BP-16 Rate Proceeding

ADMINISTRATOR'S DRAFT RECORD OF DECISION

June 2015

BP-16-A-01

ADMINISTRATOR'S PREFACE

These are transformative times for the electric utility industry in the Pacific Northwest. The region faces a series of critical issues, from the continuing impact of low natural gas prices on wholesale electricity prices and the cost of maintaining the region's aging assets, to emerging technologies, evolving markets, and new regulatory requirements. These and other factors are placing significant upward pressure on BPA's long-term cost structure, while total outstanding debt continues to rise.

BPA's ability to continue to meet its multiple statutory obligations and public purpose objectives depends on maintaining our long-term cost competitiveness and financial strength. This is a shared objective for the many customers, tribes, and others that rely on BPA for important services and programs.

This longer-term perspective weighed heavily in my decision-making, as did the near-term impact of the rate increase in the Initial Proposal. My deliberation is reflected in this Draft Record of Decision, which includes draft decisions designed to help achieve long-term stability and financial viability. This course is consistent with my recent decision during the Integrated Program Review to convert funding for BPA's Energy Efficiency program from capital to expense, eliminating the growth of our total long-term energy efficiency debt and reducing associated debt service costs.

My proposed decisions also set the stage for continued regional conversations on issues that I believe would benefit from further collaborative discussions with all interested stakeholders. For example, I considered whether to substantially increase the use of financial reserves to mitigate the proposed transmission rate increase. From an agency perspective, and with long-term regional interests in mind, I do not believe this would be the wisest use of BPA's financial reserves at this time. Rather, I will commit my staff to working with stakeholders after the conclusion of this rate case to develop disciplined financial policies that will equitably apply to BPA power and transmission rates, including the use of financial reserves and risk mitigation measures, in support of BPA's enduring financial strength.

I also respond to arguments that policies in California have devalued BPA's long-term firm transmission capacity on the Southern Intertie. I believe that seams issues exist and must be addressed. I am particularly determined to protect BPA's ability to sell long-term transmission capacity for both BPA's financial stability and the benefit of our customers and the region.

Before adopting a ratemaking solution, such as significantly increasing the Southern Intertie non-firm rate, I will seek clarity on the extent of the issue. After the rate case, BPA will conduct a broader examination of seams issues with the involved parties and evaluate both ratemaking and non-ratemaking solutions. If the examination shows that a ratemaking solution is necessary to produce an equitable outcome, BPA may conduct an expedited 7(i) rate proceeding prior to the BP-18 rate case to adjust the hourly non-firm rate.

Consistent with maintaining the value of BPA's assets, I will retain the Montana Intertie rate rather than roll it into the transmission network rates. Some parties argue that rolling it in would aid the development of renewable resources in Montana. I have concluded, however, that elimination of the Montana Intertie rate would have little effect on renewables in Montana at this time. As demonstrated by the nearly 5,000 megawatts of wind energy connected to the Federal transmission system, BPA fully supports the development of clean energy resources. I believe the involved parties can achieve the best outcome by collaborating on a planning process and a financial plan to share the risks of increased costs, which could result from eliminating the Montana Intertie rate. BPA supports and will participate in a thoughtful, cohesive process to remove barriers to the development of renewables in Montana.

As steward of a low-cost, low-carbon regional power and transmission system that provides incredible value to the region's economy, BPA must ensure that our actions sustain the system's value for generations to come. BPA will remain steadfastly focused on its long-term cost structure and service delivery model, with an eye to being the low-cost energy provider of choice when new power sales contracts are offered in 2028.

BPA is working this summer to design a set of workshops for regional leaders to establish a common understanding of our long-term cost structure and the strategic choices we face to maintain financial strength. Key issues will include our approach to capital investment in the hydropower and transmission systems, our internal operating costs, and our service delivery models, including energy efficiency. We expect these discussions to begin this fall. I look forward to working with many of you to address the region's challenges and opportunities.

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COMMONLY USED ACRONYMS AND SHORT FORMS

AAC	Anticipated Accumulation of Cash
ACNR	Accumulated Calibrated Net Revenue
AER	Actual Exchange Revenue
AER step	Actual Energy Regulation study
AFC	available flowgate capacity
AGC	Automatic Generation Control
ALF	Agency Load Forecast (computer model)
aMW	average megawatt(s)
ANR	Accumulated Net Revenues
AOP	Assured Operating Plan
ASC	Average System Cost
ATC	available transmission capacity
BAA	Balancing Authority Area
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
COE, Corps, or USACE	U.S. Army Corps of Engineers
Commission	Federal Energy Regulatory Commission
Corps, COE, or USACE	U.S. Army Corps of Engineers
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council or NPCC	Northwest Power and Conservation Council
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CSP	Customer System Peak
CT	combustion turbine
CY	calendar year (January through December)
DDC	Dividend Distribution Clause
dec	decrease, decrement, or decremental
DERBS	Dispatchable Energy Resource Balancing Service
DFS	Diurnal Flattening Service
DOE	Department of Energy
DOP	Detailed Operating Plan
DSI	direct-service industrial customer or direct-service industry
DSO	Dispatcher Standing Order
EE	Energy Efficiency
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.

ESA	Endangered Species Act
ESS	Energy Shaping Service
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
FHFO	Funds Held for Others
FORS	Forced Outage Reserve Service
FPS	Firm Power and Surplus Products and Services (rate)
FY	fiscal year (October through September)
G&A	general & administrative
GMS	Generation Management Service
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	Hydrosystem Simulator (computer model)
ICE	Intercontinental Exchange
inc	increase, increment, or incremental
IOU	investor-owned utility
IP	Industrial Firm Power (rate)
IPR	Integrated Program Review
IRD	Irrigation Rate Discount
IRM	Irrigation Rate Mitigation
IRMP	Irrigation Rate Mitigation Product
kcfs	thousand cubic feet per second
kW	kilowatt (1000 watts)
kWh	kilowatthour
LPP	Large Project Program
LDD	Low Density Discount
LLH	Light Load Hour(s)
LPTAC	Large Project Targeted Adjustment Charge
Maf	million acre-feet
Mid-C	Mid-Columbia
MMBtu	million British thermal units
MRNR	Minimum Required Net Revenue
MW	megawatt (1 million watts)
MWh	megawatthour
NCP	Non-Coincidental Peak
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation

NFB	**N**ational Marine Fisheries Service (NMFS) **F**ederal Columbia River Power System (FCRPS) **B**iological 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
NPCC or Council	Pacific Northwest Electric Power and Conservation Planning Council
NPV	net present value
NR	New Resource Firm Power (rate)
NRFS	New Resource Flattening Service
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
OATI	Open Access Technology International, Inc.
OMB	Office of Management and Budget
OPER step	operational study
OY	operating year (August through July)
Peak	Peak Reliability; the Regional Coordinator half of the former WECC
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's Power Services business line
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

REPSIA	REP Settlement Implementation Agreement
RevSim	Revenue Simulation Model
RFA	Revenue Forecast Application (database)
RHWM	Rate Period High Water Mark
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RR	Resource Replacement (rate)
RRS	Resource Remarketing Service
RSS	Resource Support Services
RT1SC	RHWM Tier 1 System Capability
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
TRAM	Transmission Risk Analysis Model
Transmission System Act	Federal Columbia River Transmission System Act
Treaty	Columbia River Treaty
TRL	Total Retail Load
TRM	Tiered Rate Methodology
TS	BPA's Transmission Services business line
TSS	Transmission Scheduling Service
UAI	Unauthorized Increase
ULS	Unanticipated Load Service
USACE, Corps, or COE	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
VOR	Value of Reserves
VR1-2014	First Vintage Rate of the BP-14 rate period
VR1-2016	First Vintage Rate of the BP-16 rate period
WECC	the Regional Entity half (the other half is Peak) of the Western Electricity Coordinating Council
WSPP	Western Systems Power Pool

PARTY ABBREVIATIONS AND JOINT PARTY DESIGNATION CODES

Joint Parties in the 2016 Power and Transmission Rate Proceeding

Party Code	Joint Party	Joint Party Members
JP01	Joint Party 1	Avista Corporation (AC) PacifiCorp (PC) Portland General Electric Company (PG) Puget Sound Energy, Inc. (PS)
JP02	Joint Party 2	Northwest Requirements Utilities (NR) Pacific Northwest Generating Cooperative (PN)
JP03	Joint Party 3	Avista Corporation (AC) Portland General Electric Company (PG) Puget Sound Energy, Inc. (PS)
JP04	Joint Party 4	Avista Corporation (AC) Iberdrola Renewables (IR) Idaho Power Company (IP) PacifiCorp (PC) Portland General Electric Company (PG) Puget Sound Energy, Inc. (PS)
JP05	Joint Party 5	Avista Corporation (AC) Idaho Power Company (IP) PacifiCorp (PC) Portland General Electric Company (PG) Puget Sound Energy, Inc. (PS)
JP06	Joint Party 6	Public Power Council (PP) Powerex Corporation (PX)
JP07	Joint Party 7	Public Power Council (PP) Industrial Customers of Northwest Utilities (IN)
JP08	Joint Party 8	Calpine Corporation (CP) Northwest & Intermountain Power Producers Coalition (NI) TransAlta Energy Marketing (TC)
JP09	Joint Party 9	Northwest Requirements Utilities (NR) Public Power Council (PP)
JP10	Joint Party 10	Northwest Requirements Utilities (NR) Pacific Northwest Generating Cooperative (PN) Public Power Council (PP)
JP11	Joint Party 11	City of Tacoma (TA) City of Seattle (SE) Snohomish County Public Utility District No. 1 (SN)
JP12	Joint Party 12	Portland General Electric Company (PG) Puget Sound Energy, Inc. (PS)

JP13	Joint Party 13	Public Utility District No. 1 of Benton County (BC) Public Utility District No. 1 of Cowlitz County (CO) Eugene Water & Electric Board (EW) Public Utility District No. 1 of Franklin County (FR) Public Power Council (PP) City of Seattle (SE) Snohomish County PUD (SN)
JP14	Joint Party 14	City of Seattle (SE) Public Utility District No. 1 of Snohomish County (SN)
JP15	Joint Party 15	Industrial Customers of Northwest Utilities (IN) Northwest Requirements Utilities (NR) Public Power Council (PP) City of Seattle (SE)
JP16	Joint Party 16	Avista Corporation (AC) Portland General Electric Company (PG) Puget Sound Energy, Inc. (PS)
JP17	Joint Party 17	Eugene Water & Electric Board (EW) Public Utility District No. 1 of Cowlitz County (CO)

1.0 GENERAL TOPICS

1.1 Introduction

The BP-16 Rate Proceeding establishes power and transmission rate schedules and General Rate Schedule Provisions (GRSPs) for the Bonneville Power Administration (BPA) that replace existing rate schedules and GRSPs, which expire on September 30, 2015.

This Draft Record of Decision (ROD) contains the draft decisions of the BPA Administrator, based on the record compiled in this rate proceeding, with respect to the adoption of power, transmission, and ancillary and control area service rates for the two-year rate period October 1, 2015, through September 30, 2017 (fiscal years (FY) 2016–2017). The proceeding included an evidentiary hearing, parties' initial briefs, and oral argument before the BPA Administrator. This Draft ROD addresses the issues raised by parties in this proceeding, as stated in their briefs. It describes the parties' and BPA Staff's positions on the issues. It then evaluates the positions and presents the Administrator's draft decisions. This Draft ROD also summarizes and responds to participant comments that were submitted during the public comment period, which ended on February 26, 2015. The next steps in the process are the filing of the parties' briefs on exceptions on July 1, 2015, and publication of the Final ROD on July 24, 2015.

1.1.1 Procedural History of this Rate Proceeding

1.1.1.1 Issue Workshops

For several months before the release of Staff's Initial Proposal, BPA sponsored a series of workshops on a variety of topics related to its power and transmission ratemaking. BPA designed the workshops so they would allow BPA Staff and interested parties to develop a common understanding of specific topics, generate ideas, and discuss alternative proposals. BPA held seven workshops between January 2014 and June 2014 on transmission segmentation issues; five workshops between May 2014 and August 2014 on generation inputs issues; eleven workshops between April 2014 and September 2014 on additional transmission rates issues; four workshops between July and September 2014 on power rates issues; and one workshop in August 2014 on financial reserves. In addition, BPA held four workshops between August and October 2014 on the Rate Period High Water Mark (RHWM) Process.

Conducting the issue workshops before the development of the Initial Proposal allowed BPA Staff and interested parties to freely exchange ideas and comments relevant to rate issues without the prohibition on *ex parte* communication that takes effect upon publication of the rate proposal in the Federal Register. The *ex parte* prohibition for this rate proceeding went into effect on December 4, 2015, and will end when BPA issues the Final ROD. The Initial Proposal incorporated a number of the ideas and proposals that were discussed in the workshops.

1.1.1.2 BP-16 Rate Proceeding

Section 7(i) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. § 839e(i), requires that BPA's rates be established according to specific procedures that include, among other things, issuance of a notice in the Federal Register announcing the proposed rates; the opportunity for interested parties to submit written and oral views, data, questions, and arguments; and a decision by the Administrator based on the record. This proceeding is also governed by BPA's rules for general rate proceedings, the *Procedures Governing Bonneville Power Administration Rate Hearings*, 51 Fed. Reg. 7,611 (1986) (hereinafter, *Procedures*). The *Procedures* implement the section 7(i) requirements.

The BP-16 rate proceeding includes power and transmission rates in a single docket. On December 4, 2015, BPA published a Federal Register notice, "Fiscal Year (FY) 2016–2017 Proposed Power and Transmission Rate Adjustments Public Hearing and Opportunities for Public Review and Comment," 79 Fed. Reg. 71,984 (2014). On December 5, 2014, BPA held a scheduling conference to discuss a procedural schedule and procedural orders with prospective parties in the case. The formal rate proceeding began with a prehearing conference on December 10, 2014. After the prehearing conference, the Hearing Officer issued orders establishing the schedule for the rate proceeding, special rules of practice, data request procedures, and general acronyms; he also granted petitions to intervene.

BPA Staff's Initial Proposal was supported by Staff's initial studies and written testimony issued on December 10, 2014. Clarification of Staff's Initial Proposal took place on December 17, 2014. The parties filed their direct testimony on February 4, 2015. BPA and all parties waived clarification of the parties' direct testimony. BPA Staff and the parties filed rebuttal testimony on March 16, 2015. Clarification of Staff's rebuttal testimony took place on March 19, 2015.

Because BPA Staff intended to propose significant changes in its rebuttal testimony on four issues, it filed a motion with the Hearing Officer to allow the parties to submit surrebuttal testimony on these issues. The issues were the Montana Intertie rate; the Utility Delivery rate, including segmentation related to the Utility Delivery segment; the use of transmission reserves, including rate schedule changes necessary to implement the proposed changes; and power risk mitigation. The Hearing Officer granted the motion, and the parties filed surrebuttal testimony on March 30, 2015. *See* Order Granting BPA's Motion to Amend the Procedural Schedule, BP-16-HOO-13. BPA and all parties waived clarification of the surrebuttal testimony.

Cross-examination of all parties was scheduled for April 8-9, 2015. Prior to that time, however, all parties waived their opportunity for cross-examination.

The parties filed their initial briefs on May 1, 2015. Oral argument before the Administrator took place on May 8, 2015. This Draft ROD is being issued on June 12, 2015. Briefs on exceptions are due to be filed July 1, 2015.

At times, certain parties to this proceeding consolidated for the purpose of filing testimony or submitting a brief on one or more issues. *See* Special Rules of Practice Governing this

Proceeding, BP-16-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 Draft ROD. *See also* Document Numbering System and Pre-Marking of Exhibits and Briefs, BP-16-HOO-04.

BPA received three written comments during the participant[1] comment period, which began with the publication of the notice in the Federal Register on December 4, 2014, and ended February 26, 2015. Participant comments are part of the record upon which the Administrator bases his decisions; they are summarized and addressed separately in Draft ROD Chapter 5. Participant comments may be viewed at BPA's Web site under "Public Involvement."

1.1.1.3 Partial Settlement of Generation Inputs and Transmission Ancillary and Control Area Services Rates

Beginning in May 2014, BPA held rate case settlement workshops with the rate case parties on generation inputs issues that form the foundation of most ancillary service and control area service rates. Fisher and Fredrickson, BP-16-E-BPA-12, at 1-2. Over the next six months, BPA and the parties developed a settlement agreement that covers all ancillary and control area service rates except (1) Scheduling, System Control, and Dispatch Service; and (2) Reactive Supply and Voltage Control from Generation Sources Service. Setting aside the Risk Mitigation Tools section of the settlement, which has the potential to adjust the settlement rates, the settlement rates for Regulation and Frequency Response Service, Variable Energy Resource Balancing Service, and Dispatchable Energy Resource Balancing Service are unchanged from the BP-14 rates for those services. *Id.* at 3-4. The settlement rates for Operating Reserves, both Spinning and Supplemental, are 5 percent higher than the BP-14 rates. *Id.* at 4.

The Partial Settlement Agreement set cost allocations from Power Services to Transmission Services for synchronous condensing, generation dropping, redispatch, segmentation of Corps of Engineers and Bureau of Reclamation network and delivery facilities, and station service. These costs are recovered in various transmission rates. *Id.* at 4-5. The settlement agreement also provides for other changes to the rate schedules and specifies the amount of balancing reserve capacity to be provided during the rate period and an acquisition budget for balancing reserve capacity. BPA tendered the Partial Settlement Agreement to the parties on September 19, 2014. Parties were given until September 25, 2014, to indicate their intent to contest the settlement. No party did so. *Id.* at 2. By the deadline, 29 parties signed or agreed not to contest the settlement agreement. BPA filed the BP-16 generation inputs Partial Settlement Agreement as part of the BP-16 Initial Proposal. *Id.*, Appendix A. On December 16, 2014, the Hearing Officer issued an order requiring that "[a]ny party wishing to object to the Generation Inputs Settlement Agreement must do so no later than 4:30 p.m. PST on Monday, December 22, 2014." Order

[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. Special Rules of Practice Governing this Proceeding, BP-16-HOO-02.

Establishing Deadline to Object to the Proposed Generation Inputs Settlement Agreement, BP-16-HOO-07. No party objected. The settlement is further discussed in Chapter 3.0.

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 any matter at issue.

Sections 1010.13(c) and (d) of the *Procedures* set forth the requirements applicable to initial briefs and briefs on exceptions. A party that raised an issue in its initial brief need not reassert that issue in its brief on exceptions in order to avoid waiving the issue; all arguments raised by a party in its initial brief are deemed to have been raised in the party's brief on exceptions. Special Rules of Practice Governing this Proceeding, BP-16-HOO-02, at 5.

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 established.

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 the Secretary of Energy shall transmit and dispose of electric power and energy in such manner as to 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 shall 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 (Transmission System Act), 16 U.S.C. § 838, 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 for transmission and for the sale of electric power and specifies that the costs of the Federal transmission system shall 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 Pac. Power & Light v. Duncan*, 499 F. Supp. 672 (D. 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 has recognized the Administrator's ratemaking discretion. *Cent. Lincoln Peoples' Util. Dist. 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"); *PacifiCorp 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"); *Atl. 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"); *Dep't of Water and Power 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"); *Pub. 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 Co. of America v. Cent. Lincoln Peoples' Util. Dist.*, 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

Under the Northwest Power Act, BPA's rates become effective upon confirmation and approval by the Commission. 16 U.S.C. § 839e(a)(2) & (k). The Commission's review is appellate in nature, based on the record developed by the Administrator. *U.S. Dep't 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. *U.S. Dep't 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 U.S. Dep't 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. *Cent. Lincoln Peoples' Util. Dist. v. Johnson*, 735 F.2d 1101, 1115 (9th Cir. 1984).

1.2 Related Topics and Processes

This section includes discussion of topics and processes separate and distinct from this rate proceeding that provide information and policy context to the proceeding, including program cost estimates developed in the Integrated Program Review (IPR), BPA's Energy Efficiency (EE) program, the 2012 Residential Exchange Program Settlement Agreement (2012 REP Settlement), and the Rate Period High Water Mark Process. Issues related to those processes are outside the scope of the BP-16 7(i) proceeding. 79 Fed. Reg. 71,986, 71,987 (2014).

1.2.1 Integrated Program Review

Since 1986, in a process separate from its rate proceedings, BPA has conducted a public review of planned spending levels used in the development of rates. The IPR process provides interested parties the 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. The first step in the IPR process, the Capital Investment Review (CIR), focuses on reviewing and discussing draft asset strategies and 10-year capital forecasts. After a January 2014 IPR kickoff meeting, the 2014 CIR was held in February and March 2014. Public comments received during the CIR informed capital cost projections for FY 2016–2017 in the 2014 IPR.

In May 2014 BPA began the IPR's public, program-level review of the planned expenses to be included in setting power and transmission rates in the BP-16 rate proceeding. In May and June 2014, BPA held technical workshops and responded to participants' requests for additional information. The IPR process provided opportunities for BPA and participants to review and discuss power, transmission, and agency services programs and included detailed review of asset strategies and associated program spending levels.

On October 2, 2014, BPA issued the Final Close-Out Report for the IPR, in which BPA responded to participants' comments. In the report, BPA established the program-level cost estimates that are used in the Initial Proposal to establish the power and transmission rates. On January 30, 2015, BPA invited the region to participate in an abbreviated IPR2 public process to discuss proposed adjustments from the 2014 IPR related primarily to energy

efficiency financing options. The process began with a public meeting in Portland on February 24, 2015. The comment period ended on March 13, 2015. On May 1, 2015, BPA issued the IPR2 close-out letter and Final Close-out Report, which detailed BPA's decision to move the Energy Efficiency program from capital financing to expense in the upcoming rate period, FY 2016–2017. BPA will offset the increase in expense due to this change with reductions in BPA spending levels and debt management actions associated with the refinancing of $757 million of Energy Northwest bonds. For further information on the IPR and IPR2 processes and outcomes, see the BPA Web site under "Finance & Rates," "Financial Public Processes," "Integrated Program Review."

1.2.2 Energy Efficiency (EE) Program

In their initial briefs, several parties request that BPA conduct a public process to develop a new delivery model for BPA's energy efficiency programs. In the context of encouraging BPA to enhance the competitiveness of its Priority Firm Power (PF) rates, WPAG recommends that BPA conduct a process during the BP-16 rate period to examine and develop an alternative to BPA's current delivery model for energy efficiency. WPAG Br., BP-16-B-WG-01, at 3. WPAG requests that if the IPR2 closeout letter does not state that BPA will conduct such a process, "BPA should commit to holding such forums in the Final Record of Decision." *Id.* Snohomish makes the same request, asking BPA to "initiate stakeholder meetings following issuance of the BP-16 Record of Decision to discuss modernizing BPA's service delivery and funding mechanisms for conservation." Snohomish Br., BP-16-B-SN-01, at 13. Snohomish states that the public process should be finalized "ahead of the BP-18 rate proceeding and initial proposal." *Id.* at 14. JP17 notes that its members, EWEB and Cowlitz, submitted comments in the IPR2 process "arguing that BPA needs to rethink how it encourages and funds energy efficiency …." JP17 Br., BP-16-B-JP17-01, at 4. JP17 reiterated in its brief its "recommendation that BPA transition … to fully expensing for rate purposes its EE expenditure." *Id.*

Staff did not address this topic in testimony because the development and implementation of BPA's Energy Efficiency program are outside the scope of the rate proceeding. 79 Fed. Reg. 71,984, 71,986 (Dec. 4, 2014). Nonetheless, BPA understands its customers' desire to engage with BPA on the EE program. BPA is preparing to conduct additional dialogue with customers, the Council, and constituents about how to support regional energy efficiency achievements as part of a broader discussion on the agency's long-term cost structure and service delivery models beginning in the fall of 2015. IPR2 Final Close-out Report at 7.

1.2.3 2012 Residential Exchange Program Settlement Agreement

On July 26, 2011, the Administrator executed the 2012 REP Settlement, which resolved longstanding litigation over BPA's implementation of the Residential Exchange Program under section 5(c) of the Northwest Power Act, 16 U.S.C. § 839c(c). The Administrator's findings regarding the legal, factual, and policy challenges to the 2012 REP Settlement are thoroughly explained in the REP-12 Record of Decision (REP-12 ROD). The 2012 REP Settlement and the Administrator's decision in the REP-12 ROD to sign the settlement were upheld by Ninth Circuit Court of Appeals in *Ass'n of Pub. Agency Customers v. Bonneville Power Admin.*, 733 F.3d 939 (9th Cir. 2013).

1.2.4 Rate Period High Water Mark Process

BPA has established FY 2016–2017 RHWMs for Public customers with Contract High Water Mark (CHWM) contracts. In the RHWM Process, which preceded the BP-16 rate proceeding and concluded in October 2014, BPA established the maximum planned amount of power a customer is eligible to purchase at Tier 1 rates during the rate period, the Above-RHWM Loads for each customer, the System Shaped Load for each customer, the Tier 1 System Firm Critical Output, RHWM Augmentation, the Rate Period Tier 1 System Capability (RT1SC), and the monthly/diurnal shape of RT1SC. The RHWM Process provided customers an opportunity to review, comment, and challenge BPA's RHWM determinations. The RHWMs and related outputs of the RHWM Process are combined with the rate case load forecast to develop billing determinants and for other ratesetting purposes.

1.3 Procedural Issues

1.3.1 Changes to PNRR and CRAC Parameters

Issue 1.3.1.1

Whether the Administrator can make adjustments to Planned Net Revenues for Risk (PNRR) or Cost Recovery Adjustment Clause (CRAC) parameters after litigants have filed their direct and rebuttal cases.

Parties' Positions

JP07 argues that if BPA retains the unilateral right to make any changes to PNRR or CRAC proposals at the end of the rate case, customers could be improperly subject to significant rate increases after all procedure has been exhausted. JP07 Br., BP-16-B-JP07-01, at 7-8.

BPA Staff's Position

BPA must have the ability to adjust its risk mitigation tools in the Final Proposal if necessary to meet BPA's Treasury Payment Probability (TPP) standard; otherwise, the standard would be impossible to implement and could not serve its purpose: to protect BPA's ability to make its Treasury payments in full and on time. Mandell and Lovell, BP-16-E-BPA-33, at 2.

Evaluation of Positions

The BP-16 Initial Proposal incorporated the possibility of many financial outcomes for FY 2015. *Id*. at 1. At the time of the Initial Proposal, nearly a full year of FY 2015 uncertainty remained. *Id*. By the time of the Final Proposal, many of the outcomes that were possible at the time of the Initial Proposal will have become impossible due to actual events in early FY 2015, and other possible outcomes will become more likely than they were at the time of the Initial Proposal. *Id*. Compared to the Initial Proposal, the distribution of possible FY 2015 outcomes will be much narrower at the time of the Final Proposal. *Id*. The actual financial outcome for FY 2015 determines the level of BPA reserves available for risk at the start of the FY 2016–2017 rate

period. *Id*. at 1-2. Thus, FY 2015 uncertainty is a key input in the calculation of BPA's rate period TPP and the determination of risk mitigation needs. *Id*. at 2.

As specified in BPA's 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 all of BPA's scheduled U.S. Treasury payments during each two-year rate period. *Id*. Rates are proposed in the Initial Proposal but established in the Final Proposal. *Id*. Therefore, BPA must have the ability to adjust its risk mitigation tools in the Final Proposal if necessary to meet the TPP standard. *Id.* Otherwise, the standard would be impossible to implement and could not serve its purpose: to protect BPA's ability to make its Treasury payments in full and on time. *Id*.

JP07 argues that if BPA retains the unilateral right to make any changes to its PNRR or CRAC proposals at the end of the rate case, customers could be improperly subject to significant rate increases after all procedure has been exhausted. JP07 Br., BP-16-B-JP07-01, at 7. Staff supports providing parties the opportunity to review and respond to updates to data that become available during the course of a rate case. Mandell and Lovell, BP-16-E-BPA-33, at 2. However, there are practical problems associated with additional review and comment opportunities that would be undesirable for all litigants, such as (1) the potential for a never-ending cycle of adjustment and review; (2) abandoning any adjustments to the risk package in the Final Proposal; and (3) structuring rates based on a worst-case outcome that would eliminate any possible need for increasing the amount of risk mitigation. *Id*.

As to the first practical problem, at some point the opportunity to review numbers must end so that BPA can finalize its rates. *Id*. Providing additional review and comment opportunities before updates are incorporated into the risk analysis would result in never-ending rounds of updates and reviews, or freezing the current year assumptions in the Initial Proposal. *Id*. Both of these possibilities are untenable. *Id*.

The second practical problem, ignoring actual financial conditions in the year when rates are set (*i.e*., the year immediately prior to the rate period), is not a sound business practice. *Id*. Furthermore, because BPA's rates must recover its costs, it is unlikely that such practice would be supported by the Federal Energy Regulatory Commission, which must confirm and approve BPA's rates before they become effective. *Id*. at 2-3.

As to the third practical problem, BPA would need to inflate risk mitigation in the Initial Proposal so that it would cover the worst-case scenario to ensure that the risk mitigation package would be sufficient to meet the TPP standard in the Final Proposal. *Id*. at 3. The risk mitigation in the Final Proposal could then be reduced from the level in the Initial Proposal. *Id*. However, this method would result in an Initial Proposal that is unnecessarily inflated and provide rate case parties little insight as to how the Final Proposal would likely turn out. *Id*. None of these alternatives is tenable. *Id*.

As noted previously, ignoring actual financial conditions at the time when rates are set (that is, the months immediately prior to the rate period) is not a sound business practice. *Id*. at 4. This point was emphasized by the Ninth Circuit when it faulted BPA for basing rates on outdated

assumptions. *See Golden NW Aluminum, Inc. v. Bonneville Power Admin.*, 501 F.3d 1037, 1052 (9th Cir. 2007) (BPA improperly relied on outdated assumptions in establishing rates). Furthermore, if risk mitigation parameters were to be "locked down" in the Initial Proposal (so that those same parameters had to be used for the Final Proposal), on average customers would be more likely to pay higher rates than in the absence of a lockdown. Mandell and Lovell, BP-16-E-BPA-33, at 4. Accepting the JP07 argument could easily be construed to prevent BPA from adjusting its Initial Proposal rates downward, thereby leaving BPA's rates at a level higher than risk conditions at the time of the Final Proposal would indicate are necessary. That result might violate BPA's statutory requirement to establish the lowest possible rates to consumers consistent with sound business principles. 16 U.S.C. § 839e(a)(1).

In the circumstance that risk mitigation in an Initial Proposal is strengthened (that is, PNRR is added or the CRAC threshold is increased from $0) to meet the 95 percent TPP standard, it is more likely that the need for such risk mitigation would decrease rather than increase between the Initial Proposal and the Final Proposal. Mandell and Lovell, BP-16-E-BPA-33, at 5. This is because current-year revenue uncertainty becomes smaller between the Initial Proposal and the Final Proposal. *Id.* Uncertainty for the year prior to the rate period generally decreases to roughly 20 percent of its Initial Proposal amount (as measured by the distribution's standard deviation). *Id.* This outcome is due to much of the year having actually occurred and much more being known about streamflow and other factors for the remainder of the year. *Id*. This reduced uncertainty increases TPP, in turn reducing the need for risk mitigation. *Id*. This result does not mean that the need for risk mitigation will always decrease between the Initial Proposal and the Final Proposal—increases or decreases in forecast revenue will also cause TPP to increase or decrease. *Id*. However, increases and decreases in the forecast should be roughly equally likely, leading to no change in TPP on average. *Id*. Because TPP commonly increases from the Initial Proposal to the Final Proposal, adjusting risk mitigation between the Initial Proposal and the Final Proposal benefits BPA's customers more often than it is adverse to them. *Id*.

JP07 argues that Staff should indicate in its Initial Proposal what modification of the risk parameters would be required to address a specific level of poor financial performance, which would afford customers the opportunity to review Staff's proposal and respond on the record. Deen *et al.*, BP-16-E-JP07-01, at 4-5. In the instant case, JP07 suggested that Staff should include information on how it would respond to a bad financial year as part of its rebuttal testimony, with brief surrebuttal allowed solely for the purpose of reacting to BPA's proposal. *Id.* at 5-6. JP07 notes that BPA Staff provided JP07 with a table containing risk mitigation scenarios for FY 2015 revenue changes and the parties had the opportunity to comment on the proposed parameters. JP07 Br., BP-16-B-JP07-01, at 7-8. Staff supported allowing the parties to file surrebuttal testimony on this topic to respond to the noted scenarios, Mandell and Lovell, BP-16-E-BPA-33, at 8, and surrebuttal was incorporated into the BP-16 procedural schedule. *See* 2016 Rate Adjustment Proceeding Amended Schedule, BP-16-HOO-13.

JP07 argues that, in order to protect BPA's customers, the Administrator should adopt its proposal that a risk mitigation scenario analysis be included in future initial proposals. JP07 Br., BP-16-B-JP07-01, at 8. JP07 acknowledges Staff's willingness to include such information in its

initial proposals in future rate cases so that customers will be able to have input regarding the reasonableness of the proposed changes. *Id*. This is a reasonable approach, and BPA will include a risk scenario analysis in BPA's future initial proposals. Mandell and Lovell, BP-16-E-BPA-33, at 8.

JP07 suggests that any changes from the risk mitigation proposal should include public involvement. JP07 Br., BP-16-B-JP07-01, at 8. In the BP-14 rate case, BPA addressed this concern by committing to keep customers and rate case parties informed of expectations for current-year financial conditions and CRAC probabilities. BP-14 Administrator's Final Record of Decision (BP-14 ROD), BP-14-A-03, at 29. BPA also committed that, in the event financial conditions worsen so that the need to adjust risk mitigation parameters appears likely, Staff will hold meetings with customers to discuss options. *Id.* BPA prefers to make adjustments to risk mitigation parameters for the Final Proposal, when necessary, with the input of customers. Mandell and Lovell, BP-16-E-BPA-33, at 4. BPA will commit to continue to keep parties informed of financial conditions as the year progresses, including updated CRAC probabilities and the likelihood of needing PNRR. In this proceeding, Staff supports meeting with parties in the event that financial conditions deteriorate in such a way that adjustment of risk mitigation parameters to meet the TPP standard appears likely. *Id*. Specifically, financial updates were provided to parties during BPA's second-quarter financial review process. *Id*. If a need to adjust risk mitigation parameters had appeared likely at that time, or if the situation had changed between the second-quarter review and the final studies, Staff would have held a meeting with parties to discuss risk mitigation adjustment options. *Id*. This approach allows Staff to provide meaningful risk mitigation options to parties and to receive feedback in a timely fashion for consideration by the Administrator in his final rate decisions. However, because BPA has not needed any changes to its BP-16 risk mitigation package, such a meeting is unnecessary.

Adding PNRR or changing CRAC parameters is not an exercise of unlimited discretion. There are established guidelines that govern when enhanced risk mitigation would be included in rates—that is, when the TPP is not otherwise being achieved. Nevertheless, in future power rate adjustment proceedings, to the maximum extent practicable, BPA will keep parties informed of any changes to the risk mitigation package from the Initial Proposal and provide an opportunity for parties to respond on the record. However, because there may be rare occasions when the need for enhanced risk mitigation arises so late in the ratesetting process as to render the consideration of feedback infeasible, BPA must reserve as a backstop the right to incorporate the latest information available to strengthen the risk mitigation provisions in final rates at the last moment.

Draft Decision

Because BPA is not proposing any changes in PNRR or CRAC parameters from the Initial Proposal, this issue is moot. Nevertheless, BPA will include a risk mitigation scenario analysis in BPA's future power rate initial proposals. To the maximum extent practicable, BPA will also ensure that parties will be informed of changes to the power risk mitigation package so they will be able to respond to such proposed changes on the record.

2.0 POWER RATES AND POLICIES

2.1 Proposed Power Rate Increase

Issue 2.1.1

Whether BPA should mitigate the proposed power rate increase to make its Priority Firm Power rates more competitive.

Parties' Positions

ICNU states that BPA's PF rates "have not been competitive with market prices for some time." ICNU Br., BP-16-B-IN-01, at 2-3. ICNU states that BPA should cut costs in the long term and "should adopt adjustments, such as those offered by JP07, that will reduce rates in the interim." *Id.* at 3.

WPAG states that BPA's power "is losing its price competitiveness compared to other power supply options." WPAG Br., BP-16-B-WG-01, at 2. WPAG cites "BPA's overall unyielding cost structure" and proposes that "BPA work with customers to begin a holistic review of its cost and rate structures" with the goal of "stable low cost-based power rates." *Id.* at 2-3.

JP07 suggests four "measures … [that] will support the health of the regional economy and move BPA's rates toward a sustainable level that would be closer to the prices available in the market." JP07 Br., BP-16-B-JP07-01, at 1.

BPA Staff's Position

Staff does not address this issue in testimony.

Evaluation of Positions

As stated in the Federal Register notice, BPA's spending levels for investments and expenses are not determined or subject to review in rate proceedings. 79 Fed. Reg. 71,984, 71,986 (Dec. 4, 2014). Therefore, the level of BPA's costs, which is determined in the IPR process, is not a rate case issue.

However, three parties—ICNU, which represents industrial consumers in the Northwest; WPAG, which represents some of BPA's public utility customers; and JP07, made up of ICNU and PPC (which represents most of BPA's public utility customers)—address BPA's rate increase and its effect on BPA's competitiveness. ICNU Br., BP-16-B-IN-01, at 2-3; WPAG Br., BP-16-B-WG-01, at 2; JP07 Br., BP-16-B-JP07-01, at 1. All are concerned that BPA's utility customers and their industrial consumers may have to pay more than they would have to pay other suppliers based on BPA's last two rate increases and the current proposed increase.

Early in the Integrated Program Review process, BPA held a meeting in which utility general managers were asked about the issues and economic challenges they face in their service

territories and the impacts BPA's rate decisions have on their customers. In response to their comments, BPA worked with its customers and the interested public to reduce the level of the expected power rate increase. IPR Close-out Letter at 1; *see* Draft ROD § 1.2.1. Even with the cost increases needed to protect the long-term asset value of the aging FCRPS hydropower resources, BPA held the program and internal funding levels established in the IPR to an overall increase that is below the level of inflation. BPA places a high priority on carefully managing its costs during both the short- and long-term time horizons.

ICNU and JP07 note that BPA has the statutory obligation to set rates 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. ICNU Br., BP-16-B-IN-01, at 2; JP07 Br., BP-16-B-JP07-01, at 2. The parties focus on the phrase "lowest possible rates," but of course this obligation must be balanced with BPA's other statutory obligations. For example, in addition to the phrase "lowest possible rates," the same sentence of the Flood Control Act and the Transmission System Act includes the phrase "consistent with sound business principles." 16 U.S.C. § 825s; 16 U.S.C. § 838g. Section 5 of the Flood Control Act also provides that rate schedules shall 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.

After the BP-16 rate case had begun, BPA held the IPR2 process. *See* Draft ROD § 1.2.1. The most significant outcome of IPR2 was BPA's decision to move the funding of the Energy Efficiency program from capital to expense in the FY 2016–2017 rate period. Doing so will reduce long-term costs and power rates by avoiding an estimated $1.3 billion in additional debt plus the associated debt service costs to fund conservation programs through 2028 while maintaining BPA's strong commitment to energy efficiency. Further, to mitigate the rate impact of transitioning EE from capital to expense in one rate period, BPA decided in IPR2 to offset this impact through a combination of additional cost reductions ($20 million per year average) and the adoption of available debt management actions.

BPA understands that, as the parties and the IPR2 closeout letter note, BPA is facing significant pressures on its long-term cost structure. In addition to the effect of low natural gas prices on wholesale electricity prices, the cost of maintaining aging Federal assets, and significant ongoing energy industry changes, BPA's total outstanding debt and related debt service costs continue to increase. Moving the EE capital program to expense reduces BPA's debt and related debt service costs, providing a significant step toward achieving the goals of long-term cost competitiveness and financial sustainability.

With an eye to BPA being the low-cost energy provider of choice when new contracts are offered in 2028, BPA is making its long-term cost structure and service delivery model a high-priority focus. The decisions in this document have been made in light of this longer-term focus in addition to the near-term concerns about the rate increase. *See* Administrator's Preface to this Draft ROD.

While BPA is mindful of the impact of the level of its rates on the regional economy, BPA is a self-financing agency and is required by law to set its rates to recover its costs. As WPAG states, many of the drivers for the rate increase involve costs that are beyond the direct control of BPA. WPAG Br., BP-16-B-WG-01, at 2. It is also important to note that BPA has varied and often competing responsibilities. These include, but are not limited to, implementing the Northwest Power Act and BPA's other statutes to encourage conservation and energy efficiency; facilitating the development of renewable resources within the region; protecting fish and wildlife impacted by the FCRPS; and ensuring that the region has an adequate, efficient, economical, and reliable power supply. The Northwest Power Act requires that "the customers of the Bonneville Power Administration and their consumers continue to pay all costs necessary to produce, transmit, and conserve resources … including the amortization on a current basis of the Federal investment in the Federal Columbia River Power System." 16 U.S.C. § 839(4). BPA must strike a balance between fulfilling its multiple obligations and keeping its rates as low as possible consistent with sound business principles. The Initial Proposal strikes the appropriate balance with information available at that time, and the Final Proposal will do the same as it incorporates the results of the IPR2 process and the latest financial information available.

Draft Decision

BPA has mitigated the proposed power rate increase to the extent reasonably possible to ensure that the agency's costs are the lowest they can be while meeting all of BPA's responsibilities as mandated by law. BPA will continue working with customers and other stakeholders to achieve the goal of long-term competitiveness and financial sustainability.

2.2 Loads and Resources

The Power Loads and Resources Study, BP-16-E-BPA-03, contains the load and resource data used to develop BPA's wholesale power rates for FY 2016–2017. Documentation supporting the results of the Power Loads and Resources Study is presented in the Power Loads and Resources Study Documentation, BP-16-E-BPA-03A. The Power Loads and Resources Study is also described in the direct testimony of Misley *et al.*, BP-16-E-BPA-18.

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 2016–2017. If BPA's resources are less than the amount of load forecast for the rate period, 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 to various other studies and calculations in the ratemaking process: (1) the Power Rates Study, BP-16-E-BPA-01; (2) the Power Revenue Requirement Study, BP-16-E-BPA-02; and (3) the Power Risk and Market Price Study, BP-16-E-BPA-04.

No party raised issues related to BPA's forecast of loads and resources for the BP-16 rate period.

2.3 Power Revenue Requirement

The Power Revenue Requirement Study, BP-16-E-BPA-02, determines the level of revenue required to recover all costs of producing, acquiring, marketing, and conserving electric power, including but not limited to:

- 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
- costs of transmission facilities needed to integrate Federal generation
- costs for purchasing other transmission services

BPA develops its revenue requirement in conformance with the financial, accounting, and ratemaking requirements of DOE Order No. RA 6120.2. BPA determines the revenue requirement separately for generation and transmission. *U.S. Dep't 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 a schedule of amortization payments and to forecast 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 two-year rate test period and extend over a 50-year repayment period.
2. For each year of the rate test period, operating expenses and the minimum required net revenues that may be added to the revenue requirement to ensure that there is adequate cash flow to repay the Federal investment.

3. Annual Planned Net Revenues for Risk, if any, based on the risks identified and quantified, the Treasury Payment Probability 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 current and proposed rates. The current revenue test determines whether revenues projected from current rates meet cost recovery requirements for the rate period and over the ensuing 50-year repayment period. The revised revenue test determines whether projected revenues from proposed rates will meet cost recovery requirements and objectives for the rate test period and over the ensuing 50-year 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. Power Revenue Requirement Study, BP-16-E-BPA-02, § 3.3. The risks are quantified and analyzed, and risk mitigation measures are incorporated into rates as needed to achieve at least a 95 percent probability that planned payments to Treasury are made on time and in full over the two-year rate period.

No party raised issues related to BPA's power revenue requirement for the BP-16 rate period.

2.4 Power Risk and Market Price

The Power Risk and Market Price Study, BP-16-E-BPA-04, identifies, models, and analyzes the impacts that key risks and risk mitigation tools have on Power Services' net revenue and cash flow. It also demonstrates that the power rates and risk mitigation tools working together meet BPA's standard for financial risk tolerance—the Treasury Payment Probability standard. This study presents BPA's natural gas price forecast, electricity market price forecast, and quantitative and qualitative analysis of risks to achieving Power Services' net revenue. It also presents tools for mitigating risk and establishes the adequacy of those tools for meeting BPA's TPP standard.

In the WP-93 rate proceeding, BPA adopted and implemented its 10-Year Financial Plan, which included a policy requiring that BPA set rates to achieve a high probability of meeting its payment obligations to the U.S. Treasury. 1993 Final ROD, WP-93-A-02, at 72-73. The specific standard set in the 10-Year Financial Plan was a 95 percent probability of making both of the annual Treasury payments in the two-year rate period on time and in full. This TPP standard was established as a rate period standard; that is, it focuses upon the probability that BPA can successfully make all of its payments to Treasury over the entire rate period rather than the probability for a single year. The Financial Plan was updated July 31, 2008, and remains in effect. The original and updated financial plans are available at http://www.bpa.gov/Finance/FinancialInformation/FinancialPlan/Pages/default.aspx.

By law, BPA's payments to Treasury are the lowest priority for revenue application, meaning that payments to Treasury are the first to be missed if financial reserves are insufficient to pay all bills on time. 16 U.S.C. § 839e(a)(2)(A). Therefore, TPP is a prospective measure of BPA's

overall ability to meet its financial obligations. The following policy objectives guide the development of the risk mitigation package:

- Create a rate design and risk mitigation package that meets BPA's financial standards, particularly achieving a 95 percent two-year Treasury Payment Probability.
- Produce the lowest possible rates consistent with sound business principles and statutory obligations, including BPA's long-term responsibility to invest in and maintain the aging infrastructure of the Federal Columbia River Power System.
- Set lower, but adjustable, effective rates rather than higher, more stable rates.
- Include in the risk mitigation package only those elements that can be relied upon.
- Do not let financial reserve levels build up to unnecessarily high levels.
- Allocate costs and risks of products to the rates for those products to the fullest extent possible; in particular, prevent any risks arising from Tier 2 rate service imposing costs on Tier 1 rates or requiring stronger Tier 1 risk mitigation.
- Rely prudently on liquidity tools, and create means to replenish them when they are used to maintain long-term availability.

It is important to understand that these objectives are not completely independent and may sometimes conflict with each other; thus, BPA must create a balance among these objectives when developing its overall risk mitigation strategy.

A procedural issue was raised regarding BPA's risk mitigation proposal for the BP-16 rate period; this issue is addressed in section 1.3. An issue related to the secondary revenue forecast portion of BPA's Power Risk and Market Price Study appears below.

Issue 2.4.1

Whether BPA should reflect secondary energy sales made at extra-regional points of delivery in BPA's forecast of secondary revenue.

Parties' Positions

JP07 notes that BPA has historically marketed secondary energy at points of delivery contiguous to the California Independent System Operator (ISO) but does not model sales at these same points of delivery in its forecast of secondary revenue. JP07 Br., BP-16-B-JP07-01, at 2. JP07 states that during FY 2014, BPA delivered approximately 26 percent of its surplus power through off-system sales to southern markets. *Id*. JP07 notes that BPA's sales within the Northwest that year had an average price of $24.97 per megawatthour, but BPA received an average weighted price of $34.43 for southern sales delivered outside the region. *Id*. Therefore, JP07 argues, BPA should increase its forecast of secondary revenue for the upcoming rate period by $25.4 million to account for the incremental value of marketing energy at southern points of delivery. *Id*. at 3.

JP07 also states that BPA holds firm transmission rights on the Southern Intertie, for which BPA pays $14.7 million per year, which enable it to market power to these points of delivery. *Id*. at 5. JP07 argues that it is not reasonable to pay for these rights if BPA does not intend to use them to market energy. *Id*. JP07 suggests that, at a minimum, BPA should establish a credit of $14.7 million to ensure that the aforementioned firm transmission rights do not represent a net cost to Power customers. *Id*. at 6.

BPA Staff's Position

Staff believes the forecast of secondary revenue should not be adjusted to account for potential extra-regional sales. Williams, BP-16-E-BPA-34, at 3. Currently, BPA does not have contracts in place to market energy into California during the upcoming rate period. *Id*. at 2. Also, changes to regulations governing energy sales in California may limit extra-regional sales. *Id*. As such, it is difficult for BPA to forecast the availability of those markets for purposes of selling its surplus energy. Further, JP07's proposed $25.4 million or $14.7 million adjustments are not reasonable proxies for the potential value of extra-regional energy sales. *Id*. at 3.

Evaluation of Positions

BPA's secondary revenue forecast uses monthly Mid-Columbia prices from AURORAxmp® to value secondary energy sales. Williams, BP-16-E-BPA-34, at 1, *citing* Power Rates Study, BP-16-E-BPA-1, at 35. The study assumes that secondary revenue sales are made at the Mid-Columbia trading hub for pricing purposes, and those sales are valued using an average hourly spot-market price. *Id.*, *citing* Hammer and Williams, BP-16-E-BPA-19, at 1. This approach is reasonable because Mid-Columbia is a liquid trading hub and represents the bulk of BPA's marketing activity. *Id.* at 1-2. Each year, variations in hydrological conditions, load, natural gas prices, and other factors result in BPA's secondary energy being marketed in different volumes and at different points of delivery. *Id.* at 2.

JP07 notes that during FY 2014, BPA delivered approximately 26 percent of its surplus power to southern markets, primarily at the California-Oregon border (COB) and the Nevada-Oregon border (NOB). JP07 Br., BP-16-B-JP07-01, at 2. COB and NOB are market nodes for selling into the California market. JP07 states that BPA's sales within the Northwest that year had an average price of $24.97 per megawatthour, but BPA received an average weighted price of $34.43 for southern sales delivered outside the region. *Id.* JP07 notes that BPA's proposed rates are calculated with the assumption that no sales will be made outside the region because Staff assigned Mid-Columbia prices to all off-system sales. *Id.* at 3. JP07 claims that Staff offers no support for the proposition that BPA will make all sales at Mid-Columbia. *Id.*

JP07's argument omits a nuance in Staff's position. Staff does not simply assume that BPA will make all sales at Mid-Columbia; rather, Staff recognizes that BPA may make some extra-regional secondary sales during the rate period and, if and when such sales are made, they may or may not be made at a premium to forecast Mid-Columbia prices. Williams, BP-16-E-BPA-34, at 2. However, forecasting the amounts and prices for such sales is problematic due to the many factors that affect the amounts and delivery points for secondary energy sales. *Id.* Because of the difficulty in developing an accurate forecast, BPA uses Mid-Columbia as a proxy

for extra-regional sales because Mid-Columbia is a liquid trading hub, represents the bulk of BPA's marketing activity, and reflects the inherent optimism in relying on forecasts from a computer model with "perfect" market knowledge. *Id.* at 1-2. This is not the same as believing that all extra-regional power sales will actually go through Mid-Columbia. Forecasts of secondary energy prices, by their very nature, are highly variable expectations of future events. Attempting to incorporate the effects of marketing power into different markets adds a measure of precision that has not been demonstrated to be necessary based on the rate case record.

JP07 assumes that the amounts of power sales and the prices of such sales during a single historical year can be used to determine power sales in the two years of the future rate period. JP07 Br., BP-16-B-JP07-01, at 3. Using only a single historical year of data, JP07 argues that the Administrator should increase the secondary revenue forecast by $25.4 million. *Id.* JP07 assumes that 24 percent of BPA's FY 2014 historical secondary sales will be made at a 38 percent premium over Mid-Columbia prices, then discounts this adjustment by 20 percent to reduce the risk of under-collection if variations in market conditions during the BP-16 rate period result in fewer available transactions in extra-regional markets. *Id*.

As logic suggests, and as the record shows, it is wrong to assume that data from a single historical year provides a reasonable estimate of what will occur in a future two-year period. Williams, BP-16-E-BPA-34, at 3. JP07's data is based on a single year, 2014, but the prices obtained at regional and extra-regional points of delivery will vary each year based on numerous different conditions. *Id.* Indeed, there is no indication that conditions in the upcoming rate period will be similar to those during FY 2014, owing to a number of factors. *Id.* First, natural gas prices are expected to be different. *Id., citing* Power Risk and Market Price Study, BP-16-E-BPA-04, at 19-23. Hydrological conditions in both the Pacific Northwest and California will be different. *Id.* at 3. Loads will be different, and the rapid growth of renewable energy in California will have a substantial impact on regional markets. *Id*. In fact, JP07 apparently recognizes that conditions in the upcoming rate period could be different from those during FY 2014 by discounting its proposed increase in the forecast of secondary revenues to reduce any risk of under-recovery in the case that FY 2014 results vary from conditions in the BP-16 rate period. JP07 Br., BP-16-B-JP07-01, at 3; Deen *et al*., BP-16-E-JP07-01, at 8. Historical pricing data for a single year is not a sufficient basis upon which to forecast future secondary prices for the FY 2016–2017 rate period. Williams, BP-16-E-BPA-34, at 3.

Furthermore, BPA's secondary revenues have never been forecast based on historical sales, but rather based on an extensive analysis of forecast conditions. JP07's estimate of $25.4 million does not reflect an appropriate difference between the current secondary revenue forecast and a more reasonable forecast. *Id.* By virtue of the fact that it is calculated retrospectively, that estimate is a statistically perilous number that is not the product of any analysis regarding expected conditions during FY 2016–2017. *Id*.

It is telling that JP07's argument for adding $25.4 million to the forecast is based solely on the differential between actual prices at Mid-Columbia and southern markets. JP07 did not examine how BPA's forecast of market prices and revenues for FY 2014 compares to actual results. BPA's net secondary revenue (secondary sales revenues minus certain purchased power

expenses) was $31 million greater than the BP-14 rate case forecast. *See* November 2014 Quarterly Business Review at 18 (Nov. 4, 2014), *available at* http://www.bpa.gov/Finance/FinancialInformation/FinancialOverview/Pages/fy2014.aspx. This extra revenue was primarily attributable to 3 million acre-feet of water above forecast. *Id.* There is no information in the rate case record to assess what role the extra-regional sales played in the FY 2014 secondary revenue variance because there is no examination of price variation between the BP-14 rate case price forecast and actual results. JP07 presented only one piece of a more complex differential analysis.

JP07 argues that when detailed projections cannot be made, it is standard practice throughout the utility industry to use, or begin with, the most recent historical test year because that information will most accurately represent the revenues and costs that can be expected in the rate period. JP07 Br., BP-16-B-JP07-01, at 4. JP07, however, cites no evidence in the record to support this assertion. Furthermore, BPA's extra-regional secondary sales vary greatly based on hydrological conditions, load, natural gas prices, and other factors. Williams, BP-16-E-BPA-34, at 3. Secondary sales are not like many items from a utility's historical test year, which may be relatively stable from year to year.

JP07 claims that BPA's rationale for using Mid-Columbia is only that forecasting sales to COB and NOB is "difficult." JP07 Br., BP-16-B-JP07-01, at 4. To the contrary, however, Staff explained *why* it is difficult to forecast extra-regional sales to COB and NOB. Williams, BP-16-E-BPA-34, at 2. Furthermore, California state laws may change, or intermediaries for some transactions may not be available, either of which would compromise BPA's ability to deliver to COB or NOB. *Id*. at 2. Also, variations in hydrological conditions, load, natural gas prices, and other factors result in BPA's secondary energy being marketed in different volumes and at different prices. *Id*.

As noted above, Staff testifies that JP07's use of only one year of historical data to develop its proposed adjustment would not produce an accurate projection of BPA's likely off-system sales, given a number of variables affecting sale amounts and prices during each year. Williams, BP-16-E-BPA-34, at 3. JP07 claims this argument is disingenuous because JP07 requested multiple years' data from BPA in order to develop a more refined projection, and BPA Staff refused to provide the data on the basis that the request was burdensome. JP07 Br., BP-16-B-JP07-01, at 4, *citing* Deen *et al*., BP-16-E-JP07-01, at Att. A. This argument is not persuasive. Although JP07 requested multiple years' data from BPA, JP07 fails to describe the enormity of the data JP07 requested. JP07's data request asked for "documentation of all of BPA's secondary/surplus energy sales for the period of FY 2010 through FY 2014 in Microsoft Excel format. Please include the counterparty, duration, amount of power sold, price, point of delivery, and product type." Deen *et al*., BP-16-E-JP07-01, at Att. A. In response, BPA stated:

> BPA objects to this data request on the following grounds: 1. The request does not identify any specific portion of the Study to which it is directed. Instead, the request cited the entire Power Risk and Market Price Study. Citation to an entire study does not comply with Attachment A of BP-16-HOO-1, Order on Data Requests, under which parties must identify the page numbers and line numbers

> that are relevant to the request. 2. The requested information is not available in the form requested. Under the Rules of Procedure Governing Rate Hearings, §1010.8(b), "no party shall be required to perform any new study or to run any analysis or computer program." Given the volume of data and the requested format, the data request is tantamount to a request for a new study, analysis, or program. 3. Given the requirements of the request and the quantity of data involved, responding to the request would be unduly burdensome. See Rules of Procedure Governing Rate Hearings, §1010.8(b).

Id. Notably, JP07 did not contest or appeal BPA's response to its data request, although it could have done so. Furthermore, the objection upon which BPA's data response relied is a well-established standard in administrative and judicial practice, and is included in BPA's hearing procedures. BPA's procedures provide that a party may not request material that is "unduly burdensome to produce." Rules of Procedure Governing Rate Hearings, § 1010.8(b). When BPA established this standard, JP07 did not object, nor was the standard challenged in court. BPA's decision not to produce all the data requested by JP07 is consistent with BPA's Rules of Procedure and as such does not support JP07's case or harm Staff's case.

JP07 also argues that no evidence has been presented to demonstrate that multiple years' results would produce results inconsistent with JP07's conclusions. JP07 Br., BP-16-B-JP07-01, at 4. This argument reverses traditional evidentiary standards. The burden of proof is upon the party seeking to establish a fact. The burden is not on BPA to establish facts supporting JP07's case. The record contains no evidence that multiple years' data would have produced results consistent with JP07's conclusions. JP07 also states that the data it used does not rely upon a small number of sales, but on over 49,000 transactions. *Id.* at 4-5. This statement proves the burdensome nature of JP07's data request, which asked for *five years* of such data. In any case, for the reasons stated above, the number of transactions in a single historical year, regardless of whether they are many or few, cannot establish a reliable forecast for a prospective two-year rate period. Williams, BP-16-E-BPA-34, at 3. This is especially true when the southern markets are conducted under an ever-changing set of rules that were not necessarily in place during the recent past.

JP07 argues that if the Administrator chooses to set rates that assume all off-system sales will be made at Mid-Columbia, there is no basis for requiring power customers to include $14.7 million in transmission purchases in rates. JP07 Br., BP-16-B-JP07-01, at 5. This argument hinges on JP07's assertion that using forecasts of Mid-Columbia prices in setting rates is tantamount to restricting BPA from making extra-regional sales during the rate period. To the contrary, however, and as noted below, it is possible that BPA will make extra-regional secondary sales. If BPA did not make transmission purchases, BPA's ability to sell power outside the region would be extremely limited. This is a logical basis for acquiring transmission rights. JP07 also claims that Staff does not provide an alternate use for such transmission rights. JP07 Br., BP-16-B-JP07-01, at 5. Again, contrary to JP07's claims, Staff addresses alternative uses of transmission rights in its rebuttal testimony. Staff notes that transmission capacity on the Southern Intertie is not a net cost. Williams, BP-16-E-BPA-34, at 4. Staff established that it

represents an option value for sales and purchases made extra-regionally and may go unused, be re-sold, or be used for other BPA transactions. *Id*.

JP07 argues that it makes no business sense for BPA to purchase long-term firm transmission rights to another market if BPA does not intend to monetize the transmission by making sales at some level greater than zero into that market. JP07 Br., BP-16-B-JP07-01, at 5. However, BPA does not know the future. It is likely that *some* unidentified amount of extra-regional sales will be made, but this amount is difficult to identify. *See* Williams, BP-16-E-BPA-34, at 2. Because of the possibility of extra-regional sales, it is a prudent business practice to acquire transmission rights to facilitate such possible sales. As noted above, absent securing transmission rights, BPA's sales would be limited. JP07 also states that no reservations of long-term firm transmission are necessary to reach California markets if a specific level of sales cannot be projected because short-term rights are available and flow ahead of many long-term transmission reservations. JP07 Br., BP-16-B-JP07-01, at 5-6. Although short-term rights might be available, relying on them would permit fewer sales than if long-term firm transmission rights were also available. Also, assuming short-term sales will be made does not help to establish the amount of extra-regional sales that may be made or the prices of such sales.

JP07 argues that if BPA assumes all off-system sales will be made at Mid-Columbia, there is no sound business reason to include $14.7 million in firm transmission rights in the power revenue requirement, and these costs should not be charged to power customers. *Id.* at 6. JP07 argues that, at a minimum, BPA should assume that it will be able to at least recover the $14.7 million through economic secondary energy sales or resale of that transmission capacity. *Id*. First, this argument fails because BPA does not simply assume all off-system sales will be made at Mid-Columbia. BPA uses the forecast of Mid-Columbia prices to represent the expected price received from all sales, no matter in which market those sales might occur. Also, as noted previously, even though BPA's forecast of secondary sales assumes such sales will occur at Mid-Columbia prices, it is prudent for BPA to acquire transmission rights to enable possible extra-regional sales during the rate period. The cost of transmission rights, however, is not a forecast of BPA's secondary revenue. The use of $14.7 million represents an arbitrary valuation of an amount of secondary marketing that has not been forecast. Williams, BP-16-E-BPA-34, at 4.

Staff recognizes the difficulty of forecasting secondary sales outside the region and has offered to work with customers outside of the rate case to examine modeling approaches to address the value of extra-regional secondary sales for the BP-18 proceeding. *Id*. JP07 states that it would support and help develop a method for refining off-system sales projections. JP07 Br., BP-16-B-JP07-01, at 5. Staff recommends that the Administrator convene an informal process with interested parties to try to achieve this goal after the BP-16 rate case and before the BP-18 rate case. Williams, BP-16-E-BPA-34, at 4. However, such an examination should not be limited solely to prices received from different markets, but whether the secondary revenue credit included in ratesetting reasonably accounts for all expected secondary revenues. Secondary revenue, not just prices, is the most important metric in judging the accuracy of BPA's forecasts.

Although the foregoing discussion in this section has been critical of JP07's proposed *methodology* for determining secondary revenue, JP07's *concept* of reviewing BPA's prospective extra-regional sales as part of determining secondary revenue is worthy of consideration. However, BPA is not entirely convinced that JP07's proposal to discount FY 2014 California revenues by 20 percent is necessarily the appropriate risk adjustment. Until BPA completes its examination of modeling approaches to address the value of extra-regional secondary sales for the BP-18 proceeding, BPA will include an ad hoc upward adjustment to the secondary revenue credit used to calculate the BP-16 power rates that incorporates a risk adjustment BPA believes is more reflective of the value of these sales. This is a less-than-desirable approach because it does not account for how price differentials among the various markets will respond to variations in water supply, weather, economic conditions, fuel prices, and the availability of other generation. BPA will make this ad hoc adjustment for BP-16 rates only; the examination of BPA's secondary market forecasts will inform if and how future rates may include any appropriate adjustments.

Draft Decision

BPA will include additional revenue recovery from secondary energy sales made at extra-regional points of delivery in its forecast of secondary revenue in the BP-16 final rate proposal. To do this, BPA will increase the forecast of secondary revenue by a risk-adjusted estimate of potential sales to points of delivery contiguous to California. Prior to the BP-18 rate case, BPA will convene an informal public process to examine BPA's forecasting of secondary energy sales.

2.5 Power Rate Development

Section 2.5 addresses issues related to the Power Rates Study and the power rate schedules, including the General Rate Schedule Provisions. Section 2.5.1 lists changes in rate development methods, rate schedules, and GRSPs proposed by BPA Staff that were not raised in the parties' briefs and thus will be adopted without further discussion.

The Power Rates Study 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. Power Rates Study, BP-16-E-BPA-01, at 1.

Section 7 of the Northwest Power Act, 16 U.S.C. § 839e, directs the allocation of costs, which is performed in the cost of service analysis, and provides a set of rate directives with further guidance on how individual rates are to be derived. BPA's rates must follow the ratesetting directives of section 7, but, as noted 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. *See, e.g.*, H.R. Rep. No. 96-976, Part I, 96th Cong., 2d Sess. 69 (1980). Section 7 reserves rate design (how the revenue is collected) to the Administrator.

As described in the Power Rates Study, the cost of service analysis and the other ratemaking steps are programmed into a spreadsheet model, RAM2016, for purposes of calculating power rates. BPA makes the RAM2016 spreadsheet model available to the public on its Web site. The Power Rates Study describes how the tiered PF 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 Tiered Rate Methodology (TRM). The TRM restricts BPA and customers with Contract High Water Mark contracts from proposing changes to the TRM except in a section 7(i) rate proceeding, and only after certain procedures specified in the TRM have been followed. TRM, BP-12-A-03, § 13. No such changes have been proposed by BPA, any customer with a CHWM contract, or any other party in this case. Rates are established to recover the costs of the Residential Exchange Program in accordance with the terms of the 2012 REP Settlement and the Administrator's decisions in the REP-12 ROD. *See* Draft ROD § 1.2.3.

2.5.1 Power Rate Development Changes

In the Initial Proposal, Staff proposed a number of changes to BPA's power rate development, rate schedules, and GRSPs, outlined below. No party raised an issue in its initial brief with the following changes, and some parties express support for the adoption of these changes. For a more complete explanation and description of each of the changes, see the Power Rates Study, BP-16-E-BPA-01; the Power Rate Schedules, BP-16-E-BPA-09; Stiffler *et al.*, BP-16-E-BPA-17; Yokota *et al.*, BP-16-E-BPA-21; Weekley *et al.*, BP-16-E-BPA-22; Chalier *et al.*, BP-16-E-BPA-23; and Abadi and Fisher, BP-16-E-BPA-36.

1. **Priority Firm Tier 2 Vintage Rate, VR1-2016.** The new Tier 2 VR1-2016 product and its associated rate allow customers to purchase stepped amounts of power with delivery beginning in FY 2016.

2. **New Resource Rate Schedule: Energy Shaping Services (ESS) Energy Charge (GRSP II.G.1.1).** The energy charge design has more granularity, obviating the need for an annual true-up. That is, the new design effectively provides a true-up monthly by charging a customer for any net energy purchased from BPA during a month at the applicable NR energy rates.

3. **New Resource Rate Schedule: ESS Capacity Charge (GRSP II.G.1.2) and Allocation of Revenues.** The new capacity charge compensates BPA for providing more flexibility to a Load Following customer serving its New Large Single Load (NLSL) with non-Federal resources. Customers will be allowed to change BPA's obligation to provide capacity with at least 30 days' notice prior to the applicable billing month. The capacity that is provided will not be treated as a Designated BPA System Obligation, and the associated revenue will be credited to the Non-Slice cost pool.

4. **New Resource Rate Schedule: Resource Flattening Service (NRFS) Charge (GRSP II.G.2).** The new NRFS charge allows a Load Following customer to apply the generation of a specified resource directly to its NLSL.

5. **Firm Power and Surplus Products and Services (FPS) Rate Schedule.** The FPS rate schedule is clarified and updated to better reflect BPA's ability to sell certain products and provide services in current wholesale energy and capacity markets.

6. **General Transfer Agreement Service Charges: Transfer Service Operating Reserves Charge (GRSP II.J.2).** The applicability section eliminates a criterion in the BP-14 rate that required that Power Services be assessed Operating Reserve charges from a third-party transmission provider in order for the Transfer Service Operating Reserve Charge to apply. This revision helps maintain parity between directly connected customers and other transfer customers.

7. **General Transfer Agreement Service Charges: WECC [Western Electricity Coordinating Council] and Peak Charges (GRSP II.J.3 and 4).** Charges are added to GTA Service Charges to recover WECC and Peak costs related to BPA transfer customer loads outside its balancing authority area.

8. **Transmission Scheduling Service (TSS): Open Access Technology International, Inc. (OATI) Registration Fee Cost Component (GRSP II.U.4).** The OATI registration fee is now included in customers' monthly TSS charges to reduce administrative burden.

9. **Supplemental Guidelines (GRSP I.E).** References to a bright-line voltage test for facilities subject to direct assignment have been removed to be consistent with Transmission Services' "Facility Ownership and Cost Assignment Guidelines."

10. **Large Project Targeted Adjustment Charge (GRSP II.A.2).** Customers that receive funds through BPA Energy Efficiency's Large Project Program will pay this new charge that recovers the borrowing costs needed to fund the customers' projects.

11. **Provisional Contract High Water Marks.** References to Provisional CHWMs have been removed from the BP-16 rate schedules and GRSPs because the implementation of Provisional CHWMs is complete.

12. **Recovery Peak Billing Determinant Adjustment (GRSP II.D.2).** The GRSP clarifies when customer loads are considered Recovery Peaks that could qualify for this adjustment.

13. **Low Density Discount (GRSP II.M).** The language is revised to clarify GRSP II.M sections 1, 1(a), and 1(b).

14. **Southeast Idaho Load Service Cost Allocation.** BPA received notice from its current transfer service provider that the exchange agreement and transmission agreement used to serve BPA customers in SE Idaho would terminate on June 30, 2016. An allocation

methodology for the power and transmission costs that will be incurred to serve these customers beginning in July 2016 will be modeled as described in the Initial Proposal.

15. **Allocation of Diurnal Flattening Service (DFS) Energy Revenue.** DFS energy revenue is allocated to the Non-Slice cost pool rather than the Composite cost pool as in BP-12 and BP-14 rate development. This change aligns the revenue allocation with the treatment of this service operationally through the Slice Computer Application.

16. **Grandfathered Generation Management (GMS) Service Charges (GRSP II.U.5).** Grandfathered GMS allows a customer to run an Existing Resource (that was supported with GMS during FY 2002-2011) against its Tier 1 load. The Grandfathered GMS charges are not new but have been added to the GRSPs to correct an inadvertent omission from earlier GRSPs.

17. **Super Peak Period (GRSP III.B.29).** The definition of the Super Peak Period for June through September has shifted one hour, *from* Hour Ending (HE) 14 through HE 19 *to* HE 13 through HE 18.

18. **Residential Exchange Program Residential Loads and the 7(b)(3) Surcharge Adjustment (GRSP II.S and II.T).** Residential Loads are updated using calendar year (CY) 2013 and CY 2014 investor-owned utility (IOU) residential and farm loads. The 7(b)(3) Surcharge Adjustment is revised to describe how the Surcharge would be adjusted for a change in a participating utility's average system cost during the BPA rate period, regardless of the reason for the change.

19. **Modifications to RAM Cost Table and Slice True-up Table: Other Expense Offset.** In the IPR2, BPA decided that it will expense Energy Efficiency program costs rather than capitalizing those costs. *See* Draft ROD § 1.2.1. BPA intends to use cash flows resulting from an extension of maturing Energy Northwest debt that is currently related to Debt Service Reassignment to mitigate the rate impact of transitioning the core EE investment program to one that is fully expensed and to accelerate an existing plan to repay Federal power appropriations.

    A new line item, "Other Expense Offset," will be added to (i) the RAM2016 Table 2.3.1, Disaggregated Costs and Credits, and (ii) Table G, Composite Cost Pool True-Up Table, in GRSP II.W. The change to the RAM2016 cost table is necessary to ensure application of cash flows to mitigate the effect of accelerated appropriations repayment and expensing the EE investment program. The change to Table G is necessary to ensure the equitable treatment of Slice and Non-Slice customers. The Other Expense Offset is subject to the Composite Cost Pool True-Up.

20. **Modifications to RAM Cost Table and Slice True-Up Table: PGE WNP-3 Settlement.** In 1998, BPA and PGE entered into a termination agreement of a 1985 power exchange contract that arose out of the decision to terminate construction of the WNP-3 nuclear plant. PGE paid BPA $74 million in 1998 to settle its contract obligations. That payment

is recognized, for accounting purposes, as revenue over the term of the contract until the settlement is fully amortized in 2019. This practice results in $3.524 million per year of non-cash revenue to BPA.

In the BP-12 and BP-14 rate cases, these non-cash revenues were assigned to the Non-Slice cost pool using the "accrual revenue" line in the cost table. To correct this allocation that placed responsibility for the financial implications of the settlement on Non-Slice customers, even though the benefit (the revenue credit) was shared by both Slice and Non-Slice customers, a new "PGE Settlement" line is added to the RAM Cost Table and Slice True-Up Table G. This new line allocates the non-cash revenue to the Composite cost pool to match costs with benefits. The PGE WNP-3 Settlement is not subject to the Composite Cost Pool True-Up.

21. **PF Rate Schedule: Slice Billing Adjustment.** The new Slice Billing Adjustment corrects for the inaccurate allocation of the PGE WNP-3 Settlement revenues in FY 2012–2015 (see number 20, above) by adjusting Slice customer bills by their share of the costs that should have been allocated to them in the previous rate periods. This one-time billing adjustment will be charged to Slice customers on their November 2015 power bills.

2.5.2 Demand Rate

Issue 2.5.2.1

Whether BPA should use an LMS100 or an F-class frame combustion turbine (F-class turbine) as the marginal resource to calculate the demand rate.

Parties' Positions

WPAG argues that BPA should use an F-class turbine for the marginal resource to calculate the demand rate instead of the LMS100. WPAG Br., BP-16-B-WG-01, at 31. WPAG bases its proposal on its assertion that an F-class turbine would be able to meet the daily and seasonal capacity needs of BPA's preference customers for load service and at a lower annual fixed cost than the LMS100. *Id.*

JP11 disagrees with WPAG and contends that WPAG's justification for the use of an F-class turbine is related solely to the cost of capacity with no reference to actual capability. JP11 Br., BP-16-B-JP11-01, at 6. JP11 further states that the system managed by BPA is significantly different from most systems across the United States and that BPA cannot be bound by the capacity resource choices of other utilities. *Id.* at 6-7.

ICNU disagrees with WPAG and argues that the Administrator should select the resource used for calculating the demand rate based on the lowest-cost resource that is actually being built and used by utilities to meet their long-term loads. ICNU Br., BP-16-B-IN-01, at 7. ICNU states that an F-class turbine has limited operational flexibility when compared to aeroderivative technologies, including the LMS100. *Id.* ICNU points out that no utility in the Northwest has

built an F-class turbine since 2008; instead, utilities have built three aeroderivative facilities in 2010 and 2011, and most recently PGE's reciprocating engine facility. *Id.*

BPA Staff's Position

In the Initial Proposal, Staff proposed using an LMS100 combustion turbine as the basis for the demand rates. Stiffler *et al.*, BP-16-E-BPA-17, at 2. Staff disagrees with WPAG's proposal to use an F-class turbine to set the demand rate. Abadi and Fisher, BP-16-E-BPA-36, at 2. Staff believes that the LMS100 should be used to set the demand rate due to its operational flexibility. *Id.* at 3. Staff notes that operational flexibility is an important quality for the resource used to price the demand rate due to the demand rate's link with Resource Support Services (RSS). *Id.* Staff states that the F-class turbine, as proposed by WPAG, does not have the operational flexibility required by BPA's RSS. *Id.* Staff also believes that the demand rate should be based on a resource that is actually being built and used by utilities to meet their long-term loads. *Id.* at 4. Staff notes that the LMS100 has become the industry standard for a flexible natural gas-fired peaking resource in the Western Interconnect, as evidenced by the 25 LMS100 plants that either are in operation or have recently been completed in California alone. *Id.*

Evaluation of Positions

The TRM requires that BPA identify the marginal capacity resource used to set the Tier 1 demand rate in each section 7(i) proceeding. The TRM states that the demand rate shall be based on the "annual fixed costs (capital and O&M) of the marginal capacity resource as determined in each 7(i) Process." TRM, BP-12-A-03, at 76. The TRM also establishes that "the capacity component of each RSS service will be priced at the Demand Rate …." *Id.* at 89.

Consistent with the past two rate cases, Staff proposes to use General Electric's LMS100 as the marginal capacity resource used to set the Tier 1 demand rate. Power Rates Study, BP-16-E-BPA-01, at 71; Stiffler *et al.*, BP-16-E-BPA-17, at 2. The LMS100 is a combustion turbine that is known for its operational flexibility. Abadi and Fisher, BP-16-E-BPA-36, at 2. The cost of the LMS100 sits in the middle of the four commonly recognized combustion capacity technologies used to meet a utility's capacity needs: heavy industrial frames (such as the F-class as proposed by WPAG), intercooled turbines (such as the LMS100), aeroderivatives, and reciprocating engines (such as the 12 Wärtsilä engines recently built by PGE). *Id.* at 7. An F-class turbine is expected to be the cheapest, though it does not have the operational flexibility found in the other three capacity technologies. *Id.* at 8; ICNU Br., BP-16-B-IN-01, at 7.

At the time of the BP-12 rate case, the LMS100 was a relatively new design and had not been built very widely. However, despite its newness, the LMS100's operational advantages, namely its flexibility-to-cost ratio, caused it to be identified as a strong candidate to meet future capacity needs. Several other inputs to the demand rate calculation were at issue in the BP-12 Record of Decision, but the use of the LMS100 as the resource used to set the demand rate was not contested. BP-12 Administrator's Final Record of Decision, BP-12-A-02, at 110-119.

Since the BP-12 rate case, the LMS100 has established itself as the industry standard for flexible capacity. Abadi and Fisher, BP-16-E-BPA-36, at 2. There are now nearly 30 LMS100 units

either under construction or recently built across the Western Electricity Coordinating Council, almost all of them in California. *Id.* No LMS100s have been built in the Pacific Northwest, but several other flexible capacity resources have been. ICNU Br., BP-16-B-IN-01, at 7. The last F-class turbine in the Pacific Northwest was built in 2008. Abadi and Fisher, BP-16-E-BPA-36, at 4; ICNU Br., BP-16-B-IN-01, at 7. Three aeroderivatives were built in the Pacific Northwest in 2010 and 2011. ICNU Br., BP-16-B-IN-01, at 7. The most recent capacity additions in the Pacific Northwest are the reciprocating engines built by PGE at its Port Westward location. Abadi and Fisher, BP-16-E-BPA-36, at 8; ICNU Br., BP-16-B-IN-01, at 7.

Staff's proposal in this case is consistent with the decision made in the BP-12 ROD, which was to use the LMS100 as the resource for the basis of the demand rate. The resources being built in the Pacific Northwest and Western Interconnect demonstrate a significant preference for flexible capacity resources, such as the LMS100. Abadi and Fisher, BP-16-E-BPA-36, at 4. In addition, incidence of construction of the LMS100 has grown considerably, making it the current industry standard for a flexible natural gas-fired peaking resource. *Id*. at 2.

As indicated above, for BPA the concept of resource operational flexibility is central to identifying the marginal capacity resource. WPAG asserts that an F-class turbine would be able to meet the daily and seasonal capacity needs of BPA's preference customers for load service and at a lower annual fixed cost than the LMS100. WPAG Br., BP-16-B-WG-01, at 31. WPAG asserts that good utility practice dictates that a utility select the marginal resource that will meet its needs at the lowest possible cost, which WPAG states is consistent with BPA's statutory obligation to encourage the widest possible diversified use of electric energy at the lowest possible rates. *Id*. Staff, however, disagrees that the F-class turbine would meet BPA's capacity needs and notes that the LMS100's operational flexibility is needed to provide RSS, which is also tied, pursuant to the TRM, to the same capacity price signal as load. Abadi and Fisher, BP-16-E-BPA-36, at 3.

JP11 also disagrees that the F-class turbine would meet BPA's capacity needs and states that WPAG provides no backup or support for its claim. JP11 Br., BP-16-B-JP11-01, at 6. JP11 also states that WPAG's argument is related solely to the cost of capacity with no reference to actual capability. *Id.* WPAG disputes, through a footnote in its brief, that RSS requires flexible capacity, but neither provides support for its claim nor responds to Staff's description of RSS that explains that RSS requires flexible capacity. WPAG Br., BP-16-B-WG-01, at 32 n.14. In addition to the description of the services in the Power Rates Study, BP-16-E-BPA-01, § 3.1.15, Staff notes that the products detailed in Diurnal Flattening Service (DFS) and Forced Outage Reserve Service (FORS), which are services provided under the RSS umbrella, require a fast-ramping, flexible capacity resource. Abadi and Fisher, BP-16-E-BPA-36, at 3. In particular, the provision of DFS requires following an intermittent resource hour to hour in order to convert it to a flat diurnal block. *Id.* Only a flexible resource can accomplish this. *Id.* Temporarily setting aside potential differences in the needs of loads and resources, the record is clear that an F-class turbine does not have the operational flexibility needed to provide RSS and therefore will not meet BPA's needs at the lowest possible cost. *Id*.

Further, WPAG is incorrect in its statement that this issue relates to BPA's statutory obligation to encourage the widest possible diversified use of electric energy at the lowest possible rates. The issue at hand is a rate design issue and is applied after BPA has allocated its total power revenue requirement. Power Rates Study, BP-16-E-BPA-01, § 3. Rate design does not change the amount of the revenue requirement that is allocated; rather, rate design determines from which customers the revenue requirement is collected. *Id.* at 53. In other words, this issue, specifically the level of the demand rate, does not change the amount of revenue collected by BPA and thus does not impact BPA's effective rate level. BPA's statutory obligation of lowest possible rates does not extend to each and every element of BPA's rates; BPA's governing statutes also grant the Administrator discretion in establishing different rate forms within the context of lowest possible rates. 16 U.S.C. § 839e(e).

WPAG also claims that the TRM does not specifically allocate the cost of flexibility to demand rates; therefore, the cost of flexibility should be allocated pursuant to the TRM's Cost Allocation Principle Number 2, which states: "Costs not otherwise expressly allocated in the TRM will be allocated to Cost Pools based on the principles of cost causation, meaning the costs will be allocated to the Cost Pool(s) that benefits from such costs." WPAG Br., BP-16-B-WG-01, at 32-33, *citing* TRM-12S-A-03, at 3. WPAG states that because RSS customers are those that benefit from the added flexibility of the LMS100, only RSS customers should be allocated the cost of flexibility. WPAG Br., BP-16-B-WG-01, at 33. WPAG adds that this allocation should be not through the demand rate but through a separate and distinct allocation because the demand rate is paid by non-RSS customers that are not benefited by the additional flexibility of the LMS100. *Id.* Despite the appeal of this argument, the TRM expressly addresses the allocation of capacity (flexible or otherwise) used to provide BPA's RSS. The TRM states that "the capacity component of each RSS service will be priced at the Demand Rate." TRM, BP-12-A-03, at 89. Therefore, the TRM language renders irrelevant the potential technical differences in how loads and resources consume capacity. The price signal used to allocate capacity costs to loads must also be used to price RSS. BPA believes that a change of the TRM would be required to distinguish between the demand rate for load service and the demand rate for RSS.

Only one resource can be selected for the purpose of setting the demand rate; therefore, the positive and negative attributes of each resource must be considered. It is undisputed that the LMS100 is operationally more flexible than the F-class turbine and the F-class turbine is less expensive than the LMS100. Abadi and Fisher, BP-16-E-BPA-36, at 3, 8. WPAG contends that not only is the F-class turbine less expensive; it should be used for setting the demand rate because the capacity sold for RSS is a small portion of the overall demand rate revenue BPA receives. WPAG Br., BP-16-B-WG-01, at 32. Staff, however, believes that the price signal needs to remain true to the underlying product being offered, regardless of the relative size of the revenue collected. Abadi and Fisher, BP-16-E-BPA-36, at 7. Staff further believes that the flexibility required by RSS cannot be ignored, and the LMS100 is a significantly better fit than the F-class turbine. *Id.* Staff's positions have merit.

ICNU argues that the use of the F-class turbine would distort the price signal and cause utilities to lean on BPA for capacity. ICNU Br., BP-16-B-IN-01, at 8. The type of capacity needed to provide RSS is required to be more flexible than an F-class turbine and is therefore more

expensive. Pricing RSS based on an operationally inadequate but less-expensive marginal resource would economically bias customers toward purchasing all their RSS requirements from BPA. This outcome does not align with one of the intentions of tiered rates and the Regional Dialogue Policy, which is to promote infrastructure development and remove a financial disincentive for BPA customers to develop regional infrastructure. Bonneville Power Administration Long-Term Regional Dialogue Final Policy, at 8 (July 2007).

With regard to revenue collection, WPAG correctly points out that the bulk of BPA's demand revenue collection is from the Tier 1 demand charge and not from providing RSS. WPAG Br., BP-16-B-WG-01, at 32. WPAG uses this revenue collection ratio to support the use of the F-class turbine, which WPAG claims has sufficient operational capability to meet load. *Id*. at 31. WPAG's argument, however, misses an important component—the billing determinant applied to the demand rate. Pursuant to the TRM, the demand charge is designed to send a price signal to a limited portion of a customer's overall demand on BPA. TRM, BP-12-A-03, at 71. The operative word in this instance is "limited." While the applicable rate is the same, the effective cost of capacity between loads and RSS is significantly different, as the demand rate for RSS is applied to all capacity BPA provides and not a limited portion as is true for load. In addition, WPAG's argument ignores the history behind the amount of revenue collected by load. The amount paid is largely the result of the negotiations that occurred when BPA and its customers collaboratively drafted the TRM and balanced the rate impacts caused by the TRM and the amount of load to be exposed to the demand rate. In other words, WPAG's argument is incomplete and is based on only one facet of a much more complex rate design.

Finally, the source of the capacity currently consumed by both load service and RSS is primarily hydro resources, which are generally considered very flexible resources. TRM, BP-12-A-03, at 139. Until BPA purchases additional capacity, the demand rate serves as a price signal that not only encourages utility demand-saving investment but also compensates other customers for increased use of the Tier 1 System capacity by those actually using it. Given this benefit, it is reasonable to compensate other customers for increased use of the Tier 1 System at the cost of flexible capacity, given that the Tier 1 System is a source of flexible capacity.

Draft Decision

BPA will continue to use the LMS100 as the marginal resource to calculate the demand rate for the BP-16 rate period.

Issue 2.5.2.2

Whether BPA should include a planning reserve margin in calculating the demand rate.

Parties' Positions

ICNU argues that a reserve margin is traditionally included when utilities calculate the cost of long-run marginal capacity for ratemaking purposes to reflect the cost of maintaining surplus capacity—beyond that needed to meet peak load—to ensure system reliability during peak

demand events. ICNU Br., BP-16-B-IN-01, at 4. ICNU argues that BPA should rely on the planning reserve margin target established for hydro systems by the North American Electric Reliability Corporation and, as a result, should increase the demand charge to $10.27/kW/mo. to account for a reserve margin of 10 percent. *Id*. at 5.

JP02 disagrees with ICNU, stating that BPA should not apply a technique used in utilities' long-term planning analyses (*e.g.*, Integrated Resource Plans) to a rate case construct intended to send a price signal. JP02 Br., BP-16-B-JP02-01, at 2-3. JP02 argues that including the cost of a reserve margin in the demand rate would result in double-recovery of certain costs in BPA's rate structure. *Id*. at 3-4.

WPAG also disagrees with ICNU, stating that including the cost of a reserve margin in the demand rate would double-count load risk that is already accounted for through AURORAxmp® modeling. WPAG Br., BP-16-B-WG-01, at 33.

BPA Staff's Position

Staff notes that the TRM states that the demand rate is to be based on the annual fixed costs (capital and O&M) of the marginal capacity resource, which do not include reserve margins. Abadi and Fisher, BP-16-E-BPA-36, at 8.

Evaluation of Positions

ICNU argues that a reserve margin is traditionally included when utilities calculate long-run marginal capacity for ratemaking purposes to reflect the cost of maintaining surplus capacity—beyond that needed to meet peak load—to ensure system reliability during peak demand events. ICNU Br., BP-16-B-IN-01, at 4. ICNU states that a reserve margin is traditionally stated as a percentage of peak load, citing the practice of various Pacific Northwest utilities. *Id*. ICNU argues that a reserve margin is embedded in the long-run cost of demand and should also be included in the demand rate charged to customers to send a correct price signal and reflect the cost for marginal capacity incurred on the system. *Id*.

In response to ICNU's arguments, first, there are established rules that govern the inclusion of costs in BPA's demand rate. The TRM states that "BPA will base the Demand Rate on the annual fixed costs (capital and O&M) of the marginal capacity resource as determined in each 7(i) Process." Abadi and Fisher, BP-16-E-BPA-36, at 8-9, *citing* TRM, BP-12-A-03, at 76. Capital and O&M costs for a generator do not include a reserve margin. Furthermore, there is no provision in the TRM that calls for BPA to include a planning reserve margin in the demand rate calculation. Abadi and Fisher, BP-16-E-BPA-36, at 8. BPA's demand rates are based upon the annual fixed costs (capital and O&M) of the marginal capacity resource, an LMS100 combustion turbine, as calculated by the Northwest Power and Conservation Council's Microfin model 15.0.1. Power Rates Study, BP-16-E-BPA-01, at 71. This calculation is consistent with the TRM. Abadi and Fisher, BP-16-E-BPA-36, at 9. It includes fixed costs of the resource, as mandated by the TRM, but does not include reserve margins. *Id*.

Staff cites a presentation by the Northwest Power and Conservation Council that lists the components of the cost of the LMS100 intercooled combustion turbine. *Id*. The Council's presentation does not list a reserve margin as a component of the cost of the LMS100 turbine. *Id.* Thus, Staff believes, reserve margins are not a proper component of BPA's long-run fixed cost of capacity. *Id*. This is a sound argument.

Second, contrary to ICNU's claim, reserve margins do not represent the *cost* of maintaining surplus capacity. *Id*. The North American Electric Reliability Corporation defines the term "Planning Reserve Margin":

> Planning reserve margin is designed to measure the amount of generation capacity available to meet expected demand in planning horizon. Coupled with probabilistic analysis, calculated planning reserve margins have been an industry standard used by planners for decades as a relative indication of adequacy.

http://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx. BPA engages in long-term resource planning, as documented in the Needs Assessment and Resource Program, to ensure that the Federal system will operate reliably during peak times. Abadi and Fisher, BP-16-E-BPA-36, at 9-10. This planning concept is different from the demand rate, which is a price signal to customers designed to reflect the actual unit cost of marginal capacity. *Id*. at 10; JP02 Br., BP-16-B-JP02-01, at 3.

Third, ICNU refers to the reserve margins of Pacific Northwest utilities. ICNU Br., BP-16-B-IN-01, at 4. This issue is addressed in Staff's rebuttal testimony. Although PGE, for example, may use a 12 percent planning reserve margin in calculating its marginal cost of capacity, ICNU does not cite any source indicating why PGE does so. Abadi and Fisher, BP-16-E-BPA-36, at 10. PGE's 2013 Integrated Resource Plan (IRP), states:

> The level of reserves we include in planning for capacity is important for maintaining supply reliability. We plan for approximately 12% of reserves, comprising 6% contingencies and an approximately 6% operating reserve margin. The operating reserve margin is required by Western Electricity Coordinating Council (WECC) reliability standards and is intended to maintain supply stability and power quality during unexpected real-time disruptions within the operating hour (i.e., must be compensated for within one hour). Examples of disruptions include plants unexpectedly going off-line and unanticipated load increases. The contingency reserve covers two types of events: 1) extreme weather events and resulting load excursions (i.e., loads going above those associated with average, or "1-in-2", weather); and 2) unplanned generator or transmission outages (either full or partial) extending beyond the time to be covered by operating reserves.

Portland General Electric, *2013 Integrated Resource Plan* § 3.3 (March 2014). PGE's 2013 IRP shows that PGE's reasons for using a 12 percent reserve margin in its calculation of marginal capacity are different from the reasons behind the development of BPA's demand rate. Abadi

and Fisher, BP-16-E-BPA-36, at 10. The foregoing quotation states that PGE's reserve margin includes 6 percent for contingencies and 6 percent for operating reserves. *Id*. BPA bills and accounts for "Operating Reserves" separately as ancillary and control area services provided by BPA's Transmission Services. *Id*. at 10-11, *citing* Transmission Rates Study and Documentation, BP-16-E-BPA-07, at 115. In addition, with regard to PGE's "contingency reserves," when a weather event occurs and loads spike, the weather event impacts the billing determinant applicable to the BPA demand rate. Abadi and Fisher, BP-16-E-BPA-36, at 11. Including the cost of the weather event in both the billing determinant and the rate would result in double-counting. *Id*.

The foregoing quotation also mentions unplanned generator or transmission outages extending beyond the time to be covered by operating reserves. *Id.* at 11. This concept follows the same principle as BPA's Forced Outage Reserve Service, which accounts for events that last longer than the amount of time covered by Operating Reserves. *Id*. The TRM defines FORS as "the service that provides an agreed-to amount of capacity and energy to load during the forced outages of a qualifying resource … FORS may be arranged for when Operating Reserves expire or when the resource operator recognizes imminent failure and must initiate a controlled shutdown." *Id*., *citing* TRM, BP-12-A-03, at 90. The cost basis for FORS is the PF demand rate. Abadi and Fisher, BP-16-E-BPA-36, at 11. BPA would be double-counting if the demand rate also included the cost of providing contingency and operating reserves. *Id*. JP02 also notes that including the cost of a reserve margin in the demand rate would result in double-recovery of certain costs in BPA's rate structure. JP02 Br., BP-16-B-JP02-01, at 2-3.

In response to the claim that including a reserve margin would constitute double-counting, ICNU argues that Staff fails to recognize that marginal capacity is part of a proper price signal, and that the reserve margin that would be associated with marginal capacity, should it be built, would have an incremental cost. ICNU Br., BP-16-B-IN-01, at 5. ICNU asserts that, likewise, while reserves needed for *existing* resources are built into BPA's Ancillary and Control Area Service rate and the PF demand rate, these rates do not reflect reserve margins for marginal resources that would need to be constructed if demand is not controlled. *Id*. Thus, ICNU claims, there is no double-counting when a reserve margin is incorporated into the demand charge; rather, a more accurate reflection of the cost of incremental resources is included in the price signal. *Id*. In response to ICNU, the design of the demand rate already reflects the cost of *marginal* capacity, or capacity that has not been built. TRM, BP-12-A-03, at 76-77. As such, it includes (as the TRM mandates) the fixed costs (capital and O&M) of that marginal capacity resource. Abadi and Fisher, BP-16-E-BPA-36, at 8. As a price signal, the demand rate must reflect the costs associated with that resource and nothing else. As mentioned above, including a reserve margin in the demand rate would add costs that are already being collected in other parts of BPA's rates. *Id.* at 11, *citing* TRM, BP-12-A-03, at 90.

ICNU's argument is also incomplete as it ignores the multiple price signals being sent to customers through BPA's other rates and assumes that the demand rate is the only source of BPA's price signal for increased use of capacity. An increase in a customer's demand will cause the customer to incur additional demand costs as well as additional ancillary and control area services costs. Abadi and Fisher, BP-16-E-BPA-36, at 10. This fact results in a customer being

exposed to a price signal for both components, the first through BPA's demand rate and the second through BPA's ancillary and control area services rates.

ICNU also inappropriately distinguishes between cost recovery for existing resource costs and the price signal for resources that have not yet been constructed. The price signals sent by BPA are consistent for both the reduction and increase in a customer's existing demand. There is no hard separation between existing and future demands because the definition of "existing" is relative to the time in which the measurement is made. In other words, today's future demand will be tomorrow's existing demand. Given that the definition of "existing" is time relative, it is impossible to reconcile ICNU's argument because ICNU concedes that "reserves needed for existing resources are built into BPA's Ancillary and Control Area Service rates and the PF demand rate." ICNU Br., BP-16-B-IN-01, at 5. Moreover, it would be inappropriate to charge existing loads on the prospect of resource costs being incurred for future loads when those future loads are not yet certain. A customer should be charged for added capacity use only if and when those future loads materialize, which is the case with BPA's multifaceted rate design.

ICNU argues that WPAG's parallel assertions that a reserve margin would change the nature of the demand rate or cause double-recovery are untrue. ICNU Br., BP-16-B-IN-01, at 5-6. ICNU notes WPAG's argument that BPA already accounts for load risk, a component of reserve margins, in its calculation of power rates based on the use of stochastic modeling. *Id.* ICNU claims that this argument misses the point because the issue is not whether power rates, overall, account for reserve margins; rather, the issue is whether the reserve margin costs are properly allocated to the demand rate component of overall power rates. *Id*. ICNU states that the point WPAG misses is that these reserve margin costs are not being allocated to the demand rate component of overall power rates. *Id*. at 6. ICNU states that it follows that the inclusion of a reserve margin in demand rate calculations would result in an appropriate and effective price signal and should be adopted by the Administrator. *Id*.

While BPA generally agrees with ICNU's arguments against WPAG's position, ICNU does not gain any ground because its arguments are essentially the same as made against Staff's position, which are addressed above. The demand rate is not the only price signal customers observe through BPA's rates for the increased use of capacity. Further, the demand charge was not designed as the only method to collect capacity-related costs from customers, as demonstrated by BPA's multiple capacity-based rates. Nor was the demand charge designed to recover all capacity costs associated with load service, as evidenced by its limited billing determinant and complete lack of applicability to Slice/Block and Block-only customers. TRM, BP-12-A-03, at 71.

Fourth, ICNU notes that regional utilities use some degree of a reserve margin construct when determining the amount of capacity that must be built or acquired to maintain reliable operations. ICNU Br., BP-16-B-IN-01, at 4; *see also* Mullins, BP-16-E-IN-01, at 9. Staff agrees that regional utilities plan for and acquire resources in excess of their anticipated peak load to maintain reliable operations; this amount of resources expressed as a percentage of the expected peak load can be thought of as a reserve margin. Abadi and Fisher, BP-16-E-BPA-36, at 12. However, the issue at hand is whether that planning reserve margin should be reflected in the

price signal for the marginal cost of capacity. Staff maintains that whether the planning reserve margin is assumed to be 10 percent, 12 percent, or some other calculated or arbitrary number, the cost of marginal capacity will continue to be fixed costs associated with building the GE LMS100 intercooled combustion turbine, and not those fixed costs increased by 10 percent or 12 percent. *Id*. This is because the costs are expressed as a per-unit amount and not a lump dollar sum. *Id*. The per-unit amount will not increase with additional units. *Id*. This argument is well-founded.

ICNU argues that BPA should rely on the planning reserve margin target of 10 percent established for hydro systems by the North American Electric Reliability Corporation. ICNU Br., BP-16-B-IN-01, at 5. NERC's definition of a planning reserve margin is quoted above. Abadi and Fisher, BP-16-E-BPA-36, at 13. Staff points out that the NERC standard deals strictly with the amount of generation needed to meet load, not cost. *Id*. NERC's recommendations do not suggest that BPA should raise its demand rate by 10 percent. *Id*.

Draft Decision

BPA will not include a planning reserve margin in calculating the demand rate.

Issue 2.5.2.3

Whether BPA should include a pipeline capacity release credit in the computation of the demand rate.

Parties' Positions

ICNU argues that BPA should remove the assumption that any fixed fuel costs associated with the demand rate could be mitigated by selling off pipeline capacity. ICNU Br., BP-16-B-IN-01, at 6-8. ICNU states that the Northwest Power and Conservation Council (Council) already removed this assumption from its analysis in the Sixth Power Plan. *Id*. at 6. ICNU also asserts that firm pipeline capacity release is a variable cost, not a fixed cost, removing any relevance to the demand rate, which should be based solely on fixed costs. *Id*. at 6-7.

JP02 argues that when the Council removed this credit from the Sixth Power Plan, it recognized that even though capacity release credits may be falsely precise for long-term planning purposes, they are a component of currently operating resources. JP02 Br., BP-16-B-JP02-01, at 4-5. Therefore, JP02 claims, it is reasonable to include the capacity release credit for purposes of setting BPA's demand rate. *Id*.

WPAG argues that ICNU's position that firm pipeline capacity is a variable cost would treat the gas transportation reservation costs as demand-related but revenue credits from the same as energy-related. WPAG Br., BP-16-B-WG-01, at 33-34. WPAG states that under standard ratemaking practice, revenue and credits such as this should retain the same classification. *Id*. at 34. WPAG asserts that ICNU's proposal treats BPA's demand rate calculation as a long-term fixed cost calculation, whereas it is more accurately identified as a short-term fixed cost

calculation. *Id.* Under short-term fixed cost calculations, WPAG states, the inclusion of revenue credits from the sale of capacity rights is the correct approach. *Id*.

BPA Staff's Position

Staff's Initial Proposal included a 10 percent capacity release credit in the calculation of the Tier 1 demand rates. Power Rates Study Documentation, BP-16-E-BPA-01A, Table 3.4. Staff does not address this issue in its testimony.

Evaluation of Positions

ICNU argues that, as currently proposed, the demand charge is artificially reduced because it includes an assumption that 10 percent of the fixed fuel transportation costs associated with the LMS100 capacity resource would "be recovered through resale of the pipeline rights or capacity release credits." ICNU Br., BP-16-B-IN-01, at 6, *citing* Mullins, BP-16-E-IN-01, at 10-11. ICNU claims that this assumption is arbitrary and should be removed from the demand charge. *Id*. ICNU notes that when it requested information regarding the source of the capacity release assumption, BPA was able to point to no study or work papers to demonstrate its reasonableness; rather, BPA pointed to testimony from BP-12, in which Staff acknowledged that the Council no longer retains a capacity release assumption. *Id.* ICNU claims that BPA declined to adjust its proposal to follow the Council on the basis that the small size of the change it would make in the demand rate did not warrant the adjustment. *Id.* ICNU argues that without any analytical basis for retaining this assumption, there is no sound business reason for including it in the demand rate. *Id*.

JP02 disagrees with ICNU and points out that BPA already considered this argument in the BP-12 rate case. JP02 Br., BP-16-B-JP02-01, at 4. In that rate case, it was determined that the Council removed the pipeline capacity release credit because the Council believed it provided false precision for long-term planning purposes and not because it was an unreasonable assumption. *Id.* at 4-5. JP02 also states that the Council still recognizes that capacity-release capability is available in firm gas transportation contracts. *Id.* at 4. JP02 further notes that the demand rate is not a long-term planning concept but rather a rate to send a price signal to a limited portion of a customer's overall demand on BPA. *Id.* at 5. In contrast to ICNU, JP02 argues that the removal of the capacity release credit would artificially increase the demand rate and would cause the demand rate to be less accurate than it otherwise would be. *Id.*

It is undisputed that capacity-release capability is included in firm gas transportations contracts. JP02 Br., BP-16-B-JP02-01, at 4. Further, no party disputes that at some point prior to the release of the Council's Sixth Power Plan, the Council included a 10 percent pipeline capacity release credit in its estimate of the fixed cost of a natural gas combustion turbine. However, as ICNU correctly points out, there is nothing on the record that explains the methodology that the Council used to reach its 10 percent assumption. Rather, what is on the record is a statement by Council staff that the assumption was removed for purposes of long-term planning and not because it was determined to be unreasonable. JP02 Br., BP-16-B-JP02-01, at 4. This assumption was uncontested in two rate cases, BP-12 and BP-14.

Although, as ICNU correctly points out, the 10 percent value was based on analysis conducted by the Council and this analysis is not in the BP-16 record, the Council's conclusion remains in the record. Given the Council's practice of public and collaborative development of the inputs to its long-run resource planning model (Microfin) and the statement of Council staff prior to the BP-12 rate case, which is on the record, it is unlikely the Council arbitrarily used a 10 percent assumption. If this were the only argument presented against the capacity release credit, it might be prudent to postpone the decision on this issue until BP-18 to avoid unnecessary demand rate volatility. This, however, is not the only argument raised by ICNU in opposition to the pipeline capacity release credit.

ICNU also argues that the release of pipeline capacity is a variable credit that depends, like fuel costs, upon the level of operation of the turbine and also upon market conditions for short-term pipeline capacity. ICNU Br., BP-16-B-IN-01, at 6-7. ICNU claims that, as a result, the credit should not be included in the calculation of fixed costs, and BPA should increase the demand rate by approximately $0.33/kW/mo. to account for removal of variable capacity release credits. *Id*. WPAG disagrees with ICNU and argues that ICNU's proposal treats BPA's demand rate calculation as a long-term fixed cost calculation, whereas it is more accurately identified as a short-term fixed cost calculation. WPAG Br., BP-16-B-WG-01, at 34. WPAG claims that under short-term fixed cost calculations, the inclusion of revenue credits from the sale of capacity rights is the correct approach. *Id*. WPAG also argues that the elimination of the assumed 10 percent capacity release credit in the demand rate calculation would treat the gas transportation reservation costs as demand-related, but revenue credits from such costs as energy-related. *Id.* at 33-34. WPAG states that under standard ratemaking practice revenue and credits such as this should retain the same classification. *Id*. at 34.

WPAG's arguments regarding long-term costs, short-term costs, energy costs, and demand costs are misplaced. This is not a long-term versus short-term cost issue. Nor is this an energy versus capacity cost issue. Rather, it is a fixed versus variable cost issue. The TRM is clear that the pipeline capacity release credit should be included for purpose of setting the demand rate if it is characterized as a reduction in the fixed cost. TRM, BP-12-A-03, at 76-77. Conversely, the TRM is equally clear that the pipeline capacity release credit should *not* be included for purposes of setting the demand rate if it is characterized as variable revenue. *Id*. As stated earlier, it is undisputed that the Council at one point characterized the capacity release credit as a reduction in fixed costs. However, also undisputed is that the Council no longer uses this assumption for long-term planning purposes.

Whether pipeline capacity release is variable revenue and not a reduction in fixed cost is the controlling issue. This is the more compelling argument against including a pipeline capacity release credit in the calculation of the demand rate. The description of the pipeline capacity release credit supports ICNU's argument. The credit is described as an offsetting revenue credit of 10 percent to account for the resale of firm pipeline rights. Power Rates Study, BP-16-E-BPA-01, at 72. It is described as a revenue credit a utility would receive after it first incurred a fixed cost for the full pipeline capacity rights. The right to release pipeline capacity provides the utility an opportunity to generate revenue by reselling its pipeline capacity when the utility determines that the capacity is not needed for its own purposes. In fact, the amount of any

available credit at any particular decision point becomes part of the determination of whether to generate or not, which is the very essence of a variable cost in this context. The revenue that is generated is both uncertain and occurs after a fixed cost is incurred. ICNU Br., BP-16-B-IN-01, at 6-7. This description comports with the definition of variable revenue and thus, pursuant to the TRM language, should not be included in the demand rate calculation. TRM, BP-12-A-03, at 76-77.

Draft Decision

BPA will not include a pipeline capacity release credit in the computation of the demand rate.

2.5.3 Load Growth Rate Billing Adjustment

The Load Growth Rate Billing Adjustment is designed to address a cost recovery and equity issue that became apparent when BPA was setting its BP-14 rates. Weekley *et al.*, BP-16-E-BPA-35, at 9; *see also* BP-14 ROD, BP-14-A-03, at 67. The issue concerns the allocation of costs of a BPA 5 aMW purchase of power stemming from BPA's obligations under the CHWM contracts.

Each Load Following customer had multiple options for serving its Above-RWHM Load. One of those options was to elect the Load Growth rate alternative. Under this rate alternative, a customer placed on BPA the obligation to serve its Above-RHWM Load at the Tier 2 Load Growth rate for the entire contract term, through FY 2028. Weekley *et al*., BP-16-E-BPA-35, at 9-10.

More than 50 of BPA's customers elected this option. These customers became the Load Growth customers and are enumerated in the 2016 Power Rate Schedules, BP 16-E-BPA-09, Appendix B. Weekly *et al.*, BP-16-E-BPA-35, at 10. In response to this long-term commitment, and based on the expectation that the amount of Above-RHWM Load would grow over time, BPA purchased 5 aMW in 2011 (FY 2012) to serve these customers' Above-RHWM Load. *Id.*

After BPA made the 5 aMW purchase two factors changed. First, more recent projections of load growth of the Load Growth service customers are considerably less than the forecast at the time the purchase was made. *Id.* Most customers in the Load Growth customer pool currently have projected Above-RHWM loads of less than 1 aMW a year. Under the TRM, customers with less than 1 aMW (8,760 MWh) of Above-RWHM Load can receive service at the Load Shaping rate and not pay for the power at the Tier 2 Load Growth Rate. *Id.; see also* TRM, BP-12-A-03, at 54. For the BP-16 rate period, only one customer in the Load Growth pool has Above-RHWM Load in excess of 1 aMW in a year. Weekley *et al*., BP-16-E-BPA-35, at 10. This customer has an Above-RHWM Load amount of about 1.1 aMW per year and will be charged for this load at the Tier 2 Load Growth Rate. *Id.* This leaves about 3.9 aMW of BPA's 5 aMW purchase to be remarketed. *Id.*

The second factor that has changed is the price of power. This factor is significant because the TRM directs that the portion of the 5 aMW purchase not needed for Load Growth service must

be remarketed to other Tier 2 cost pools or, if necessary, applied to reduce system augmentation. *Id.* at 11; *see also* TRM, BP-12-A-03, at 26-28. This remarketing occurs at the current forecast of market prices and may result in either a debit or a credit to the Load Growth customer cost pool depending upon whether current prices are higher or lower than the original acquisition price. Weekley *et al*., BP-16-E-BPA-35, at 11. The prevailing market price for power today is substantially less than the price BPA paid for the 5 aMW acquisition in 2011, resulting in a financial shortfall. *Id.* For the BP-16 Initial Proposal, the shortfall was forecast to be $376,693 in FY 2016 and $428,748 in FY 2017. *Id.*; *see also* Stiffler *et al*., BP-16-E-BPA-17, at 4-5.

To recover the shortfall between the purchase price paid and the remarketing value in BP-14 rates, BPA instituted the Load Growth Rate Billing Adjustment paid by Load Growth customers with Above-RHWM Load greater than zero but less than 8,760 MWh. Staff proposes to continue using the Load Growth Rate Billing Adjustment for BP-16 rates. Please note that the discussion below uses numbers calculated for the BP-16 Initial Proposal; these amounts will be updated for the Final Proposal.

Issue 2.5.3.1

Whether BPA should adopt the Load Growth Rate Billing Adjustment to recover the financial shortfall from customers that elected the Tier 2 Load Growth service and have Above-RHWM load but are not currently purchasing power at the Tier 2 Load Growth rate.

Parties' Positions

WPAG objects to Staff's proposal to use the Load Growth Rate Billing Adjustment to recover the cost of the shortfall. WPAG Br., BP-16-B-WG-01, at 34. WPAG argues that assigning these costs to customers that are not purchasing power at a Tier 2 rate is contrary to the terms of the TRM. *Id.*

WPAG proposes that BPA defer recovering the shortfall, with interest, until the end of FY 2024, at which point more customers may be purchasing power at the Tier 2 Load Growth rate. *Id.* at 38. WPAG proposes that if BPA is still unable to recover the shortfall by the end of FY 2024 BPA should recover these costs by assigning them to the Composite cost pool. *Id*.

BPA Staff's Position

Only one customer is purchasing power at the Tier 2 Load Growth rate, and it would be inequitable to require this single customer to shoulder the entire burden of the shortfall. Weekley *et al.*, BP-16-E-BPA-35, at 12. Staff recommends that the shortfall be allocated, through the Load Growth Rate Billing Adjustment, to the customers that elected the Load Growth service option and have Above-RHWM load but are not currently purchasing power at the Tier 2 Load Growth rate. *Id*. at 18.

Evaluation of Positions

As noted above, only one customer will purchase power at the Tier 2 Load Growth rate in the BP-16 rate period. Allocating the entire shortfall to the Tier 2 Load Growth rate in this case would burden this single customer with over $800,000 in additional costs for the rate period. Weekley *et al.*, BP-16-E-BPA-35, at 11. Staff does not consider it consistent with equity or cost causation principles to assign the entire shortfall for the 5 aMW purchase to the single customer purchasing power (1.1 aMW) at the Tier 2 Load Growth rate. *Id.* at 10-11. This customer will pay its proportionate share (about 20 percent) of the costs of the 5 aMW purchase through the application of the Load Growth rate, which results in a Load Growth rate for this customer of $45.32/ MWh in FY 2016 and $49.73/ MWh in FY 2017. *Id.* at 11; *see also* Power Rate Schedules, BP-16-E-BPA-09, at 10.

Staff proposes, instead, to recover the $800,000 shortfall by allocating these costs to the other customers that elected the Load Growth service and have Above-RHWM load but do not presently pay the Tier 2 Load Growth rate because their Above-RWHM load is less than 1 aMW. Weekley *et al.*, BP-16-E-BPA-35, at 11-12; *see also* TRM, BP-12-A-03, at 54. Staff contends this alternative is reasonable because these customers elected the Load Growth service, have Above-RWHM load need that is not eligible for service at Tier 1 rates, and benefit from the 5 aMW purchase because it reduces their exposure to market volatility. Weekley *et al.*, BP-16-E-BPA-35, at 11-14.

WPAG agrees that allocating the entire shortfall to the Tier 2 Load Growth rate would be inequitable because only a single customer is purchasing power at that rate; however, WPAG argues that Staff's proposal is contrary to the terms of the TRM. WPAG Br., BP-16-B-WG-01, at 38. Specifically, WPAG argues that section 3.4 of the TRM requires that the shortfall from the 5 aMW purchase be recovered from the Tier 2 cost pool for which the power was acquired, which in this case would be the Load Growth cost pool. *Id*. at 34-35. WPAG argues, however, that BPA may recover costs from the Load Growth cost pool only through the application of a Tier 2 rate for "power purchased under a CHWM Contract to meet a customer's Above-RHWM load." *Id*. at 35. Citing various definitions in the TRM, WPAG maintains that Staff's proposal violates this construct by assessing the Load Growth Rate Billing Adjustment to the Load Shaping rate, which WPAG contends is a sale of power at a Tier 1 power rate, not a Tier 2 rate. *Id*. at 36. WPAG concludes that the better approach is to defer recovering the shortfall until the end of FY 2024, when it is more likely that other customers will be purchasing power at the Tier 2 Load Growth rate. Saleba *et al*., BP-16-E-WG-01, at 23.

Staff and WPAG are in alignment on certain aspects of this issue. For instance, Staff does not disagree with WPAG's assessment that under the normal course of the TRM implementation, the default means of collecting the total contract cost would be through the application of the Tier 2 Load Growth rate. Weekley *et al*., BP-16-E-BPA-35, at 13. In addition, WPAG agrees with Staff's assessment that following the default operation of the TRM in this instance would be unreasonable. WPAG Br., BP-16-B-WG-01, at 38. Finally, WPAG does not disagree with Staff's finding that the 5 aMW purchase was originally made to meet the needs of the Load Growth service group and that the costs of this purchase are properly allocable to the Load

Growth cost pool. Saleba *et al*., BP-16-E-WG-01, at 17. Where Staff and WPAG differ is on selecting the alternative *means* for recovering the shortfall from the Load Growth customers.

Staff's proposal recovers the shortfall as it is realized from the Load Growth rate pool customers by applying a billing adjustment to Load Growth customers that have Above-RWHM load greater than zero and less than 8,760 MWh. Weekley *et al*., BP-16-E-BPA-35, at 11-12, *citing* Stiffler *et al*., BP-16-E-BPA-17, at 4-7. These customers technically have load subject to Tier 2 rates (and therefore would be subject to the Tier 2 Load Growth rate) but the TRM permits these customers to serve this load using the Load Shaping rate because the load is projected to be under 8,760 MWh. Weekley *et al*., BP-16-E-BPA-35, at 11-12, 15.

WPAG argues that this proposal violates the TRM because, in WPAG's view, the only means BPA has of recovering Tier 2 costs (and hence the shortfall) is through the sale of power to a customer at a Tier 2 rate. In this case, WPAG contends, the Load Growth customers are not purchasing power from BPA at a Tier 2 rate but purchasing power at the Load Shaping rate, which is a Tier 1 rate. WPAG Br., BP-16-B-WG-01, at 35-36. For support, WPAG points to the definitions of Tier 2 Costs, Tier 2 Cost Pool, Tier 2 Rate, and the TRM provisions governing the Load Shaping Rate. *Id.*

Contrary to WPAG's claims, Staff's proposal does not run afoul of the terms of the TRM. The terms Tier 2 Costs, Tier 2 Cost Pool, and Tier 2 Rate are defined as follows:

- "Tier 2 Costs" are the expenses and revenue credits that BPA will identify on [TRM] Table 2 and allocate to the appropriate Tier 2 Cost Pool during the applicable 7(i) Process.

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

- "Tier 2 Rate" means any Priority Firm Power (PF) rate that reflects Tier 2 Costs and applies to power purchased under a CHWM Contract to meet a customer's Above-RHWM Load.

TRM, BP-12-A-03, at xxiv-xxv.

A related term not mentioned by WPAG but relevant here is the term "Cost Pool," which is defined as follows:

- "Cost Pool" means a grouping of expenses and revenue credits allocated to a specific product, service, or customer type.

Id. at xi.

Staff's proposal is consistent with these definitions. First, the Load Growth service customers have purchased a specific product from BPA (Load Growth service), BPA has incurred costs to

provide this service (5 aMW purchase), and BPA is allocating these costs to this group in this section 7(i) proceeding. PRS Documentation, BP-16-E-BPA-01A, Table 3.10. Second, the costs BPA is allocating to these Load Growth service customers are Tier 2 costs. This is the case because the costs being allocated to the Load Growth cost pool were incurred to meet these customers' Above-RHWM load (load not eligible for service at Tier 1 rates). Weekley *et al*., BP-16-E-BPA-35, at 13. Finally, Staff proposes to apply a "Tier 2 Rate" to the Load Growth customer group; the Load Growth Rate Billing adjustment is a Tier 2 rate because it reflects Tier 2 costs and applies to power purchased under a CHWM contract for Above-RHWM load.

WPAG objects to this interpretation, arguing that these customers are purchasing power at the Load Shaping rate, which WPAG claims is a Tier 1 rate, not a Tier 2 rate. WPAG Br., BP-16-B-WG-01, at 36-37. WPAG claims BPA's rate schedule and the TRM identify the Load Shaping rate as a Tier 1 rate without reference to whether the power being sold at the Load Shaping rate is for Above-RHWM Load, and therefore, the Load Shaping rate is always a Tier 1 rate. WPAG Br., BP-16-B-WG-01, at 36.

WPAG's argument, however, confuses the issue. The TRM permits a customer's Above-RHWM load to be served at the Load Shaping rate (when less than 8,760 MWh); the application of the Load Shaping rate to this load, however, does not transform this Above-RHWM load to Tier 1 service or preclude BPA from allocating appropriate Tier 2 costs to customers with Above-RHWM load.

In effect, the Load Growth Rate Billing Adjustment functions as a customer charge applicable to customers with Above-RHWM load. A customer charge is a frequently used component of rate design, and the TRM is clear that rate design for BPA's Tier 2 rate alternatives will be determined in 7(i) processes. TRM, BP-12-A-03, at 79. The customer charge proposed by Staff reflects Tier 2 costs and applies to power purchased under a CHWM contract to meet a Load Growth customer's Above-RHWM load. This is exactly the definition of a Tier 2 rate in the TRM. *Id.* at xxv. The application of any other rate to the customer's Above-RHWM load, Load Shaping or otherwise, is irrelevant.

To clarify the intent and result of the Load Growth Rate Billing Adjustment, BPA will rename it the Load Growth Rate Customer Charge. Further, BPA will add a section to the Tier 2 rate schedules that clarifies that the Load Shaping rates are Tier 2 rates when applied to a customer's Above-RHWM load served by BPA. The modified Tier 2 rate schedule will be:

2.2 Tier 2 Charges

2.2.1 Tier 2 Load Shaping Charge

Pursuant to section 4.3 of the Tiered Rate Methodology, BP-12-A-03, the Tier 2 Load Shaping charge is applicable to customers that have elected to serve Above-RHWM Load with purchases at Tier 2 rates and are forecast to have Above-RHWM Load less than 8,760 MWh.

2.2.1.1 Tier 2 Load Shaping Rates
The Tier 2 Load Shaping Rates shall be the rates specified in section 2.1.3.1.

2.2.1.2 Tier 2 Load Shaping Billing Determinant
The Tier 2 Load Shaping billing determinant for each billing period is incorporated into the billing determinant established in section 2.1.3.2.

[The former section 2.2.1, Short-Term Charge, and subsequent sections will be renumbered accordingly.]

* * * *

2.2.3 Load Growth Charge

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2.2.3.3 Load Growth Rate ~~Billing Adjustment~~ <u>Customer Charge</u>
Load Growth Rate Customers are subject to a ~~billing adjustment~~ <u>customer charge</u> for FY 2016 and FY 2017.

The ~~adjustment~~ <u>monthly</u> amounts ~~for~~ <u>charged</u> to each Customer are set forth in Appendix B to the General Rate Schedule Provisions.

WPAG also appears to contend that because the Load Growth customers are paying for their Above-RHWM load at the Load Shaping rate, these customers are now insulated from being allocated Tier 2 costs associated with their Above-RHWM load. WPAG reaches this conclusion because it believes the Load Shaping rate is a Tier 1 rate. WPAG Br., BP-16-B-WG-01, at 36-37. This is incorrect. When the Load Shaping rate is used to charge for power used to serve Above-RHWM load it is a Tier 2 rate. It meets each element of the definition of Tier 2 rate in the TRM: (1) it is a PF rate; (2) it reflects Tier 2 costs; (3) it is purchased under a CHWM contract; and (4) it is applied to power that meets a customer's Above-RHWM load. TRM, BP-12-A-03, at xxv. That the Load Shaping rate is a Tier 2 rate in this context can also be seen from several aspects of the Load Shaping rate design. First, the Load Shaping rate is a market-based rate that, pursuant to the TRM, is set equal to BPA's forecast of market prices during the rate period. *Id.* at 64. Thus, unlike Tier 1 rates that are set to recover the cost of BPA's existing system, the Load Shaping rate is set equal to the forecast cost BPA will incur to purchase additional power in the market to serve a customer's Above-RHWM load. Second, the Load Shaping charge is subject to a true-up at the end of each year "to avoid charging or crediting the market-based Load Shaping rate for energy within the customer's RHWM." *Id.* at 65. In other words, the Load Shaping rate must be adjusted to a different level if it is applied to power purchased under Tier 1 rates. It remains unadjusted through the true-up to the extent that the power purchased is in excess of the customer's RHWM. Third, the TRM makes clear that the Tier 1 rates apply only to a customer's RHWM load, *not* to a customer's Above-RHWM load. The RHWM is defined as:

> the amount, calculated by BPA in each RHWM Process pursuant to the formula in 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 equal to the RHWM for Load Following customers and the lesser of RHWM or Annual Net Requirement for Block and Slice/Block customers.*

Id. at xix (emphasis added).

As the above-quoted language makes clear, a customer cannot receive service for its Above-RHWM load at a Tier 1 rate because the "maximum planned amount of power a customer may purchase under Tier 1 Rates … is equal to the RHWM for Load Following customers[.]" Consequently, when Load Following customers (such as those purchasing Load Growth service) receive power service for their Above-RHWM load at the Load Shaping rate, the transaction is made pursuant to a rate that is *not* a Tier 1 rate. Thus, the only remaining alternative is a Tier 2 rate. The TRM did not deem, as WPAG argues, that Above-RHWM load less than 8,760 MWh is eligible for service at Tier 1 rates, as that would be prohibited by the TRM's definition of RHWM. Rather, the TRM uses the market-based Load Shaping rates as a substitute for a cost-based Tier 2 rate when a Load Following customer's Above-RHWM load is less than 8,760 MWh.

WPAG's citations to various provisions of the TRM and BPA's rate schedules, WPAG Br., BP-16-B-WG-01, at 36-37, also do not support its claim that the Load Shaping rate is a Tier 1 rate when applied to Above-RHWM load. TRM section 5.2 states that the Load Shaping charges are "designed to recover 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, BP-12-A-03, § 5.2 (emphasis added). This section, however, does not state that the Load Shaping rate is a Tier 1 rate, but rather a separate rate that is designed to recover costs associated with *shaping* the Tier 1 purchases of Load Following customers. Indeed, the TRM differentiates between rates that are Tier 1 rates and rates that are used to provide tertiary services for Tier 1 service (such as the Load Shaping rate). Later provisions of this same section of the TRM make this point clear. TRM section 5.2.4 establishes an elaborate true-up mechanism, which is intended "to avoid charging or crediting *the market-based Load Shaping Rate* for energy *within the customer's RHWM*." TRM, BP-12-A-03, at 65 (emphasis added). The true-up applies so that a customer neither pays for nor receives credits associated with the Load Shaping rates for load *within* its RHWM (*i.e.*, load subject to Tier 1 rates). This "true-up," however, applies only to the extent that "a Load Following customer's TOCA Load or Actual Annual Tier 1 Load is *less than* its RHWM." *Id.* (emphasis added). Customers with Above-RHWM load are not subject to this true-up and are left to pay costs (or receive credits) associated with the market-based Load Shaping rate. *Id.*

WPAG notes that TRM Table 2.D allocates both the costs of serving load at the Load Shaping rate (*i.e.*, the cost of Balancing Power Purchases) and the credits from the Load Shaping rate to Tier 1's Non-Slice pool. Thus, WPAG claims, because costs and credits related to the Load Shaping rate are allocated to a Tier 1 cost pool, that rate is a Tier 1 rate under the TRM. WPAG Br., BP-16-B-WG-01, at 36. This is incorrect. There is no linkage between the effective

rate type and the allocation of the revenue received from that rate. DSI revenue, RSS revenue, New Resource revenue, FPS revenue, and secondary sales revenue are all allocated to Tier 1 cost pools, but none of this revenue is generated from Tier 1 rates. PRS Documentation, BP-16-E-BPA-01A, at 75-76. Further, some of the revenue generated from Tier 2 rates is explicitly allocated to both the Composite cost pool and the Non-Slice cost pool, specifically the Tier 2 Overhead Adder, Tier 2 Risk Adder (if applicable), and Tier 2 RSS revenue. *Id.* This crediting occurs because the cost of providing these non-Tier 1 services is allocated to the Composite cost pool, and the crediting assures Tier 1 customers that they are not paying the costs of such services.

WPAG also argues that even if the Load Shaping rate is a Tier 2 rate when applied to Above-RHWM load, it would be a rate associated with a Tier 2 cost pool separate from the Load Growth customer cost pool. WPAG Br., BP-16-B-WG-01, at 37. Again, WPAG misses the issue. The Load Growth Rate Customer Charge recovers costs incurred on behalf of Load Growth customers that are undisputedly allocable to the Load Growth cost pool. There is no reason, semantic or otherwise, to create a new cost pool to recover these costs. In fact, it would needlessly complicate the issue as the new cost pool would be associated with the same customers that are responsible for the Load Growth cost pool. It is undisputed that the financial shortfall is associated with, and thus should be allocated to, the Load Growth cost pool. Staff is proposing to recover the Load Growth cost pool's shortfall through a fixed cost charge that is applicable to customers that elected service at BPA's Tier 2 Load Growth rate alternative.

WPAG claims that the TRM constrains the Administrator's ratemaking authority to recover Tier 2-related costs only through actual purchases of power at a Tier 2 rate. This, WPAG asserts, "gets to the heart of WPAG's concerns[.]" WPAG Br., BP-16-B-WG-01, at 37. In WPAG's view, if a customer is not purchasing power from BPA at a Tier 2 rate, the TRM prohibits BPA from developing a rate mechanism to recover Tier 2 costs from that customer. *Id.*

As described above, Staff's proposal meets both the letter and the intent of the TRM and is not prohibited by its terms. Nonetheless, even if Staff's proposal were to fail WPAG's restrictive interpretation of the TRM, BPA would be well within its authority to adopt Staff's proposal. The TRM does not prohibit BPA from adopting other rate mechanisms that ensure Tier 2 costs are recovered from the customers that caused BPA to incur the cost. TRM, BP-12-A-03, at 79-80. A number of TRM provisions make this clear.

First, the TRM is clear that Tier 2 rate design issues are left to BPA's discretion and determined in a section 7(i) process. Section 6 of the TRM states: "Consistent with the provisions below, the specific rate designs for BPA's Tier 2 Rate Alternatives will be determined in 7(i) Processes." TRM, BP-12-A-03, at 79. The Tier 2 Load Growth Rate Customer Charge is a rate design component of a "Tier 2 Rate Alternative" and, consequently, the design of this rate is left to BPA's discretion. *Id.* In this case, BPA has determined that the most appropriate rate design for recovering the costs of the 5 aMW purchase from the Load Growth customer cost pool is through two rate mechanisms: (1) the Tier 2 Load Growth rate, which assesses a proportional share of the costs of the 5 aMW purchase to the single customer that is purchasing power from BPA; and (2) the Load Growth Rate Customer Charge, which assesses the remaining shortfall to the

customers that elected the Load Growth service option and have Above-RHWM load but are purchasing such power at the Load Shaping rate.

Second, the TRM expressly permits BPA to adopt a "Tier 2 Rate Alternative," which is defined as a "rate option established by BPA in a 7(i) Process for a customer with a CHWM Contract that elects to purchase power from BPA to serve its Above-RHWM Load." TRM, BP-12-A-03, at xxv. TRM section 6.1 confirms that BPA may propose new Tier 2 rate alternative constructs in a rate case: "BPA may propose in any 7(i) Process to add Tier 2 Rate Alternatives." TRM, BP-12-A-03, at 79. The Load Growth Rate Customer Charge is such an alternative. It is a rate established by BPA in a section 7(i) process for customers with a CHWM contract that elected to purchase power from BPA to serve their Above-RHWM load. Weekley *et al*., BP-16-E-BPA-35, at 15. Although this rate is not based on the full cost of the power purchased to serve Load Growth customers' Above-RHWM load, nothing in the TRM requires that Tier 2 rate alternatives be so limited. The TRM directs BPA to recover certain costs from various cost pools but leaves it to BPA to determine through the rate case process how best to structure its rates to recover these costs. In this case, the Load Growth Rate Customer Charge is acting as a reservation or availability charge, essentially recovering costs from customers that elected BPA to provide a stand-ready service. *Id*.

Establishing the Load Growth Rate Customer Charge as a Tier 2 rate alternative is also consistent with the TRM's cost recovery direction. Section 6 of the TRM requires BPA to allocate Tier 2 costs and design its Tier 2 rates such that they "to the maximum extent possible" recover the "full allocated cost of BPA service to planned Above-RHWM Load." TRM, BP-12-A-03, at 79. The Load Growth Rate Customer Charge does just this. It ensures that the cost of standing ready to provide Load Growth service is allocated to the Tier 2 cost pool of the customers that elected this service. The TRM also directs that the Tier 1 system not subsidize service for Tier 2 customers. *Id.* ("The Tier 1 System will not be used in a manner that subsidizes the allocated costs of Tier 2 Rate service, when such rates are established in the applicable 7(i) Processes.") Here again, the Load Growth Rate Customer Charge follows the TRM by ensuring the costs of the shortfall do not remain uncollected costs but are recovered from Load Growth customers that have Above-RHWM load.

Third, the Load Growth Rate Customer Charge is also consistent with the Administrator's discretion to develop risk mitigation measures for the Tier 2 Load Growth rate. The TRM provides the Administrator with broad discretion to develop tools to mitigate risk associated with providing Tier 2 service. TRM section 9.2 provides: "Risks in Tier 2 will be assessed in each 7(i) Process both for each Tier 2 Rate Alternative and collectively for all Tier 2 Rate Alternatives to determine if the terms and conditions have mitigated such risks sufficiently to meet BPA's risk standards." TRM, BP-12-A-03, § 9.2. The specific mitigation tools BPA may develop to address the risk of providing Tier 2 rate alternatives are left to the Administrator's discretion in each rate case:

> In each 7(i) Process, when there is more specificity about the resource and purchase costs allocated to the various Tier 2 Cost Pools, BPA will assess the risks of providing service at the various Tier 2 Rate Alternatives. BPA will

> propose risk mitigation tools for each Tier 2 Cost Pool (e.g., planned net revenues for risk, cost recovery adjustment clauses, true-ups to actual costs). . . .

TRM, BP-12-A-03, § 9.2. Nothing in TRM section 9.2 limits BPA to developing risk tools such that they apply only to actual purchases of power at a Tier 2 rate. Rather, the TRM is clear that these mitigation tools apply "for each Tier 2 Cost Pool," which may be mitigated by whatever means BPA determines is reasonable. The TRM does not specify, nor preclude, Staff's proposed method for recovering these costs from Load Growth customers and thus leaves it to BPA's discretion to develop methods other than a sale of power, such as with a customer charge, reservation fee, stranded-cost fee, and/or true-up charge. Weekley *et al*., BP-16-E-BPA-35, at 14.

Fourth, the TRM expressly permits BPA to recover Tier 2 costs from rates other than Tier 2 rates only "when necessary to ensure BPA's cost recovery during a Rate Period …." TRM, BP-12-A-03, at 3. In this case, Staff believes that it is necessary for BPA to use the proposed adjustment mechanism to recover the costs of the 5 aMW acquisition from the appropriate customers. Weekley *et al*., BP-16-E-BPA-35, at 15-16. If BPA included all of the costs of the 5 aMW purchase in the Load Growth rate, the single customer purchasing at that rate would be unfairly burdened with the entire purchase, which would not be equitable. *Id.* at 16. But, if BPA does nothing at this time, it would not be taking steps to ensure BPA's cost recovery during the rate period. *Id.* Staff's proposal strikes the proper balance between these two extremes: it ensures BPA timely recovers its costs, but it does so in a way that does not inequitably burden one customer when the cost was incurred to protect all Load Growth customers from market volatility. *Id.* 14, 16.

Fifth, WPAG's interpretation would also hinder BPA's ability to mitigate market risk and take reasonable actions to provide power service to its customers. This is particularly true for the Load Growth rate option because it is a rate for service where customers elected for BPA to manage the cost of power to the collective power need of all Load Growth customers. Weekley *et al*., BP-16-E-BPA-35, at 13; Regional Dialogue Guidebook,[2] at 33 ("BPA manages resource acquisitions to meet the Above-RHWM loads of customers in this cost pool and melds the costs of these resource acquisitions into the cost pool over time."). There are several ways to balance purchase price risk and manage an unknown portfolio power need, such as through different power purchase strategies (long-term versus short-term purchases) as well as through financial options (such as the right to buy power at a set price). Weekley *et al*., BP-16-E-BPA-35, at 14. While BPA decided to buy a certain amount of power to reduce the Load Growth rate pool's exposure to market volatility, nothing precluded BPA from purchasing an option to reduce exposure to market volatility. *Id.* Had BPA used an option instead of the long-term purchase, a cost would have been incurred to protect Load Growth customers but no physical power purchase would have been made. *Id.* In that case, cost recovery responsibility would clearly belong to the Load Growth customer cost pool and would require that BPA adopt a rate mechanism other than the per-unit Load Growth rate to collect these costs, similar to, or exactly

[2] The Regional Dialogue Guidebook, *Background on Products, Rates, and Resource Support Services Available to BPA's Public Utilities*, updated June 4, 2010, *available at* http://www.bpa.gov/power/pl/regionaldialogue/implementation/documents/docs/2010-06-04_RDproductsratesguidebook_Revised.pdf.

the same as, the Load Growth Rate Customer Charge. *Id.* No language in the TRM prohibits BPA from recovering the costs of these market mitigation strategies from the Load Growth customers; nor is there any indication that these costs are uncollectable under the TRM from Tier 2 customers simply because the option would not result in the sale of power to these customers at a Tier 2 rate.

For these reasons, Staff's proposal is consistent with the terms of the TRM and within the discretion afforded to BPA under the TRM.

WPAG claims, however, that it has a better solution to the shortfall; one that, it claims, is "more consistent" with the TRM. WPAG Br., BP-16-B-WG-01, at 38. To be clear, WPAG does not recommend that BPA apply the default method for recovering these costs from the Load Growth customer cost pool. *Id*. Instead, WPAG proposes to defer the recovery of these costs until the end of FY 2024, when WPAG believes there will be more customers purchasing power at the Tier 2 Load Growth rate. *Id*. To ensure that no customers are financially harmed by such deferral, WPAG suggests that interest be applied to the outstanding balance. Saleba *et al*., BP-16-E-WG-01, at 22. WPAG claims this proposal is "more consistent with the language of the TRM, and does not attempt to collect these costs from customers who are not purchasing power during the rate period under the Load Growth Rate." WPAG Br., BP-16-B-WG-01, at 38.

WPAG's claim that Staff's proposal is inconsistent with the TRM is wrong for the reasons described above. But more importantly, BPA need not determine which proposal is "more consistent" with the default method for recovering Tier 2 costs (a method neither Staff nor WPAG supports applying in this case) to decide this issue; rather, the question is whether either alternative is permissible under the TRM, and if they both are, which BPA should adopt.

WPAG claims its proposal is superior because it follows more closely the letter of the TRM, but on this front WPAG is incorrect. WPAG readily acknowledges that its proposal does not ensure recovery of the costs of the shortfall and argues that in the unlikely event that future load growth does not materialize "BPA should reallocate these costs to the Composite Cost Pool pursuant to the terms of the TRM." WPAG Br., BP-16-B-WG-01, at 38. The TRM, however, does not support a "wait and see" approach to recovering Tier 2 costs. Instead, the TRM places on BPA an affirmative obligation to take reasonable actions to avoid a reallocation of costs from the Tier 2 cost pool to the Tier 1 rates. For instance, the TRM provides:

> This TRM specifies how PF rates will be developed by BPA to ensure, *to the maximum extent possible*, that Tier 1 Rates do not include costs of serving Publics' Above-RHWM Load.
>
> * * * *
>
> The allocation of Tier 2 Costs and the design of Tier 2 Rates will ensure *to the maximum extent possible that the Tier 2 Rates will recover the full allocated cost of BPA service to planned Above-RHWM Load.* The Tier 1 System will not be used in a manner that subsidizes the allocated costs of Tier 2 Rate service, when such rates are established in the applicable 7(i) Processes.

TRM, BP-12-A-03, at 1, 79 (emphasis added).

In addition, section 2.6 of the TRM provides that before BPA reallocates costs from the Tier 2 cost pool to any Tier 1 cost pool BPA must, among other actions,

> make reasonable efforts to recover the costs from the party(s) that would otherwise be responsible for such costs. Such efforts may include making demand on any available credit support and pursuing legal action when BPA determines it is appropriate.

Id. at 10.

Taken together, these provisions make clear that BPA must "to the maximum extent possible" set its rates to recover costs allocated to the Tier 2 cost pool from customers with Above-RWHM load, and such recovery may be assigned to "the party(s) that would otherwise be responsible for such costs." Weekley *et al*., BP-16-E-BPA-35, at 18. Deferring these costs to future rate periods in the hope that a future generation of Load Growth customers might pay these costs through the explicit Tier 2 rate, as WPAG suggests, is not consistent with the affirmative steps BPA is expected to take to ensure these costs are recovered from Tier 2 ratepayers. *Id*.

WPAG responds that these provisions "do not eliminate the TRM requirement that the applicable Tier 2 Rate(s) can only be applied to those customers actually purchasing power from the applicable Tier 2 Cost Pool." WPAG Br., BP-16-B-WG-01, at 39. WPAG concurs that BPA must take reasonable steps to recover Tier 2 costs, but WPAG asserts these steps are limited to selling power at Tier 2 rates. *Id.*

WPAG's reading of the TRM, however, is inconsistent with its language and would nullify BPA's ability to properly protect Tier 1 customers from Tier 2 costs. TRM section 2.6 is clear that BPA must make "reasonable efforts" to recover costs from the parties responsible for those costs. Nowhere in the TRM is this general obligation limited only to selling power at a Tier 2 rate. Indeed, if that were BPA's only means of recovering Tier 2 costs, then this section would have no meaning—the only "reasonable effort" BPA could take to recover these costs would be to sell more power at Tier 2 rates.

WPAG's restrictive reading of the TRM would also lead to an unreasonable limitation on BPA's ability to recover its costs from appropriate cost pools. In effect, WPAG contends that if BPA did not have a single customer purchasing power at the Tier 2 Load Growth rate, BPA would have no means of recovering these costs from the Load Growth customers. The shortfall would then have to be allocated to the Composite cost pool and be borne by *all* of BPA's power customers, even though it is undisputed that these costs were incurred for the benefit of the Load Growth customers alone. This outcome is contrary to the TRM's main principles that costs are allocated to the customers that benefit from the costs and that Tier 1 rates be protected from subsidizing Tier 2 cost pools:

> This TRM specifies how PF rates will be developed by BPA to ensure, to the maximum extent possible, that Tier 1 Rates do not include costs of serving Publics' Above-RHWM Load.

TRM, BP-12-A-03, at 1. The TRM also states:

> Costs not otherwise expressly allocated in the TRM will be allocated to Cost Pools based on the principles of cost causation, meaning the costs will be allocated to the Cost Pool(s) that benefits from such costs.
>
> Tier 1 Costs will be kept separate and distinct from Tier 2 Costs. Tier 1 Costs will be recovered through the Tier 1 Rates. Tier 2 Costs will be recovered through Tier 2 Rates, except when necessary to ensure BPA's cost recovery during a Rate Period.
>
> BPA will seek to recover all costs of the applicable Tier 2 Cost Pool from customers purchasing power from that Tier 2 Cost Pool before proposing any reallocation of costs to the Composite Cost Pool.

Id. at 3. The TRM notes:

> [C]osts and benefits of the sale of or inability to sell excess electric power allocated under section 7(g) of the Northwest Power Act will be allocated to the Cost Pools to which the costs of the resources that generate such excess electric power are allocated.

Id. at 4. The TRM requires that:

> The Tier 1 System will not be used in a manner that subsidizes the allocated costs of Tier 2 Rate service, when such rates are established in the applicable 7(i) Processes.

Id. at 79.

Staff's proposal avoids this unreasonable outcome because it recognizes that BPA has the authority to design its rates to ensure that costs are properly assigned to the cost pools that caused BPA to incur the costs (the Load Growth customer cost pool) and protects the Tier 1 cost pool from subsidizing other cost pools. This is a clear application of basic cost causation principles.

WPAG's proposal also contravenes basic ratemaking principles. In effect, WPAG's proposal would have BPA burden future ratepayers with acquisition decisions made in 2011 (FY 2012), with the resulting costs incurred in FY 2016-2017, even though by the time these costs are ultimately included in rates (FY 2024) the underlying 5 aMW acquisition will have long expired. Weekley *et al*., BP-16-E-BPA-36, at 17. Future ratepayers would then not only have to pay for the acquisitions used to serve their own loads under the Tier 2 Load Growth rate but would also have to pay the costs (as well as any interest) of the acquisitions that were delivered more than five years earlier. *See id*. While deferring costs between rate periods may be prudent in some

circumstances, BPA can find no reason to ignore basic cost causation and general ratemaking principles to intentionally shift a cost to future ratepayers if there is a viable means available to recover such costs from the customers that caused BPA to incur the costs. This is especially true given the speculative amount of Tier 2 Load Growth sales that will be present in FY 2024; there is no guarantee that incorporating the costs of this purchase with the cost of purchases to serve such loads in FY 2024 will result in a rate that those customers will be able to shoulder.

Furthermore, WPAG's proposal to shift the costs to the Composite cost pool if there is insufficient Load Growth rate pool load in FY 2024 does not work. Shifting costs from a Tier 2 cost pool to the Composite cost pool is an option only when all other options are exhausted. In the event there is insufficient load purchasing power under the Tier 2 Load Growth rate at that time, there still remains the option to use this same adjustment mechanism. Tier 1 customers would rightfully object to using the Composite cost pool as the fallback source of revenues when a viable alternative such as Staff's proposed adjustment is available.

Finally, WPAG's proposal violates BPA's accounting policies. BPA's Accounting for Regulatory Assets and Liabilities Policy (Accounting Policy), which is based on Financial Accounting Standards Board, Accounting Standards Codification 980, Regulated Operations, requires that costs incurred must be recoverable through rates for the regulated services or products. Weekley *et al*., BP-16-E-BPA-35, at 18. Deferring the costs in the manner proposed by WPAG is inconsistent with this policy. *Id.* While the Accounting Policy allows for certain costs to be deferred, such deferrals would be done on a case-by-case basis and are reserved for large (generally greater than $5 million), unexpected, one-time expenditures. *Id.*

The stranded costs associated with the Load Growth rate do not fit these requirements. *Id.* The costs at issue are relatively small ($800,000) when compared to costs typically eligible for deferral. The costs are not unexpected because they are known now, have occurred previously, and can be calculated with relative precision as part of the normal rate case process. Finally, the costs are not "one-time" expenditures. These costs have already shown up in two rate cases, and it is entirely possible that they may occur in the next rate case if Load Growth customers' loads do not grow and market prices remain at their current levels.

WPAG contends that, even if its proposal violates BPA's Accounting Policy, BPA should adopt it because its proposal is consistent with the TRM, while Staff's proposal is not. WPAG Br., BP-16-B-WG-01, at 39. WPAG asserts that if WPAG's proposal violates BPA's Accounting Policy, then the TRM provides that the ratemaking allocations determined in accordance with the TRM are to govern BPA's ratemaking. *Id*. Accordingly, WPAG claims, if there is a conflict between its proposal and BPA's Accounting Policy, WPAG's proposal should control. *Id*. at 40.

WPAG's reasoning is faulty. BPA's Accounting Policy is subservient to the terms of the TRM only in circumstances where the TRM's treatment of any cost or revenue is in conflict with BPA's Accounting Policy. TRM, BP-12-A-03, at 3. Here, however, WPAG has failed to establish that its proposal to defer costs is founded on the express terms of the TRM. Much like Staff's proposal, WPAG's proposal is an alternative means of recovering the shortfall from the Load Growth customer cost pool. Because the TRM does not directly speak to WPAG's

proposal, BPA's Accounting Policy remains relevant in determining whether the treatment proposed by WPAG is reasonable. As described above, that treatment is not.

The better option in this case is Staff's proposal, which is consistent with the TRM *and* BPA's Accounting Policy. Weekley *et al*., BP-16-E-BPA-35, at 20. The Load Growth Rate Customer Charge is a Tier 2 rate, whether viewed as a component of the charge assessed for customers purchasing power at Load Shaping rates for their Above-RHWM load or as a Tier 2 Alternative reservation charge for Tier 2 Load Growth service. In addition, Staff's proposal follows the TRM's directive that BPA take actions to recover Tier 2 cost pool costs from the customers that caused BPA to incur the costs. Finally, Staff's proposal does not require BPA to change or otherwise violate BPA's Accounting Policy, recovers these costs from current ratepayers, and ensures the recovery of these costs, which is consistent with the TRM and general ratemaking principles.

Draft Decision

BPA will adopt the Load Growth Rate Customer Charge to recover the financial shortfall from customers that elected the Tier 2 Load Growth service and have Above-RHWM load but are not currently purchasing power at the Tier 2 Load Growth rate.

2.5.4 Transmission Scheduling Service (TSS) Cap

Issue 2.5.4.1

Whether BPA should remove the monthly TSS price cap for unspecified resource amounts.

Parties' Positions

JP02 argues that BPA should not completely remove the monthly TSS price cap for unspecified resource amounts. JP02 Br., BP-16-B-JP02-01, at 5; *see also* Stratman *et al.*, BP-16-E-JP02-02, at 13. JP02 recommends that instead BPA should apply a modified monthly cap to TSS for unspecified resource amounts based on an assumption of three scheduling transactions per day. JP02 Br., BP-16-B-JP02-01, at 5, 9.

BPA Staff's Position

In the Initial Proposal, Staff proposed to continue to apply the TSS price cap to customers with specified resources but to remove the price cap entirely for customers with unspecified resource amounts. Stiffler *et al.*, BP-16-E-BPA-17, at 9. In rebuttal testimony, Staff identifies an alternative, which would set the TSS price cap for unspecified resource amounts based on an assumption of three schedules per day. Weekley *et al.*, BP-16-E-BPA-35, at 31.

Evaluation of Positions

TSS is a service provided by BPA's Power Services to undertake certain scheduling operations on behalf of the customer. Stiffler *et al.*, BP-16-E-BPA-17, at 9. The current BP-14 TSS charge

is subject to a cap such that if the annual cost to the customer using the TSS rate exceeds $990/month, then the monthly charge is capped at $990/month. *Id.;* BP-14 Power Rate Schedules, GRSP II.U.4. The current price cap applies to specified resources and unspecified resource amounts. A "specified resource" as defined in the CHWM contract refers to a generating resource or contract resource the customer must use to serve its Total Retail Load. An "unspecified resource amount," also as defined in the CHWM contract, is an amount of energy the customer must use to serve its Total Retail Load and is not attributed to a specified resource.

In the Initial Proposal, Staff proposed to limit application of the TSS price cap to customers with specified resources. *Id.* The current price cap was calculated based on a cost to BPA per transaction. *Id.* However, customers with unspecified resource amounts can use, and are using, multiple scheduling transactions to meet the single unspecified resource contractual obligation. *Id.* When Staff originally designed the TSS rate, it assumed that a single contractual obligation was equal to a single transaction. *Id.* at 10. This assumption is true for specified resources but is not necessarily true for unspecified resource amounts. *Id.* The intent of the cost cap is to reflect the assumption that BPA's costs do not increase with the size of a transaction. *Id.*

JP02 disagrees with entirely uncapping monthly TSS charges for unspecified resource amounts for two reasons. JP02 Br., BP-16-B-JP02-01, at 7. First, JP02 argues that BPA has not clearly demonstrated the extent of the additional burden that additional scheduling transactions are placing on Staff. *Id*. Second, JP02 asserts that by attempting to address a cost shift that might be borne by specified resources, BPA's proposal to entirely uncap TSS charges for unspecified resource amounts would in turn create an unfair cost shift to those unspecified resource amounts. *Id*. In rebuttal testimony, Staff notes that there is some merit to JP02's proposal that unspecified resource amounts should be subject to a higher TSS price cap rather than the price cap being removed entirely. Weekley *et al.*, BP-16-E-BPA-35, at 30. This is true particularly if customers with unspecified resource amounts are willing to limit their daily scheduling transactions to a specific number instead of being completely unbound, as they are currently. *Id.* However, Staff believes it appropriate to wait until the BP-18 rate case to explore whether customers are willing to place a cap on daily scheduling transactions. *Id.* In the meantime, for BP-16, Staff states that it would support either of the two alternatives. *Id.* at 31. Staff also suggests that both alternatives should be reevaluated if customers are willing to commit in the next rate case (BP-18) to schedule no more than a pre-established number of daily transactions. *Id*.

JP02 urges the Administrator to adopt the second of the two alternatives proposed by Staff for BP-16, whereby an assumption of three schedules per day would be used to set the TSS price cap for unspecified resource amounts. JP02 Br., BP-16-B-JP02-01, at 9. JP02 states that BPA has not offered evidence that any unspecified resource amount has used more than three scheduling transactions per day to date, yet many have used fewer than three transactions per day. JP02 Br., BP-16-B-JP02-01, at 9. JP02 argues that, given that information, this is a conservative cap and one that will still result in some unspecified resource amounts paying a significantly higher charge for TSS than an equivalently sized specified resource would, even when they both use only one scheduling transaction. *Id*.

Draft Decision

BPA will not remove the TSS cost cap for unspecified resource amounts but will change the existing cap to be based on an assumption of three scheduling transactions per day.

3.0 GENERATION INPUTS AND THE ANCILLARY AND CONTROL AREA SERVICES RATE SCHEDULE

The purpose of the generation inputs portion of the rate proceeding is to assign certain power costs from Power Services to Transmission Services. Many products and services that Transmission Services provides to its customers require generation to supply capacity or energy. 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.

BPA Staff proposes FY 2016–2017 rates for the ancillary and control area services of the BP-16 rate case that reflect the terms of the Partial Settlement Agreement between BPA and the rate case parties. Fisher and Fredrickson, BP-16-E-BPA-12. As noted in Draft ROD section 1.1.1.3, no rate case party objected to the Partial Settlement Agreement. The ACS-16 rates for Regulation and Frequency Response, Variable Energy Resource Balancing Service, Dispatchable Energy Resource Balancing Service, Operating Reserve – Spinning, Operating Reserve – Supplemental, Energy Imbalance, and Generation Imbalance are specified in Attachment 2 to the Partial Settlement Agreement. Fisher and Fredrickson, BP-16-E-BPA-12, Appendix A, at 16-45.

Attachment 3 to the Partial Settlement Agreement, Inter-Business Line Allocations, includes the cost allocation for generation inputs for other products and for inter-business line costs. *Id.* at 57. In addition to the generation inputs needed to provide ancillary and control area services described above, generation inputs also refers to certain cost assignments for specific services that Transmission Services either requires to maintain system reliability or offers to its customers. These generation inputs include Synchronous Condensing, Generation Dropping, Redispatch, and Station Service. *Id.* The inter-business line assignment of costs also includes the segmentation of U.S. Army Corps of Engineers and U.S. Bureau of Reclamation transmission facilities. *Id.* These segmented costs are not generation inputs but instead are costs in the Power Services' revenue requirement that are assigned to Transmission Services to be recovered through transmission rates.

The Partial Settlement Agreement is the product of a regional consensus, and the rates established in the Partial Settlement Agreement meet BPA's statutory ratemaking standards discussed in Draft ROD sections 1.1.2.1 and 1.1.2.2. The rates and cost allocations proposed in the Partial Settlement Agreement will be adopted.

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4.0 TRANSMISSION TOPICS

4.1 Segmentation

Segmentation is the process under which BPA assigns its transmission facilities to "segments" based on the types of services those facilities provide and then assigns to each segment the investment and historical operations and maintenance (O&M) expenses associated with the facilities in that segment. Tenney *et al*., BP-16-E-BPA-16, at 2. The aggregate investment and historical O&M assigned to each segment are used in the Revenue Requirement Study to develop each segment's revenue requirement, which is then used in the Transmission Rates Study to calculate rates. *Id.*

BPA Staff proposes to maintain the same seven segments as in BP-14: Generation Integration, Network, Southern Intertie, Eastern Intertie, Utility Delivery, Direct Service Industry (DSI) Delivery, and Ancillary Services. *Id*. at 25. In its Initial Proposal, Staff proposed three changes to the segment definitions:

(1) Revising the definitions of the Network and Utility Delivery segments to distinguish facilities by function instead of by a 34.5-kV voltage threshold

(2) Removing the term "integration" from the definition of the Network segment

(3) Revising the definition of the Generation Integration segment to restore comparable treatment of equipment interconnecting Federal and non-Federal generators

Id. As discussed further below, in rebuttal testimony Staff maintained the new segment definitions but applied a functional test for distinguishing between Network and Utility Delivery to specific equipment within substations providing delivery service. Fredrickson *et al*., BP-16-E-BPA-27, at 2-9, 13.

Staff also proposed three changes to the segmentation analysis to better align investment and historical O&M with the different segments:

(1) Basing annual O&M expenses on the average expenses of the last seven years instead of three

(2) Allocating historical vegetation management and right-of-way O&M expenses to the segments based on the percentage of transmission line O&M assigned to those segments, instead of the percentage of O&M related to lines, stations, and meters

(3) Allocating station investment in facilities used for delivering Grand Coulee reserved power to all segments based on the share of direct station investment in each segment, instead of allocating this investment solely to the Utility Delivery segment

Tenney *et al.*, BP 16-E-BPA-16, at 25. Except for Staff's revised application of the functional test, no party challenged or raised an issue regarding the changes. Therefore, the new definitions and the changes to the segmentation analysis are adopted.

Assignment of Facilities to the Network and Delivery Segments

The segmentation of facilities between the Network and Utility Delivery segments has been a controversial issue ever since BPA unbundled its power and transmission rates in 1996. *See* 1996 Wholesale Power and Transmission Rate Proposal, Administrator's Final Record of Decision, WP-96-A-02, at 413-15 (July 1996). The controversy was abated though not fully resolved by settlements in 1996 and subsequent rate cases (until the BP-14 rate case, which was BPA's first fully litigated transmission case in over two decades). In the 1996 settlement, most parties accepted, and the Administrator adopted, a 34.5 kV voltage threshold to distinguish between the Network segment and the DSI and Utility Delivery segments. Based on that threshold, facilities at 34.5 kV and above were assigned to the Network, and facilities below 34.5 kV were assigned to the appropriate delivery segment.

In the BP-14 rate case, the Administrator adopted Staff's proposal to maintain the 34.5 kV voltage threshold. However, the Administrator took notice of the issues raised by a number of parties and committed Staff to engage with the region after the rate case to review BPA's segmentation methodology. *See* BP-14 Power and Transmission Rate Proceeding, Administrator's Final Record of Decision, BP-14-A-03, at 81-85 (July 2013) (BP-14 ROD).

The resulting regional review focused primarily on the assignment of facilities to the Network and Utility Delivery segments. Tenney *et al*., BP-16-E-BPA-16, at 10-16. Participants proposed a wide range of alternatives, including the status quo. At the conclusion of the review, Staff prepared a white paper describing the alternatives and impacts of each alternative on BPA's rates and customers. *See id*. at Attachment 2. BPA Staff used the review to develop its BP-16 Initial Proposal. *Id.* at Attachment 2, at A2-4.

In the Initial Proposal, Staff proposed to replace the 34.5 kV voltage threshold with a functional test under which facilities are assigned to the appropriate delivery segment if delivery of power is made at the customer's prevailing distribution voltage and to the Network segment if delivery is made above the customer's prevailing distribution voltage. Tenney *et al*., BP-16-E-BPA-16, at 26-30. Recognizing the longstanding agreements and understandings between BPA and its customers regarding the construction of existing utility delivery facilities, Staff also proposed to grandfather into the Network and Utility Delivery segments all existing facilities in those segments. *Id*. at 31.

BPA's small public customers strongly opposed Staff's Initial Proposal, claiming that it left the Utility Delivery rate at an unsustainable level. Saven *et al.*, BP-16-E-NR-01, at 3-4; Scott, BP-16-E-PN-01, at 1; Saleba *et al.*, BP-16-E-WG-01, at 39-40. Over the past 20 years, BPA has sold many of its low-voltage delivery substations to its customers. Because of these sales, "the Utility Delivery segment is a shadow of its former self." Saven *et al.*, BP-16-E-NR-01, at 9. Many remaining substations pose financial or operational issues that impede utilities from acquiring them. *Id.* at 9-10. They are often the more expensive substations on a per-megawatt

basis. Fredrickson *et al*., BP-16-E-BPA-27, at 7. This not only makes them more difficult to sell but, as the less-expensive substations have been sold, increases the average cost of the remaining substations and thus the Utility Delivery rate. *Id*. Therefore, as the number of delivery facilities has declined, the pressure on the Utility Delivery rate has grown; under Staff's Initial Proposal, BPA would have to increase the rate by 147 percent to achieve full cost recovery. Frederickson *et al.*, BP-16-E-BPA-14, at 13, Fredrickson *et al*.; BP-16-E-BPA-14-E01, at 1; *see also* Saven *et al.*, BP-16-E-NR-01, at 10.

Only 33 utilities still take Utility Delivery service, and they are among BPA's smallest and most rural customers. Saleba *et al*., BP-16-E-WG-01, at 38. Fifty-two percent of these utilities have an annual load of less than 10 aMW, and 64 percent have fewer than 5,000 retail customers. *Id.* These utilities are the least able to bear significant rate increases. Furthermore, for 12 of these customers, the only point of delivery on BPA's transmission system is a Utility Delivery facility. *Id.* Those utilities pay both the Utility Delivery charge and a Network transmission rate for all of their power deliveries on BPA's transmission system. *Id.*

In its rebuttal testimony, Staff refined its functional test by applying it to the equipment within a substation rather than to the substation as a whole. Staff had determined that the equipment on the high side of the transformers (such as switches and circuit breakers installed to isolate the delivery equipment from the network) and all station general (station general includes roads, fences, buildings, and other basic infrastructure) serve a Network function. Therefore, Staff assigned this equipment to the Network. Staff assigned the delivery transformer and low-side equipment to the delivery segments. Fredrickson *et al*., BP-16-E-BPA-27, at 2-9.

No parties oppose the new segment definitions or Staff's proposal to apply a functional test to new facilities and to grandfather existing Network facilities. However, Staff's proposal to assign the high-side equipment and all station general in facilities that provide delivery service to the Network segment received both support and opposition.

Issue 4.1.1

Whether equipment on the high side of delivery transformers and station general in facilities that provide delivery service should be assigned to the Network segment.

Parties' Positions

Iberdrola, JP12, JP14, and Powerex oppose Staff's revised proposal. Iberdrola argues that Staff's revised proposal to assign the high-side equipment and station general to the Network segment is a reversal of BPA's prior positions and contrary to BPA's own segmentation studies. Iberdrola Br., BP-16-B-IR-01, at 17. Iberdrola asserts that Staff has not provided adequate reasoning to depart from the functional test proposed in the Initial Proposal. *Id*. at 18. Iberdrola urges the Administrator to reject Staff's revised proposal and end the "improper subsidization" of the Utility Delivery segment by Network customers. *Id*. at 15, 19.

JP12 argues that Staff's revised proposal violates cost-causation principles because delivery substations were built to provide delivery service. JP12 Br., BP-16-B-JP12-02, at 3. JP12 argues that Network customers should not be assigned the costs of facilities that provide "low-voltage deliveries" since they were built for some customers and not others. *Id*. at 4. JP12 concludes that Staff's revised proposal violates section 7(a)(2)(C) of the Northwest Power Act, which requires BPA to equitably allocate transmission costs between Federal and non-Federal power using the transmission system. *Id*. at 5.

JP14 argues that Staff's revised proposal is inconsistent with the Administrator's decision in the BP-14 rate case to gradually increase the Utility Delivery rate to full cost recovery. JP14 Br., BP-16-B-JP14-01, at 2-3. JP14 contends that there have been no changes since BP-14 to justify a change to the existing Utility Delivery segment. *Id*. at 4-5. JP14 also asserts that Staff's revised proposal inappropriately bases segmentation on rate design rather than technical criteria and that it violates general cost-causation principles because it assigns facilities to the Network segment that were built to support the delivery of power to particular customers. *Id*. at 5-8. Finally, JP14 argues that grandfathering existing facilities into the Network segment while reassigning certain delivery facilities to the Network segment based on function is arbitrary and contrary to sound business principles. *Id*. at 8-9.

Powerex argues that Staff's revised proposal is an "outcome-determinative, rate-driven exercise" intended to ameliorate a substantial rate increase to Utility Delivery customers. Powerex Br., BP-16-B-PX-01, at 28. Powerex contends that Staff's revised proposal undermines the regional review process held prior to the BP-16 rate case. *Id*. at 26-27.

NRU, PNGC, and WPAG support Staff's revised proposal. NRU and PNGC argue that the revised proposal comports more closely with cost causation because it creates a more refined demarcation between the Network and delivery segments. NRU Br., BP-16-B-NR-01, at 3-4; PNGC Br., BP-16-B-PN-01, at 2-5. NRU and PNGC also argue that Staff's revised proposal provides a sustainable solution to a longstanding, contentious issue. NRU Br., BP-16-B-NR-01, at 8; PNGC Br., BP-16-B-PN-01, at 5.

PNGC and WPAG argue that Staff's revised proposal encourages the widest possible diversified use of electric energy. PNGC Br., BP-16-B-PN-01, at 5; WPAG Br., BP-16-B-WG-01, at 7-8. WPAG further argues that the revised proposal creates a better balance between encouraging the widest possible diversified use and cost-causation because it balances the economic impact to BPA's smallest customers—those that pay the Utility Delivery charge—and the costs of the equipment necessary to provide delivery service. *Id*. at 11-12.

BPA Staff's Position

BPA Staff states that its revised proposal creates a long-term, sustainable solution to the Utility Delivery rate. Fredrickson *et al.*, BP-16-E-BPA-27, at 12. Under Staff's revised proposal, the rate fully recovers the costs of the Utility Delivery segment. *Id*. at 19. Moreover, this proposal balances cost causation with BPA's statutory directive to encourage the widest possible diversified use at the lowest possible rates consistent with sound business principles while not imposing an undue economic burden on Utility Delivery customers. *Id*. at 12.

Staff states that the assignment of high-side equipment to the Network is appropriate because these facilities perform a Network function. *Id*. at 8. In addition, Staff's Initial Proposal assigned high-side equipment to the Utility Delivery segment if it was located in a facility segmented entirely to Utility Delivery and to the Network if it was located in either a multi-segmented facility or a Network-only facility, even if the equipment performed the same function. *Id.* at 10-12. Staff's revised proposal segments the high-side equipment the same way regardless of the location of the equipment. *Id*.

Staff states that station general should be included in the Network segment because the substation exists to deliver power to customers over BPA's Network, whether the substation includes transformation to delivery voltage or not. *Id*. at 8-9. BPA would have built the substation and incurred station general costs regardless of the voltage at which BPA delivers the power. *See id*.

Evaluation of Positions

In the Initial Proposal, BPA Staff proposed a segmentation methodology that would have resulted in a 25 percent increase to the Utility Delivery rate. Fredrickson *et al*., BP-16-E-BPA-27, at 6. That increase would have followed a 25 percent rate increase in the BP-14 rate case. WPAG Br., BP-16-B-WG-01, at 10. Under the Initial Proposal, the BP-16 rate would have been $1.749/kW/mo., which is almost the same as the NT rate for Network service ($1.753/kW/mo.). Scott, BP-16-E-PN-01, at 3. This result seemed unreasonable because delivery service is the final and shortest portion of the customer's total transmission path, usually only a few feet, and is the last in a series of transformations. Fredrickson *et al*., BP-16-E-BPA-27, at 6. A customer taking Utility Delivery service in addition to Network service would have paid $3.502/kW/mo. ($1.749 + $1.753) under the Initial Proposal, while a customer taking only Network service would pay $1.753/kW/mo. Staff expected the Utility Delivery rate to exceed the NT rate after the next rate case. *Id*.

Staff's Initial Proposal would likely cause Utility Delivery customers significant economic harm. Scott, BP-16-E-PN-01, at 1, 4-5; Saleba *et al*., BP-16-E-WG-01, at 39-40. For example, the Town of Steilacoom is one of BPA's smallest customers, with an annual load of 4.9 aMW. Saleba *et al*., BP-16-E-WG-01, at 39-40. Steilacoom has a single point of delivery on BPA's transmission system, the Steilacoom substation, a 12.5 kV Utility Delivery facility. *Id.* Under the Initial Proposal, the Utility Delivery charge would have been 40 percent of Steilacoom's total transmission bill. *Id.* Under the Initial Proposal segmentation, a Utility Delivery rate that fully recovered costs would increase the Utility Delivery charge for Steilacoom to 56 percent of its total transmission bill. *Id.* at 40. The cost of Utility Delivery service would represent almost eight percent of Steilacoom's total annual utility budget ($269,336 ÷ $3,402,884 = 0.079). *Id.* at 41. Steilacoom is not unique. As noted above, the customers that remain subject to the Utility Delivery charge lack the size and diversity of larger utilities and therefore are generally least able to absorb the impact of continued rate increases. *Id.* at 42.

Upon re-evaluation, Staff agreed that its Initial Proposal would have placed too great a financial burden on Utility Delivery customers. Fredrickson *et al*., BP-16-E-BPA-27, at 6-7. Increasing the rate by 25 percent per rate period over successive rate periods would have caused significant

rate shock, especially because until 1996 BPA recovered the costs of the delivery facilities in rates for the sale of delivered power. Before 1996 BPA had no separate utility delivery rate, and between 1996 and 2014 a series of transmission rate settlements established a Utility Delivery rate that did not fully recover costs. Fredrickson *et al.*, BP-16-E-BPA-27, at 4; *see also* Scott, BP-16-E-PN-01, at 4. It was only in the BP-14 rate case that BPA began the transition to full cost recovery by the Utility Delivery rate, leading to the prospect of large rate increases over successive rate periods. Fredrickson *et al.*, BP-16-E-BPA-27, at 4.

Thus, considering the economic impact of the rate on customers is consistent with BPA's historical treatment of Utility Delivery facilities. Moreover, BPA is statutorily required to set rates that encourage the widest possible diversified use of electric power in the Pacific Northwest at the lowest possible rates consistent with sound business principles. *See, e.g.*, 16 U.S.C. §§ 832a(b), 832e, 825s, 838g. By making delivery service costs unduly burdensome, these significant rate increases would run counter to this directive. Fredrickson *et al*., BP-16-E-BPA-27, at 6-7; Scott, BP-16-E-PN-01, at 5; Saleba *et al*., BP-16-E-WG-01, at 42-43. As Senator McNary stated regarding the inclusion of the directive in the Bonneville Project Act:

> That is not in the Boulder Canyon Act, it is not in the Muscle Shoals Act. It is sought by their provision to make certain that any benefits which may accrue shall not be provincial in their application but shall be distributed as far as is practicable, a matter which can only be worked out through experience and study. But we have placed no limitations on the area of distribution. *The language encourages a wide and equitable distribution of the benefits of the rates which may be enjoyed by the people who live in the great Northwest section of the country.*

75 Cong. Rec. S8523 (daily ed. Aug. 9, 1937) (remarks of Sen. McNary) (emphasis added).

JP14 argues, however, that Staff is attempting to resolve "a rate design issue" through segmentation, which JP14 says should be based on engineering and technical analysis. JP14 Br., BP-16-B-JP14-01, at 5-6. To the contrary: segmentation involves both rate design and engineering and technical analysis. Segmentation fundamentally concerns the allocation of costs among customers, which is part of rate design. This allocation should be based on BPA's various statutory directives and policies, and should be structured to achieve the best possible balance among them.

Iberdrola and Powerex argue that Staff's revised proposal is an outcome-determinative, rate-driven exercise intended to ameliorate a substantial rate increase to Utility Delivery customers. Iberdrola Br., BP-16-B-IR-01, at 18; Powerex Br., BP-16-B-PX-01, at 27-28. Staff acknowledges that it re-evaluated its Initial Proposal because of the issues raised by PNGC and WPAG regarding the level of the Utility Delivery charge. Fredrickson *et al.*, BP-16-E-BPA-27, at 6. Iberdrola and Powerex's mistake is in thinking that the effort to render the rate more affordable is inappropriate. To the contrary, it would be inappropriate for BPA to ignore the effect of rate increases on its customers.

Powerex contends that Staff's revised proposal undermines the regional review process held prior to the BP-16 rate case because Staff proposed a different segmentation in rebuttal testimony. Powerex Br., BP-16-B-PX-01, at 26-27. The purpose of the regional review process was to engage the region in a discussion regarding segmentation that would inform Staff's Initial Proposal; decisions regarding segmentation must be made in a rate case. Powerex is essentially arguing that, once Staff decided on a proposal, it should have disregarded the parties' testimony. That course would make a nullity of the rate case. Although Powerex argues that Staff "disregards customer input," *id*. at 27, the opposite is true. By responding to the parties' cases Staff showed that it values customer input highly.

The distinction between Staff's initial and revised proposals concerns the high-voltage equipment and station general at substations where BPA provides delivery transformation (transformation to distribution-level voltages). Fredrickson *et al*., BP-16-E-BPA-27, at 5, 8. Under Staff's Initial Proposal, the Utility Delivery segment included the high-voltage equipment associated with the delivery transformation and a pro rata share of station general investment, which was based on the investment in major equipment, such as transformers, circuit breakers, and disconnect switches at the substation. *Id*. at 2-3. Under Staff's revised proposal, the high-side equipment and all of station general are assigned to the Network segment, just as they are in all other substations that provide service to Network customers. *Id.* at 7-8.

JP14 asserts that Staff presented no evidence that the substations or associated equipment have changed from an engineering or technical standpoint. JP14 Br., BP-16-B-JP14-01, at 7-8. JP14 again incorrectly assumes that segmentation must be based entirely on engineering and technical criteria. *Id*. at 5-6. Moreover, Staff's revised proposal does hinge largely on technical criteria. Staff included the high-side equipment in the Network because that equipment exists to separate BPA's Network from the customer's system for operational, maintenance, and reliability purposes and as such serves a Network function. Fredrickson *et al*., BP-16-E-BPA-27, at 7-8. The high-side equipment is necessary to protect the Network from faults in the delivery transformer or low-voltage equipment. Only the delivery transformer and the low-side equipment perform a delivery function. This equipment remains assigned to the Utility Delivery segment. *Id.* at 8. NRU, PNGC, and WPAG agree with Staff's analysis. NRU Br., BP-16-B-NR-01, at 4-7; PNGC Br., BP-16-B-PN-01, at 2-4; WPAG Br., BP-16-B-WG-01, at 11-12.

The difference between Staff's Initial Proposal and its revised proposal is that Staff performed a more refined analysis of the substations. Instead of using a gross analysis that assigned an entire substation to one or the other segment, Staff analyzed the actual equipment in the substation to determine the function it performs. Fredrickson *et al.*, BP-16-E-BPA-27, at 8. As NRU, PNGC, and WPAG assert, the revised proposal adheres even more closely to cost causation principles because it provides a more granular demarcation between the Network and delivery segments. NRU Br., BP-16-B-NR-01, at 4-7; PNGC Br., BP-16-B-PN-01, at 2-4; WPAG Br., BP-16-B-WG-01, at 12-13.

Moreover, BPA's existing segmentation assigns some high-side equipment to different segments depending on whether the equipment is in a delivery substation or in a substation that also includes Network equipment. Staff's Initial Proposal continued this treatment. Fredrickson

et al., BP-16-E-BPA-27, at 10-12. Staff's revised proposal, however, consistently assigns equipment to segments based on function. For example, in its rebuttal testimony Staff compares the segmentation of equipment in the Reedsport, Gardiner, and Tahkenitch substations. *Id*. at 11-12 & Att. 2. At both the Reedsport and Gardiner substations BPA delivers power at the customer's distribution voltage. *Id*. at 11-12. The high-side equipment that isolates the delivery transformer at the Reedsport substation is in the Reedsport substation. Under the existing segmentation this equipment is assigned to the Utility Delivery segment.

The high-side equipment that isolates the delivery transformer at Gardiner is located a short distance away from Gardiner at the Tahkenitch substation. *Id*. Under the existing segmentation this equipment is assigned to the Network segment. Yet in both cases the high-side equipment performs the same function—protecting the network from faults in the delivery transformer or low-side equipment. The only difference, which is irrelevant from a technical standpoint, is the location of the equipment. Under BPA's existing segmentation the equipment is treated inconsistently because Staff viewed the substation as a whole instead of considering the function of the equipment within it. Under Staff's more refined approach, the high-side equipment at both the Reedsport and Tahkenitch substations is assigned to the Network segment.

Staff assigned all station general to the Network segment because the substation where the delivery transformation occurs is a Network facility. The Network extends to where the delivery transformation occurs; the substation is the terminus of the network line. Fredrickson *et al.*, BP-16-E-BPA-27, at 8-9. Some substations transform power down to a level—say, 69 kV—that is still a Network-level voltage. These substations are assigned entirely to the Network segment. Other substations transform power down to a distribution voltage–say, 12.5 kV. Under BPA's existing segmentation, station general in these substations is assigned in part to the Network segment and in part to the Utility Delivery segment.

Yet the two substations are identical except for the voltage on the low side of the transformer. *Id*. Both exist to deliver power over BPA's Network to the customer; the voltage on the low side of the transformer does not change the function of the remainder of the substation. *Id*. BPA would incur similar station general costs regardless, and they should not be assigned to Utility Delivery customers simply because those customers take an additional service that does not cause BPA to incur additional station general costs.

JP14 argues that Staff's revised proposal regarding high-side equipment is inconsistent with Staff's own proposed definition of the Network segment. The Network segment includes facilities that provide certain reliability and other benefits to BPA and its customers. JP14 Br., BP-16-B-JP14-01, at 6. As stated above, the high-side equipment benefits the Network segment because it allows BPA to isolate the Network from the delivery transformer and the customer's system for operational, maintenance, and reliability purposes. This equipment provides benefits to the Network just as similar equipment does in substations at which higher-voltage delivery occurs.

Iberdrola argues that the revised proposal is a reversal of BPA's prior positions and contrary to BPA's own segmentation studies. Iberdrola Br., BP-16-B-IR-01, at 17. It is true that prior

segmentation studies assigned certain high-side equipment and station general to the delivery segments. However, as explained above, that assignment was inconsistent with the segmentation of other high-side equipment and station general in the Network segment performing the identical function at other locations. Staff's revised proposal treats this equipment and station general consistently across BPA's system.

JP12 contends that it is inequitable to require network customers to pay for a portion of the cost of substations that were installed to provide lower-voltage deliveries to a subset of BPA's customers. JP12 Br., BP-16-B-JP12-02, at 4. JP12 incorrectly assumes that these substations exist only because they include a low-voltage transformer. As discussed above, if BPA had not installed a low-voltage transformer, it still would have built the substation, which would deliver power to the customer at a transmission voltage.

It is true that under BPA's former customer service policies BPA built low-voltage facilities for some customers but not for others. BP-14 ROD at 99. As discussed above, however, the high-side equipment and station general serve a Network function, and therefore it is appropriate to assign them to the Network segment.

JP12's argument highlights the fundamental flaw in the opposition to Staff's revised proposal. Under the Bonneville Project Act, the Administrator is authorized to adopt rate schedules that "provide for uniform rates or rates uniform throughout prescribed transmission areas in order to extend the benefits of an integrated transmission system and encourage the equitable distribution of the electric energy developed at the Bonneville project." 16 U.S.C. § 832e. The Transmission System Act likewise authorizes the Administrator to establish "uniform rates or rates uniform throughout prescribed transmission areas." *Id*. § 838h.

If it is permissible to roll all facilities into one segment and charge a single rate for all transmission service without regard to cost causation, surely it is permissible to establish segments based on rational criteria grounded not only in cost causation but in BPA's enabling statutes taken as a whole. That is particularly true in a case such as this, in which a segmentation policy is being adopted in part to fulfill the policy of the uniform rates statute itself.

JP12 argues, however, that Staff's revised proposal violates the equitable allocation standard, under which BPA must equitably allocate the costs of the transmission system between Federal and non-Federal power utilizing the system. JP12 Br., BP-16-B-JP12-02, at 5, *citing* 16 U.S.C. § 839e(a)(2)(C).

JP12 offers no evidence that Staff's revised proposal assigns costs differently for Federal and non-Federal uses. Under Staff's proposal, costs are not allocated separately for Federal and non-Federal uses, and all customers pay the same rate. Tenney *et al.*, BP-16-E-BPA-16, at 33-34; *see also* WPAG Br., BP-16-B-WG-01, at 6-7. Thus, the proposal does not advantage either Federal or non-Federal power. If Federal use is greater, Federal use will recover more of the costs of the transmission system; if Federal use is less, it will recover less. The same holds for non-Federal use.

JP14 argues that Staff's revised proposal is inequitable because it grandfathers existing facilities into the Network segment regardless of whether they would be considered Network facilities today, but transfers some existing facilities from the Utility Delivery segment to the Network if they are no longer considered Utility Delivery facilities. JP14 Br., BP-16-B-JP14-01, at 8-9. These two cases are fundamentally different. Unlike the Network segment, in which facilities are socialized over a broad base of customers, the Utility Delivery segment is socialized over a small subset of customers that also pay the Network rate. The effect of grandfathering the Network facilities is far less than the effect of grandfathering Utility Delivery facilities would be. Tenney *et al*., BP-16-E-BPA-16, at 32. BPA can satisfy all of its rate objectives despite the grandfathering of certain Network facilities; if BPA grandfathered Utility Delivery facilities, on the other hand, it could seriously burden its existing Utility Delivery customers.

Draft Decision

Equipment on the high side of delivery transformers and station general in facilities that provide delivery service will be assigned to the Network segment.

Issue 4.1.2

Whether operations and maintenance (O&M) costs of facilities that are transferred to the Network should be allocated to the Utility Delivery segment.

Parties' Positions

JP14 argues that Network customers should not bear the O&M costs of any existing Utility Delivery facilities the Administrator assigns to the Network segment. JP14 Br., BP-16-B-JP14-01, at 9. According to JP14, allocating O&M costs to the Utility Delivery segment would provide an incentive for Utility Delivery customers to purchase delivery facilities and to replace facilities when the facilities are no longer cost-effective. *Id*.

BPA Staff's Position

Staff did not address this issue, but both its Initial Proposal and rebuttal proposal would assign O&M to segments pro rata based on investment. Transmission Segmentation Study and Documentation, BP-16-E-BPA-06, at 16-19.

Evaluation of Positions

JP14's argument that Utility Delivery customers should continue to bear O&M costs of reassigned facilities as an incentive to purchase them contradicts one of JP14's own arguments: that O&M costs should be based solely on technical and engineering criteria. JP14 Br., BP-16-B-JP14-01, at 6. Here, JP14 argues that BPA should explicitly adopt economic criteria as a basis for segmentation. *Id.* at 4-5. In this case, however, there is no reason to do so. JP12's argument is inconsistent with one of the fundamental tenets of segmentation and rate design—that O&M follows investment. This tenet makes sense because operations and maintenance of a facility performs the same function as the facility itself. BPA has never allocated O&M to segments on a basis different from the allocation of the investment.

In addition, Staff's revised proposal is based in part on technical criteria. Fredrickson *et al*., BP-16-E-BPA-27, at 7-8. JP14 proposes an arbitrary assignment of O&M costs. The high-side equipment performs a network function and exists for the benefit of the network; the O&M for this equipment does so as well.

Draft Decision

O&M costs of facilities that are transferred to the Network segment will be allocated to the Network segment.

Issue 4.1.3

Whether the cost of replacements for Utility Delivery facilities should be assigned to Utility Delivery customers.

Parties' Positions

JP14 argues that allocating replacement costs to Utility Delivery customers would put all customers on a level playing field and transition BPA away from providing delivery service. JP14 Br., BP-16-E-JP14-01, at 9.

Conversely, WPAG argues that the Administrator should clarify that even when a grandfathered facility is replaced with a facility with greater capacity to serve load growth, the facility should remain grandfathered. WPAG Br., BP-16-B-WG-01, at 10. WPAG contends that directly assigning the costs of replacement facilities needed for load growth would contradict BPA's Open Access Transmission Tariff and BPA's statutory obligation to encourage the widest possible diversified use of energy at the lowest possible rates consistent with sound business principles. *Id*. Moreover, a policy that directly assigned the costs of replacements to delivery customers would penalize them when BPA made past decisions regarding how it would serve those customers and the customers built their infrastructure accordingly. *Id*. at 9.

BPA Staff's Position

Staff proposes that segmentation of replacement facilities be determined on a case-by-case basis. Fredrickson *et al.*, BP-16-E-BPA-27, at 19. Replacement facilities that provide equivalent capacity would most likely be segmented in the same manner as existing facilities. *Id*. at 20. However, segmentation of replacement facilities that provide greater capacity than needed to serve a customer would likely depend on whether the higher-capacity facility was constructed for BPA's or the customer's convenience. *Id*.

Evaluation of Positions

The segmentation of replacement facilities need not be decided in this rate case. Staff is correct, however, that a number of considerations may govern this choice. Fredrickson *et al*., BP-16-E-BPA-27, at 19-20. For now it suffices to say that this question will be decided on a case-by-case basis until a compelling reason is offered to establish a firm policy.

Draft Decision

Decisions regarding the segmentation of replacement facilities will be made on a case-by-case basis.

4.2 Transmission Revenue Requirement and Risk Analysis

4.2.1 Transmission Revenue Requirement

The transmission and ancillary services rates being established in this case are designed to recover BPA's costs as set forth in the transmission revenue requirement. BPA determines generation (power) and transmission revenue requirements using separate repayment studies, consistent with the Commission's 1984 order. *See U. S. 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 are being established in the power portion of the BP-16 case. The costs established in the power portion of the case also include inter-business line costs, or 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 establishes ancillary and control area services rates to recover these costs and passes the revenues on to Power Services. BPA Staff proposes rates for the ancillary and control area services for the FY 2016–2017 rate period that reflect the terms of the Partial Settlement Agreement between BPA and the rate case parties. For additional information, see Draft ROD Chapter 3, Generation Inputs and the Ancillary and Control Area Services Rate Schedule.

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 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-16-E-BPA-08, § 1.1.

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.*

As described in the study, BPA calculated its transmission revenue requirement for the FY 2016–2017 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 2016–2017).
3. Annual planned net revenues for risk, if any, are determined based on the risks identified, BPA's cost recovery goals, and risk mitigation measures.

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 would meet cost recovery requirements for the rate test period and repayment periods. If the current revenue test indicates that cost recovery and risk mitigation requirements can be met, BPA can, on that basis, choose to extend current rates. The current revenue test shows that current rates would be insufficient to demonstrate cost recovery. *Id.*

After calculating proposed rates, BPA conducts a revised revenue test to determine whether projected revenues from proposed rates will meet cost recovery requirements for the rate test and repayment periods. BPA has proposed to increase the transmission 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.*

In the Initial Proposal, as in the previous five rate cases, BPA Staff proposed to use $15 million of cash reserves attributed to Transmission Services (generally referred to below as reserves or financial reserves) in each year of the FY 2016–2017 rate period (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. Lennox *et al.*, BP-16-E-BPA-13, at 10. The use of additional financial reserves attributed to Transmission to mitigate the proposed rate increase is discussed in Issue 4.2.2.1 below.

Issue 4.2.1.1

Whether BPA's forecast of net interest expense for transmission should be reduced by $26.3 million per year to compensate for BPA's past forecasting errors.

Parties' Positions

JP07 argues that during the six-year period of 2009 to 2014, BPA over-forecast net interest expense for transmission by an average of $34.4 million per year, and never less than $28 million. JP07 Br., BP-16-B-JP07-01, at 8. JP07 states that although BPA has refined its revenue forecasting model and reduced under-forecasting of transmission revenue, the over-forecasting of interest expense has not declined. *Id.* JP08 recommends that to compensate for its persistent over-forecasting, BPA should reduce its forecast of net interest expense by 80 percent of the average error over the last six years, or $26.3 million. *Id.* at 9. JP07 claims that since this amount is less than the smallest error in any year during that time period, it is a conservative

adjustment. *Id.* JP07 claims that failure to adjust the forecast would perpetuate the errors, and sound business principles require that BPA consider past results in implementing its policies. *Id.*

BPA Staff's Position

Interest rate forecasts are based on the best available information at the time the forecasts are made, and a reduction of the forecast by $26.3 million would be arbitrary. Lennox *et al*., BP-16-E-BPA-25, at 1, 4. Differences between forecasts and actual results exist because of a number of factors. For example, refinancing of debt, which BPA cannot always predict, accounted for a significant portion of the difference in 2011 and 2014. *Id*. at 2. In addition, the low-interest-rate environment that has persisted for a number of years has made forecasting difficult, as the long-expected increase in interest rates has yet to materialize. *Id*. at 3. BPA continues to refine its forecasting methodology and should continue to base the forecast on the best information available. *Id*. at 3-4.

Evaluation of Positions

JP07 notes correctly that in recent years BPA has tended to over-forecast net interest expense for transmission. However, Staff notes correctly that JP07's proposal for more accurate forecasts is arbitrary, and there is no reason to believe it will result in a more accurate forecast in this case. *Id.* at 4-5. JP07's only basis for reducing the forecast by 80 percent of the average error over the last six years is that it is "conservative." JP07 Br., BP-16-B-JP07-01, at 9. JP07 offers no reason to believe that the forecast will be off by that amount.

As with all other forecasts, the forecast of net interest expense should be based on the best information available at the time. Instead of reducing the forecast by an arbitrary percentage of past forecasting errors, BPA Staff has worked to refine its methodology to increase accuracy. Lennox *et al.*, BP-16-E-BPA-25, at 3-4. For example, Staff has refined its methodology for projecting the amount of debt it will issue during the rate period. *Id.* Staff projects borrowings with shorter maturities and lower interest rates, which reduces net interest expense. *Id*. at 4. In addition, the repayment model has been upgraded to more precisely calculate interest expense. Lennox *et al*., BP-16-E-BPA-13, at 8.

JP07 argues that it is not businesslike to ignore the results of operations because they may be driven by individual events with unique causes. JP07 Br., BP-16-B-JP07-01, at 9. As shown above, Staff is not ignoring the results of operations. Instead, Staff continues to refine and improve its methodology and modeling tools to improve the accuracy of its forecasts. Lennox *et al.*, BP-16-E-BPA-25, at 3-4. If there is a systematic error in the forecast—and six years of data do not necessarily demonstrate as much—that is the appropriate response.

Draft Decision

The forecast of net interest expense for transmission will not be reduced by $26.3 million per year.

Issue 4.2.1.2

Whether the repayment study should be modified to eliminate critical years, change the due date of $49 million of projected debt from FY 2027 to FY 2024, and increase use of the rollover feature.

Parties' Positions

JP04 argues that BPA's repayment study should be modified to minimize or eliminate the critical year identified in FY 2027 by changing the due date of $49 million in projected debt from FY 2027 to FY 2024, which will reduce debt service included in transmission rates. JP04 Br., BP-16-B-JP04-02, at 14. JP04 also argues that the repayment study should be modified to reduce mandatory amortization in the critical year by paying some debt earlier as discretionary amortization whenever such action would reduce debt service. *Id*. In addition, JP04 argues, bond rollovers should be considered in the repayment model as a way to reduce debt service. *Id*. at 13.

BPA Staff's Position

Changing the due dates of projected investments and the associated interest rates in the repayment study, which will affect the timing of principal payments by the repayment model, is a reasonable approach to reduce debt service. Lennox *et al.*, BP-16-E-BPA-25, at 7. At JP04's request, Staff performed two studies in which the due date of the $49 million projected bond was changed, in one case to FY 2024. *Id.* at 6. In both studies debt costs were lower than in the Initial Proposal. *Id.* at 7. Staff committed to work toward reducing the repayment levels in the Final Proposal but could not commit to adopting JP04's proposal because Staff did not yet know how the model would respond to the updates Staff would make for the Final Proposal. *Id.*

Evaluation of Positions

A critical year in the repayment study is a year in which only debt that is due is paid. No discretionary amortization is paid that year. *Id.* at 6. Thus, the critical year sets the lowest possible level of debt service for the year being studied and the 35-year repayment period. *Id*.

JP04 notes correctly that 2027 is a critical year in the Initial Proposal repayment study. JP04 Br., BP-16-B-JP04-02, at 5. The two studies that Staff performed at JP04's request, Study 1 and Study 2, changed the due date and resulting interest rates for a single $49 million bond that was projected to be issued in 2016 with an 11-year term. Lennox *et al.*, BP-16-E-BPA-25, at 6. Study 1 changed the term to 8 years. *Id.* Study 2 gave the bond its maximum possible term of 35 years, making it due in 2050. *Id.* at 7. Both studies produced lower levelized debt service than the Initial Proposal repayment study. *Id*.

Staff is updating the repayment study for the Final Proposal. The updates include new Federal and non-Federal debt issuances, refinancing of debt, repayment of principal since the Initial Proposal was issued, and a new interest rate forecast. After the updates, changing the terms of the $49 million bond likely will not achieve the results obtained in the two earlier studies. Instead, Staff is applying the approach of the two studies to all of the projected investments by

revising the due dates of all debt—either lengthening or shortening the term—and the resulting interest rates. Staff is performing a number of studies and will utilize the one that results in the lowest debt service. Staff expects the revisions to allow the model to lower debt service by more than the reduction in either Study 1 or Study 2. This would be a greater reduction than would have resulted from simply changing the terms of the single $49 million bond.

As to bond rollovers, the repayment model does have a rollover feature. JP04 cited the extension of a particular bond's due date in Study 2 as an example of the use of rollover to lower debt service. JP04 Br., BP-16-B-JP04-02, at 13. However, the change in the bond's due date in Study 2 was not based on the rollover feature, which remained the same as in the Initial Proposal. Lennox *et al*., BP-16-E-BPA-25, at 8-9. Therefore, JP04 has made no specific suggestion for changing the rollover feature or cited any instance in which different or additional use of the rollover feature would lower debt service. As noted, the repayment study includes a rollover feature that Staff has utilized.

Draft Decision

The repayment study will not be modified to eliminate critical years or to change the due date of the $49 million bond from FY 2027 to FY 2024. Instead, the revised repayment study with a critical year of 2043 will be used for establishing rates. No changes will be made to the use of the rollover feature.

Issue 4.2.1.3

Whether the repayment of discretionary amortization should be scheduled based on the principle that debt with the highest interest rate is amortized first.

Parties' Positions

JP04 argues that if a discretionary amortization schedule results in lower debt service than a schedule under which debt with the highest interest rate is amortized first, BPA should adopt the alternative discretionary amortization schedule. JP04 Br., BP-16-B-JP04-02, at 9. JP04 states that DOE Order No. RA 6120.2, which governs BPA's repayment study, does not impose an absolute requirement that discretionary amortization always be scheduled by selecting the highest-interest-bearing investment first. *Id*. at 8. Instead, JP04 states, the DOE order allows for an exception to this principle when "otherwise indicated by legislation." *Id*. JP04 claims that the Transmission System Act's requirement that BPA set the lowest possible rates consistent with sound business principles is legislation that overrides the DOE order. *Id*. at 9, 17-18.

BPA Staff's Position

JP04 appears to misunderstand how Study 1 and Study 2 were performed. Both studies followed the highest-interest-rate-first principle of DOE Order No. RA 6120.2. Lennox *et al.*, BP-16-E-BPA-25, at 11. Therefore, the studies do not support JP04's argument that an alternative schedule would result in lower debt service. It is true that DOE Order No. RA 6120.2 allows for exceptions to the general rule. *Id.* at 10. Any alternative, however, must be consistent with

sound business principles. Establishing the lowest possible rates is not always consistent with sound business principles. *Id.*

Evaluation of Positions

DOE Order No. RA 6120.2 provides that "to the extent possible … and unless otherwise indicated by legislation," revenues available for amortization shall be applied to the highest-interest-bearing investment first. JP04 Br., BP-16-B-JP04-02, at 8. Thus, the rule has two qualifications: the alternative amortization schedule must be possible, and legislation must indicate that BPA should follow an alternative schedule. JP04 has seized on the second qualification, arguing that BPA's statutory obligation to establish the lowest possible rates consistent with sound business principles means that it must use a different amortization schedule if it will result in lower rates. *Id.* at 17-18. JP04 challenges Staff's testimony that this statutory requirement is not the type of legislation Order No. RA 6120.2 was referring to. *Id*.

Although Staff stated its position inartfully, its testimony demonstrates that it was challenging the notion that BPA must always establish the lowest possible rates. As Staff noted, JP04 quotes the statute correctly but ignores its requirement that rates be consistent with sound business principles. Lennox *et al*., BP-16-E-BPA-25, at 10. JP04 also argues that the repayment study should be modified to reduce mandatory amortization in the critical year "if such modification would reduce debt service included in BPA's transmission rates." *Id*. at 14.

JP04 makes no argument that its alternative proposals are consistent with sound business principles. Moreover, JP04 did not contest Staff's testimony that Study 1 and Study 2—the evidence JP04 relies on—followed the highest-interest-rate-first principle. Lennox *et al*., BP-16-E-BPA-25, at 11. As Staff testified, establishing the lowest possible rates is not always consistent with sound business principles, for example if lower rates today would mean significantly higher rates in the future and possible rate shock. *Id*.

In any case, JP04 has offered no evidence that an alternative amortization would result in lower rates. And as noted above, the updates to the repayment study lowered annual debt service by $6 million, almost as much as JP04 requested.

Draft Decision

Repayment study results will be based on the highest-interest-rate-first principle. No evidence has been offered to justify deviating from this rule.

Issue 4.2.1.4

Whether the repayment model should be made available to rate case parties.

Parties' Positions

JP04 argues that BPA's repayment model should be made available to rate case parties in executable form. JP04 Br., BP-16-B-JP04-02, at 20. JP04 claims that unless BPA makes the

model available, parties will not have the opportunity required by the Northwest Power Act to offer refutation or rebuttal of any material submitted in the rate case and BPA's rates will not be supported by substantial evidence. *Id.*

BPA Staff's Position

The repayment model uses a proprietary system as its database with a Web-based interface in a multi-server environment. It cannot be installed off-the-shelf on a desktop computer. However, Staff is willing to explore ways to make the model accessible to the parties. Lennox *et al.*, BP-16-E-BPA-25, at 11-12.

Evaluation of Positions

The features of the model that Staff cites make it difficult to make the model available to the parties. *Id.* Staff did what it could in this rate case to ensure the parties' procedural rights. Staff ran the two studies the parties requested and made the results available. *Id*. at 6, 11-12. Staff was unable to go further and make the model available in executable form. However, BPA will explore whether it is possible to make the model more accessible to the parties, and if so, how to do so. BPA will discuss this issue with parties after the conclusion of this rate proceeding.

Draft Decision

BPA will explore ways to make the repayment model available to rate case parties.

4.2.2 Transmission Risk Analysis

In the 1993 Final Record of Decision, BPA determined that, as a long-term policy, it would set its rates to maintain financial reserves sufficient to achieve at least a 95 percent probability of making its scheduled payments to the U.S. Treasury in full and on time for each two-year rate period. 1993 Wholesale Power and Transmission Rate Proposal, Administrator's Record of Decision, WP-93-A-02, at 72-73 (July 1993) (1993 ROD).

Because the Treasury payment is the last payment made in a fiscal year, the probability of making BPA's year-end payments to the U.S. Treasury for each year of the rate period (TPP) is the primary measure of BPA's ability to meet not only the Treasury obligation but all of its financial obligations within a fiscal year. BPA has applied the same risk analysis methods as it has in the past to measure the TPP for the FY 2016–2017 rate period. Lovell *et al.*, BP-16-E-BPA-15, at 2. Specific issues raised with respect to the revenue requirement and risk analysis are addressed below.

Issue 4.2.2.1

Whether financial reserves for risk attributed to Transmission Services should be used to mitigate the proposed transmission rate increase or fund transmission capital investment above $15 million per year.

Parties' Positions

Many parties support using some amount of transmission reserves to offset costs and reduce rates for FY 2016 and FY 2017. JP04 and Powerex argue that transmission reserves are unreasonably high and propose that BPA use $84 million of reserves during each year of the rate period to reduce rates. JP04 Br., BP-16-B-JP04-01, at 3-9, 34; Powerex Br., BP-16-B-PX-01, at 3-5. M-S-R, which also argues that transmission reserves are unreasonably high, proposes that BPA use $40 million of reserves per year for rate mitigation. M-S-R Br., BP-16-B-MS-01, at 3. In their joint brief, JP13 and ICNU (filing as "JP13") propose that BPA use $20 million per year for rate relief. JP13 Br., BP-16-B-JP13-01, at 11. As an alternative to using reserves to offset costs, WPAG suggests that BPA "increase the amount of reserves used to fund transmission capital investments during the rate period by a modest amount above the $15 million per year proposed in BPA's initial proposal." WPAG Br., BP-16-B-WG-01, at 23 n.7.

BPA Staff's Position

The Initial Proposal set rates to recover the transmission revenue requirement. Lovell *et al*., BP-16-E-BPA-30, at 7. Other than making $15 million per year of financial reserves for risk attributed to Transmission Services (transmission reserves) available as a means to fund capital investments in lieu of borrowing, the Initial Proposal did not use transmission reserves to reduce rates for the BP-16 rate period. Transmission Revenue Requirement Study, BP-16-E-BPA-08, at 20.

Staff opposes proposals to use reserves to offset costs and reduce rates without regard to agency reserve levels because such action would be viewed negatively by the credit rating agencies. Lovell *et al.*, BP-16-E-BPA-30, at 8-9. Using significant amounts of reserves for rate relief, such as $84 million per year, would intentionally decrease transmission and agency reserves to levels that might not be sufficient to maintain the agency's desired AA credit rating. *Id*. at 11. Using reserves for rate relief also would amount to an "ad hoc decision" (*i.e.*, a decision made on a rate case-by-rate case basis without having longer-term frameworks or principles in place) that credit rating agencies may view negatively because it does not demonstrate a record of willingness to charge the rates required to recover operating and capital costs. *Id* at 10. Finally, using reserves for the "short-term benefit" of reduced transmission rates would neglect the "long-term benefits" that robust agency financial reserves can provide to the transmission system, such as lowering BPA's interest expense on non-Federal debt. *Id*. at 8.

Evaluation of Positions

While broadly supporting the use of reserves for rate relief, many of the parties also acknowledge the role that agency reserve levels play in BPA's creditworthiness and the importance of maintaining a strong credit rating. JP04 Br., BP-16-B-JP04-01, at 23-24; Powerex

Br., BP-16-B-PX-01, at 6; JP13 Br., BP-16-B-JP13-01, at 7; M-S-R Br., BP-16-B-MS-01, at 11. For example, Powerex states that "BPA's agency-wide credit rating – and the means to support that credit rating – become even more important as BPA relies more heavily on its credit rating for future borrowings." Powerex Br., BP-16-B-PX-01, at 9. JP13 recognizes the "significant potential cost implications for a credit rating downgrade." JP13 Br., BP-16-B-JP13-01, at 7.

Maintaining BPA's strong credit rating is very important to BPA's long-term financial health: BPA's credit rating is "the primary factor" that determines the interest rate on all BPA-backed bonds. Lovell *et al.*, BP-16-E-BPA-30, at 5. Credit rating agencies rate BPA's credit each time a BPA-backed bond is publicly issued and sold by a third party. *Id*. The credit rating for any bond issuance secured by BPA payments is judged on the financial health of the entire agency. *Id*. at 4. This is true whether the bond issuance is for power facilities, such as Energy Northwest net-billed nuclear projects, or for transmission facilities under BPA's transmission lease-purchase program. *Id*.

M-S-R "acknowledges that reserves need to be considered from an agency perspective." M-S-R Br., BP-16-B-MS-01, at 11. Transmission reserves contribute to agency reserve levels and support BPA's credit rating, which lowers costs and rates over the long term. Higher transmission reserves levels result in higher interest income, which offsets the revenue requirement. Lovell *et al*., BP-16-E-BPA-30, at 23. More importantly, a strong credit rating lowers interest expense on borrowed debt. *Id*. at 8-9; Opatrny, BP-16-E-PX-01, at 20-21.

Keeping interest costs low is particularly important for transmission rates because of the lease-purchase program. Lovell *et al*., BP-16-E-BPA-30, at 5-6. Under the program, third parties lease transmission facilities to BPA and commit the lease payments from BPA to the payment of debt service on loans and bonds. *Id*. at 5. At the end of the lease period, BPA has an option to purchase the facilities for a minimal purchase price. *Id*. Under these arrangements, BPA's lease payments fund the debt service on the loans and bonds. *Id*. The facilities are not pledged as collateral. *Id*. at 6. Rather, the interest rates and other terms of the loans and bonds are based almost entirely on BPA's creditworthiness. *Id*. BPA expects the program to grow significantly in the future. *Id*. If BPA's credit rating were downgraded, the interest costs associated with the lease-purchase program could grow significantly, thereby significantly increasing the transmission revenue requirement and transmission rates over time.

Using a significant amount of reserves for rate relief could threaten BPA's credit rating. Credit rating agencies judge a utility's creditworthiness on a number of factors, but two factors are particularly important when determining whether to use financial reserves for rate relief: the total level of the utility's reserves, not the level of reserves a utility attributes to a particular division, and whether the utility shows "[a] demonstrated record of willingness to charge the rates required to recover operating and capital costs[.]" Lovell *et al*., BP-16-E-BPA-30, at 4, 8, *citing* Dan Aschenbach & John Medina, Moody's Rating Methodology for U.S. Public Power Electric Utilities with Generation Ownership Exposure, Report No. 135299, at 9 (Nov. 9, 2011), available at http://www.rmgfinancial.com/core/files/rmgfinancial/uploads/files/9%20US%20Public%20Power%20Utilities%20RM%202011(1).pdf. Using reserves to offset costs and reduce rates can undermine both of these factors.

JP04's, Powerex's, and M-S-R's proposals would reduce transmission reserves and, consequently, agency reserves by substantial amounts ($80 million to $168 million by the end of the BP-16 rate period). Moody's (one of the three major credit rating agencies) reports that AA-rated entities maintain between 150 and 250 days' cash on hand, which Staff translated to between roughly $850 million and $1.4 billion in agency financial reserves. *Id*. at 11; Lovell, *et al*., BP-16-E-BPA-30-E01, at 1. Powerex argues that its proposal would leave Transmission Services with sufficient transmission reserves for risk to satisfy the 150 to 250 days' cash on hand metric. Powerex Br., BP-16-B-PX-01, at 8. As stated above, however, credit rating agencies consider total agency reserves. If BPA were to use $80 million to $168 million per year of transmission reserves to lower transmission rates, total agency reserves would be far lower than 150 to 250 days' cash on hand.

Powerex and JP04 assert that using $84 million of transmission reserves per year to mitigate the rate increase will not undermine BPA's financial health because the 95 percent TPP standard would still be satisfied. Powerex Br., BP-16-B-PX-01, at 5; JP04 Br., BP-16-B-JP04-01, at 33-34. Powerex adds that BPA would still have sufficient reserves for Transmission Services' within-year liquidity need. Powerex Br., BP-16-B-PX-01, at 5. However, BPA's credit rating was downgraded after BPA filed its BP-12 rates even though the rates satisfied the 95 percent TPP standard. The downgrade was due "*in large part* because Agency reserves had declined by 36 percent between 2009 and 2010 and were expected to further decline as a result of the filed transmission rates." Lovell *et al.*, BP-16-E-BPA-30, at 4 (emphasis added).

Furthermore, TPP is an internal BPA standard for determining whether BPA will meet its obligations to the Treasury; it is not intended as a credit-rating tool. Powerex itself observed that

> [t]he TPP mechanism is not designed to be a holistic tool to evaluate financial strength and BPA's level of creditworthiness. In other words, the TPP was designed to be used by BPA to manage its relationship with the U.S. Treasury. Another metric is needed to manage BPA's relationship with Wall Street and creditors.

Opatrny, BP-16-E-PX-01 at 21. Drawing transmission reserves down to the lowest possible amount that satisfies the TPP standard, without regard to agency reserve levels, will not protect BPA's overall financial health or credit rating. Lovell *et al*., BP-16-E-BPA-30, at 7, 22-23. Powerex argues that "a modicum of consistency" with the BP-14 proceeding "warrants" the use of at least $20 million of reserves per year, because BPA used $20 million of transmission reserves to reduce rates in the BP-14 rate case. Powerex Br., BP-16-B-PX-01, at 5. JP04 similarly argues that BPA's use of reserves to reduce rates in the BP-14 rate case "demonstrated [BPA's] ability and willingness" to use transmission reserves to mitigate rate increases." JP04 Br., BP-16-B-JP04-01, at 29-30. JP13 also proposes that BPA use $20 million per year for rate relief. JP13 Br., BP-16-B-JP13-01, at 11. As explained above, however, use of reserves to mitigate a proposed rate increase would reduce transmission and agency reserves and would not demonstrate the record that credit rating agencies look for when assessing BPA's creditworthiness. Reserves should no longer be used on an ad hoc basis for rate mitigation because continuing to do so could threaten BPA's credit rating.

Powerex argues that Staff contradicted itself, as Staff proposed a Dividend Distribution Clause (DDC) (annual downward adjustment in rates if reserves exceed a threshold) that could reduce reserve levels and "does not express concerns over BPA's credit rating should the DDC trigger." Powerex Br., BP-16-B-PX-01, at 7. Unlike the ad hoc use of reserves during a rate case to mitigate rate increases, however, a formal DDC mechanism reflects a considered approach to the use of reserves with explicit criteria for when to use reserves and how much to use. Lovell *et al*., BP-16-E-BPA-30, at 10.

Powerex argues that BPA can use reserves to lower transmission rates because the proposed CRAC (annual upward adjustment in rates if reserves are below a threshold) mechanism will have a positive impact on BPA's credit rating. Powerex Br., BP-16-B-PX-01, at 6-7. However, as discussed in Issue 4.2.2.2, no CRAC is being adopted in this rate period.

As an alternative to using reserves to offset costs and reduce rates, WPAG proposes to use a modest additional amount of reserves to fund transmission capital investments during the rate period beyond the $15 million per year in Staff's Initial Proposal. WPAG Br., BP-16-B-WG-01, at 23 n.7. WPAG argues that its proposal "will preserve limited borrowing authority, reduce BPA's long-term debt-related costs, and provide long-term benefits to the transmission system and transmission rate-payers." *Id*. On the one hand, WPAG's proposal is consistent with the Initial Proposal's use of $15 million of reserves for capital expenditures, which does not threaten BPA's credit rating. Lovell *et al*., BP-16-E-BPA-30, at 7.

On the other hand, WPAG's proposal would further reduce transmission and agency reserve levels, which credit rating agencies could view negatively. As discussed in Issue 4.2.2.2, many parties ask that BPA hold workshops after the conclusion of the BP-16 rate proceeding to discuss and develop a long-term financial reserves policy. The soundest course would be to develop this policy before using additional reserves for rate relief.

Finally, M-S-R argues that "intergenerational equity" requires that BPA use transmission reserves for rate relief in the BP-16 rate period; since current customers "funded the excess," current customers should receive the benefit. M-S-R Br., BP-16-B-MS-01, at 4. As discussed in Issue 4.2.2.3 below, BPA must establish the lowest possible rates consistent with sound business principles. During the decade over which M-S-R claims BPA accumulated excess transmission reserves, no party argued that BPA's transmission rates failed to meet this standard. To the contrary, most of the transmission cases since 1996 have been settled, with customers agreeing to the rates and consequently accepting the agency's reserves levels. As the Administrator stated in the BP-14 ROD, customers during prior rate periods (1996 to 2013) have no right to the accumulation of reserves during those periods because the rates were set to achieve cost recovery and customers agreed to the rates in settlements. BP-14 ROD, BP-14-A-03, at 141. In addition, the rates did not contain any mechanism requiring that revenues in excess of costs be returned to customers. *Id*. The Administrator also stated that

> embedded in BPA's origins was the understanding that any accumulation of reserves would be put to use for the long-term benefit of the system, and ultimately, ratepayers.

Id. Moreover, M-S-R ignores the benefits that current transmission customers receive from maintaining robust transmission reserves during the BP-16 rate period, such as higher interest income to offset the revenue requirement.

Draft Decision

Financial reserves available for risk attributed to Transmission Services will not be used to mitigate the proposed rate increase or fund transmission capital investment above $15 million per year.

Issue 4.2.2.2

Whether transmission risk mitigation objectives and CRAC and DDC mechanisms should be adopted.

Parties' Positions

JP04 proposes that BPA adopt transmission risk objectives and CRAC and DDC mechanisms similar to the risk objectives and mechanisms in power rates. JP04 Br., BP-16-B-JP04-01, at 20. Under JP04's proposal, the DDC mechanism would trigger when transmission reserves exceed $500 million. *Id*.; Holland *et al*., BP-16-E-JP04-08, at 5. Powerex supports JP04's proposal and argues that a CRAC mechanism would reinforce BPA's credit rating. Powerex Br., BP-16-B-PX-01, at 6-7.

JP04, Powerex, and M-S-R argue that Staff's proposal for a CRAC and DDC (made in rebuttal testimony) would result in transmission customers disproportionately supporting the agency credit rating. JP04 Br., BP-16-B-JP04-01, at 13-16; Powerex Br., BP-16-B-PX-01, at 10, 12, 14-18; M-S-R Br., BP-16-B-MS-01, at 9. Specifically, these parties oppose tying a transmission DDC mechanism to agency reserve levels when the power DDC mechanism is not tied to agency reserves. JP04 Br., BP-16-B-JP04-01, at 21-26; Powerex Br., BP-16-B-PX-01, at 11, 18; M-S-R Br., BP-16-B-MS-01, at 9-10. M-S-R asserts that the proposed DDC mechanism would "continue the over collection of financial reserves for transmission." M-S-R Br., BP-16-B-MS-01, at 9.

JP04 and M-S-R also oppose Staff's proposal to apply 50 percent of the amount above the DDC threshold to debt retirement. JP04 Br., BP-16-B-JP04-01, at 26-28; M-S-R Br., BP-16-B-MS-01, at 10. Both parties assert that Staff's proposal would violate statutory obligations to ensure that rates are sufficient to repay the Federal investment over a reasonable number of years. JP04 Br., BP-16-B-JP04-01, at 28; M-S-R Br., BP-16-B-MS-01, at 10.

JP04 and Powerex support the allocation of the Treasury Facility (an arrangement allowing BPA to borrow money from the U.S. Treasury on a short-term basis) to support Transmission Services in general but argue that it is unclear whether Staff's proposal, which allocated some of the Treasury Facility to Transmission Services to cover transmission within-year liquidity needs, is

equitable between business lines. JP04 Br., BP-16-B-JP04-01, at 10-11; Powerex Br., BP-16-B-PX-01, at 5.

JP13, NRU, WPAG, JP17, and PNGC argue that the Administrator should not adopt Staff's proposal because it makes a significant change to the agency's policy on use of reserves very late in the rate case, was unexpected, is incomplete, and could pre-judge the outcome of further discussions on BPA's financial reserve policies. JP13 Br., BP-16-B-JP13-01, at 3-4, 7, 11-12; NRU Br., BP-16-B-NR-01, at 9, 16-18; WPAG Br., BP-16-B-WG-01, at 23; JP17 Br., BP-16-B-JP17-01, at 1-2; PNGC Br., BP-16-B-PN-01, at 6-7. NRU argues that BPA gave parties inadequate due process on this issue because "it is nearly impossible to quantify or qualitatively consider the impacts" of Staff's proposal. NRU Br., BP-16-B-NR-01, at 15-16.

JP13 alleges that BPA gave "inadequate notice" of the Staff proposal because BPA indicated in pre-rate case workshops that it did not anticipate using financial reserves for rate relief during the BP-16 rate period and neither the Federal Register notice nor the Initial Proposal mentioned or proposed changes to transmission reserves policies. JP13 Br., BP-16-B-JP13-01, at 4, 7-8. JP13 asserts that proposing the policy for the first time in rebuttal testimony "did not allow for the transparent public process that a revision of BPA's financial policies warrants." *Id*. at 7.

All parties that commented on this issue suggest that BPA hold workshops at the conclusion of the BP-16 proceeding to discuss and develop an agency financial reserves policy. JP04 Br., BP-16-B-JP04-01, at 11,18; Powerex Br., BP-16-B-PX-01, at 20; M-S-R Br., BP-16-B-MS-01, at 8-11; JP13 Br., BP-16-B-JP13-01, at 7; NRU Br., BP-16-B- NR-01, at 9; WPAG Br., BP-16-B-WG-01, at 23; JP17 Br., BP-16-B-JP17-01, at 1-2; PNGC Br., BP-16-B-PN-01, at 6-8.

BPA Staff's Position

In rebuttal testimony, Staff proposes transmission risk objectives and CRAC and DDC mechanisms similar to the ones in JP04's proposal but with several major differences. Lovell *et al.*, BP-16-E-BPA-30, at 1, 11. Staff includes as a transmission risk objective maintenance of the agency's AA credit rating and did not include an objective stating a preference for lower adjustable rates over higher, more stable rates. *Id*. at 2-3. Staff also includes a DDC mechanism that would trigger if both transmission reserves and agency reserves exceed a specific threshold. *Id*. at 11. Staff proposes to apply 50 percent of the amount above the DDC threshold to rate relief and the other 50 percent to debt retirement. *Id*. at 13. In addition, Staff proposes to allocate some of the Treasury Facility to transmission to support Transmission Services' within-year liquidity needs. *Id*. at 16. Staff did not propose parallel risk objectives and CRAC and DDC mechanisms for power rates, but proposes workshops to be held before the BP-18 rate case to further discuss and develop parallel risk objectives and a CRAC and DDC mechanism for both power and transmission. *Id*. at 9, 12.

Staff did not address the procedural issues because they were raised after Staff's rebuttal testimony was submitted.

Evaluation of Positions

Both JP04's and Staff's proposals include the formal structure of a DDC but differ on the level of reserves that would trigger the DDC. Under JP04's proposal, the DDC would trigger when transmission reserves exceed $500 million. JP04 Br., BP-16-B-JP04-01, at 20. Under Staff's proposal, the DDC would trigger when transmission reserves exceed $500 million *and* agency reserves exceed a certain amount: $800 million in July 2016 (for applying the DDC to FY 2016 rates) and $900 in September 2016 (for applying the DDC to FY 2017 rates). Lovell *et al*., BP-16-E-BPA-30, at 12, & Att. 1, at 8. The formal structure of a DDC would likely mitigate some of the credit rating risk associated with applying reserves to reduce rates. *Id*. at 10. A DDC mechanism reflects a considered approach for using reserves that is intended to be applied consistently over time, with explicit criteria for when to use reserves and how much to use. *Id*. It is also important that the DDC mechanism be structured to maintain sufficient agency reserve levels to support the agency's credit rating. *Id*. at 4, 11.

JP04's proposal could threaten BPA's credit rating because its proposed DDC mechanism could significantly reduce transmission reserve levels without regard to any minimum threshold for agency reserves. Although Staff's proposal is preferable to JP04's proposal in this respect, no party supports it. Parties' concerns include the completeness and equity of Staff's proposal, inadequate procedure, and potential impacts on future policy development. All parties that addressed this issue propose that the Administrator reject Staff's proposal and, instead, initiate a public process to discuss and develop BPA's long-term financial reserves policy after the BP-16 rate case.

The proposal to initiate a public process has merit and will be adopted. Adopting risk objectives and implementing a DDC and CRAC are significant decisions. As the parties note, Staff's proposal was made late in the proceeding. A more considered approach would be preferable. Holding workshops after the conclusion of the BP-16 rate proceeding is a reasonable alternative to adopting Staff's proposal and will provide a robust opportunity to engage customers in the development of a long-term financial reserves policy.

Powerex suggests principles to guide workshop discussions. Powerex argues that each business line should bear its respective weight for BPA's overall credit rating and that the Treasury Facility should be apportioned between the business lines by an appropriate metric. Powerex Br., BP-16-B-PX-01, at 19. Powerex also suggests that the DDC thresholds, measures used to determine the triggering of the DDC or CRAC, and DDC distributions should be applied comparably between the business lines. *Id*. Because Powerex provided these principles in its brief, no party, including Staff, has had an opportunity to respond to them. Therefore, rather than adopt principles in this Draft Record of Decision, parties and BPA Staff should work together to develop guiding principles for the workshop discussions.

As stated above, JP04's DDC is similar to the DDC Power Services has established. Power Services' DDC mechanism is tied only to business line (in that case power) reserve levels. JP04 Br., BP-16-B-JP04-01, at 18; Lovell *et al*., BP-16-E-BPA-30, at 12. Although JP04's DDC threatens BPA's credit rating, it should be noted that the DDC in power rates does not. Transmission reserves are robust. Lovell *et al*., BP-16-E-BPA-30, at 22. If power reserves grew

sufficiently to trigger the DDC (Staff does not think this a likely event), agency reserves would be "very robust." *Id*. at 12. In that case, reducing agency reserves in the amount triggered "should present little jeopardy to BPA's credit rating." *Id*.

Finally, given the draft decision, the procedural issues are moot. Nevertheless, it should be noted that, although the time for parties' response was limited in this case, several parties objected simply to the fact that Staff made its proposal, which they viewed as an unexpected and significant change, in rebuttal testimony. JP13 Br., BP-16-E-JP13-01, at 7-9; PNGC Br., BP-16-B-PN-01, at 6-7; M-S-R Br., BP-16-B-MS-01, at 7-8; JP17 Br., BP-16-B-JP17-01, at 2. Staff did so in response to proposals made by parties to the case. Lovell *et al*. BP-16-E-BPA-30, at 1, 10-11, *citing* Holland *et al.*, BP-16-E-JP04-01, at 17-21; Opatrny, BP-16-E-PX-01, at 15-16, 23-24; Arthur, BP-16-E-MS-01, at 1-2. The very purpose of parties' testimony is to convince BPA Staff, and ultimately the Administrator, to pursue a particular course, often one different from that originally proposed. If BPA Staff could never incorporate parties' ideas into its rebuttal testimony or make new proposals based on the parties' arguments, there would be little point to the parties' testimony. Therefore, Staff's efforts were consistent with the spirit of the rate case.

Draft Decision

Transmission risk mitigation objectives and CRAC and DDC mechanisms will not be adopted. After conclusion of the rate proceeding, BPA will engage the region regarding a financial reserves policy. Staff and interested stakeholders should work together at the outset of the workshops to identify the framework and agenda for the discussions.

Issue 4.2.2.3

Whether either the level of transmission reserves or the fact that transmission TPP is above 95 percent indicates that the proposed transmission rates are too high.

Parties' Positions

JP04, Powerex, and M-S-R characterize the levels of transmission reserves as "unreasonably high" and "excessive." JP04 Br., BP-16-B-JP04-01, at 3; Powerex Br., BP-16-B-PX-01, at 3; M-S-R Br., BP-16-B-MS-01, at 3. The parties claim that transmission reserve levels are unreasonable because the actual levels of reserves at the end of prior rate periods have exceeded the forecast levels. JP04 Br., BP-16-B-JP04-01, at 3; Powerex Br., BP-16-B-PX-01, at 3; M-S-R Br., BP-16-B-MS-01, at 3. JP04 also argues that transmission reserve levels are unreasonable because transmission reserves represent approximately 50 percent of transmission operating expenses and revenues, whereas power reserves represent approximately 14 percent of power operating expenses and revenues. JP04 Br., BP-16-B-JP04-01, at 8-9. Powerex and M-S-R make similar arguments. Powerex Br., BP-16-B-PX-01, at 3; M-S-R Br., BP-16-B-MS-01, at 3.

JP04 and Powerex argue that a TPP of 100 percent shows that reserves are too high. JP04 Br., BP-16-B-JP04-01, at 5; Powerex Br., BP-16-B-PX-01, at 3. JP04 adds that, because the TPP for Transmission Services "significantly exceeds" 95 percent, BPA's proposed transmission rates

are not the lowest possible rates consistent with sound business principles. JP04 Br., BP-16-B-JP04-01, at 33.

BPA Staff's Position

Although transmission reserves are above the absolute minimum necessary to meet the 95 percent TPP standard, exceeding the TPP standard does not mean transmission reserves are unreasonably high. Lovell *et al.*, BP-16-E-BPA-30, at 22-23. Since no PNRR was added to the revenue requirement to increase financial revenues during the rate period to achieve the TPP goal, the rates are set at the lowest level sufficient to meet the revenue requirement. *Id*. at 20-21.

Evaluation of Positions

The parties argue that transmission reserves are unreasonably high because the actual levels of reserves at the end of prior rate periods have exceeded forecasts. JP04 Br., BP-16-B-JP04-01, at 3; Powerex Br., BP-16-B-PX-01, at 3; M-S-R Br., BP-16-B-MS-01, at 3. Powerex adds that "BPA's reserve forecasts have typically underestimated the actual levels by approximately $90 million per year." Powerex Br., BP-16-B-PX-01, at 3. However, the FY 2016–2017 rates are set to recover forecast rate period costs and nothing more. Staff's forecasts of revenues and expenses are based on the best available information. Lennox *et al*., BP-16-E-BPA-25, at 2. By its nature forecasting is imperfect, and actual results will differ from forecasts.

The parties also argue that transmission reserves are unreasonable because they are a greater percentage of transmission operating expenses and revenues than power reserves are of power operating expenses and revenue. JP04 Br., BP-16-B-JP04-01, at 8-9; Powerex Br., BP-16-B-PX-01, at 3; M-S-R Br., BP-16-B-MS-01, at 3. There is no reason to conclude from this fact that transmission reserves are too high—as opposed to power reserves being too low—and in any case that comparison has no effect on rates. Lovell *et al*., BP-16-E-BPA-30, at 23.

Regarding the arguments that the TPP level indicates that reserves and rate levels are too high, the TPP standard is a "policy tool" to help ensure that Treasury payments can be made in full and on time during the rate period. Lovell *et al.*, BP-16-E-BPA-30, at 23. The Administrator addressed the same issue in the BP-14 rate case, explaining that the 95 percent TPP standard is not intended to be a maximum level and does not require BPA to use reserves to offset costs and reduce rates when the level of reserves exceeds the minimum required to meet the standard. BP-14 ROD at 129-32. The TPP standard was not designed to be a policy tool to determine when reserves should be used to reduce rates.

Critically, the TPP level has no impact on the FY 2016–2017 Initial Proposal rates because they include no PNRR. Lovell *et al.*, BP-16-E-BPA-30, at 20. PNRR is added if the risk analysis tests indicate that there will be insufficient reserves on hand during the rate period to meet the 95 percent standard. *Id.* These tests are performed after rates are set at the minimum level sufficient to meet the revenue requirement. *Id*. If the tests indicate that the TPP standard is below 95 percent, PNRR is added to the revenue requirement until the 95 percent TPP standard is met. *Id*. No PNRR was added to the revenue requirement in the Initial Proposal. Therefore, rates are not higher because TPP is above 95 percent. *Id*. at 21.

JP04 argues that the TPP level indicates that the proposed rates are not the lowest possible rates consistent with sound business principles. JP04 Br., BP-16-B-JP04-01, at 33. JP04 overstates the statutory mandate. Section 9 of the Transmission System Act provides that rate schedules for the sales of electric power and for the transmission of non-Federal electric power over the Federal transmission system shall be fixed and established "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." 16 U.S.C. § 838g. Similarly, section 5 of the Flood Control Act of 1944 provides that BPA shall dispose of power "in such manner as to encourage the most widespread use thereof at the lowest possible rates to consumers consistent with sound business principles." *Id*. § 825s.

As noted in the BP-12 and BP-14 Administrator's Records of Decision, the Ninth Circuit Court of Appeals has found that the obligation to "encourag[e] … the lowest possible rates to consumers" is not a mandate to set the lowest rates possible without regard to any other business or legal principle. 2012 Wholesale Power and Transmission Rate Adjustment Proceeding, Administrator's Final Record of Decision, BP-12-A-02, at 127 (July 2011) (BP-12 ROD); BP-14 ROD at 124-25. As the Court has explained:

> [T]he 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 accepted, 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.

BP-12 ROD at 127-28, *quoting Cal. Energy Comm'n v. Bonneville Power Admin.*, 909 F.2d 1298, 1308 (9th Cir. 1990); BP-14 ROD at 124-25. Whether BPA's rates have been set with "a view to encouraging the widest possible diversified use … at the lowest possible rates to consumers consistent with sound business principles," 16 U.S.C. § 838g, "is a matter for BPA to decide, subject to judicial review." *Bonneville Power Admin*., 32 FERC ¶ 61,014, at 61,053 (1985). It is not a matter for Federal Energy Regulatory Commission review. *Id*.; *see also* 16 U.S.C. § 839e(a)(2) (stating the standards for the Commission's review of BPA's rates). Moreover, BPA has other rate directives. The first directive stated in the Northwest Power Act is the requirement that BPA "establish … rates … to recover, in accordance with sound business principles, the costs associated with the acquisition, conservation, and transmission of electric power." 16 U.S.C. § 839e(a)(1). Ensuring BPA's cost recovery is also the Commission's primary charge. The Commission reviews BPA's rates under three standards, the first of which is that the rates "are sufficient to assure repayment of the Federal investment in the Federal Columbia River Power System over a reasonable number of years after first meeting the

Administrator's other costs." *Id*. § 839e(a)(2)(A). The Administrator has concluded that recovery of costs is BPA's primary rate mandate: "Overall cost recovery is the paramount objective of BPA's rate directives." Administrator's Record of Decision, 1996 Final Rate Proposal, WP-96-A-02, at 393 (June 1996).

Significantly, under the Transmission System Act the Administrator is also required to establish rates not only to recover the cost of producing and transmitting electric power but also "at levels to produce such additional revenues … to pay when due the principal 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. § 838g. Finally, in the 1993 Administrator's Record of Decision, the Administrator evaluated arguments that BPA should reduce rate increases to be competitive. 1993 ROD at 11. In response to these arguments, the Administrator stated:

> If, viewed as a whole, all reasonable rate actions have been taken to establish the rates as low as possible consistent with sound business principles – and here it must be understood that decisions on many issues trade off and factor into decisions on other issues – the consequence is that the rates are the lowest consistent with sound business principles.

Id. at 14. As shown above, the trade-off of using reserves for rate mitigation is that it poses increased risk of a credit rating downgrade and consequent increased financing costs. As also noted above, the public workshops to be held after the rate case will allow BPA to develop a more considered policy for use of reserves.

Draft Decision

The level of transmission reserves and the fact that transmission TPP is above 95 percent does not indicate that the proposed rates are too high.

Issue 4.2.2.4

Whether maintaining transmission reserves for risk to support BPA's credit rating is a cost of the Federal transmission system.

Parties' Positions

Powerex and JP04 characterize the maintenance of transmission reserves to support the agency credit rating as a cost that must be equitably allocated between power and transmission rates. Powerex Br., BP-16-B-PX-01, at 11-12; JP04 Br., BP-16-B-JP04-01, at 20. Powerex asserts that "BPA disproportionately relies upon Transmission reserves to support its credit rating" and claims that there is a measurable cost associated with this reliance. Powerex Br., BP-16-B-PX-01, at 11-13. Powerex argues that the "disproportionate reliance on Transmission reserves … runs afoul of FERC's prohibition of cross-subsidization between the business lines." *Id*. at 12.

BPA Staff's Position

Staff did not specifically address this issue, but stated that transmission reserves do not add costs to transmission rates and, instead, result in higher interest income, which offsets the revenue requirement. Lovell *et al*., BP-16-E-BPA-30, at 23.

Evaluation of Positions

Section 7(a)(2) of the Northwest Power Act and section 10 of the Transmission System Act require BPA to equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing the system. 16 U.S.C. §§ 839e(a)(2) & 838h. The Commission approves BPA's rates only upon a finding that they satisfy this standard. In determining whether costs are equitably allocated, the Commission requires a separate accounting of power and transmission costs so that the Commission can determine that "(1) transmission revenues are only used to repay transmission costs; (2) costs assigned to transmission are only transmission related costs; and (3) any deficiencies or surpluses in transmission revenues are being tracked and collected or credited to the appropriate customer class." *U.S. Dep't of Energy–Bonneville Power Admin.*, 25 FERC ¶ 61,140, at 61,375-76 (1983).

The crux of Powerex's argument is that transmission reserve levels support a strong agency credit rating that benefits both Transmission Services and Power Services. Neither Powerex nor JP04 has argued that the transmission rates violate any of the above tests. There is no evidence, nor any reason to believe, that transmission reserve levels impose any costs on Power Services or Transmission Services or have any effect on power or transmission rates.

Powerex argues that transmission reserves levels have "a real and quantifiable cost." Powerex Br., BP-16-B-PX-01, at 12. Powerex avers that Transmission Services would "merit a higher credit rating than Power Services" because Transmission Services has "over 400 days' cash on hand" and Power Services has "only 50 days' cash on hand." *Id*. at 13. Powerex then estimates that Power Services' lower credit rating could result in $10 million to $30 million of increased interest expense per year. *Id*. None of this analysis demonstrates an increased cost to Transmission Services. No party has offered any evidence that the proposed transmission rates over-recover transmission costs. The alleged balance or imbalance of power and transmission reserves has no bearing on the equitable allocation of the costs of the Federal transmission system.

Finally, both business lines contribute to and benefit from the agency's strong credit rating. Transmission customers, in particular, benefit from the agency's strong credit rating because of the lease-purchase program. As discussed in Issue 4.2.2.1, the interest rates and other terms of the loans and bonds associated with the lease-purchase program are based almost entirely on BPA's creditworthiness. Lovell *et al*., BP-16-E-BPA-30, at 6. BPA expects the program to grow significantly in the future; eventually it could finance as much as half of Transmission Services' planned capital investments. *Id*.

Draft Decision

Maintaining transmission reserves for risk to support the agency credit rating is not a cost of the Federal transmission system.

4.3 Transmission Rate Design

BPA's transmission rate design process involves determining the overall costs of the transmission system, allocating those costs among transmission customers, and calculating the proposed transmission rates for BPA's wholesale transmission products and services for the rate period, FY 2016 and 2017. The Transmission Rates Study and Documentation, BP-16-E-BPA-07, includes the results of this process and demonstrates that the rates for BPA's wholesale transmission services for FY 2016–2017 have been developed consistent with BPA's statutory and contractual obligations and will recover the transmission revenue requirement.

This section of the Draft ROD addresses transmission rate design issues raised by the parties, including direct assignment of the costs of certain reliability compliance activities, elimination of the Montana Intertie rate, the BP-14 O&M error, the oversupply rate, and the Southern Intertie hourly non-firm rate.

4.3.1 BP-14 O&M Error

After the end of the BP-14 rate case, BPA Staff discovered that it had allocated costs in the segmentation study based on historical averages of O&M costs that were developed for the BP-12 rate case. BPA did not under-recover its costs, but instead unintentionally shifted costs between segments. The Network and Eastern Intertie segments were allocated more than their correct share of O&M costs, while the Generation Integration, Southern Intertie, Utility Delivery, and DSI Delivery segments were allocated less than their correct share (as explained below, the under-allocation of costs did not reduce the rates for the Utility Delivery and DSI Delivery segments). Staff proposed to correct the error in this rate case. Fredrickson *et al.*, BP-16-E-BPA-14, at 14-15.

Issue 4.3.1.1

Whether BPA should correct the misallocation of O&M costs made in the BP-14 rate case.

Parties' Positions

Iberdrola argues that correction of the error would be prohibited as retroactive ratemaking. Iberdrola Br., BP-16-B-IR-01, at 11. Iberdrola also argues that the correction would not adjust fairly for the error because the Southern Intertie segment would be allocated $6 million more annually while the Utility Delivery and DSI segments would be unaffected. Wrigley and Kester, BP-16-E-IR-01, at 16. According to Iberdrola, BPA leaves other errors of similar or greater magnitude uncorrected, and correction of the BP-14 error would set "a troubling precedent" and

encourage parties to argue for future "corrections" whenever actual results deviate from rate case forecasts. *Id*. at 17-18.

JP08 also argues that correction of the error would be illegal retroactive ratemaking. JP08 Br., BP-16-B-JP08-01, at 8. JP08 argues that BPA should not correct the error because it is important to maintain the stability and predictability of rates. Smith *et al*., BP-16-E-JP08-01, at 11. In addition, because neither the customer groups nor their transmission usage will be the same in the BP-16 rate period as in the BP-14 rate period, correction of the error would result in generational inequity. *Id*. In addition, BPA has not explained why a $12 million shift in costs is not large enough to require a change in segmentation, yet a similar shift with respect to the error is too large to leave uncorrected. *Id*. at 14-15. Finally, JP08 argues that because BPA now uses seven years of historical data to determine O&M costs rather than three, if BPA corrects the BP-14 error it should use seven years of data to calculate the correct allocators instead of the three years it has proposed. JP08 Br., BP-16-B-JP08-01, at 16-18.

Powerex also argues that correction of the error would be illegal retroactive ratemaking. Powerex Br., BP-16-B-PX-01, at 22. Powerex adds that correction of the error would not reflect "customer class fairness" because the Utility Delivery and DSI Delivery segments would not be reallocated any costs, and that the error should be left as is in the interest of rate finality. Powerex Br., BP-16-B-PX-01, at 22-24. Finally, Powerex suggests that instead of allocating additional costs to certain segments to correct for the error, BPA should use transmission financial reserves. *Id*. at 24-25.

Snohomish argues that BPA should correct the error because the error violated principles of cost causation: certain transmission customers paid for O&M costs of facilities that did not benefit them. Snohomish Br., BP-16-B-SN-01, at 5. Snohomish argues that correction of the error would not be retroactive ratemaking and that the error warrants an equitable remedy. *Id*.

WPAG argues that BPA should not correct errors from past rate cases until it adopts a policy that sets forth the criteria it will use to determine when to correct errors and when to leave them uncorrected. WPAG Br., BP-16-B-WG-01, at 26-27.

BPA Staff's Position

Staff states that the over-allocation of $9 million to the Network segment and the under-allocation of $6 million to the Southern Intertie segment are too large to leave uncorrected. Fredrickson *et al*., BP-16-E-BPA-14, at 15. Because almost all of BPA's customers in the BP-16 rate period will be the same as the customers in the BP-14 rate period, fixing the error will result in little generational inequity. Fredrickson *et al.*, BP-16-E-BPA-26, at 10. Moreover, because the error did not reduce the costs allocated to the Utility Delivery and DSI Delivery segments in the BP-14 rate case, these segments should not be allocated any costs of correcting the error. *Id*. at 3-15. Finally, a three-year historical period for O&M costs should be used to fix the error because that was the historical period used to establish O&M costs in the BP-14 rate case. *Id*. at 11.

Evaluation of Positions

Rate stability and finality are among the most significant ratemaking principles. It is critical that, in order to plan their business affairs, parties know that established rates will not be revisited except under the most extraordinary circumstances. As JP08 noted, both the Administrator and the Commission approved the BP-14 rates. Smith *et al*., BP-16-E-JP08-01, at 7-8. Correction of the BP-14 error would be the first time that, on its own initiative, BPA has revisited rates in one rate case to correct for a ratemaking error or decision it made in a prior rate case. Rates should not be revisited lightly, and this is not the case in which to do so.

Staff correctly notes that correction of a mathematical error is not the same as correction for deviations from forecasts, which are an inevitable and normal part of ratemaking. Fredrickson *et al*., BP-16-E-BPA-26, at 7. Yet the effects of those deviations can be just as large as or even significantly larger than the effects of an error. For example, Staff did not contest JP07's testimony that, from FY 2009 through FY 2014, BPA over-forecast net interest expense for transmission by an average of $34.4 million per year. *See* Deen *et al*., BP-16-E-JP07-01, at 12; Lennox *et al*., BP-16-E-BPA-25, at 2. Although Staff continually works to refine and improve its forecasting process, Staff correctly rejected arguments to reduce net interest expense in this rate case because of past forecast errors. *Id*. at 4. Ratemaking is an intricate and complicated endeavor, and rates will never be set perfectly.

Staff argues that, because almost all of BPA's customers in the BP-16 rate period will be the same as the customers in the BP-14 rate period, fixing the error will result in little generational inequity. Fredrickson *et al*., BP-16-E-BPA-26, at 10. As the parties note, however, the customer mix will not be identical in both rate periods, and transmission usage by customer will differ, so the effects of the error cannot be corrected precisely. Smith *et al*., BP-16-E-JP08-01, at 11; Opatrny, BP-16-E-PX-01, at 30-31. To the extent that the correction affects a new customer or one that has significantly changed its usage, correction could compound the error.

As the parties pointed out, Staff has not explained why this particular error is too large to leave uncorrected. The amount at issue is less than the cost of facilities Staff proposed to grandfather into the Network when Staff changed its segmentation policy in the Initial Proposal. Yet Staff defended the grandfathering on the ground that, if the facilities were removed from the Network, the revenue requirement "would change very little." Tenney *et al*., BP-16-E-BPA-16, at 32. If that is true, the Network revenue requirement was changed very little by this error, which therefore is not too large to leave uncorrected.

Finally, given the draft decision, the question of retroactive ratemaking is moot. Nevertheless, it should be noted that the prohibition of retroactive ratemaking does not apply to BPA. *Cent. Elec. Power Coop., Inc. v. Southeastern Power Admin*., 338 F.3d 333, 337-38 (4th Cir. 2003). Because no re-allocation is being made, it is not necessary to explore this issue further at this time.

Draft Decision

No re-allocation of costs will be made to correct for the misallocation of costs in the BP-14 rate case.

4.3.2 Cost Allocation for BPA's Reliability Activities

Issue 4.3.2.1

Whether BPA should directly assign the projected costs of reliability compliance activities it performs under agreements it has with certain customers.

Parties' Positions

JP05 argues that BPA should directly assign its projected costs of performing reliability compliance activities for certain customers related to the customer's transmission facilities. JP05 Br., BP-16-B-JP05-01, at 1-2. JP05 argues in the alternative that since virtually all of the customers for which BPA performs these activities are BPA preference customers, the costs should be assigned to BPA's power rates. *Id.*

WPAG argues that JP05 has failed to identify any additional costs BPA incurs because it performs the activities. WPAG Br., BP-16-B-WG-01, at 24. Further, WPAG argues, because all customers benefit from the activities, JP05's proposal "is at odds with the widely accepted cost causation principle that costs follow benefits." *Id.* at 25.

BPA Staff's Position

Staff opposes JP05's recommendation. Tenney *et al.*, BP-16-E-BPA-28, at 5-7. Staff states that all customers benefit from these reliability-related activities. *Id.* Depending on the type of contract BPA has with the customer, BPA either (1) does not incur additional costs, or (2) incurs some costs in documenting compliance activities, but also saves costs because performing the activities simplifies BPA's compliance responsibilities. *Id.*

Evaluation of Positions

JP05 argues that BPA should directly assign any costs of BPA's actions under its reliability-related agreements to the customers that are parties to the agreements because those actions benefit only those customers. JP05 Br., BP-16-B-JP05-01, at 5. BPA's agreements with these customers fall into two primary categories: (1) delegation agreements, under which BPA is responsible for compliance with certain standards that apply to the customer as a load-serving entity and distribution provider; and (2) transmission operator agreements, under which BPA has agreed to register with NERC as the transmission operator for certain customers' facilities and to assume legal responsibility for complying with the reliability standards that apply to transmission operators. Tenney *et al*., BP-16-E-BPA-28, at 1.

Under the delegation agreements, BPA must: (1) maintain load-resource balance; (2) ensure that customers' facilities that interconnect to BPA's transmission system do not harm the reliability of the FCRTS; and (3) analyze the effectiveness of BPA's under-frequency load shedding (UFLS) program. *Id.* at 3-4. Further, BPA must respond to customers' requests for information in advance of a compliance audit. *Id.* at 4. JP05 states that the customers, not BPA, are obligated to perform the compliance activities for their facilities. JP05 Br., BP-16-B-JP05-01, at 5. However, JP05 does not rebut Staff's testimony that NERC reliability standards require BPA to maintain load-resource balance and that BPA would have to perform this activity even in the absence of the delegation agreements. Tenney *et al*., BP-16-E-BPA-28, at 3. Because BPA must already maintain load-resource balance, BPA incurs no additional costs because of the reliability-related agreements.

Similarly, JP05 does not rebut Staff's testimony that, under BPA's Open Access Transmission Tariff, BPA must ensure that customers' facilities that interconnect to the FCRTS do not harm the transmission system and that, under NERC reliability standards, BPA must analyze the effectiveness of its UFLS program. *Id.* at 3-4. These responsibilities would exist even without the reliability-related contracts and thus result in no additional costs.

Finally, JP05 offers no evidence to contradict Staff's testimony that BPA is already required to respond to customers' requests for information in advance of a compliance audit. *Id.* at 4. Again, the delegation agreements impose no additional obligations or costs. BPA entered into the agreements to memorialize responsibility for activities it has historically performed for its customers. *Id*. at 4-5. Therefore, it is incorrect that BPA's obligations would be borne by customers in the absence of delegation agreements, and the existence of the agreements provides no reason to directly assign the costs.

BPA does incur costs under the transmission operator agreements. However, these agreements enhance the reliability of the transmission system and therefore benefit all customers. *Id*. at 5-6. For example, by acting as the customer's transmission operator, BPA can establish service more quickly after an outage, establish system operating limits on the customer's transmission system to ensure that the customer's facilities are operated within acceptable reliability criteria, and gain more control over planned outages on the customer's facilities. *Id*. JP05 acknowledges that "the interconnected electrical system benefits from any operational efficiency and reliability compliance that may result from each individual utility's performance of its reliability obligations[,]" but argues "[t]hat does not, however, provide any basis or rationale for BPA's ratepayers to subsidize compliance activities for any other utility." JP05 Br., BP-16-B-JP05-01, at 5. To the contrary: the benefits to the system as a whole provide a compelling reason to include the costs in general transmission rates. Tenney *et al*., BP-16-E-BPA-28, at 7. BPA would have to perform some of the activities in any case; for example, BPA must have a NERC-qualified dispatcher to be the transmission operator for a customer or to operate its own system; and BPA saves costs by not having to coordinate with new transmission operators. *Id.* In sum, the transmission operator agreements are more akin to reliability tools for BPA's system than they are to agreements benefitting particular customers.

Citing testimony from the BP-14 rate case, JP05 argues that Staff has not presented any evidence that the costs associated with delegation and transmission operator agreements are minimal. JP05 Br., BP-16-B-JP05-01, at 8-9. However, BPA addressed this issue in the 2014 Record of Decision:

> Staff acknowledged that it does not track the costs individually, but it evaluated the actions it takes to comply with the standards addressed in the agreements and excluded the costs of activities that it would perform anyway for its own compliance obligations. Staff concluded that the costs attributable specifically to these agreements relate to staff time and administrative expense. Bogdon *et al*., BP-14-E-BPA-43, at 24-25. Under the agreements, BPA does not perform operations and maintenance work that involves a physical presence out in the field, and its actions generally involve simple certifications of compliance, cooperation, and coordination with other transmission entities and actions that BPA would perform for the FCRTS regardless of the agreements. *Id.* at 19-21. Given the evidence regarding the nature and extent of the tasks that BPA is performing under the agreements, it is reasonable to conclude that the costs are limited.

BP-14 Power and Transmission Rate Proceeding, Administrator's Final Record of Decision, BP-14-A-03, at 184 (July 2013). JP05 has not presented any evidence that changes this conclusion. JP05's argument that "BPA is silent as to the level of any cost it incurs of documenting the compliance of the *customers* under the delegation agreements or transmission operator agreements" is unpersuasive. JP05 Br., BP-16-B-JP05-01, at 9-10 (emphasis in original). In the case of transmission operator agreements, the customer has no compliance responsibilities to document because BPA has assumed legal responsibility for complying with the reliability standards that apply to the transmission operator. In the case of delegation agreements, the above statement from the 2014 Record of Decision still holds true, and it is still reasonable to conclude that the costs are limited.

JP05 also expresses concern that BPA may be liable for monetary penalties for actions taken under the agreements and that BPA may receive a much larger penalty than the customer because of BPA's greater ability to pay a large penalty. JP05 Br., BP-16-B-JP05-01, at 13. However, BPA has not paid any penalties under the agreements and expects this record to continue. Tenney *et al*., BP-16-E-BPA-28, at 2. Indeed, a primary purpose of the agreements is to avoid violations and potential penalties through improvements to reliability.

Finally, JP05 argues that if BPA does not directly assign the costs of the agreements to the customers, then it should assign such costs to power rates because virtually all of the customers with such agreements are BPA preference customers that purchase Federal power. JP05 Br., BP-16-B-JP05-01, at 1-2. However, JP05 has not established a connection between these agreements and the sale of Federal power. To the contrary, the agreements are related to the reliability of the transmission system, not the sale of Federal power. Tenney *et al*., BP-16-E-BPA-28, at 7. Transmission costs are always assigned to transmission rates; the identity of the purchaser is immaterial. These costs, if any, are no different.

Draft Decision

BPA will not directly assign the costs of reliability compliance activities BPA performs on behalf of individual customers.

4.3.3 Southern Intertie Hourly Non-Firm Rate

The rate for hourly non-firm service on the Southern Intertie is set by first dividing the annual Southern Intertie long-term firm rate by the average number of hours per year in the rate period (8,772 hours for the BP-16 rate period). Next, that result is multiplied by 24/16 (24 hours per day divided by the 16 heavy load hours). This step ensures that customers that reserve transmission during all 16 heavy load hours, when loads are typically the highest, pay the same amount as long-term firm customers that have the right to schedule transmission 24 hours a day. Linn *et al*., BP-16-E-BPA-31, at 1-2. That result is multiplied by 7/5 (7 days a week divided by 5 weekdays). This step ensures that customers that reserve transmission for five weekdays, again when loads are typically the highest, pay the same amount as long-term firm customers that have the right to schedule every day of the week. *Id.; see also* Transmission Rates Study and Documentation, BP-16-E-BPA-07, § 5.1. The practical result of this methodology is that a customer that reserves 1 MW for 80 hours of hourly non-firm transmission service a week (16 hours a day multiplied by five days) pays the same amount as a long-term firm customer that buys 1 MW. Linn *et al*., BP-16-E-BPA-31, at 1-2. Staff proposes to retain this methodology for FY 2016–2017, resulting in a proposed rate of 3.59 mills/kWh.

JP06 opposes calculating the hourly non-firm rate based on 80 hours a week and instead proposes that BPA base the rate on actual reservations of hourly non-firm service in FY 2012–2014. JP06 Br., BP-16-B-JP06-01, at 10-12. JP06 calculates the actual use of hourly non-firm service to be approximately 23 hours per customer per week. *Id.* Based on that calculation, JP06 proposes setting the hourly non-firm rate so that a customer that reserves 1 MW for 23 hours per week of hourly non-firm transmission service pays the same amount as a long-term firm customer that buys 1 MW. JP06's proposal results in a rate of 12.97 mills/kWh. *Id.*

Issue 4.3.3.1

Whether basing the Southern Intertie hourly non-firm rate on 80 hours of reservations a week is equitable.

Parties' Positions

JP06 argues that basing the hourly non-firm rate on 80 hours a week does not equitably allocate the costs between firm and non-firm transmission service on the Southern Intertie. *Id.* at 10. JP06 also states that Staff's use of 80 hours a week "is not based on any actual data regarding reservations of IS HNF [Southern Intertie hourly non-firm] service." *Id.* JP06 argues that actual usage of Southern Intertie non-firm service from FY 2012 to FY 2014 was 23 hours per week, and that the rate should be based on this figure. *Id*. at 10-12.

BPA Staff's Position

Staff states that its proposal equitably distributes costs between firm and non-firm service while still maintaining an incentive to reserve long-term firm service. Linn *et al*., BP-16-E-BPA-31, at 3. Staff claims its "methodology is not based on the assumption that customers will actually purchase 16 hours of non-firm transmission service, five days a week (80 hours of transmission per week)." *Id.* Instead, Staff's method "creates an incentive to purchase long-term firm transmission by making it more expensive to purchase hourly service if a customer's demand exceeds 80 hours per week." *Id.*

Evaluation of Positions

JP06 states that Staff's proposal to base the hourly non-firm rate on 80 hours a week of reservations is inequitable because a customer that schedules 1 MW for 23 hours of non-firm service per week would pay $86 per week for that service, whereas a long-term firm customer would pay $298 to schedule 1 MW for that same 23 hours per week. JP06 Br., BP-16-B-JP06-01, at 11. JP06 contends that this result "is contrary to BPA's rate design framework that seeks to set rates that result in similar total weekly contributions to embedded cost recovery across all types of Southern Intertie transmission service." *Id.*

The example that JP06 provides is not persuasive. An hourly non-firm customer pays $86 for service because it can use the Southern Intertie for only the 23 hours a week it has reserved, whereas a long-term firm customer has the right to schedule its Southern Intertie reservation for all 168 hours of the week. Linn *et al*., BP-16-E-BPA-31, at 3. Long-term firm customers pay more because they can use the Southern Intertie more.

JP06's argument that Staff's proposal "is not based on any actual data regarding reservations of IS HNF service," JP06 Br., BP-16-B-JP06-01, at 10, is also misplaced. Staff's use of 80 hours a week "is not an attempt to anticipate the number of hours that the average customer will use hourly non-firm transmission in a given week." Linn *et al*., BP-16-E-BPA-31, at 3. Rather, it is meant to provide an incentive to purchase long-term firm service and is a methodology commonly used by other transmission providers. *Id.*

JP06 states that its methodology is based on actual reservations of hourly non-firm transmission. JP06 Br., BP-16-B-JP06-01, at 25. However, the methodology does not reflect actual demand for hourly non-firm service because it accounts only for hours in which a customer can make an hourly non-firm reservation and overlooks those hours in which there is a lack of capacity. Linn *et al*., BP-16-E-BPA-31, at 7. This limitation artificially lowers the number of hours to 23 and increases the rate. *Id.* Similarly, the methodology overlooks the fact that there are two separate paths on the Southern Intertie (the alternating-current (AC) path and the direct-current (DC) path). *Id.* If a customer makes one hourly non-firm reservation on the AC path and one reservation on the DC path in the same hour, these should count as two reservations: they are two hours of reservation under two separate paths. *Id.* However, JP06 counts this as only one reservation for one hour. *Id*. This method lowers the number of hours and increases the rate.

Furthermore, JP06's methodology ignores the volume (MW) of hourly non-firm transmission reservations. *Id.* For example, a 1 MW hourly non-firm reservation and a 100 MW reservation both count as one hour of use, even though the latter reservation results in one hundred times more revenue than the former. *Id.*

Finally, JP06 argues that its proposal results in hourly non-firm rates similar to those of the Transmission Agency of Northern California (TANC), the Sacramento Municipal Utility District (SMUD), and the Los Angeles Department of Water and Power (LADWP). JP06 Br., BP-16-B-JP06-01, at 12. Although the absolute levels of these transmission providers' hourly non-firm rates are close to the rate in JP06's proposal, their rates are meaningful only when compared to their long-term firm rates. On TANC's system, a customer would have to reserve 60 hours of non-firm transmission to pay the same as the long-term firm rate; on SMUD's system, 104 hours; and on LADWP's system, between 80 and 168 hours. Linn *et al*., BP-16-E-BPA-31, at 6. These figures are much more in line with BPA's methodology than with JP06's proposal.

Draft Decision

Basing the Southern Intertie hourly non-firm rate on 80 hours of reservations a week is equitable.

Issue 4.3.3.2

Whether basing the Southern Intertie hourly non-firm rate on 80 hours of reservations a week creates an adequate incentive for customers to reserve long-term firm service on the Southern Intertie.

Parties' Positions

JP06 maintains that "the California Independent System Operator … has designed its market in a manner that grants awards for deliveries into its markets without regard to the seller's transmission priority under BPA's Open Access Transmission Tariff … framework." JP06 Br., BP-16-B-JP06-01, at 1-2. According to JP06, this market design leads to a "disincentive for future LTF [long-term firm] subscriptions and renewals that, if left unchecked, could ultimately jeopardize BPA's cost recovery for existing and future expansion projects." *Id.* at 2. JP17 agrees that "the current rate fails to meet its intended objective to incentivize the purchase of long-term service." JP17 Br., BP-16-B-JP17-01, at 4.

BPA Staff's Position

Staff states that its methodology creates an adequate incentive for customers to reserve long-term firm service. Linn *et al*., BP-16-E-BPA-31, at 4. The Southern Intertie remains fully subscribed in the southbound direction, and there is a queue of customers waiting for long-term firm service. *Id.*

Evaluation of Positions

JP06 states that the rate disparity between long-term firm and non-firm service makes it "attractive for a shipper to rely on IS HNF [hourly non-firm] service, purchased only in the specific hours in which service is desired, rather than committing to paying for IS LTF [long-term firm] service for every hour of the year in order to access the California ISO market." JP06 Br., BP-16-B-JP06-01, at 11. As JP06 acknowledges, however, the California ISO adopted its current market design in 2009. *Id*. at 9. Yet the Southern Intertie remains fully subscribed in the southbound direction, and BPA has a long queue of customers waiting for capacity. Linn *et al*., BP-16-E-BPA-31, at 4. Nonetheless, JP06 argues that the disincentive to purchase long-term firm service "has materialized and accelerated in the past two years as the California ISO has more actively publicized that its market process ensures that those participants receiving California ISO awards will be able to obtain transmission service on external providers' systems." JP06 Br., BP-16-B-JP06-01, at 9-10.

In fact, however, participants that rely on hourly non-firm transmission often cannot obtain service on BPA's system during times of high Intertie demand because the capacity is being scheduled by customers with long-term service. From FY 2012 to FY 2014 there were a significant number of hours where customers attempted to obtain hourly non-firm service on the Southern Intertie, but it was unavailable. Linn *et al*., BP-16-E-BPA-31, at 4. Furthermore, JP06's arguments are focused solely on the California ISO markets. Its proposal does not recognize any value for other uses of its long-term transmission, such as bilateral sales. *Id.* at 4-5. The robust sales and long queue for Southern Intertie service demonstrate that the capacity has significant value. Although JP06 has asserted that BPA should expect to lose revenues in the future, it has presented no evidence that this is likely to be the case.

JP06 also notes that the California ISO has designed its market in a manner that grants awards for deliveries without regard to the seller's transmission priority under BPA's Open Access Transmission Tariff. JP06 Br., BP-16-B-JP06-01, at 1-2. JP06 states that the result is that power bid by transmission customers that reserve hourly non-firm service flows ahead of power bid by customers that have reserved long-term firm transmission from BPA. *Id.* at 9. Thus, JP06 concludes, "the superior service that LTF [long-term firm] is supposed to enjoy as a matter of right under BPA's OATT is overridden by the California ISO market design." *Id.*

In fact, the OATT and the California ISO market rules govern separate transactions. The OATT concerns the transmission provider's sale of transmission capacity. It does not govern power purchasers' decisions. The OATT does not apply to downstream actions by other entities, particularly entities that themselves do not operate under the *pro forma* OATT. BPA's OATT does not prevent an organized market (or any purchaser, for that matter) from selecting bids that utilize non-firm transmission service. Instead, a purchaser can select any bid for power it wants without regard to transmission priority.

Therefore, it is not appropriate to adopt JP06's proposed methodology. Nevertheless, there may be a need for focused exploration of JP06's and JP17's concerns. JP06 is correct that customers with current long-term firm reservations have no obligation to renew, that parties in the queue for long-term firm service on the Southern Intertie are not generally under any binding obligation to

commit to service, and that over half of long-term firm reservations will expire by 2020. JP06 Br., BP-16-B-JP06-01, at 3, 17. JP06 also states that loss of long-term firm sales on the Southern Intertie may reduce utilization of the Intertie, as well as "simply make it impossible to recover the embedded costs of the Southern Intertie from the users of those facilities." *Id.* at 18.

As explained above, none of these events has occurred, even though the same conditions have existed since 2009. However, BPA does not dismiss JP06's witnesses' "real-world experience coping with the impact of the California ISO market design decisions." *Id.* at 2. After the Final Record of Decision is issued, BPA will hold a series of workshops in which all interested stakeholders will have an opportunity to address the issues raised by JP06, JP17, and any other interested parties, as well as potential rates and non-rates options to address the issues if necessary. Meanwhile BPA will continue to monitor Southern Intertie sales to help determine whether any action is necessary. This draft decision does not foreclose the possibility of a separate rate proceeding prior to the BP-18 rate case if it is concluded that action is needed and a rates option is identified.

Draft Decision

Basing the Southern Intertie hourly non-firm hourly rate on 80 hours of reservations a week currently creates an adequate incentive for customers to reserve long-term firm service on the Southern Intertie. BPA will hold workshops after the conclusion of the rate case to explore this issue further.

Issue 4.3.3.3

Whether BPA's ability to discount the hourly non-firm rate mitigates concerns regarding the stability of an hourly non-firm rate based on actual usage.

Parties' Positions

JP06 states that it recognizes Staff's concern that basing the hourly non-firm rate on historical usage could create upward pressure on the rate, as rate increases lead to declines in usage and consequent additional rate increases. JP06 Br., BP-16-B-JP06-01, at 24. JP06 argues, however, that BPA's ability to discount the hourly non-firm rate should mitigate any concerns about rate instability. *Id.*

JP17 states that JP06's proposal to base the hourly non-firm rate on recent years' usage of 23 hours is a clear step toward more accuracy, and there will be no more reason to modify this number in future rate cases than there has been to modify BPA's use of 80 hours. JP17 Br., BP-16-B-JP17-01, at 3-4.

BPA Staff's Position

Staff argues that "[i]f BPA were to adopt JP06's proposal to more than triple hourly non-firm rates, the use of hourly non-firm transmission likely would drop in the next rate period." Linn *et al*., BP-16-E-BPA-31, at 7. Since the rate is based on historical usage, that would result in

even higher rates during the next rate period, which would result in even less usage and even higher rates. *Id.* Staff also states that hourly non-firm transmission is not always available, yet JP06's methodology is based only on what customers were able to reserve. *Id.* Therefore, JP06's calculation of hours per week is skewed towards a lower result, based as much on available hours as true demand. *Id.*

Evaluation of Positions

Basing the hourly non-firm rate on actual usage would raise significant concerns regarding the stability of the rate. JP06's proposal would more than triple the non-firm rate in the BP-16 rate period, which would likely significantly reduce the use of hourly non-firm service. *Id.* at 7. If BPA ignored this reduction in use and kept the rate the same, the rate would no longer be based on usage and the rationale for the rate would no longer exist. Therefore, JP06's proposal would likely lead to higher rates in future rate periods. *Id.*

JP06 states that BPA can discount the hourly non-firm rate to ensure rate stability. JP06 Br., BP-16-B-JP06-01, at 24. Thus, JP06 suggests that BPA can mitigate its concerns by adopting JP06's proposal and then effectively reversing it. Rather than addressing rate stability from rate period to rate period by discounting the rate, the rate should be based on a more durable methodology that does not need to be undone to preserve rate stability.

JP17 argues that there would be no more reason to re-evaluate JP06's figure for actual usage every rate period than there has been to re-evaluate BPA's use of 80 hours, which according to JP17 is based on "anticipated use" of non-firm hourly service. JP17 Br., BP-16-B-JP17-01, at 3. The existing rate, however, is not based on anticipated usage. Linn *et al*., BP-16-E-BPA-31, at 3. Instead, the existing methodology is intended to create an incentive to purchase long-term firm service by making it more expensive to purchase hourly non-firm service if a customer's demand exceeds 80 hours per week. *Id*. Because the methodology is not based on changing historical data, there is no need to revisit it each rate period. A rate based on actual usage, however, could quickly become inaccurate unless it is regularly revisited.

Draft Decision

BPA's ability to discount the hourly non-firm rate does not mitigate concerns regarding the stability of an hourly non-firm rate based on actual usage. Staff's proposal will be adopted.

4.3.4 Oversupply Rate

The OS-16 rate recovers costs attributable to BPA's Oversupply Management Protocol (OMP). Staff's proposal is the same as the OS-14 rate that was adopted pursuant to the OS-14 rate proceeding, except for three limited revisions: (1) removing the exemption from cost allocation that applied to generators that did not submit displacement costs in 2012; (2) deleting a billing provision that was specific to the recovery of costs from 2012 and no longer applies; and (3) updating the Modified Tier 1 Cost Allocators (TOCAs) to reflect the forecast of FY 2016 and FY 2017 TOCAs. Bliven and Fredrickson, BP-16-E-BPA-11, at 3. In addition, Staff proposes to

recover the administrative costs of OMP incurred from FY 2012 through FY 2014, plus the forecast OMP administrative costs for FY 2015–2017, by including these costs in the transmission revenue requirement and allocating the costs across all transmission segments. *Id.* at 4-5. The administrative costs consist of the fee of an independent evaluator that collects the costs of displacement submitted by generators, audits the costs, and constructs a least-cost displacement cost curve that BPA uses to determine which generators should be curtailed during oversupply events. *Id.* at 4.

In initial briefs, no party raised any specific issues with Staff's proposal to recover the administrative costs. Therefore, Staff's proposal will be adopted.

The Oversupply Management Protocol

BPA markets power from the Federal hydro projects operated by the U.S. Army Corps of Engineers (Corps) and the Bureau of Reclamation in the Pacific Northwest. During spring runoff, water flows can be higher than needed to meet regional electric load and exports. In addition, water storage and hydro generating capacity at Federal dams are limited. Therefore, excess water sometimes must be spilled over the dams' spillways (channels to permit the release of excess water). However, high levels of spill can create excessive amounts of total dissolved gas (TDG) in the water, which can lead to gas bubble trauma that threatens the health of the ecosystem and aquatic life, including Endangered Species Act-listed fish. Bonneville Power Administration, BPA's Interim Environmental Redispatch and Negative Pricing Policies: Administrator's Final Record of Decision, at 5-11 (May 2011).

The states of Washington and Oregon have authority under the Clean Water Act to set TDG levels. BPA must adhere to both the Clean Water Act and the Endangered Species Act. Therefore, the Corps and the Bureau of Reclamation plan FCRPS operations to comply with applicable state and tribal water quality standards and minimize excess TDG to the extent practicable by limiting the amount of excess spill. For the last several years, spill and water quality constraints were adopted by court order in litigation mandating that spill operations be conducted as set forth in annual spill orders and Fish Operation Plans. *Nat'l Wildlife Fed'n v. Nat'l Marine Fisheries Serv.*, 839 F. Supp. 2d 1117 (D. Or. 2011).

To avoid excess spill, historically BPA offered to displace non-Federal generation with low-cost or free Federal hydropower. In recent years, however, BPA has integrated 4,500 megawatts of wind generation into the Federal Columbia River Transmission System (FCRTS). Some wind generators receive Federal production tax credits (PTCs) and state renewable energy credits (RECs). PTCs are credits against wind generators' Federal income taxes, and RECs are credits that purchasers of wind generation can use to satisfy their obligations under state law to ensure that a certain percentage of the electricity they sell is produced by renewable resources. Because the generators are granted credits based on the amount of energy they generate, wind generators have no incentive to accept free power to curtail their production and allow BPA to mitigate excess spill.

In March 2011 BPA established an interim environmental redispatch policy under which BPA displaced generators that did not accept offers of free power during periods of high water. BPA substituted free Federal hydropower for the displaced generation. Wind generators and other parties filed a complaint with the Commission under section 211A of the Federal Power Act. That Act authorizes the Commission to order unregulated transmitting utilities (including BPA) to offer transmission service on terms and conditions that are comparable to the terms and conditions under which they provide transmission service to themselves and that are not unduly discriminatory or preferential. The complainants argued that BPA's policy discriminated against wind projects.

The Commission held that BPA's environmental redispatch policy violated section 211A and directed BPA to file tariff revisions within 90 days that addressed the comparability concerns raised in the proceeding in a manner that provides comparable transmission service that is not unduly discriminatory or preferential. BPA responded by adopting the Oversupply Management Protocol, under which BPA compensates displaced generators for certain costs related to displacement, including (1) PTCs; (2) RECs unbundled (sold separately) from the sale of energy; and (3) for contracts executed prior to March 6, 2012, certain losses under bundled contracts (sales of renewable energy credits and energy together) because of the generators' failure to deliver wind power.

On March 6, 2012, BPA filed the OMP with the Commission. In the filing, BPA informed the Commission that it intended to make an initial proposal in the oversupply rate case to allocate 50 percent of the costs of oversupply to power customers and 50 percent to wind generators.

On December 20, 2012, the Commission issued an order conditionally accepting the OMP on an interim basis, subject to BPA's filing a new cost allocation proposal within 90 days. BPA requested rehearing on this issue and also requested a stay of the compliance filing deadline to allow BPA to complete its rate case. The Commission denied rehearing but granted BPA's request for a stay, extending the deadline for filing the cost allocation methodology to a date 30 days after BPA submits its final oversupply rate decision to the Commission.

BPA's original OMP expired on March 30, 2013. Therefore, on March 1, 2013, BPA filed an updated protocol to be effective from March 31, 2013, through September 30, 2015. On October 16, 2014, the Commission issued a final order approving BPA's OMP filing. *Iberdrola Renewables, Inc., v. Bonneville Power Admin.*, 149 FERC ¶ 61,044 (2014).

<u>The OS-14 Rate Proceeding</u>

On November 8, 2012, BPA began the OS-14 rate proceeding to establish a rate to recover the displacement costs BPA incurred under the OMP. BPA originally proposed a cost allocation methodology that allocated 50 percent of the costs to power customers and 50 percent of the costs to wind generators. The Commission rejected that proposal in its order conditionally approving the OMP. On March 27, 2014, the Administrator issued a Final ROD in the OS-14 rate case establishing a rate that allocates costs to generators in BPA's balancing authority area

based on their transmission schedules during oversupply event hours. The Administrator concluded that this allocation

> best aligns with principles of cost causation because the scheduling of generation during oversupply events, as measured by transmission schedules, causes the need to displace generation and hence oversupply costs, and because the need to displace extends only to generators within BPA's balancing authority area.

OS-14 Oversupply Rate Proceeding, Administrator's Record of Decision, OS-14-A-02, at 19 (March 2014) (OS 14 ROD). On October 16, 2014, the Commission issued two final orders approving BPA's OS-14 rate, one approving the OS-14 rate under section 211A of the Federal Power Act and one approving the OS-14 rate under the Northwest Power Act. *Iberdrola Renewables, Inc., v. Bonneville Power Admin.*, 149 FERC ¶ 61,044 (2014); *Bonneville Power Admin.*, 149 FERC ¶ 61,043 (2014). Staff proposes to adopt the same cost allocation for the OS-16 rate.

Issue 4.3.4.1

Whether Staff's cost allocation proposal should be adopted.

Parties' Positions

Iberdrola argues that oversupply costs are caused by BPA's fish and wildlife obligations and inability to sell excess power and therefore should be allocated to power rates. Iberdrola Br., BP-16-B-IR-01, at 7-9. Iberdrola argues that the need to pay wind generators to displace is not the cause of oversupply costs. *Id.* at 8. In addition, Iberdrola argues that oversupply costs are also a result of BPA's inability to sell excess power on the market for a price other than a negative price. *Id.*

JP01 also argues that oversupply costs should be allocated to power rates because they are caused by BPA's fish and wildlife obligations and inability to sell excess power. JP01 Br., BP-16-B-JP01-01, at 9. JP01 denies that transmission usage causes oversupply costs, arguing that BPA would still experience the same oversupply problems if non-Federal generation did not use BPA's transmission. *Id.* at 6. JP01 also argues that BPA's rationale is inconsistent with the Commission's conclusion, as the Commission concluded that oversupply was caused by insufficient transmission capacity. *Id.* at 7-8.

JP-09, WPAG, ICNU, and M-S-R all support Staff's proposal. JP-09, ICNU, and WPAG argue that JP01 and Iberdrola make the same arguments that were raised and rejected by BPA in the OS-14 rate proceeding and that they should be rejected again. JP-09 Br., BP-16-B-JP09-01, at 8; ICNU Br., BP-16-B-IN-01, at 10-11; WPAG Br., BP-16-B-WG-01, at 27-28. JP-09 and ICNU additionally argue that there has been no change in facts or circumstances that would justify a different cost allocation. JP-09 Br., BP-16-B-JP09-01, at 8-9; ICNU Br., BP-16-B-IN-01, at 10-11. M-S-R argues that it would be inefficient to adopt a new proposal given "the pending challenges and market dynamics." M-S-R Br., BP-16-B-MS-01, at 24.

BPA Staff's Position

Staff proposes the same cost allocation methodology established in the OS-14 rate case. Bliven and Fredrickson, BP-16-E-BPA-11, at 2. Staff reiterates the position adopted in the OS-14 ROD that the scheduling of generation in BPA's balancing authority area, as measured by transmission schedules, causes the need to displace generation and hence the incurrence of oversupply costs. *Id.* at 1-3.

Evaluation of Positions

Iberdrola's and JP01's argument that oversupply costs are caused solely by BPA's fish and wildlife obligations and inability to sell excess power has already been considered and rejected in the OS-14 ROD. As BPA explained:

> These arguments overlook the fact that BPA incurred no oversupply costs before the interconnection and integration of wind generation. Because of the interconnection of wind generation in BPA's balancing authority area, and because these generators require compensation for displacement, BPA now incurs oversupply costs.

OS-14 ROD, at 21. Staff reiterated this position in testimony, and neither Iberdrola nor JP01 has presented any new arguments that would compel a different conclusion. Bliven and Fredrickson, BP-16-E-BPA-24, at 1-3.

JP01's argument that non-Federal generation does not cause oversupply costs, because BPA would still experience the same oversupply problems if non-Federal generation used non-Federal transmission, was also raised and rejected in the OS-14 ROD. OS-14 ROD, at 21-22. As explained in that ROD, BPA satisfies its environmental responsibilities when it displaces the generation in its balancing authority area over which BPA has operational control. *Id.* Because BPA does not have operational control over generation outside its balancing authority area, BPA has no obligation to displace those generators and incur costs. *Id.* Thus, if non-Federal generation used non-Federal transmission, there would be no oversupply costs. Staff reiterated this position in its testimony in this case. Bliven and Fredrickson, BP-16-E-BPA-24, at 4. Again, JP01 has offered no reason for a different conclusion.

JP01 also argues that BPA's rationale is inconsistent with the Commission's rationale in approving BPA's OS-14 rate and that BPA cannot rely on the Commission's approval without explaining the inconsistency. JP01 Br., BP-16-B-JP01-01, at 7-8. Specifically, JP01 argues that the Commission found that oversupply costs are caused by the lack of transmission capacity, whereas BPA found that transmission capacity was not an issue. *Id.* This issue was raised in a request for rehearing of the Commission's order approving the OS-14 rate and in JP01's direct testimony. Holland *et al.*, BP-16-E-JP01-01, at 8-9. The Commission rejected the argument on rehearing:

> We recognize that it is not a lack of transmission capacity that causes the need to displace generators, but rather a need to match generation being delivered over

> the system with load. Oversupply costs are nevertheless appropriately viewed as transmission costs because it is generation scheduled to be delivered over the system … which is then displaced that creates the oversupply costs.

Iberdrola Renewables Inc. v. Bonneville Power Admin., 150 FERC ¶ 61,113, at P 19 n. 27 (2015). The Commission thus made clear that it did not base its conclusion on a transmission capacity problem. Moreover, the Commission, the agency statutorily charged with reviewing and approving BPA's rates, approved BPA's OS-14 rate, and it would defy reason for BPA to reject the Commission's approval based on one sentence in the Commission's order. Thus, JP01's argument has no basis.

Draft Decision

Staff's cost allocation proposal will be adopted.

Issue 4.3.4.2

Whether the allocation of oversupply costs to transmission rates complies with section 7(g) of the Northwest Power Act.

Parties' Positions

Iberdrola and JP01 argue that under section 7(g) of the Northwest Power Act, the costs of fish and wildlife measures and the inability to sell excess power must be allocated to power rates. Iberdrola Br., BP-16-B-IR-01, at 4-6; JP01 Br., BP-16-B-JP01-01, at 15-18. These parties also argue that it is unfair to allocate the benefits of the sale of surplus power to power rates but allocate the cost of a sale of power at a negative price through OMP to transmission rates. Iberdrola Br., BP-16-B-IR-01, at 5-6; JP01 Br., BP-16-B-JP01-01, at 16-17.

JP09 and WPAG argue that in the OS-14 rate proceeding BPA rejected parties' arguments that section 7(g) of the Northwest Power Act requires oversupply costs to be allocated to power rates. JP09 Br., BP-16-B-JP09-01, at 10-11; WPAG Br., BP-16-B-WG-01, at 28-29. In addition, JP09 and WPAG argue that oversupply costs are transmission costs that are allocated to transmission rates through other provisions of the Northwest Power Act; therefore, section 7(g) does not apply. JP09 Br., BP-16-B-JP09-01, at 10-11; WPAG Br., BP-16-B-WG-01, at 28-29.

BPA Staff's Position

This is a legal issue and was not addressed by Staff in testimony.

Evaluation of Positions

Iberdrola and JP01 raise the same argument challenging the allocation of costs to transmission customers under section 7(g) of the Northwest Power Act that was raised in the OS-14 rate proceeding. Section 7(g) of the Northwest Power Act provides as follows:

> *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 accepted 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 section 839d of this title, the cost of credits granted pursuant to section 839d of this title, operating services, and the sale of or inability to sell excess electric power.

16 U.S.C. § 839e(g) (2006) (emphasis added).

In the OS-14 ROD, the Administrator found that oversupply costs are attributable to the interconnection of wind generation in BPA's balancing authority area. OS-14 ROD, at 27-28. Because interconnection is a transmission service, the Administrator found that oversupply costs were costs attendant to the transmission of power that are properly allocated under sections 9 and 10 of the Transmission System Act and section 7(a)(1) of the Northwest Power Act. *Id.* at 30. The first clause of section 7(g) of the Northwest Power Act makes clear that the section does not apply if costs are already allocated under other provisions of law. Therefore, section 7(g) does not require that the costs of oversupply be allocated to power rates.

In the OS-14 rate proceeding, parties also made the same argument that Iberdrola and JP01 make here regarding the allocation of the costs and benefits of the sale and inability to sell excess power. In rejecting that argument, BPA explained, "[s]econdary sales—the sale of additional power off-system after BPA has satisfied its contractual obligations for the sale of power—are purely a power function. The revenues from these sales are not created by the interconnection of generators or by any other transmission action." OS-14 ROD, at 32. Because oversupply costs are caused by the interconnection of wind generators, which is a transmission service, and secondary sales are a power function, there is no inequity in allocating secondary sales revenues to power and oversupply costs to transmission.

<u>Draft Decision</u>

The allocation of oversupply costs to transmission rates complies with section 7(g) of the Northwest Power Act.

Issue 4.3.4.3

Whether the OS-16 rate equitably allocates costs between Federal and non-Federal users of the transmission system under section 10 of the Transmission System Act and section 7(a)(2)(C) of the Northwest Power Act.

Parties' Positions

JP01 argues that, because oversupply costs are power costs, the equitable allocation standard of section 10 of the Transmission System Act and section 7(a)(2)(C) of the Northwest Power Act prohibits the allocation of the costs to transmission rates. JP01 Br., BP-16-B-JP01-01, at 18-19.

JP09 and WPAG argue that oversupply costs are transmission costs and thus satisfy the equitable allocation standard. JP09 Br., BP-16-B-JP09-01, at 14-15; WPAG Br., BP-16-B-WG-01, at 30. JP09 and WPAG argue that BPA and the Commission have already concluded that the allocation of oversupply costs to transmission meets the equitable allocation standards and that there is no reason to reach a different conclusion in this case. JP09 Br., BP-16-B-JP09-01, at 14-15; WPAG Br., BP-16-B-WG-01, at 30.

BPA Staff's Position

This is a legal issue and was not addressed by Staff in testimony.

Evaluation of Positions

Section 10 of the Transmission System Act provides, in part, that "[t]he 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 (2006). This standard was reiterated in section 7(a)(2)(C) of the Northwest Power Act, under which the Commission approves BPA's transmission rates upon a finding that such rates "equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing such system." § 839e(a)(2)(C) (2006). *See Cent. Lincoln Peoples' Util. Dist. v. Johnson*, 735 F.2d 1101, 1114-15 (9th Cir. 1984) (the equitable allocation requirement of section 7(a)(2)(C) of the Northwest Power Act "has its roots" in section 10 of the Transmission System Act). The Commission has interpreted section 7(a)(2)(C) to require a separate accounting of power and transmission costs so that the Commission can determine that "(1) transmission revenues are only used to repay transmission costs; (2) *costs assigned to transmission are only transmission related costs*; and (3) any deficiencies or surpluses in transmission revenues are being tracked and collected or credited to the appropriate customer class." *U.S. Dep't of Energy–Bonneville Power Admin.*, 25 FERC ¶ 61,140, at 61,375-76 (1983) (emphasis added).

JP01's argument was raised and rejected in the OS-14 ROD, as JP09 and WPAG correctly point out. As the Administrator explained:

> [Oversupply] costs are caused by BPA's interconnection of wind generators and BPA's management of the transmission system during oversupply conditions. Both interconnection and the exercise of operational control are actions attendant

> to the transmission of power. Therefore, assigning oversupply costs to transmission rates is consistent with the equitable allocation standard.

OS-14 ROD, at 37. The Commission approved the OS-14 rate as meeting the equitable allocation standard under section 7(a)(2)(C) of the Northwest Power Act. *Bonneville Power Admin.*, 149 FERC ¶ 61,043, at P 24 (2014). For the reasons stated above, the allocation of oversupply costs meets the equitable allocation standards under section 10 of the Transmission System Act and section 7(a)(2)(C) of the Northwest Power Act.

Draft Decision

The OS-16 rate equitably allocates costs to Federal and non-Federal users of the transmission system and complies with section 10 of the Transmission System Act and section 7(a)(2)(C) of the Northwest Power Act.

4.3.5 Elimination of the Montana Intertie

The Montana Intertie is the 500-kV line that runs from Broadview substation on NorthWestern Energy's transmission system west to Townsend, and then west from Townsend on BPA's system to Garrison substation. The Montana Intertie (IM) rate is available to transmission customers taking Point-to-Point transmission service on the Eastern Intertie, which is the part of the Montana Intertie owned by BPA. The Eastern Intertie is the 500-kV line between Townsend and Garrison substation. BPA's Network begins at Garrison substation and extends west from there.

The westbound capacity of the Eastern Intertie is 1930 MW. BPA has sold 1730 MW of this capacity to the owners of the Colstrip coal plant. Of the remaining 200 MW, BPA has sold 16 MW. Elimination of the IM rate, as proposed by Renewable Northwest, would mean that BPA's share of Eastern Intertie costs would be included in Network rates. BPA's share of the costs equals the amount of remaining westbound capacity BPA sells divided by the total capacity sold. For example, if BPA sells 100 MW of the remaining capacity, the total sold would be 1830 MW. BPA's share of the costs would be 5.5 percent (100/1830).

Some parties framed their opposition to Renewable Northwest's proposal in terms of opposing roll-in of BPA's share of the costs of the Eastern Intertie into Network rates. In terms of ratemaking, "roll-in of the costs" and "elimination of the IM rate" are the same thing—inclusion of BPA's share of Eastern Intertie costs in Network rates.

Issue 4.3.5.1

Whether to eliminate the IM rate and charge Network rates for Point-to-Point service over the Eastern Intertie starting at Townsend.

Parties' Positions

Renewable Northwest argues that BPA should eliminate the IM rate for open access service on the Eastern Intertie in order to encourage use of BPA's 200-MW share of the Eastern Intertie and the development of wind resources in Montana. RN Br., BP-16-B-RN-01, at 1. Renewable Northwest adds that, although BPA's Eastern Intertie capacity was originally intended for the use of one party, that deal was terminated before the capacity was ever used for that purpose, and the capacity is now available under BPA's OATT. *Id.* at 4.

JP15, M-S-R, WPAG, and JP12 oppose elimination of the IM rate. JP15 argues that no material fact has changed since the last two Administrators rejected similar proposals to roll BPA's share of the Eastern Intertie costs into the Network rate. JP15 Br., BP-16-B-JP15-01, at 5. JP15 argues that retaining the IM rate would strike an appropriate balance between BPA's obligation to promote widespread use of electric power and cost causation. *Id.* at 12. JP15 states that the Eastern Intertie serves only a small subset of BPA customers and rolling its costs into the Network would expose BPA's Network customers to a variety of costs and risks. *Id*. at 12-13.

WPAG also argues that elimination of the IM rate would expose Network customers to long-term cost risks. WPAG Br., BP-16-B-WG-01, at 16-18. M-S-R argues that the Eastern Intertie is radial to BPA's system, that it is a generation tie, and that Federal Energy Regulatory Commission policy and the evidence in the record do not support rolling its costs into the Network rate. M-S-R Br., BP-16-B-MS-01, at 14-15. JP15, M-S-R, WPAG, and JP12 all argue that elimination of the IM rate could be a precedent for roll-in of the Southern Intertie costs to the Network rate, which would result in a much larger Network rate increase than would elimination of the IM rate. JP15 Br., BP-16-B-JP15-01, at 16; M-S-R Br., BP-16-B-MS-01, at 21-22; WPAG Br, BP-16-B-WG-01, at 15-16; JP12 Br., BP-16-B-JP12-01, at 2-3.

BPA Staff's Position

In the Initial Proposal, BPA Staff proposed to retain the Eastern Intertie segment and the IM rate. Tenney *et al.*, BP-16-E-BPA-16, at 23. Staff testified that although separate delivery and intertie rates might be viewed as a discouragement of widest possible use, the status quo "strikes an appropriate balance between the widest diversified use requirement and cost causation." *Id.* In rebuttal testimony, although Staff did not explicitly change its position, Staff said that Renewable Northwest's proposal to eliminate the IM rate should be seriously considered. Metcalf *et al.*, BP-16-E-BPA-32, at 6. The impact on the Network rate of eliminating the IM rate could be either positive or negative, but in any case would be exceedingly small. *Id.* at 4. Elimination of the rate could encourage use of BPA's unused Eastern Intertie capacity. *Id.* at 12. Elimination of the rate would tend to encourage development of renewable generation within the Pacific Northwest, help Northwest utilities meet needs for high-quality wind

generation, and help Montana meet its obligations under the Environmental Protection Agency's proposed Clean Power Plan. *Id.* at 8-11.

Evaluation of Positions

Renewable Northwest's proposal in BP-16 to eliminate the IM rate is the same as previous proposals to roll the portion of BPA's share of the Eastern Intertie that is sold into the Network. Metcalf *et al.*, BP-16-E-BPA-32, at 1-2. Renewable Northwest also argued in the BP-12 and BP-14 rate cases that costs of the Eastern Intertie should be rolled into the Network rate. Tenney *et al.*, BP-16-E-BPA-16, at 22. In both cases the Administrator rejected the proposal. JP15 Br., BP-16-B-JP15-01, at 5; Tenney *et al.*, BP-16-E-BPA-16, at 23.

Impact on renewable resource development in Montana

Renewable Northwest claims that elimination of the IM rate would reduce transmission costs for Montana wind generation delivered to BPA's Network and therefore could support development of renewable generation in Montana. RN Br., BP-16-B-RN-01, at 5. RN notes that one of the purposes of BPA's statutes is "to encourage … the development of renewable resources within the Pacific Northwest." *Id.* at 13, *citing* 16 U.S.C. § 839(1)(B). The high-quality wind resource areas identified by BPA Staff within the Vigilante and Glacier Electric Cooperative service areas are in the Pacific Northwest as defined by the Northwest Power Act. Metcalf *et al.*, BP-16-E-BPA-32, at 9-10 & Att. 2.

It is not clear, however, that the IM rate is a significant impediment to the development of wind generation in Montana. Renewable Northwest argues that this additional transmission charge undermines the competitiveness of Montana wind generation, but offers no support for this conclusion. RN Br., BP-16-B-RN-01, at 5; Yourkowski, BP-16-E-RN-01, at 6. Renewable Northwest compared the cost of Montana wind generation to the cost of new natural gas facilities on BPA's network rather than to other wind generation. Yourkowski, BP-16-E-RN-01, at 6. Comparing Montana wind generation to other wind generation compels a different conclusion.

At a 40 percent capacity factor (the percentage of actual generation of a resource compared to its capacity), the IM rate adds $2/MWh to the delivered cost of energy. *Id*. This is a relatively small addition to the total cost of over $100/MWh. Baker *et al*., BP-16-E-JP07-03, at 7. The average capacity factor for Montana wind generation is slightly lower at 38 percent, but is still significantly higher than the expected capacity factor of 29 percent for Columbia Gorge wind generation, thus making Montana wind generation quite competitive. Metcalf *et al.*, BP-16-E-BPA-32, at 10. A presentation that Renewable Northwest itself cited in testimony shows the cost of Columbia Basin wind generation to be higher than the cost of Montana wind generation by more than $2/MWh. *See* Baker *et al*., BP-16-E-JP07-03, Att. A (*cited by* Yourkowski, BP-16-E-RN-01, at 6 n.6). Thus, even having to pay the IM rate, Montana wind generation has comparable or lower costs.

Moreover, although Montana's potential wind generation exceeds 9,000 MW, Metcalf *et al.*, BP-16-E-BPA-32, at 10, the absence of available transmission capability in Montana and on BPA's Network would make large-scale wind development unlikely. *Id.* at 7-8. NorthWestern

Energy, the likely transmission provider for Montana wind generation to BPA's Network, currently posts only 49 MW of available transfer capability to BPA at Townsend. *Id.* at 7. BPA has only 184 MW of available capacity on the Eastern Intertie. *See id.* at 3. BPA's Network is constrained over the West of Garrison and West of Hatwai flowgates. Transmission requests in BPA's transmission queue that would use those flowgates exceed the available transfer capability. *Id.* at 8. Therefore, given current transmission constraints it is unlikely that eliminating the IM rate would lead to significant renewable resource development in Montana. *Id.* at 7-8.

JP07 and JP15 raise significant concerns regarding the costs and cost responsibility of the transmission upgrades and balancing capacity that would be necessary to support additional wind development. Baker *et al*., BP-16-E-JP07-03, at 13-14; Baker *et al*., BP-16-E-JP15-01, at 6-9. Renewable Northwest did not address these concerns. BPA would be willing to work with the parties after the rate case to continue to discuss the potential for wind development in Montana. As part of those discussions, parties should discuss plans for upgrades, including cost issues.

Southern Intertie roll-in

JP15, WPAG, and M-S-R claim that elimination of the IM rate would be a precedent for rolling the costs of the Southern Intertie into the Network rate. JP15 Br., BP-16-B-JP15-01, at 16; WPAG Br., BP-16-B-WG-01, at 15-16; M-S-R Br., BP-16-B-MS-01, at 21-23. Rolling in the costs of the Southern Intertie to the Network rate would result in a 12.5 percent Network rate increase. Metcalf *et al.*, BP-16-E-BPA-32, at 12. A rate increase of this size could result in rate instability and rate shock. It would not be consistent with encouraging the widest possible use of electric power at the lowest possible rates to consumers consistent with sound business principles.

In addition, because BPA's Southern Intertie capacity is fully reserved southbound, roll-in would not result in increased southbound reservations. *Id*. Therefore, the Network rate increase would not yield commensurate benefits to Network customers.

Because no party has proposed roll-in of the Southern Intertie costs to the Network rate and the IM rate is not being eliminated, it is unnecessary to consider other arguments regarding the Southern Intertie at this time.

Draft Decision

The IM rate will not be eliminated. It is unlikely that, by itself, elimination of the IM rate would result in additional Montana wind generation. However, BPA is willing to work with interested parties after the rate case to discuss transmission issues relating to potential wind development in eastern Montana, including necessary upgrades and costs.

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5.0 PARTICIPANT COMMENTS

This chapter summarizes and evaluates the comments of participants in the rate case. As defined in BPA's procedures for conducting rate proceedings, "participants" are persons that comment on BPA's rate proposal but do not take part in the formal hearing process with the responsibilities of "parties." Parties to the case file testimony and briefs and thus are not allowed to submit comments as participants. Participant comments are part of the official record of the rate proceeding and are considered when the Administrator makes his final decisions.

On December 4, 2014, BPA published in the Federal Register a Notice of "Fiscal Year (FY) 2016–2017 Proposed Power and Transmission Rate Adjustments Public Hearing and Opportunities for Public Review and Comment." 79 Fed. Reg. 71,984 (2014). The Federal Register notice may be viewed at the link: https://www.federalregister.gov/articles/2014/12/04/2014-28463/fiscal-year-fy-2016-2017-proposed-power-and-transmission-rate-adjustments-public-hearing-and. The Federal Register notice set a deadline of February 26, 2015, for participant comments.

BPA received three comments through the participant comment process. Summaries of the participant comments, and BPA's responses, are provided below.

Comment BPRP140001. Participant Charles Pace stated that setting February 26, 2015, as a final date for participants to submit written comments violates the procedural requirements in the Northwest Power Act and limits BPA's ability to develop a full and complete record. Dr. Pace stated: "This is in violation of the statutory requirements of section 7(i)(2)(A) of the Northwest Power Act, 94 Stat. 2726, which, in relevant part, provides as follows: ANY PERSON shall be provided an adequate opportunity by the hearing officer to offer refutation or rebuttal of ANY MATERIAL submitted by ANY OTHER PERSON OR the ADMINISTRATOR, 16 U.S.C. 839e(i)(2)(A) (emphasis added). By establishing February 26, 2015, as the close of opportunity for participants to submit comments, all persons other than parties are denied the procedural protections established by Congress to offer refutation or rebuttal of material submitted by other persons, including the Administrator, after February 26, 2015."

Dr. Pace stated that BPA should establish a date at the close of the hearing for participant comments so that participants could comment on all material submitted, including, among other things, rebuttal testimony, briefs, and the Draft Record of Decision. Finally, he added that participants should be allowed to participate in the hearing and have the opportunity to engage in "non-dilatory" cross-examination (questioning that does not delay the process).

Comment BPRP0002. Dr. Pace submitted a second comment that corrects a typographical error in his first comment.

Response to Comments BPRP0001 and 0002. Setting a reasonable limit on the time for submitting participant comments (such as the February 26 limit) does not violate the procedural requirements of the Northwest Power Act. Dr. Pace's underlying concern appears to be that BPA denied participants procedural protections when it set the date for public comment before

the filing of parties' rebuttal cases, cross-examination, filing of briefs, and publication of the Draft Record of Decision. The Northwest Power Act requires the Administrator to publish notice of the "proposed rates" in the Federal Register, 16 U.S.C. § 839e(i)(1), and requires the hearing officer to conduct a hearing to "receive public comment in the form of written and oral presentation of views, data, questions, and argument related to *such proposed rates*." *Id*. § 839e(i)(2) (emphasis added). That is, the public has the right to respond to BPA's initial rate proposal.

BPA published its Initial Proposal on December 10, 2014, almost three months before the date set for the end of receipt of public comments. As a result, all participants had adequate opportunity to review and comment on BPA's rate proposal. In addition, the date for participant comments was more than three weeks after the filing of the parties' direct cases, allowing participants the opportunity to comment on that material as well.

It would be unwieldy and administratively burdensome to allow participants to take part in the hearing and to conduct cross-examination. The Administrator must be allowed to exercise the discretion necessary to establish the scope of the proceeding in order to allow the proceeding to be conducted in an orderly and timely manner.

Comment BPRP0003. The Governor of Montana filed a participant comment stating that BPA should eliminate the Montana Intertie rate (IM rate). The governor stated: "Montana power generators using BPA's Eastern Intertie continue to pay both the IM rate and the Network rate, and this duplicative charge negatively impacts energy development in Montana." The governor added that elimination of the IM rate would help Montana comply with the EPA's Clean Power Plan and encourage wider use of BPA's Eastern Intertie. Finally, the governor stated, it would "significantly benefit the economy in Montana, provide regional benefits, and contribute to domestic energy security."

Response to comment BPRP0003. This issue has been litigated in the rate case and is addressed in Draft Record of Decision section 4.3.5.

6.0 NATIONAL ENVIRONMENTAL POLICY ACT ANALYSIS

BPA is in the process of assessing the potential environmental effects that could result from implementation of the FY 2016–2017 proposed power and transmission rate adjustment, consistent with the National Environmental Policy Act (NEPA). The NEPA analysis is conducted separately from the formal rate process. No comments concerning NEPA compliance and/or potential environmental effects of the proposal were received during the participant comment period for the rate proceeding. As discussed in the Federal Register notice for the BP-16 power and transmission rate proposal, 79 Fed. Reg. 71,984, 71,987 (2014), this proposal appears to fall within the scope of the Market-Driven Alternative that was evaluated in BPA's Business Plan Final Environmental Impact Statement, DOE/EIS-0183, June 1995 (Business Plan EIS) and adopted in the August 1995 Business Plan ROD. Accordingly, BPA expects to tier its decision under NEPA to the Business Plan EIS and ROD. BPA will complete its NEPA process and issue its NEPA ROD or other appropriate final NEPA documentation concerning the proposal when it issues its Final Record of Decision for the BP-16 rate proceeding.

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BONNEVILLE POWER ADMINISTRATION

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