will not also assess a charge pursuant to Section II (D) (1) of this ACS-12 schedule.

Reduction or Waiver of Persistent Deviation Penalty

BPA-TS, 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.

E. OPERATING RESERVE -- SPINNING RESERVE SERVICE

The rates below apply to Transmission Customers taking Operating Reserve – Spinning Reserve Service from BPA-TS 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-TS will determine the Transmission Customer’s Spinning Reserve Requirement in accordance with applicable NERC, WECC and NWPP standards.

1. RATES

a. Spinning Reserve Service

- (i) For customers that elect to purchase Operating Reserve – Spinning Reserve Service from BPA-TS, the rate shall not exceed 11.20 mills per kilowatthour.
- (ii) For customers that are required to purchase Operating Reserve – Spinning Reserve Service from BPA-TS because they defaulted on their self-supply or third-party supply obligations, the rate shall be 12.88 mills per kilowatthour.

b. For energy delivered, the generator shall, as directed by BPA-TS, either:

- (i) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or
- (ii) Return the energy at the times specified by BPA-TS.

2. BILLING FACTORS

- a. The Billing Factor for the rates specified in section 1.a. is the Transmission Customer’s Spinning Reserve Requirement determined in accordance with applicable WECC and NWPP standards. BPA-TS will post on its OASIS Web site the Spinning Reserve Requirement. If the Federal Energy Regulatory Commission approves a new Spinning Reserve Requirement during the FY 2012-2013 rate period, such Spinning Reserve Requirement will go into effect on the effective date set by FERC, and BPA will update the Spinning Reserve Requirement posted on its OASIS Web site accordingly.
- 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-TS and to generators in the BPA Control Area for settlement of energy deliveries. Supplemental Reserve Service is needed to serve load immediately in the event of a system contingency. BPA-TS will determine the Transmission Customer’s Supplemental Reserve Requirement in accordance with applicable NERC, WECC and NWPP standards.

1. RATES

a. Supplemental Reserve Service

- (i) For customers that elect to purchase Operating Reserve-- Supplemental Reserve Service Transmission Services, the rate shall not exceed 9.52 mills per kilowatthour.
- (ii) For customers that are required to purchase Operating Reserve -- Supplemental Reserve Service from BPA-TS because they defaulted on their self-supply or third-party supply obligations, the rate shall be 10.95 mills per kilowatthour.

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

- (i) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or
- (ii) Return the energy at the times specified by BPA-TS.

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 section 1.a. is the Transmission Customer’s Supplemental Reserve Requirement determined in accordance with applicable WECC and NWPP standards. BPA-TS will post on its OASIS Web site the Supplemental Reserve Requirement. If the Federal Energy Regulatory Commission approves a new Supplemental Reserve Requirement during the FY 2012-2013 rate period, such Supplemental Reserve Requirement will go into effect on the effective date set by FERC, and BPA will update the Supplemental Reserve Requirement posted on its OASIS Web site accordingly.

- 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-TS 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 0.13 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 same basis as the intra-hour scheduling period.

1. RATES

a. Imbalances Within Deviation Band 1

Deviation Band 1 applies to deviations that are less than or equal to: i) $\pm 1.5\%$ of the scheduled amount of energy, or ii) ± 2 MW, whichever is larger in absolute value. BPA-TS 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-TS 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:

- (i) 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.
- (ii) 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 $\pm 1.5\%$ of the scheduled amount of energy or ± 2 MW, whichever is larger in absolute value, ii) up to and including $\pm 7.5\%$ of the scheduled amount of energy or ± 10 MW, whichever is larger in absolute value.

- (i) When energy delivered in a schedule period from the generation resource is less than the energy scheduled, the charge is 110% of BPA's incremental cost.
- (ii) When energy delivered in a schedule period from the generation resource is greater than the scheduled amount, the credit is 90% of BPA's incremental cost.

c. Imbalances Within Deviation Band 3

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

- (i) When energy delivered in a schedule period from the generation resource is less than the energy scheduled, the charge is 125% of BPA's highest incremental cost that occurs during that day. The highest daily incremental cost shall be determined separately for HLH and LLH.
- (ii) When energy delivered in a schedule period from the generation resource is greater than the scheduled amount, the credit is 75% 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-TS will post the name of the index to be used on the OASIS at least 30 days prior to its use. BPA-TS will not change the index more often than once per year unless BPA-TS 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:

- (i) For negative deviations (actual generation greater than scheduled) within Band 1, no credit will be given.
- (ii) For negative deviations (actual generation greater than scheduled) within Band 2, the charge is the energy index for that hour.
- (iii) For negative deviations (actual generation greater than scheduled) 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:

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-TS).

For positive deviations (actual generation less than scheduled) which are determined by BPA-TS to be Persistent Deviations, the charge is the greater of: i) 125% 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-TS determines to be a Persistent Deviation, the charge is the energy index for that hour.

If BPA-TS assesses a Persistent Deviation Penalty charge in any scheduled period for a positive deviation, BPA-TS will not also assess a charge pursuant to Section III (B) (1) of this ACS-12 schedule.

For variable energy resources (wind and solar resources), BPA-TS 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.

Participants in BPA's Committed Intra-Hour Scheduling Pilot are exempt from the Persistent Deviation penalty charge.

Reduction or Waiver of Persistent Deviation Penalty

BPA-TS, 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. Exemptions from Deviation Band 3

The following resources are not subject to Deviation Band 3:

- (i) wind resources;
- (ii) solar resources; and
- (ii) new generation resources undergoing testing before commercial operation for up to 90 days.

All such deviations greater than $\pm 1.5\%$ 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-TS, and such Spinning Reserve Service is not provided for under a BPA-TS 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-TS will determine the Transmission Customer’s Spinning Reserve Requirement in accordance with applicable NERC, WECC and NWPP standards.

1. RATES

a. Spinning Reserve Service

- (i) For customers that elect to purchase Operating Reserve--Spinning Reserves from BPA-TS, the rate shall not exceed 11.20 mills per kilowatthour.
- (ii) For customers that are required to purchase Operating Reserve--Spinning Reserve Service from BPA-TS because they defaulted on their self-supply or third-party supply obligations, the rate shall be 12.88 mills per kilowatthour.

b. For energy delivered, the customer shall, as directed by BPA-TS, either:

- (i) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or
- (ii) Return the energy at the times specified by BPA-TS.

2. BILLING FACTORS

- a. The Billing Factor for the rates specified in section 1.a. is the Spinning Reserve Requirement determined in accordance with applicable WECC and NWPP standards. BPA-TS will post on its OASIS Web site the Spinning Reserve Requirement. If the Federal Energy Regulatory Commission approves a new Spinning Reserve Requirement during the FY 2012-2013 rate period, such Spinning Reserve Requirement will go into effect on the effective date set by FERC, and BPA will update the Spinning Reserves Requirement posted on its OASIS Web site accordingly.
- 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-TS, and such Supplemental Reserve Service is not provided for under a BPA-TS 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-TS will determine the Transmission Customer's Supplemental Reserve Requirement in accordance with applicable NERC, WECC and NWPP standards.

1. RATES

a. Reserve Service

- (i) For customers that elect to purchase Operating Reserve-- Supplemental Reserve Service from BPA-TS, the rate shall not exceed 9.52 mills per kilowatthour.
- (ii) For customers that are required to purchase Operating Reserve-- Supplemental Reserve Service from BPA-TS because they defaulted on their self-supply or third-party supply obligations, the rate shall be 10.95 mills per kilowatthour.

b. For energy delivered, the customer shall, as directed by BPA-TS, either:

- (i) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or
- (ii) Return the energy at the times specified by BPA-TS.

2. BILLING FACTORS

- a. The Billing Factor for the rates specified in section 1.a. is the Supplemental Reserve Requirement determined in accordance with applicable WECC and NWPP standards. BPA-TS will post on its OASIS Web site the Supplemental Reserve Requirement. If the Federal Energy Regulatory Commission approves a new Supplemental Reserve Requirement during the FY 2012-2013 rate period, such Supplemental Reserve Requirement will go into effect on the effective date set by FERC, and BPA will update the Supplemental Reserves Requirement posted on its OASIS Web site accordingly
- 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 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.

Provisional Variable Energy Resource Balancing Service (“Provisional Balancing Service”) cannot be requested, but is offered to customers integrating variable energy resources in the BPA Control Area that: (1) have elected to self-supply in accordance with section 2(c) but are unable to continue self-supplying one or more components to Variable Energy Resource Balancing Service; or (2) have a projected interconnection date after FY 2013, but interconnect during the FY 2012-2013 rate period.

Variable Energy Resource Balancing Service Supplemental Service (“Supplemental Service”) is an optional monthly service. BPA offers this service only upon request to Variable Energy Resource Balancing Service customers in accordance with BPA business practices. Purchase of this Supplemental Service augments balancing reserves available to the Customer to mitigate the effects of DSO 216 curtailments on variable energy resource schedules.

The rates that apply to participants in BPA’s Committed Intra-Hour Scheduling Pilot are also included in this rate schedule.

2. VARIABLE ENERGY RESOURCE BALANCING SERVICE FOR WIND RESOURCES

(a) RATES

Except as provided in section 7, Formula Rate Adjustments, below, the total rate for Variable Energy Resource Balancing Service for wind resources shall not exceed \$1.23 per kilowatt per month and each component of the rate shall not exceed the following:

- (i) Regulating Reserves \$0.08 per kilowatt per month
- (ii) Following Reserves \$0.37 per kilowatt per month
- (iii) Imbalance Reserves \$0.78 per kilowatt per month

(b) BILLING FACTOR

The Billing Factor is as follows:

- (i) 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.
- (ii) 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.

(c) EXCEPTIONS

- (i) The rates in 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-TS 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.
- (ii) Any component of the rates in 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 criteria specified in BPA-TS 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. PROVISIONAL BALANCING SERVICE

(a) RATES

The total rate for Provisional Balancing Service shall not exceed the total rate specified in section 2(a) above, as adjusted pursuant to section 7, Formula Rate Adjustments.

(b) **BILLING FACTOR**
See section 2(b) above.

(c) **EXCEPTIONS**

(i) Dynamic Transfer Capability Provision: If BPA recalls an award of dynamic transfer capability from a customer that elected to self-supply one or more components of Variable Energy Resource Balancing Service on May 1, 2011, the total rate for such customer taking Provisional Balancing Service shall not exceed 70 percent of the total rate specified in section 2(a) above, as adjusted pursuant to section 7, Formula Rate Adjustments.

(ii) See section 2(c) above.

4. VARIABLE ENERGY RESOURCE BALANCING SERVICE FOR SOLAR RESOURCES

(a) **RATES**

The total rate for Variable Energy Resource Balancing Service for solar resources shall not exceed \$0.21 per kilowatt per month and each component of the rate shall not exceed the following:

(i)	Regulating Reserves	\$0.04 per kilowatt per month
(ii)	Following Reserves	\$0.18 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.

5. COMMITTED INTRA-HOUR SCHEDULING PILOT PARTICIPANTS

(a) **RATES**

The total rate for Variable Energy Resource Balancing Service for participants in BPA's Committed Intra-Hour Pilot shall not exceed 66 percent the total rate specified in section 2(a) above, as adjusted pursuant to section 7, Formula Rate Adjustments.

(b) **BILLING FACTOR**

See section 2(b) above.

(c) **EXCEPTIONS**

None.

6. **SUPPLEMENTAL SERVICE**

(a) **RATES**

The monthly Supplemental Service rate in \$/MW shall equal:
(Purchase Cost / Imbalance Reserve)

+ Administrative Charge

Where:

Purchase Cost = The sum of all purchase costs incurred by BPA to supply Supplemental Service for the relevant number of months to customers that commit to take such service, in dollars (\$).

Imbalance Reserve = The sum of all imbalance reserves purchased by BPA to supply Supplemental Service for the relevant month or months for customers that commit to take such service in MW-months.

Administrative Charge = \$134 per MW-month

(b) **BILLING FACTOR**

The billing factor shall be the monthly amount of reserve that the Supplemental Service customer has contractually committed to purchase or supply.

(c) **EXCEPTIONS**

None.

7. **FORMULA RATE ADJUSTMENTS**

The Imbalance Reserves rate specified in section 2(a)(iii) above may be adjusted by: (1) Formula Rate I below to recover the costs of replacing Federal balancing reserve capacity that becomes unavailable during the rate period with non-Federal balancing reserve capacity; or (2) Formula Rate II below to increase non-Federal sources of balancing reserve capacity for the imbalance component to Variable Energy Resource Balancing Service.

Public Notification Process for Rate Adjustment:

Purchases of balancing reserve capacity for a term not longer than two months:
BPA-TS will post on its OASIS a notice stating the adjusted rate at least 30 days in advance of the effective date of the adjusted rate.

Purchases of balancing reserve capacity for a term of longer than two months:
BPA-TS will provide 15 calendar days advance notice on its OASIS of a public meeting to discuss the proposed purchase of balancing reserve capacity and the expected adjusted rate. Written comments on the proposed purchase will be accepted for 15 calendar days after the public meeting. BPA-TS will notify customers on its OASIS within 30 days of the public meeting of its decisions regarding the purchase and the adjusted Variable Energy Resources Balancing Service rate.

- (i) Formula Rate I for Replacement of Federal Balancing Reserve Capacity that Becomes Unavailable

BPA may apply Formula Rate I to adjust the imbalance reserves rate set forth in section 2(a)(iii) of this rate schedule if BPA determines that it can no longer provide the level of balancing reserve capacity for Variable Energy Resource Balancing Service that BPA forecast it could provide for the rate period and BPA purchases non-Federal balancing reserve capacity to replace the unavailable Federal balancing reserve capacity.

Formula Rate I:

$$\text{Adj Imb Rate} = \text{Imb rate} + (\text{Avg Net Cost} / \text{Avg Sales})$$

Where:

Adj Imb Rate = The adjusted Imbalance Reserves rate that replaces section 2(a)(iii), in \$/kW/mo.

Imb Rate = The Imbalance Reserves rate identified in section 2(a)(iii) plus any previous adjustments under this section (Formula Rate I or Formula Rate II), in \$/kW/mo.

Avg Net Cost = The average, spread over the remaining months of the rate period, of the net costs associated with acquiring replacement balancing reserve capacity, in \$/mo.

Avg Sales = The average forecasted billing factor for the remaining months of the rate period, as identified in the rate case, in kilowatts.

- (ii) Formula Rate II for Purchases of Balancing Reserve Capacity to Increase the Amount of Balancing Reserve Capacity to Provide the Imbalance Component for Variable Energy Resource Balancing Service

BPA may apply Formula Rate II to adjust the imbalance reserve rate set forth in section 2(a)(iii) of this rate schedule, with a commensurate increase in non-Federal sources of balancing reserve capacity for Variable Energy Resources Balancing Service, if:

- a. one or more participants in the Pacific Northwest utility industry, including regional organizations, asks the Administrator to increase the amount of balancing reserve capacity provided for Variable Energy Resource Balancing Service; or
- b. because of a legal challenge to DSO 216, BPA is prevented from implementing DSO 216 or is required to amend it materially.

Formula Rate II:

$$\text{Adj Imb Rate} = \text{Imb rate} + (\text{Avg Cost} / \text{Avg Sales})$$

Where:

Adj Imb Rate = The adjusted Imbalance Reserves rate that replaces section 2(a)(iii), in \$/kW/mo.

Imb Rate = The Imbalance Reserves rate identified in section 2(a)(iii) plus any previous adjustments under this section (Formula Rate I or Formula Rate II), in \$/kW/mo.

Avg Cost = The average, spread over the remaining months of the rate period, of the costs associated with acquiring additional balancing reserve capacity, in \$/mo.

Avg Sales = The average forecasted billing factor for the remaining months of the rate period, as identified in the rate case, in kilowatts.

F. DISPATCHABLE ENERGY RESOURCE BALANCING SERVICE

The rate below applies to all non-Federal Dispatchable Energy Resources of 3 MW nameplate rated capacity or greater in the BPA Control Area except as provided in sections III.F.3. Dispatchable 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.

1. RATES

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

- (i) Incremental Reserves = 14.50 mills per kW maximum hourly deviation
- (ii) Decremental Reserves = 3.60 mills per kW maximum hourly deviation

2. BILLING FACTOR

- (a) The hourly billing factor for use of Incremental Reserves is the maximum of the absolute value of the one-minute average negative station control error (under-generation), including ramp periods, that exceeds 2 MW for that hour.
- (b) The hourly billing factor for use of Decremental Reserves is the maximum of the one-minute average positive station control error (over-generation), including ramp periods, that exceeds 2 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.

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 section II.D of the GRSPs.

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, Provisional 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 section II.H of the GRSPs.

GENERAL RATE SCHEDULE PROVISIONS

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SECTION I. GENERALLY APPLICABLE PROVISIONS

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A. APPROVAL OF RATES

These 2012 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, 2011. All rate schedules shall remain in effect until they are replaced or expire on their own terms.

B. GENERAL PROVISIONS

These 2012 rate schedules and the GRSPs associated with these schedules supersede BPA's 2010 rate schedules (which became effective October 1, 2009) to the extent stated in the Availability section of each rate schedule. These schedules and GRSPs shall be applicable to all BPA-TS 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 2012 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-TS 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-TS, or by wire transfer to a bank named by BPA-TS.

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-TS.

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-TS on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after BPA-TS 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-TS 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-TS and the Transmission Customer, BPA-TS 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-TS 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 facilities and Utility Delivery facilities.

1. RATES

a. DSI Delivery

Use-of-Facilities (UFT-12) Rate, section III.B.1 or III.B.2

b. Utility Delivery

\$1.119 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 Utility Delivery facilities.

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

b. Metering Adjustment

At those Points of Delivery that do not have meters capable of determining the demand on the hour of the Monthly Transmission Peak Load, the Billing Factor under section 2.a. shall equal the highest hourly demand that occurs during the billing month at the Point of Delivery multiplied by 0.79.

B. FAILURE TO COMPLY PENALTY CHARGE

1. RATE FOR FAILURE TO COMPLY PENALTY CHARGE

If a party fails to comply with BPA-TS's dispatch, curtailment, redispatch, or load shedding orders, the party will be assessed the Failure to Comply Penalty Charge. 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-TS will post on the OASIS the name of the index to be used. BPA-TS will not change the index more often than once per year unless BPA-TS determines that the existing index is no longer a reliable price index

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 the BPA-TS of the situation upon occurrence of the force majeure.

2. BILLING FACTORS

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-TS 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 the BPA-TS 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-TS 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-TS 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. POWER FACTOR PENALTY CHARGE

1. DESCRIPTION OF THE POWER FACTOR PENALTY CHARGE

Any party that is interconnected with the Federal Columbia River Transmission System (FCRTS) shall be charged for its reactive power requirements as described in this section, unless otherwise specified in an agreement existing prior to October 1, 1995.

Each point of interconnection or point of delivery shall be monitored and billed independently for determining the party's total reactive power requirements and all associated billing factors, including the Reactive Deadband. If a party is taking transmission service under multiple rate schedules, the party will pay for its reactive power requirements as if it is taking delivery under only one rate schedule.

2. CONDITIONS FOR APPLICATION OF THE POWER FACTOR PENALTY CHARGE

a. Measured Data

The Power Factor Penalty Charge will apply to only the party's reactive power requirements for which measured data exist.

b. Party's Generating Resource Connected to the FCRTS

Irrespective of the direction of real power flow, the Power Factor Penalty Charge shall apply to points of interconnection where a party's generating resource is directly connected to the FCRTS, *unless* the party's generating resource is either:

- (1) a synchronous generator equipped with a voltage regulator, or
- (2) equipped with reactive power control devices that comply with BPA-TS's applicable interconnection standards.

Such resource must actively support the voltage schedule at the point of integration at all times when the resource is in service, as determined by BPA-TS, for this exemption to apply. Generating resources that do not satisfy the above criteria shall not be exempt from the Power Factor Penalty Charge.

c. Bi-directional Real Power Flow

For points other than those specified in section 2.b, the Power Factor Penalty Charge will *not* be applied, and no new Ratchet Demand for

reactive power will be established, at a specific point if the metered real power (on an hourly integrated basis) flows from the party's system to the FCRTS at that point for as little as one hour during the billing period. However, the party will still pay any previously incurred demand ratchet charges. The direction of the real power flow will be determined based on metered quantities, not on scheduled quantities.

d. Service by Transfer

Points of delivery that are served by transfer over another utility's transmission system will *not* be subject to the Power Factor Penalty Charge *unless* there are significant BPA-TS Network facilities between the party's points of delivery and the transferor's system.

e. Specific Points Exempt from the Power Factor Penalty Charge

The Power Factor Penalty Charge will *not* apply to the following points:

- Nevada-Oregon Border (NOB)
- Big Eddy 500 kV
- Big Eddy 230 kV
- John Day 500 kV
- Malin 500 kV
- Captain Jack 500 kV
- Garrison 500 kV
- Townsend 500 kV

f. Special Circumstances

The party may submit requests to BPA-TS for consideration of unique circumstances. BPA-TS will evaluate the request and may make arrangements with the party to address the special circumstances.

3. RATES

BPA-TS will bill the party for reactive power at each point each month as follows:

Reactive Demand

\$0.28 per kVAr of lagging reactive demand in excess of the Reactive Deadband during HLH in all months of the year.

\$0.24 per kVAr of leading reactive demand in excess of the Reactive Deadband during LLH in all months of the year.

No charge for leading reactive demand during HLH.

No charge for lagging reactive demand during LLH.

4. BILLING FACTORS

a. Reactive Deadband

The Reactive Deadband (measured in kVAr) is used to determine the Reactive Billing Demand and Ratchet Demand for the Power Factor Penalty Charge.

The Reactive Deadband for each billing period is the maximum hourly integrated metered real power demand (measured in kW) at each point during the billing period multiplied by 25 percent.

The Reactive Deadband for either HLH or LLH:

- (1) is computed once per billing period (the same quantity is used for both HLH and LLH),
- (2) does not vary during the billing period, and
- (3) is based on the maximum hourly integrated metered real power demand during that billing period.

b. Reactive Billing Demand

The party's Reactive Billing Demand shall be calculated independently for lagging reactive power and leading reactive power at each point for which a Power Factor Penalty Charge is assessed.

All reactive demands shall be established in the particular HLH or LLH at each point during which the party's maximum applicable reactive demand is placed on BPA-TS, regardless of the time of the real power peak at each point.

All reactive demand at each point shall be established on a non-coincidental basis, regardless of whether the party is billed for real power or transmission at such point on a coincidental or non-coincidental basis, *unless* otherwise specified in the agreement between BPA-TS and the party, *or* coincidental billing is, in BPA-TS's sole determination, more practical for BPA-TS.

There will be separate reactive demands for lagging (HLH) and leading (LLH) demands. The party's Reactive Billing Demand for each point for the billing month shall be the *larger* of:

- (1) the largest measured reactive demand in excess of the Reactive Deadband during the billing period, *or*
- (2) the Ratchet Demand for reactive power.

The Ratchet Demand for reactive power is equal to 100 percent of the largest measured reactive demand in excess of the Reactive Deadband during the preceding 11-month period. Each point shall have a separate Ratchet Demand for lagging (HLH) and leading (LLH) reactive demand.

5. ADJUSTMENTS FOR REACTIVE LOSSES

Measured data shall be adjusted for reactive losses, if applicable, before determination of the Reactive Billing Demand.

D. 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, however, 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.

E. 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.

F. TRANSMISSION AND ANCILLARY SERVICES RATE DISCOUNTS

BPA-TS 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 the Transmission Provider in conjunction with its provision of transmission service, as follows:

1. any offer of a discount made by the Transmission Provider 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, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go 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 the Transmission Provider's System.

G. 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-TS will notify a Transmission Customer that is subject to a UIC once BPA-TS has verified the UIC amount.

1. RATE

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

The UIC rate shall be the lower 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-TS shall determine the amount by which the Transmission Customer exceeds its capacity reservation at each POD and POR, to the extent practicable. BPA-TS 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-TS 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-TS will sum these amounts that exceed capacity reservations: (1) for all PODs, and (2) 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-TS 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-TS'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-TS OASIS.

b. Transmission Rate if BPA-TS Waives or Reduces the UIC

If BPA-TS 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-TS waives or reduces the UIC:

- (1) If BPA-TS 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-TS 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-TS 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-TS waives the UIC; or (b) if BPA-TS reduces the UIC, the Transmission Customer's highest excess transmission demand that is not subject to the UIC as a result of the reduction.

H. CRAC, DDC, AND THE 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, sections II.C, II.D, and II.K.

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

Exception: The CRAC, DDC and Emergency NFB Surcharge apply only to the base unadjusted Variable Energy Resource Balancing Service rates specified in section III.E.2(a) of the Variable Energy Resource Balancing Service rate schedule, and not to the difference between that base unadjusted Variable Energy Resource Balancing Service rate and any adjusted Variable Energy Resource Balancing Service rate calculated under Formula Rates I or II in Section III.E.7 in the Variable Energy Resource Balancing Service rate schedule. In addition, the CRAC does not apply to the Variable Energy Resource Balancing Service Supplemental Service rate.

- Dispatchable Energy Resource Balancing Service

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 via the ACS rates specified above; the balance of the DDC Amount

is to be distributed via 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, sections II.C, II.D, and II.K, are incorporated by reference.

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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 the BPA-TS's Transmission System in accordance with Good Utility Practice. Ancillary Services include:

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

Ancillary Services are available under the ACS rate schedule.

2. BILLING FACTOR

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

3. 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:

1. 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);
2. maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
3. maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and
4. provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

4. 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-TS. 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 the Northwest Power Pool (NWPP) reliability criteria. Control Area Services, include, without limitation:

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

5. 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.

6. DIRECT ASSIGNMENT FACILITIES

Direct Assignment Facilities are facilities or portions of facilities that are constructed by BPA-TS for the sole use/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.

7. DIRECT SERVICE INDUSTRY (DSI) DELIVERY

The *DSI Delivery* segment is the segment of the FCRTS that provides service to DSI customers at voltages of 34.5 kV and below.

8. 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.

9. DYNAMIC SCHEDULE

Add definition adopted in Dynamic Transfer Operating and Scheduling Business Practice.

10. DYNAMIC TRANSFER

Add definition adopted in Dynamic Transfer Operating and Scheduling Business Practice.

11. EASTERN INTERTIE

The *Eastern Intertie* is the segment of the Federal Columbia River Transmission System (FCRTS) for which the transmission facilities consist of the Townsend-Garrison double-circuit 500 kV transmission line segment, including related terminals at Garrison.

12. ENERGY IMBALANCE SERVICE

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area. The BPA-TS 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 the BPA-TS or make alternative comparable arrangements specified in the Transmission Customer's Service Agreement to satisfy its Energy Imbalance Service obligation.

13. 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.

14. 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:

1. 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 which may be scheduled by BPA;

2. which BPA may use under contract or license; or
3. 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.

15. 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.

16. GENERATION IMBALANCE SERVICE

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 schedule period.

17. HEAVY LOAD HOURS (HLH)

Heavy Load Hours (HLH) are all those hours in the peak period 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). BPA matches NERC Standards in classifying six holidays as Light Load Hour.

18. 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.

19. 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.

20. LIGHT LOAD HOURS (LLH)

Light Load Hours (LLH) are all those hours in the off-peak period 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 matches 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 they fall on a Sunday, the holiday is celebrated the Monday immediately following that Sunday, so that Monday is also LLH all day. If these days fall on a Saturday, the holiday remains on that Saturday, and that Saturday is classified as LLH.

21. 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.

22. 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.

23. 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.

24. 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.

25. 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.

26. 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.

27. MEASURED DEMAND

The *Measured Demand* is that portion of the customer's Metered or Scheduled Demand for transmission service from BPA-TS 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.

28. 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:

1. at each point of delivery (receipt) for which the Metered Demand is the basis for the determination of the Measured Demand;
2. during each time period specified in the applicable rate schedule; and
3. 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-TS 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.

29. MONTANA INTERTIE

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

30. MONTHLY SERVICE

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.

31. 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.

32. NETWORK (OR INTEGRATED NETWORK)

The *Network* is the segment of the Federal Columbia River Transmission System (FCRTS) for which the transmission facilities provide the bulk of transmission of electric power within the Pacific Northwest.

33. NETWORK INTEGRATION TRANSMISSION (NT) SERVICE

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

34. 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.

35. NETWORK UPGRADES

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

36. 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.

37. 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. The BPA-TS must offer this service in accordance with applicable NERC, WECC, and NWPP standards. The Transmission or Control Area Service Customer must either purchase

this service from the BPA-TS or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The Transmission or Control Area Service Customer's obligation is determined consistent with North American Electric Reliability Council (NERC), Western Systems Coordinating Council (WECC) and Northwest Power Pool (NWPP) criteria.

38. OPERATING RESERVE – SUPPLEMENTAL RESERVE SERVICE

Operating Reserve – Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, 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. The BPA-TS must offer this service in accordance with applicable NERC, WECC, and NWPP standards. The Transmission or Control Area Service Customer must either purchase this service from the BPA-TS or make alternative but comparable arrangements to satisfy its Supplemental Reserve Service obligation. The Transmission Customer's obligation is determined consistent with North American Electric Reliability Council (NERC), Western Electricity Coordinating Council (WECC) and Northwest Power Pool criteria.

39. 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 which impose a reserve obligation on the BPA Control Area.

The specific amounts required are determined consistent with North American Electric Reliability Council (NERC) Policies, the Northwest Power Pool (NWPP) Operating Manual, "Contingency Reserve Sharing Procedure," and the Western Electricity Coordinating Council (WECC) Standards.

40. PERSISTENT DEVIATION

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

1. 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:

- (a) both 15% of the schedule and 20 MW in each scheduled period for four consecutive hours or more in the same direction;

- (b) both 7.5% of the schedule and 10 MW in each scheduled period for six consecutive hours or more in the same direction;
- (c) both 1.5% of the schedule and 5 MW in each scheduled period for twelve consecutive hours or more in the same direction; or
- (d) both 1.5% of the schedule and 2 MW in each scheduled period for twenty-four consecutive hours or more in the same direction.

2. 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:

- (a) both 15% of the schedule and 20 MW in each scheduled period for four consecutive hours or more in the same direction;
- (b) both 7.5% of the schedule and 10 MW in each scheduled period for six consecutive hours or more in the same direction;
- (c) both 1.5% of the schedule and 5 MW in each scheduled period for twelve consecutive hours or more in the same direction; or
- (d) both 1.5% of the schedule and 2 MW in each scheduled period for twenty-four consecutive hours or more in the same direction.

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

Upon 90 days written notice on BPA-TS's OASIS that BPA-TS has implemented intra-hour scheduling for exports and imports of energy within and out of the BPA Balancing Authority Area, parts 1(a) and 2(a) above shall be deemed replaced with the following:

- (a) both 15% of the schedule and 20 MW in each scheduled period for three consecutive hours or more in the same direction.

41. 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 the BPA-TS 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-TS.

42. 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.

43. 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.”

44. 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-TS 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-TS.

45. PROVISIONAL VARIABLE ENERGY RESOURCE BALANCING SERVICE

Provisional Variable Energy Resource Balancing Service is a type of Variable Energy Resource Balancing Service (VERBS) that is offered during a rate period to customers that lose their status as a self-supplier of one or more components of VERBS and to customers that did not have an expected interconnection date during the rate period and accelerate their interconnection date into the rate period.

46. RATCHET DEMAND

The *Ratchet Demand* in kilowatts or kilovars is the maximum demand established during a specified period of time either 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. The Ratchet Demand for reactive power is defined in the Power Factor Penalty Charge at section II.C of these GRSPs.

47. REACTIVE POWER

Reactive Power is the out-of-phase component of the total volt-amperes in an electric circuit. Reactive Power has two components: reactive demand (expressed in kilovars or kVAR) and reactive energy (expressed in kilovarhours or kVARh).

48. 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-TS's transmission facilities within acceptable limits. In order to maintain transmission voltages on BPA-TS's transmission facilities within acceptable limits, generation facilities (in the Control Area where the BPA-TS 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-TS'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-TS. The Transmission Customer must purchase this service from BPA-TS.

49. 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 generating 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 the BPA-TS. The BPA-TS 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 the BPA-TS or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation.

50. 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 North American Electric Reliability Council (NERC), Western Electricity Coordinating Council (WECC), and Northwest Power Pool (NWPP) standards. BPA-TS offers Ancillary Services and Control Area Services to allow resources or loads to meet their Reliability Obligations.

51. RESERVED CAPACITY

Reserved Capacity is the maximum amount of capacity and energy that BPA-TS 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.

52. SCHEDULED DEMAND

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

53. 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-TS.

54. 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.

55. 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.

56. 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.

57. SECONDARY SYSTEM INTERMEDIATE TERMINAL

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

58. SECONDARY TRANSFORMATION

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

59. 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.

60. 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.

61. 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.

62. 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 which impose a reserve obligation on the BPA Control Area.

The specific amounts required are determined consistent with North American Electric Reliability Council (NERC) Policies, the Northwest Power Pool (NWPP) Operating Manual, "Contingency Reserve Sharing Procedure," and the Western Electricity Coordinating Council (WECC) Standards.

63. 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 which impose a reserve obligation on the BPA Control Area.

The specific amounts required are determined consistent with North American Electric Reliability Council (NERC) Policies, the Northwest Power Pool (NWPP) Operating Manual, "Contingency Reserve Sharing Procedure," and the Western Electricity Coordinating Council (WECC) Standards.

64. TOTAL TRANSMISSION DEMAND

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

65. 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-TS 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-TS.

66. TRANSMISSION DEMAND

Transmission Demand is the maximum amount of capacity BPA-TS 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.

67. TRANSMISSION PROVIDER

A *Transmission Provider*, such as BPA-TS, 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.

68. UTILITY DELIVERY

The *Utility Delivery* segment is that segment of the FCRTS that provides service to utility customers at voltages below 34.5 kV.

69. 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.

70. 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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