

BP-18 Rate Proceeding

ADMINISTRATOR'S FINAL RECORD OF DECISION

BP-18-A-04

July 2017



ADMINISTRATOR'S PREFACE

The Bonneville Power Administration's ability to continue meeting its multiple statutory obligations and public-purpose objectives depends on maintaining cost competitiveness and financial health. To that end, this rate case addressed four factors that are critical to our long-term commercial success: rigorously managing costs, strengthening our finances, investing in the future of the grid, and managing our competitive position in the rapidly changing electricity market. The rate case also highlighted costs outside of BPA's direct control that continue to place significant upward pressure on rates.

The final rates for fiscal years 2018 and 2019 represent significant efforts to offset the less controllable elements of our revenue requirement and reduce the degree of programmatic cost escalation in both Power and Transmission. The Power Services rates in particular reflect the reality of changes underway in our operating environment and take into account the long-term interests of BPA and its customers by, among other things, rebuilding financial reserves through the newly established Financial Reserves Policy.

Consistent with our Draft Record of Decision, the average power rate increase is 5.4 percent, and the average transmission rate is decreasing 0.7 percent. I believe the power rate increase is necessary to set the stage for greater rate stability and cost competitiveness over the long term. And while transmission rates on average are decreasing, I have highlighted a concern about our capital investment strategy that we must address in the near future. We will focus on this concern as well as the less controllable cost pressures we are facing as we develop our long-term strategic plan throughout the balance of 2017 in collaboration with customers and regional partners.

Managing Costs

Bonneville's rates are driven both by controllable costs and costs that are beyond our direct control. Without our determined efforts to offset them, the less controllable power rate drivers alone would have resulted in a 7 percent rate increase. More than half of the 5.4 percent power rate increase is due to the combination of decreasing customer loads and lower market price expectations for sales of BPA's surplus power. The amount of load placed on BPA by public customers and directly served industrial customers has continued to decline—a dynamic many utilities in the region are experiencing. This results in higher rates, as BPA has fewer sales over which to spread its costs.

Market prices have declined due to lower forecast natural gas prices and increasing amounts of new generating resources coming on line. Relative to BP-16, the forecast value of our surplus sales is expected to decrease by roughly \$28 million on average each year of the 2018–2019 rate period due to reduced market price expectations. Escalating Residential Exchange Program settlement payments, increasing transmission rates BPA pays to other providers for transfer service, decreasing renewable balancing service revenue, and expiring long-term power sales contracts also contributed to this potential 7 percent upward rate impact. The table on the next page illustrates the power rate drivers.

Power Rate Drivers

	Rate Impact (BP-18 compared to BP-16 rates)
Costs beyond BPA’s direct control	7.2%
BPA’s program costs (IPR)	1.7%
Debt-management actions	- 4.5%
Replenishing Power financial reserves	1%
Overall power rate change	5.4%

Although not included in the rate increase, another source of significant rate pressure we will face this rate period is the March 27 spill ruling, amended April 3, by the U.S. District Court for the District of Oregon. The court indicated that it will order increased spill for the 2018 spring migration season. The ruling will have cost implications for BPA that we are still evaluating. Therefore, I am adopting a spill surcharge that will allow us to adjust rates in both FY 2018 and 2019 based on the cost associated with increased spill and lost generation relative to current spill assumptions. I recognize the uncertainty this places on our customers, and I am committed to working with our regional partners to find program cost savings, including in our Environment, Fish and Wildlife spending, to help offset this surcharge.

I also recognize that BPA’s less controllable costs, if not offset by other cost reductions, would build on an unsustainable trajectory of rate increases. Following four sequential rate periods with power rate increases averaging nearly 8 percent, we heard consistent demands from customers to address the rising costs of operating the Federal Columbia River Power System. We responded by significantly mitigating cost escalations in the Integrated Program Review (IPR) and subsequent IPR 2. As a result, the impact of BPA’s program costs on power rates over the next two years is 1.7 percentage points. This required a determined effort across BPA and demonstrates our deepening commitment and capacity to manage costs. The table below illustrates the pattern of reduced cost escalation since BP-12.

Cost Reductions since BP-12

	BP-14 change from BP-12	BP-16 change from BP-14	BP-18 change from BP-16
All IPR costs	6%	6%	3%
Internal operations	8%	2%	1%
Capital-related costs	-7%	-1%	-10%

We also reduced our capital-related costs by 10 percent. This is the third rate case in which debt-management actions provided significant rate relief, offsetting the upward drivers mentioned above by nearly half. In partnership with Energy Northwest, capital expenses going into BP-18 power rates are \$91 million per year lower than in BP-16. These lower capital expenses provide not only rate relief in the upcoming rate period, but also enduring interest savings for future rate periods. I appreciate the efforts of Energy Northwest and the many BPA Staff and other regional partners who helped make the benefits of Regional Cooperation Debt possible.

We intend to maintain this focus on aggressive cost control into the next rate period and beyond.

While we worked to mitigate the significant upward pressures on BP-18 rates, our fiscal year 2017 financial reserves for risk dwindled as a consequence of load loss and low market prices for our surplus power. Power Services faced a high probability of reaching negative financial reserves for risk—the threshold for triggering the cost recovery adjustment clause (CRAC), which would lead to a one-year power rate increase in FY 2018. We mitigated that risk through an additional effort, concurrent with the IPR 2 process, to reduce FY 2017 expenses and offset the decline in this year’s revenues. That effort resulted in a forecast reduction of \$46 million from the first quarter to help us end the fiscal year with enough financial reserves to avoid a CRAC.

Strengthening BPA’s Finances

The use of more than \$700 million in Power’s financial reserves over the last 10 years provided significant rate relief for the region’s power customers. Although BPA has adequate liquidity for the rate period because of the Treasury note, BPA’s financial reserves at the end of FY 2017 will be at their lowest levels since the West Coast energy crisis in 2000-2001. It is time to begin replenishing those financial reserves to support BPA’s credit ratings, liquidity, equity between business lines and future rate stability.

BPA worked with customers and stakeholders before and during this rate case to develop a proposed policy for managing financial reserves, and the parties presented well-reasoned arguments and counter-proposals. I have carefully reviewed and considered their positions, including requests to delay a decision on how best to allocate reserves between the business lines. I am convinced that the Financial Reserves Policy adopted in this BP-18 Record of Decision is the appropriate approach. The policy will provide both clarity and transparency in our management of financial reserves. It sets upper and lower financial reserves thresholds by business line, based on the metric of days cash on hand, to support BPA’s credit rating, promote equity, provide liquidity and rate stability, and ultimately support the agency’s long-term financial health. Days cash is widely recognized as the industry standard and best reflects the amount of financial reserves each business line should hold to prudently manage its business. Under the policy, we will begin rebuilding Power’s financial reserves by collecting \$20 million above projected net costs each year until the lower threshold is reached. This accounts for one-fifth of the BP-18 power rate increase. The policy will not require future rate increases, as the same amount will be included in Power’s future revenue requirement.

While I am adopting the Financial Reserves Policy in this decision, I have left some implementation features open for further development, including how to phase in the lower threshold for Power's financial reserves and how to best leverage financial reserves to manage long-term wholesale market price exposure and promote greater rate stability. I believe that the region will be best served by focusing on these elements in future processes, such as the upcoming long-term strategic planning discussions and BP-20 Rate Case workshops.

Investing in the Future of the Grid

Investing in system modernization and taking advantage of new markets and technology is vital to our long-term success. BPA will continue to aggressively pursue cost management actions, but we know we cannot rely on cost-control measures alone to mitigate future rate pressures. As discussed in IPR 2, through the Commercial Operations effort we are committing to modernizing systems to provide state awareness and technological advances that will preserve and enhance the value of the Federal power and transmission systems. Also, as reflected in our decision not to build the I-5 Corridor Reinforcement Project, we recognize that the cost and complexity of building assets require us to use existing resources as efficiently as possible, embrace new technology, and develop the ability to interface with new markets.

Positioning BPA in the Rapidly Changing Electricity Market

Efforts to modernize our system will take time to scope and implement, but we are already addressing the effects of the changing markets on our operations. For instance, in this rate case I am changing the hourly Southern Intertie rate design to address seams issues between the Pacific Northwest and California that we first acknowledged in the BP-16 Rate Case. The continued integration of new resources in California has only heightened these seams issues. I believe this rate methodology will ensure that we recover the costs of the Southern Intertie appropriately between both long-term and short-term users and maintain the stable revenue stream of our long-term firm intertie sales.

I have also carefully considered the perspectives of key stakeholders regarding the Montana Intertie (IM) rate and decided not to eliminate it, consistent with my decision in the BP-16 Rate Case. Although my fundamental policy position on this issue has not changed, I do agree with stakeholder comments further detailed in Briefs on Exceptions that the IM and Eastern Intertie rates are calculated inconsistently, so I am making minor changes to align these rate methodologies and make them consistent with other tariff-based services. Going forward, the IM rate will recover a portion of the segmented revenue requirement for the Eastern Intertie, resulting in an IM rate decrease of about 15 percent.

Regarding my decision to retain the IM rate, BPA encourages and will continue to partner in efforts supporting economic growth in the region, including the development of renewable generation resources in Montana. While BPA will continue to process transmission service requests pursuant to its Open Access Transmission Tariff, I believe achieving utility-scale development of renewable resources in Montana will require the active engagement of other regional utilities, transmission planners, policymakers, and other interested stakeholders in a regional setting. This is much like what occurred decades ago for the Colstrip generation project, which resulted in the building of the Montana Intertie. The goal would be a

comprehensive commercial and policy framework that appropriately balances the opportunities, risks, and costs of such development, including interconnection, provision of ancillary services, and potential upgrades to BPA's transmission system. To that end, BPA is preparing to help establish and actively participate in a thoughtful, cohesive process to address barriers to the development of renewables in Montana. Details will be revealed shortly after the completion of this rate case.

Looking Forward

The low market prices that are affecting BP-18 power rates are likely to maintain pressure on future rates. Going forward, we will need to have candid discussions about market prices and BPA's secondary revenue forecast; potentially adopt different rate mechanisms with more conservative forecasts; and most importantly, look for ways to offset our exposure to the commodity market. As well, we will need to find ways to address the effects of the load-resource balance that continues to impact our revenues.

And while we are not seeing a transmission rate increase in BP-18, we have to address the significant impact of long-term capital costs, which could lead to steep increases in future transmission rates. In our strategic planning conversations later this summer, we will take a hard look at BPA's capital needs and constraints to develop a sustainable investment strategy that strengthens our balance sheet and addresses pending transmission rate increases.

Given the significant changes under way in Transmission Services' business model, I have also heard some customers express concerns that we may need to make additional investments in Transmission's human capital and technical capability. While I am committed to the disciplined management of BPA's workforce and making overall personnel cost reductions in the coming years, I am also sensitive to these concerns and will carefully evaluate such needs in preparation for the next rate period and beyond.

Throughout BPA, we are taking meaningful steps to strengthen our culture of cost management and bring the rate of programmatic cost escalation under control. But the fact remains that power rates are increasing again, and we have more work to do. BPA is gearing up for the next phase of dialogue with the region to further improve management of our programmatic costs and discuss the significant cost drivers that cannot be controlled by agency decisions alone.

As we face the many challenges in our operating environment, there are also opportunities on the horizon, and we need to position ourselves to take advantage of them. We are particularly focused on emerging opportunities to deploy the surplus capability of our clean, flexible hydroelectric resources to support regional reliability and the growing demand for flexible capacity in the Western Interconnection.

I look forward to working with you in the months ahead to enable BPA to remain the wholesale power provider of choice for our Northwest power customers, to become an increasingly innovative and responsive transmission provider, and to continue delivering on our role as an engine of the region's economic prosperity and environmental sustainability.

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BP-18 ADMINISTRATOR’S FINAL RECORD OF DECISION

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- Appendix B: BP-18 Generation Inputs and Transmission Ancillary And Control Area Services Rates Settlement Agreement

Under separate cover:

- Appendix C: 2018 Power Rate Schedules And General Rate Schedule Provisions (BP-18-A-04-AP03)
- Appendix D: 2018 Transmission, Ancillary, And Control Area Service Rate Schedules and General Rate Schedule Provisions (BP-18-A-04-AP04)

COMMONLY USED ACRONYMS AND SHORT FORMS

AAC	Anticipated Accumulation of Cash
ACNR	Accumulated Calibrated Net Revenue
ACS	Ancillary and Control Area Services
AF	Advance Funding
AFUDC	Allowance for Funds Used During Construction
aMW	average megawatt(s)
ANR	Accumulated Net Revenues
ASC	Average System Cost
BAA	Balancing Authority Area
BiOp	Biological Opinion
BPA	Bonneville Power Administration
Bps	basis points
Btu	British thermal unit
CIP	Capital Improvement Plan
CIR	Capital Investment Review
CDQ	Contract Demand Quantity
CGS	Columbia Generating Station
CHWM	Contract High Water Mark
CNR	Calibrated Net Revenue
COB	California-Oregon border
COE	U.S. Army Corps of Engineers
COI	California-Oregon Intertie
Commission	Federal Energy Regulatory Commission
Corps	U.S. Army Corps of Engineers
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council	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)
DD	Dividend Distribution
DDC	Dividend Distribution Clause
<i>dec</i>	decrease, decrement, or decremental
DERBS	Dispatchable Energy Resource Balancing Service
DFS	Diurnal Flattening Service
DNR	Designated Network Resource
DOE	Department of Energy
DOI	Department of Interior
DSI	direct-service industrial customer or direct-service industry
DSO	Dispatcher Standing Order

EE	Energy Efficiency
EIM	Energy imbalance market
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
FERC	Federal Energy Regulatory Commission
FOIA	Freedom Of Information Act
FORS	Forced Outage Reserve Service
FPS	Firm Power and Surplus Products and Services
FPT	Formula Power Transmission
FY	fiscal year (October through September)
G&A	general and administrative (costs)
GARD	Generation and Reserves Dispatch (computer model)
GMS	Grandfathered Generation Management Service
GSP	Generation System Peak
GSR	Generation Supplied Reactive
GRSPs	General Rate Schedule Provisions
GTA	General Transfer Agreement
GWh	gigawatthour
HLH	Heavy Load Hour(s)
HOSS	Hourly Operating and Scheduling Simulator (computer model)
HYDSIM	Hydrosystem Simulator (computer model)
IE	Eastern Intertie
IM	Montana Intertie
<i>inc</i>	increase, increment, or incremental
IOU	investor-owned utility
IP	Industrial Firm Power
IPR	Integrated Program Review
IR	Integration of Resources
IRD	Irrigation Rate Discount
IRM	Irrigation Rate Mitigation
IRPL	Incremental Rate Pressure Limiter
IS	Southern Intertie
kcfs	thousand cubic feet per second
kW	kilowatt
kWh	kilowatthour
LDD	Low Density Discount
LGIA	Large Generator Interconnection Agreement
LLH	Light Load Hour(s)

LPP	Large Project Program
LPTAC	Large Project Targeted Adjustment Charge
LTF	Long-term Form
Maf	million acre-feet
Mid-C	Mid-Columbia
MMBtu	million British thermal units
MNR	Modified Net Revenue
MRNR	Minimum Required Net Revenue
MW	megawatt
MWh	megawatthour
NCP	Non-Coincidental Peak
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NFB	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NOB	Nevada-Oregon border
NORM	Non-Operating Risk Model (computer model)
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NP-15	North of Path 15
NPCC	Pacific Northwest Electric Power and Conservation Planning Council
NPV	net present value
NR	New Resource Firm Power
NRFS	NR Resource Flattening Service
NT	Network Integration
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.
OS	Oversupply
OY	operating year (August through July)
PDCI	Pacific DC Intertie
Peak	Peak Reliability (assessment/charge)
PF	Priority Firm Power
PFp	Priority Firm Public
PFx	Priority Firm Exchange
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
POR	Point of Receipt
Project Act	Bonneville Project Act
PS	Power Services
PSC	power sales contract
PSW	Pacific Southwest
PTP	Point to Point
PUD	public or people's utility district
PW	WECC and Peak Service
RAM	Rate Analysis Model (computer model)
RCD	Regional Cooperation Debt
RD	Regional Dialogue
REC	Renewable Energy Certificate
Reclamation	U.S. Bureau of Reclamation
RDC	Reserves Distribution Clause
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
RRS	Resource Remarketing Service
RSC	Resource Shaping Charge
RSS	Resource Support Services
RT1SC	RHWM Tier 1 System Capability
SCD	Scheduling, System Control, and Dispatch rate
SCS	Secondary Crediting Service
SDD	Short Distance Discount
SILS	Southeast Idaho Load Service
Slice	Slice of the System (product)
T1SFCO	Tier 1 System Firm Critical Output
TCMS	Transmission Curtailment Management Service
TGT	Townsend-Garrison Transmission
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	Transmission Services
TSS	Transmission Scheduling Service
UAI	Unauthorized Increase

UFT	Use of Facilities Transmission
UIC	Unauthorized Increase Charge
ULS	Unanticipated Load Service
USACE	U.S. Army Corps of Engineers
USBR	U.S. Bureau of Reclamation
USFWS	U.S. Fish & Wildlife Service
VERBS	Variable Energy Resources Balancing Service
VOR	Value of Reserves
VR1-2014	First Vintage Rate of the BP-14 rate period (PF Tier 2 rate)
VR1-2016	First Vintage Rate of the BP-16 rate period (PF Tier 2 rate)
WECC	Western Electricity Coordinating Council
WSPP	Western Systems Power Pool

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PARTY ABBREVIATIONS AND JOINT PARTY DESIGNATION CODES

Party Abbreviations

AC	Avista Corporation
AR	Avangrid Renewables, LLC.
BC	Benton County Public Utility District No. 1
BW	Burbank Water and Power
CO	Cowlitz County Public Utility District No. 1
CP	Calpine Corporation
EW	Eugene Water & Electric Board
FR	Franklin County Public Utility District No. 1
IF	City of Idaho Falls
IN	Industrial Customers of Northwest Utilities
IP	Idaho Power Company
IR	Idaho Rivers United
JP01	PP, PX
JP02	AC, AR, IP, PC, PG, PS
JP03	NC, SM, TU
JP04	AC, AR, IP, PG, PS
JP05	CO, EW, IF, NR, PN, PP, SN
JP06	CO, EW
JP07	NR, PP, PN
JP08	NR, PP
KT	Kalispel Tribal Utility
LA	Los Angeles Department of Water and Power
MS	M-S-R Public Power Agency
NC	Transmission Agency of Northern California
NE	NorthWestern Corporation
NR	Northwest Requirements Utilities
NW	Northwest Irrigation Utilities
PC	PacifiCorp
PG	Portland General Electric Company
PN	Pacific Northwest Generating Cooperative
PP	Public Power Council
PS	Puget Sound Energy, Inc.
PX	Powerex Corporation
RN	Renewable Northwest
SC	Sierra Club and Montana Environmental Information Center
SE	City of Seattle
SM	Sacramento Municipal Utility District
SN	Snohomish County Public Utility District No. 1
TA	City of Tacoma
TC	TransAlta Energy Marketing (U.S.)
TU	Turlock Irrigation District
WG	Western Public Agencies Group

Joint Party Designation Codes for the 2018 Rate Proceeding

Party Code	Joint Party	Joint Party Members
JP01	Joint Party 1	Public Power Council (PP) Powerex Corporation (PX)
JP02	Joint Party 2	Avista Corporation (AC) Avangrid Renewables, LLC (AR) Idaho Power Company (IP) PacifiCorp (PC) Portland General Electric Company (PG) Puget Sound Energy, Inc. (PS)
JP03	Joint Party 3	Transmission Agency of Northern California (NC) Sacramento Municipal Utility District (SM) Turlock Irrigation District (TU)
JP04	Joint Party 4	Avista Corporation (AC) Avangrid Renewables, LLC (AR) Idaho Power Company (IP) Portland General Electric Company (PG) Puget Sound Energy, Inc. (PS)
JP05	Joint Party 5	Cowlitz County Public Utility District No. 1 (CO) Eugene Water & Electric Board (EW) City of Idaho Falls (IF) Northwest Requirements Utilities (NR) Pacific Northwest Generating Cooperative (PN) Public Power Council (PP) Snohomish County Public Utility District No. 1 (SN)
JP06	Joint Party 6	Cowlitz County Public Utility District No. 1 (CO) Eugene Water & Electric Board (EW)
JP07	Joint Party 7	Northwest Requirements Utilities (NR) Pacific Northwest Generating Cooperative (PN) Public Power Council (PP)
JP08	Joint Party 8	Northwest Requirements Utilities (NR) Public Power Council (PP)

1.0 GENERAL TOPICS

1.1 Introduction

The BP-18 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, 2017.

This Final Record of Decision (ROD) contains the 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, 2017, through September 30, 2019 (fiscal years (FY) 2018–2019). The proceeding included an evidentiary hearing, filings of parties' initial briefs and briefs on exceptions, oral argument before the BPA Administrator, publication of a Draft ROD, and publication of a Supplemental Draft ROD. This Final 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 final decisions. This Final ROD also summarizes and responds to participant comments that were submitted during the public comment period, which ended on February 17, 2017.

1.1.1 Procedural History of this Rate Proceeding

1.1.1.1 Issue Workshops

For about a year before the start of the BP-18 Proceeding, BPA sponsored a series of workshops and other meetings to discuss certain topics related to power and transmission rates before the release of Staff's Initial Proposal. BPA designed the workshops to allow Staff and interested parties to develop a common understanding of specific topics, generate ideas, and discuss alternative proposals and settlement options. BPA held six workshops between September 2015 and February 2016 to discuss seams issues between the Pacific Northwest and California and potential rates and non-rates solutions to those issues. BPA held a total of seven workshops and settlement meetings between January 2016 and September 2016 on generation inputs issues; three workshops between March 2016 and June 2016 on financial reserves; 10 workshops between April 2016 and September 2016 on transmission rate issues; three workshops between April 2016 and September 2016 on power rate issues; and five workshops between May 2016 and September 2016 on issues related to the development of both power and transmission rates. In addition, BPA held three workshops between May and August 2016 on the Rate Period High Water Mark (RHWM) Process, a separate process outside the scope of this rate case.

1.1.1.2 BP-18 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 in the *Procedures Governing Bonneville Power Administration Rate Hearings*, 51 Fed. Reg. 7,611 (March 5, 1986) (hereinafter Hearing Procedures). The Hearing Procedures implement the Section 7(i) requirements.

The BP-18 rate proceeding includes power and transmission rates in a single docket. On November 10, 2016, BPA published a Federal Register notice, "Fiscal Year (FY) 2018–2019 Proposed Power and Transmission Rate Adjustments[,] Public Hearing and Opportunities for Public Review and Comment," 81 Fed. Reg. 78,999. On October 25, 2016, 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 November 17, 2016. 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 November 17, 2016. Clarification of Staff's Initial Proposal took place on December 6, 2016. The parties filed direct testimony on January 31, 2017. Clarification of parties' direct testimony took place on February 7, 2017. BPA Staff and the parties filed rebuttal testimony on March 14, 2017. Clarification of BPA and the parties' rebuttal testimony took place on March 20, 2017.

Cross-examination of BPA Staff and the parties' witnesses took place on April 6-7, 2017.

On April 27, 2017, BPA Staff filed supplemental testimony proposing to establish a Spill Surcharge for BPA's power rates. Parties filed direct testimony in response to BPA's supplemental testimony on May 11, 2017. BPA and the parties filed rebuttal testimony on May 25, 2017. The parties then filed supplements to their initial briefs on June 9, 2017.

The parties filed their initial briefs in the general rate hearing on May 2, 2017. Oral argument before the Administrator took place on May 9, 2017. A Draft ROD was issued on June 13, 2017, and a Supplemental Draft ROD on the Spill Surcharge was issued on June 21, 2017. Parties' briefs on exceptions were filed June 30, 2017.

At times, certain parties to this proceeding consolidated for the purpose of filing joint testimony or briefs on one or more issues. *See* Special Rules of Practice Governing this Proceeding, BP-18-HOO-02. The rate case clerk assigned each 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 Final ROD. *See also* Document Numbering System and Pre-Marking of Exhibits and Briefs, BP-18-HOO-04.

BPA received three written comments during the participant¹ comment period, which began with the publication of the Federal Register notice on November 10, 2016 and ended February 17, 2017. Participant comments are part of the record upon which the Administrator bases his decisions; they are summarized and addressed separately in Final ROD Chapter 7. Participant comments may be viewed at BPA’s website under “Involvement & Outreach,” “Public Comments.”

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

Beginning in August 2016, in response to customer interest in exploring a settlement, BPA held rate case settlement workshops with interested parties on generation inputs issues that form the foundation of most ancillary service and control area service rates. Fredrickson & Fisher, BP-18-E-BPA-18, at 1-2. Over the next two months, BPA and the parties developed a settlement agreement that covers all ancillary and control area service (ACS) rates except (1) Scheduling, System Control, and Dispatch Service; and (2) Reactive Supply and Voltage Control from Generation Sources Service. *Id.* at 2-3. The Settlement Agreement sets estimated quantities of balancing reserves using a 99.7 percent planning standard, sets the balancing capacity rates, and sets the dollar amount Power Services is compensated for capacity provided. *Id.* at 3-4. The Settlement Agreement also adjusts other ACS rates, with some increasing and some decreasing, and exempts the Variable Energy Resource Balancing Service and Dispatchable Resource Balancing Service rates from Power Services’ risk mitigation measures. *Id.* at 4-5.

In addition, the Settlement Agreement sets cost allocations from Power Services to Transmission Services for synchronous condensing, generation dropping, redispatch, segmentation of U.S. Army Corps of Engineers (Corps) and Bureau of Reclamation (Reclamation) network and delivery facilities, and station service. These costs are recovered in various transmission rates. *Id.* at 5. BPA tendered the Settlement Agreement to the parties on September 23, 2016. Parties were given until October 5, 2016, to indicate their intent to contest the settlement. No party did so. *Id.* at 2. By the deadline, 18 parties had signed or agreed not to contest the Settlement Agreement. BPA filed the BP-18 generation inputs Settlement Agreement as part of the BP-18 Initial Proposal. *Id.*, Appendix A. On November 25, 2016, 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 Wednesday, November 30, 2016.” Order Establishing Deadline to Object to the Proposed Generation Inputs Settlement Agreement, BP-18-HOO-07. No party objected. The settlement is further discussed in Chapter 4.0.

¹ For interested persons who are not eligible or do not wish to become parties to the formal evidentiary hearings, BPA’s Hearing Procedures provide opportunities to participate in the ratemaking process through submission of comments as “participants.” See Section 1010.5 of BPA’s Hearing 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-18-HOO-02.

1.1.1.4 Waiver of Issues by Failure to Raise in Briefs

Pursuant to Section 1010.13(b) of the Hearing 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 Hearing 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-18-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 a 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), codified at 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 United States Supreme Court has also recognized the deference given to the Administrator’s interpretation of the Northwest Power Act. *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 Federal Energy Regulatory Commission (FERC or 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. Dept. 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. Dept. 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, 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-18 proceeding. *See* Fiscal Year (FY) 2018–2019 Proposed Power and Transmission Rate Adjustments[,], Public Hearing and Opportunities for Public Review and Comment, 81 Fed. Reg. at 79,000-03.

1.2.1 Spending 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, now known as the Integrated Program Review (IPR). At the same time, BPA conducts a public review of its proposed capital spending forecasts, known as the Capital Investment Review (CIR). Both processes provide 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.

In June 2016, BPA held a series of technical workshops to review the proposed expense and capital spending to be the basis for power and transmission rates in the BP-18 rate proceeding. This combined process provided opportunities for BPA and participants to review and discuss power, transmission, and agency service programs and included detailed review of asset strategies and associated program spending levels.

BPA issued the Final Close-Out Report for the IPR and CIR, in which BPA responded to participants' comments, in October 2016. In the report, BPA established the program-level spending estimates that were used in the Initial Proposal to establish the proposed power and transmission rates.

On January 18, 2017, BPA invited the region to participate in an abbreviated IPR 2 public process to discuss proposed adjustments from the 2016 IPR. Four technical workshops were

held on February 15 and 16, 2017. The comment period ended on March 13, 2017. BPA issued the IPR 2 close-out letter and Final Close-out Report in April 2017. For further information on the IPR, CIR, and IPR 2 processes and outcomes, see the BPA website under “Finance & Rates,” “Financial Public Processes,” and “Integrated Program Review.”

1.2.2 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 through 2028. 2012 REP Settlement Agreement, REP-12-A-02A (misfiled as REP-12-A-02-AP01) (2012 REP Settlement); 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 Administrator’s Record of Decision. Administrator’s Final Record of Decision, REP-12-A-02. The 2012 REP Settlement and the Administrator’s decision in the REP-12 ROD to sign the settlement were upheld by the Ninth Circuit Court of Appeals in *Ass’n of Pub. Agency Customers v. Bonneville Power Admin.*, 733 F.3d 939 (9th Cir. 2013).

1.2.3 Rate Period High Water Mark Process

BPA has established FY 2018–2019 RHWMs for public agency customers with Contract High Water Mark (CHWM) contracts. In the RHWM Process, which preceded the BP-18 rate proceeding and concluded in September 2016, BPA established the maximum planned amount of power a customer is eligible to purchase at Priority Firm 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 ratemaking purposes.

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2.0 JOINT POWER AND TRANSMISSION TOPICS

2.1 Error Correction Policy

During pre-rate-case workshops, a BPA customer presented a straw proposal for a process to correct ratemaking errors identified in established rates. The proposal was in response to BPA's treatment of two errors in the BP-16 rate case. Fisher & Fredrickson, BP-18-E-BPA-16, at 2-7. The customer was concerned about the consistency and transparency of BPA's treatment of errors and proposed that the agency establish a process for correcting future errors. *Id.* In response to the straw proposal, Staff developed a proposal and made it available for public comment. *Id.* In response to customer comments, Staff revised its preliminary guidelines and shared them with customers. *Id.* The revised guidelines formed the basis of the guidelines included in the BP-18 Initial Proposal. *Id.*

Staff proposed six guidelines to be considered when addressing the correction of errors. *Id.* The first two guidelines address the kinds of errors that would qualify for possible correction; guidelines 3 through 5 address the nature of adjustments; and the sixth guideline establishes the administrative forum in which corrections would be established. *Id.* The six guidelines are:

1. **Qualifying Type:** Corrections would apply to ministerial cost allocation and calculation errors but not forecast errors. A ministerial error means an error in addition, subtraction, or other arithmetic function; a clerical error resulting from inaccurate copying, duplication, or the like; and any other similar type of unintentional error.
2. **Qualifying Size:** Errors should exceed an annual average aggregate effect of \$5 million per year for the applicable rate period to be eligible for "backward correction" (making a prospective adjustment to rates to correct the effect of an error during the previous rate period). For cost allocation errors, Staff would add the absolute values of the increased and decreased allocations. For example, an error that over-allocated \$3 million to rate class A and under-allocated \$3 million to rate class B in each year of the rate period would be eligible for correction because the sum of the absolute values is \$6 million per year.
3. **Applied Generally:** Adjustments to the proposed rates would be rate class specific (*e.g.*, (1) Slice and Non-Slice or (2) NT, PTP and Southern Intertie) and not customer-specific.
4. **Limited Applicability:** Backward correction would be limited to one rate period (*e.g.*, backward correction to BP-18 rates would be limited to the financial impacts of the error on BP-16 rates, regardless of whether the error had existed in rates prior to the BP-16 rate period).
5. **Exceptions:** Extenuating circumstances should be considered in the application of these guidelines, because the specific circumstances of a particular error may provide compelling reasons to propose an exception to certain

guidelines (*i.e.*, the size threshold identified in Guideline 2 may not be reasonable in situations where an error causes a disproportionate impact on small customers).

6. **Implementation:** Errors would be corrected prospectively in the next general rate case.

Id. at 3-4. Additional information regarding the proposed guidelines can be found in Fisher & Fredrickson, BP-18-E-BPA-16, at 2-7, and Fisher & Fredrickson, BP-18-E-BPA-30, at 1-3.

Although Staff proposed the error correction guidelines in the Initial Proposal, the proposal drew little interest from parties, with only one party (ICNU) filing responding testimony. In addition, no party (other than BPA) filed rebuttal to ICNU's testimony. ICNU generally opposes the adoption of any error correction guidelines, believing the guidelines could undermine BPA's policy interest in rate finality. ICNU Br., BP-18-B-IN-01, at 111. ICNU, however—the only party opposed to the guidelines—has supported in this rate proceeding prospective adjustments for previous rates. In response to a party's proposal for the Financial Reserves Policy (FRP), ICNU recommends, "if such a mechanism were to be developed, BPA should go back as far as 2005 and provide similar compensation to Power customers for the periods when Power reserves exceeded Transmission reserves." Mullins, BP-18-E-IN-02, at 16-17. Although ICNU's recommended prospective adjustment would not be a qualifying error as defined in the first guideline, ICNU's proposal highlights the guidelines' value and reason they were proposed—specifically, to provide transparent and consistent guidance when Staff is evaluating the need for a prospective adjustment for previous rates.

ICNU argues that the Administrator established a precedent on the issue of error corrections in the BP-16 rate case. ICNU Br., BP-18-B-IN-01, at 111. In the BP-16 rate case, the Administrator was faced with a transmission-related issue of whether BPA should correct the misallocation of O&M costs made in the BP-14 rate case. *Id.* at 111-12. The Administrator decided not to fix the error, noting that "[r]ates should not be revisited lightly . . ." *Id.* at 112 (citing Administrator's Final Record of Decision, BP-16-A-02, at 103). The Administrator also noted that "[r]ate 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." ICNU Br., BP-18-B-IN-01, at 112 (citing Final Record of Decision, BP-16-A-02, at 103).

Despite these statements, however, the Administrator took a different tack when adopting a correction to a power ratemaking error in the same ROD. In the BP-16 rate case, the Administrator was faced with a power-related issue of whether BPA had erroneously assigned non-cash revenues from the PGE WNP-3 Settlement Agreement to the Non-Slice cost pool. Final Record of Decision, BP-16-A-02, at 29-30. BPA adopted a new Slice Billing Adjustment that corrected the inaccurate allocation of the PGE WNP-3 Settlement revenues in FY 2012–2015 by adjusting Slice customers' bills by their share of the costs that should have been allocated to them in the previous rate periods. *Id.* at 30. The Administrator's decisions in BP-16 to correct a power rate error and not correct a transmission rate error created an ambiguity in the Administrator's approach to addressing ratemaking errors. As noted above, this ambiguity was a

major factor in a BPA customer's straw proposal for a process to correct ratemaking errors identified in established rates, which led to the current Staff proposal.

ICNU suggests that the Administrator, as opposed to Staff, would consider whether to adopt Staff's proposal, and thereby allow error correction offsets to become a normative feature of BPA ratemaking. ICNU Br., BP-18-B-IN-01, at 113. This misunderstands Staff's proposal. The guidelines would only be used by Staff to determine whether to propose corrections to errors identified in BPA's rates. Fisher & Fredrickson, BP-18-E-BPA-30, at 1-2. Staff would use the guidelines to develop its initial rate proposal position in a general Section 7(i) hearing regarding whether to apply a prospective adjustment to correct for a past rate case error. *Id.* While the guidelines would inform Staff's initial position, they would not preclude rate case parties from proposing other treatments, nor prohibit Staff from considering other parties' proposals, nor diminish the Administrator's authority to make the final decision in the ROD. *Id.* The Administrator is not deciding to adopt the guidelines; the Staff is deciding whether to adopt the guidelines. BPA does not believe that Staff's mere adoption of guidelines would undermine customer confidence in BPA's rates.

ICNU also argues that if Staff adopted its proposed guidelines, it would be violating applicable precedent by seeking a policy change without sufficient justification. ICNU Br., BP-18-B-IN-01, at 114. This argument is overreaching. As noted previously, the Administrator's "precedent" was to make a correction on one issue in BP-16 and not make a correction on another. This is hardly a clear precedent, much less the unequivocal, ironclad decision ICNU makes it out to be. Indeed, it was the desire to address this apparent inconsistency that led to customer meetings and proposals to eliminate such inconsistencies. Again, however, the decision to adopt guidelines for Staff is made at the Staff level and not by the Administrator.

ICNU argues that Staff's first proposed guideline—which establishes a "Qualifying Type" of errors for potential correction—is subjective because whether one perceives a correction as ministerial or not ultimately depends on what one considers "correct." ICNU Br., BP-18-B-IN-01, at 115-116. In response, Staff believes Guideline 1, Qualifying Type, describes the types of errors that would be evaluated in simple straightforward language. Fisher & Fredrickson, BP-18-E-BPA-30, at 2. Although Staff cannot specify every possible situation that might qualify as an error under Guideline 1, ICNU's previously suggested application of Guideline 1 to an example like a thoroughly considered and well-reasoned cost allocation decision is inappropriate. *Id.* Guideline 1 limits ministerial errors to "error[s] in addition, subtraction, or other arithmetic functions; a clerical error . . . ; and any other similar type of unintentional error." *Id.* (citing Fisher & Fredrickson, BP-18-E-BPA-16, at 3). Although a thoroughly considered and well-reasoned cost allocation decision would not be considered a ministerial error, an obvious and inadvertent cost allocation error would qualify as a ministerial error under the guidelines. Fisher & Fredrickson, BP-18-E-BPA-30, at 2. While ICNU speculates at length over possible circumstances where an error might be ministerial, each case must be reviewed on its facts.

ICNU argues that if the Administrator should choose to adopt Staff's error correction guideline proposal going forward, a Minimum Required Net Revenue (MRNR) adjustment, as proposed by ICNU, should also be subject to an offsetting correction. ICNU Br., BP-18-B-IN-01, at 117. First, the Staff, not the Administrator, will determine whether to adopt guidelines to govern

Staff's error correction proposals. Second, Guideline 1 refers to ministerial errors, clerical errors and unintentional errors. Fisher & Fredrickson, BP-18-E-BPA-30, at 3. A straightforward reading of Guideline 1 would not allow a change in a long-term interpretation of a DOE Order to qualify as a possible correction under the error correction guidelines. *Id.* (citing Fisher & Fredrickson, BP-18-E-BPA-16, at 3–4). *See also* Lennox *et al.*, BP-18-E-BPA-31, at 1-13, for rebuttal of ICNU's arguments regarding MRNR. Fisher & Fredrickson, BP-18-E-BPA-30, at 3.

ICNU argues that Staff's proposed correction related specifically to the allocation in power rates of Lost Creek and Green Springs transmission costs should not be considered a ministerial error, and ICNU similarly recommends that BPA not make any correction with respect to these costs, going forward. ICNU Br., BP-18-B-IN-01, at 117. First, BPA and ICNU agree that a prospective adjustment for the previous misallocation is inappropriate in this instance. Therefore, the only issue is whether the misallocation should be corrected prospectively. Because the Lost Creek and Green Springs issue concerns correcting an error prospectively, not retrospectively, the issue of whether the misallocation is a ministerial error is irrelevant. BPA routinely makes changes to rates beginning with BPA's Initial Proposal and ending with the Administrator's Final ROD. When BPA identifies a plain error in a previous allocation of costs, it is permitted, if not required, to correct that error when establishing new rates. Although this does not concern any "retroactive" change in BPA's rates, BPA's position on such changes is addressed in the WP-07S Administrator's Final ROD, WP-07-A-05, at 15-30, which is incorporated by reference. Second, the merits of the Lost Creek and Green Springs issue are addressed elsewhere in this Final ROD. *See* Section 3.4.5. The discussion of that issue provides substantial evidence supporting BPA's proposal on the Lost Creek and Green Springs issue.

In the Draft ROD, Staff's draft decision was to not adopt the guidelines given the lack of interest from parties and uncertainty regarding whether the guidelines provide much more assistance than would be available to Staff from a review absent the guidelines. Administrator's Draft Record of Decision, BP-18-A-02, at 12. In response, Snohomish informed BPA that it supports the guidelines and urges Staff to adopt them. Snohomish Br. Ex., BP-18-R-SN-01, at 1-4, 7. Snohomish notes that, despite having proposed guidelines in the BP-18 Initial Proposal based on Staff and stakeholders' engagement in a pre-rate-case process, Staff refuting the lone objecting party's arguments in rebuttal testimony, and the Administrator refuting similar opposing arguments in the Draft ROD, Staff stated it would not adopt the guidelines for two reasons: (i) uncertainty whether the guidelines provide much more assistance than would be available to Staff from a review absent the guidelines, and (ii) little interest from parties. *Id.* at 2. Snohomish believes that Staff's proposed guidelines provide customers with an increased level of certainty as to how errors will be addressed in the future. *Id.* at 3. Snohomish also believes that the guidelines help avoid "reinventing the wheel" each time a mathematical or clerical error is discovered, and prevent differing treatment for the correction of similar types of errors as observed during BP-16. *Id.* Snohomish notes that Staff's proposed guidelines can help BPA and parties save significant time and resources when Staff identifies an error. *Id.* Further, Snohomish believes the guidelines would guide Staff in determining how to deal with future errors, knowing that customers already have an expectation and an understanding of how an error, at a certain threshold, would be addressed. *Id.* Snohomish also recognizes that there is no major drawback to adopting the guidelines because Guideline 5 includes an exception from

extenuating circumstances, and the guidelines neither eliminate the Administrator’s discretion nor bind his decision-making when it comes to future errors. *Id.* Snohomish’s arguments are well-reasoned and establish a sound basis for Staff’s adoption of the guidelines to inform the preparation of the Initial Proposal.

Finally, Snohomish notes that although only one rate case party objects to the guidelines, no other rate case party objected. *Id.* at 2. Snohomish suggests that BPA “should perceive this as an acquiescence” to adoption of the guidelines and that “lack of interest” from parties toward the guidelines is likely a result of the parties’ many discussions and thorough understanding of the guidelines through pre-rate case workshops, which required no further support. *Id.* at 3-4. However, BPA notes that failure to state a position in either testimony or Initial Briefs does not necessarily convey agreement with a Staff position merely because parties participated in pre-rate case workshops.

In summary, Staff adopts the error correction guidelines as described in Staff’s testimony.

2.2 Revenue Requirement

The Revenue Requirement Studies, BP-18-FS-BPA-02 and BP-18-FS-BPA-09, determine the level of revenue required to recover BPA’s costs. The power revenue requirement reflects 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; and
- costs for purchasing other transmission services.

The transmission revenue requirement reflects all costs of transmitting electric power, including but not limited to:

- the Federal investment in transmission and transmission-support facilities;
- operations and maintenance expenses;
- transmission marketing and scheduling expenses; and
- the cost of generation inputs for ancillary services and reliability.

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. Dept. of Energy—Bonneville Power Admin.*, 26 FERC ¶ 61,096 (1984).

The power and transmission revenue requirements are developed independently 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 MRNR 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 (PNRR), if any, based on the risks identified and quantified, the Treasury Payment Probability (TPP) standard, and other risk mitigation tools.

Based on these three components, the revenue requirement is set at the 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 repayment period: 50 years for power and 35 years for transmission. The current revenue tests for power and transmission show that current rates would be insufficient to demonstrate cost recovery.

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. The revised revenue test demonstrates that proposed rates are sufficient to meet cost recovery requirements for the rate test and repayment periods. Revenues from proposed power rates will recover generation costs in the rate test period and over the ensuing 50-year repayment period. Similarly, revenues from proposed transmission rates will recover transmission costs in the rate test period and over the following 35-year repayment period.

Issue 2.2.1

Whether the Power revenue requirement should include Minimum Required Net Revenues (MRNR).

Parties' Positions

ICNU states, “BPA is not justified in including any MRNR in [the Power] revenue requirement.” ICNU Br., BP-18-B-IN-01, at 89. ICNU states that Power revenue requirements under the current revenue test show a surplus of \$6.6 billion over the 50-year repayment period. *Id.* at 89-90. ICNU states that BPA has not strictly followed the technical requirements of DOE Order RA 6120.2 and that BPA’s repayment study is inconsistent with the Order. *Id.* at 91. ICNU interprets RA 6120.2 to require only that BPA show that surplus revenues over the repayment period exceed outstanding federal debt in any given year. ICNU Br. Ex., BP-18-R-IN-01 at 17. ICNU argues that BPA is required to adopt policies that result in lower rates. ICNU Br., BP-18-B-IN-01, at 91-92. ICNU claims there is a lack of a business case or statutory requirement for the inclusion of MRNR. ICNU Br. Ex, BP-18-R-IN-01 at 17-18. ICNU also argues that BPA fails to consider advanced repayments that have occurred and should offset MRNR against advanced repayments from prior periods when establishing its repayment schedule. ICNU Br., BP-18-B-IN-01, at 93. Finally, ICNU proposes that BPA modify its repayment model to produce lower repayment obligations. *Id.* at 103.

BPA Staff's Position

Any surplus revenue during the 50-year repayment period is immaterial if revenues are insufficient to recover costs in the 2018–2019 rate period as required by DOE Order RA 6120.2. Lennox *et al.*, BP-18-E-BPA-31, at 5. The revenues in later years of the repayment period cannot be used to offset the shortfall of cash within the current rate period. *Id.* Staff adheres to the criteria of DOE Order RA 6120.2, and the methodology developed to apply the requirements of the Order is derived from longstanding BPA practices. *Id.* at 2-3. When establishing the repayment schedule, BPA adopts the lowest level of debt service across the repayment period to maintain reasonable rates consistent with sound business principles. *Id.* at 13.

Evaluation of Positions

MRNR is a revenue requirement construct that occurs only when the forecast of cash flow from rates is insufficient to ensure the repayment of debt that is scheduled for repayment in the year in question. *Id.* BPA’s initial proposal revenue requirement study included \$68.1 million of MRNR in FY 2019. The calculation of MRNR is an assessment of the non-cash elements forecast in the revenue requirement and the schedule of debt repayment, which is evident in the statement of cash flows. Power Revenue Requirement Study, BP-18-E-BPA-02, Table 4. The scheduled Federal debt is determined using a longstanding methodology that seeks to produce the lowest level of total debt service through the allowable repayment period. Lennox *et al.*, BP-18-E-BPA-31, at 13. This methodology analyzes Federal and non-Federal debt, and includes existing debt and projected investments. *Id.* For example, as non-Federal debt payments go up, Federal debt payments move in the opposite direction. Lennox *et al.*, BP-18-E-BPA-14, at 2-3.

In other words, Federal debt payments are scheduled around non-Federal debt payments to the extent possible to produce level debt service over time. As a result, the amount of MRNR is best seen in the context of total capital-related costs because of the leveling of total debt service.

MRNR, however, was not fixed in the Initial Proposal because it is not a static calculation. Many of the variables used in repayment modeling were updated for the Final Proposal to account for the latest forecasts as well as the actuals for transactions completed subsequent to publication of the Initial Proposal. *Id.* at 20-21, 23-24. Consequently, the results of the modeling have changed so that MRNR in the Final Proposal is higher than in the Initial Proposal. However, this does not mean that the revenue requirement is higher. In 2018, MRNR is \$220 million, due to the repayment of the Energy Northwest (EN) Line of Credit (LOC), compared to zero in the Initial Proposal. *See* Power Revenue Requirement Study, BP-18-FS-BPA-02, Table 3; Power Revenue Requirement Study, BP-18-E-BPA-02, Table 3. This increase, however, is offset by reductions in other capital-related costs due to the Regional Cooperation Debt (RCD) refinancing that was accelerated by the use of the LOC. Non-Federal Debt Service is \$156 million lower. *Id.* The RCD Effect, embedded in the Other Income, Expenses, and Adjustments line, is \$44 million lower. *Id.* Net Interest Expense is \$30 million lower. *Id.* These offsets produce a net reduction to the revenue requirement of \$10 million, despite the significant increase to MRNR. There are also changes to capital-related costs in 2019, though not as dramatic. Still, a comparison of the Initial Proposal and Final Proposal shows a net reduction in that year of \$9 million. *Id.* Clearly, it is essential that we consider MRNR as part of an integrated whole rather than in isolation.

ICNU first objects to BPA's inclusion of MRNR by arguing that the agency's repayment study shows current rates result in an over-collection of about \$6.6 billion in surplus revenues in the 50-year repayment period. ICNU Br., BP-18-B-IN-01, at 91. In other words, current rates are forecast to generate more revenue than is needed to repay Federal debt over the 50-year horizon. However, this argument ignores the rate period that is the subject of this proceeding. For both years of this period, current revenues are insufficient to recover BPA's costs in that rate period. This is illustrated by the negative values in the "net position" of the repayment study, which means that cash flows from current rates would not be sufficient to recover BPA's costs and repay Federal investment. Lennox *et al.*, BP-18-E-BPA-31, at 4; *see* Power Revenue Requirement Study, BP-18-E-BPA-02, Table 7, column K. As described by Staff, the 50-year repayment period is simply an illustration of whether revenues are at least equal to the costs projected through that period. Lennox *et al.*, BP-18-E-BPA-31, at 5. In other words, it is a test of minimal sufficiency. *Id.* The 50-year repayment period is not an illustration of whether current rates would be sufficient to recover BPA's forecast costs in the current rate period. *Id.* The Final Proposal repayment study clearly shows that current rates would fall short by \$137 million in the rate approval period, FY 2018–2019. Power Revenue Requirement Study, BP-18-FS-BPA-02, Table 7.

Notwithstanding ICNU's argument, BPA is required by statute to set rates to recover its costs under Section 7(a)(2) of the Northwest Power Act, codified at 16 U.S.C. § 839e(a)(2). BPA would not be able to recover its costs for FY 2018–2019 under the current rates, as shown in the net position column referred to above. Lennox *et al.*, BP-18-E-BPA-31, at 4. ICNU's response

to this fact is that the net position column is not required under DOE Order RA 6120.2, and that the Order does not require the net position to be positive in each year. ICNU Br., BP-18-B-IN-01, at 90. This argument lacks merit. BPA believes the net position is essential because the Order requires that a repayment study must “demonstrate” whether revenues produce adequate cash flow to recover costs and make payments on the Federal investment within the rate period. Lennox *et al.*, BP-18-E-BPA-31, at 4-5. The net position column is necessary to display the mathematical outcomes. The column merely shows the results of the calculations. In other words, the net position column demonstrates whether rates will be sufficient to recover costs in a given rate period. The position espoused by ICNU in its brief would obviate the need for BPA to present a calculation of cost recovery, the fundamental requirement of the Order. Moreover, the net position column provides the reader an easy way to assess whether the requirements of the Order have been met.

ICNU presents a series of additional arguments about the application of DOE Order RA 6120.2. First, it is important to lay a foundation for what is required by the Order. Section 7(f) of the Order defines a “power repayment study” as:

. . . [P]ortraying the annual repayment of power production and transmission costs of a power system through the application of revenues over the repayment period of the power system. The study shows, among other items, estimated revenues and expenses, year by year, over the remainder of the power system’s repayment period (based upon conditions prevailing over the cost evaluation period), the estimated amount of Federal investment amortized during each year, and the total estimated amount of Federal investment remaining to be amortized.

Lennox *et al.*, BP-18-E-BPA-31, at 2 (citing DOE Order RA 6120.2, § 7(f)).

A repayment study is designed to demonstrate whether revenues from rates are sufficient to satisfy the criteria described in Section 12 of the Order:

COST RECOVERY CRITERIA. The current rates for a power system will be adequate if, and only if, a power repayment study indicates that:

- a. The expected revenues are at least sufficient to recover annually, except for a possible initial short transition period:
 - (1) All costs of operating and maintaining the power system during the year in which such costs are incurred; plus,
 - (2) The cost of acquiring power through purchase and/or exchange agreements, the costs for transmission services, and other costs during the year in which such costs are incurred; plus,
 - (3) Expensed interest on the unamortized investment in Federal power facilities in the year for which the interest charges are assessed, except that recovery of the annual interest expense may

be deferred in unusual circumstances for short periods of time;
plus,

(4) Interest and amortization of revenue bonds where PMAs are authorized to issue such bonds.

b. In addition to the recovery of the above costs on a year-by-year basis, the expected revenues are at least sufficient to recover:

(1) Each dollar of power investment at Federal hydroelectric generating plants within 50 years after they become revenue producing, except as otherwise provided by law; plus,

(2) Each annual increment of Federal transmission investment within the average service life of such transmission facilities or within a maximum of 50 years, whichever is less; plus,

(3) The cost of each replacement of a unit of property of a Federal power system within its expected service life up to a maximum of 50 years; plus,

(4) Each dollar of assisted irrigation investment within the period established for the irrigation water users to repay their share of construction costs; plus,

(5) Other costs such as payments to basin funds, participating projects or States.

DOE Order RA 6120.2, § 12.

All of the criteria in the Order must be satisfied and displayed in a manner that shows that BPA has met its statutory obligation to recover total system costs and repay the Federal investment. *Lennox et al.*, BP-18-E-BPA-31, at 2. This is not based on the “self-asserted interests of some staff.” ICNU Br. Ex., BP-18-R-IN-01, at 19. It is based on DOE and BPA policy and practice that has been in place and accepted for decades. In addition, the definition of a repayment study clearly requires that the repayment of system costs and the Federal investment be demonstrated on an annual basis. DOE Order RA 6120.2, § 12.

ICNU’s arguments regarding the application of DOE Order RA 6120.2 are based upon a misreading of the definition of a repayment study. ICNU argues that Section 12 can be read as creating two separate tests for cost recovery. ICNU Br., BP-18-B-IN-01, at 95-96. ICNU claims one test satisfies Section 12a, which requires a year-by-year analysis for paying expenses and interest and amortization of revenue bonds. *Id.* The other test satisfies Section 12b, which requires the repayment of other Federal investments over the allowable repayment period. *Id.*

Based on its reading of the requirements of Section 12, ICNU presents an alternative repayment study that shows a different result for the Section 12a test and then suggests that the analysis

under Section 12a should be done on an accrual basis. Mullins, BP-18-E-IN-01-AT02-E01, Table 2; ICNU Br., BP-18-B-IN-01, at 95-96. But the repayment of debt is fundamentally an analysis of the adequacy of cash flows to repay debt as it is scheduled. Whether the debt is referenced in Section 12a or Section 12b is irrelevant. Any business or organization following generally accepted accounting principles (GAAP) will place the repayment of its debt on its statement of cash flows. BPA's revenue requirement statement of cash flows is an illustration of this treatment. *See* Power Revenue Requirement Study, BP-18-FS-BPA-02, Table 6. This means that the repayment of BPA's debt is not shown on an accrual basis but on a cash basis.

ICNU instead argues that Section 12(a) creates a repayment test that is satisfied only through application of an accrual perspective. ICNU Br., BP-18-B-IN-01, at 96. In other words, debt repayment would be accounted for in the income statement. Yet ICNU's own proposed table does not show all accrued expenses. Lennox *et al.*, BP-18-E-BPA-31, at 11. ICNU's table is a hybrid, comprised of some but not all accrued expenses and some debt repayment. For example, the table excludes depreciation and amortization expense, a fairly significant accrued expense. *Id.* at 12. ICNU's approach results in a table that is akin to a partial statement of cash flows, which is only marginally useful in this context. The table also includes significant non-cash revenues and expenses. *Id.* at 11. ICNU fails to account for this anomaly in its table. Staff noted that ICNU's argument using an accrual perspective alone produces a misleading picture of BPA's ability to repay debt. *Id.* The only way to accurately demonstrate that repayment can be achieved is to analyze cash flows comprehensively, which BPA does in its repayment studies. BPA's repayment studies provide a true accrual perspective, accounting for all costs for which BPA is responsible, and then translates that information into available cash flows against which debt repayment is matched. *Id.*

ICNU disagrees with Staff's argument that the accrual perspective alone produces a misleading picture of BPA's ability to repay debt. ICNU argues that its table was never intended to be a comprehensive repayment study. Instead, ICNU claims that its table reflects an analysis under Section 12(a) of the Order, and is only an alternative power repayment study, and that a cash flow analysis would only be needed for the analysis of Section 12(b) for the transmission repayment study. ICNU Br., BP-18-B-BPA-IN-01, at 99. But a repayment study must address all of the requirements of Section 12, which necessarily requires a comprehensive approach. ICNU's interpretation of the Order and resulting table is unhelpful in this context.

ICNU argues that BPA misinterprets DOE Order RA 6120.2. *Id.* at 91. ICNU claims that BPA is misapplying the elements of Section 12(b) by requiring that a repayment study show the repayment of "each annual increment" of transmission investment because BPA includes annual repayment of Federal appropriations and irrigation assistance. Instead, ICNU suggests that there is no requirement to show any annual repayment of appropriations so long as the surplus revenues in the repayment period exceed the outstanding debt. ICNU Br., BP-18-B-IN-01, at 97; ICNU Br. Ex., BP-18-R-IN-01 at 17. BPA includes a repayment schedule for all Federal investments because that is the definition of a repayment study. Section 12 of the Order clearly states that rates are adequate only if "a power repayment indicates that . . . expected revenues are at least sufficient to recover each dollar of power investment . . ." DOE Order RA 6120.2, § 12. Satisfying the language in the Order can be done only if repayment is shown in the study. In its

discussion of Section 12(b), ICNU ignores the definition of a repayment study in Section 7(f) of the Order, which is one that shows “the estimated amount of Federal investment amortized *each year*.” Lennox *et al.*, BP-18-E-BPA-31, at 8 (emphasis added). A repayment study is complete only if it shows the repayment of the Federal investment annually, including Federal appropriations.

ICNU argues that BPA changed the repayment study methodology over the years and thus cannot use historical practices as a defense against ICNU’s alternative interpretations of the Order. ICNU Br., BP-18-B-IN-01, at 94-95. ICNU cites data responses that reference changes that occurred in 1965 and 1972. In this case, ICNU confuses the requirements of the Order and the methods for determining some components of a repayment study. The requirements of the Order in Section 12 are reasonably straightforward. BPA has used the same basic approach to developing repayment studies since it first created them in the 1940s. Lennox *et al.*, BP-18-E-BPA-31, at 6. While Staff may have unartfully described the construction of the repayment study as a “methodology,” the repayment study simply shows whether revenues equal the agency’s costs and its schedule of debt repayment. The format of BPA’s repayment studies may have varied slightly over time, but the examples show the same basic data. *Id.* BPA’s current display of the repayment study was created in collaboration with FERC staff to fulfill the Order requirements. *Id.* at 3. Moreover, all other Power Marketing Administrations (PMA) utilize the same basic approach in presenting data in their repayment studies. *Id.* at 10. The Order does not prescribe how to determine any component of the repayment study.

The 1965 change that ICNU references was not a change to the repayment study. It was a change to how BPA determined the schedule of debt repayment that would be used in the repayment study. In other words, it is a change to one of the inputs to the repayment study, not a change to the repayment study itself. BPA has always provided a schedule of debt repayment for use in the study. The 1972 change was actually an amendment to the Department of Interior order that guided PMAs prior to their organizational transfer to the Department of Energy (DOE) and subsequent adoption of DOE Order RA 6120.2. Regardless of these changes, ICNU offers no methodology for determining a debt repayment schedule other than to state “don’t do what you’re doing” as a counter to BPA’s current approach. BPA’s approach to repayment studies, which has been in use for decades, is consistent with the requirements of the Order and has been found reasonable by FERC.

ICNU objects to BPA’s current display because it includes the column “non-cash expenses,” which is not expressly required by the Order. ICNU Br., BP-18-B-IN-01, at 98. It argues that it is irrelevant because a Section 12(b) repayment study would show repayment on a cash basis. *Id.* However, ICNU never shows such a study. Indeed, ICNU implies that it is not even necessary because of the surplus revenues identified in BPA’s repayment study. *Id.* at 97. But as previously explained, the repayment of debt is ultimately dependent on a cash flow analysis. It is the only way to determine whether there is sufficient cash to repay debt. Lennox *et al.*, BP-18-E-BPA-31, at 10-11. Without this analysis, BPA would end up with a repayment study table like ICNU’s, which ignores significant non-cash revenues and expenses, thus distorting the determination of whether BPA would be able to repay its debt. BPA’s repayment study shows both an accrual view and cash view of its costs. *Id.* The non-cash expenses column does not

distort the reconciliation and demonstration of cost recovery and repayment. Indeed, it is a necessary means to transition between the accrual and cash views. Moreover, the current format of the repayment study was developed in collaboration with FERC staff more than 30 years ago and has been used by BPA and accepted by FERC since then. Lennox *et al.*, BP-18-E-BPA-31, at 3.

ICNU argues that BPA should avoid MRNR because it has paid significantly more Federal debt than scheduled in rate proceedings. ICNU Br., BP-18-B-IN-01, at 100. It argues that the methodology for scheduling repayment should be changed to take into account BPA's significant advanced payments. *Id.* ICNU perhaps misunderstands how BPA schedules repayment. BPA's methodology seeks the lowest level of debt service through the repayment period. Lennox *et al.*, BP-18-E-BPA-14, at 2–3. This analysis takes into account all existing debt and projected investments when making this determination. Power Revenue Requirement Study, BP-18-FS-BPA-02, at 24. The repayment of debt lowers future repayment requirements. Lennox *et al.*, BP-18-E-BPA-31, at 19. In other words, the methodology for scheduling debt repayment already takes into account prior payments.

Lastly, ICNU proposes that BPA should modify its computer model so that the model will “prepay lower cost debt” when scheduling debt repayment. ICNU Br., BP-18-B-IN-01, at 103. Although Staff did not have an opportunity to address this argument in rebuttal because it was not raised in ICNU's direct case, its response is provided here. Regardless of whether BPA's model is capable of conducting such analysis, it is not a permissible method for scheduling debt. DOE Order RA 6120.2 provides clear guidance in this regard. Section 8(c)(3) states that “to the extent possible, while still complying with the repayment periods established for each increment of investment and unless otherwise indicated by legislation, amortization of the investment will be accompanied by application to the highest interest-bearing investment first.” The Order gives little flexibility to deviate from this highest-interest-rate-first provision. The Order requires that BPA adhere to this principle “to the extent possible.” All BPA debts are paid according to their terms and, where possible, are scheduled for repayment based on the principle that highest-interest-rate debt is paid first. The only flexibility provided in the Order is if it is impossible to schedule repayment based on the highest interest rate first. Since BPA's computer model produced a repayment schedule that shows repayment of the highest interest rate first, it is obvious that BPA is capable of complying with the central requirement of the Order. Therefore, ICNU's argument to manipulate the computer model would have the effect of producing results that run counter to one of the fundamental principles of the Order.

Decision

MRNR will be used as needed in the development of the revenue requirement to meet BPA's cash obligations.

Issue 2.2.2

Whether the Energy Northwest (EN) Line of Credit (LOC) is being treated appropriately in the revenue requirement.

Parties' Positions

ICNU states that Staff's proposed treatment of the LOC creates the risk of rate shock and is inconsistent with GAAP. ICNU Br., BP-18-B-IN-01, at 103. Instead, ICNU suggests that the LOC should be treated as a deferred liability. *Id.* at 104. ICNU argues that the LOC is being used improperly as a source of financing by BPA. *Id.* In addition, ICNU argues that the LOC is not covered by the net billing agreements. *Id.* at 105-06.

BPA Staff's Position

Staff states that BPA's accounting treatment of the LOC is settled. Lennox *et al.*, BP-18-E-BPA-31, at 15. The changes to the revenue requirement's statement of cash flows are essential to avoid dramatic changes in the Slice true-up. *Id.* at 18.

Evaluation of Positions

The Initial Proposal included two new lines—non-cash expenses and repayment of non-Federal obligations—in the statement of cash flows to accommodate the use of the LOC. ICNU argues that the proposed new lines are inconsistent with GAAP. ICNU Br., BP-18-B-IN-01, at 103. BPA's accounting treatment is settled and has been accepted as consistent with GAAP by BPA's external auditor. Lennox *et al.*, BP-18-E-BPA-31, at 15. BPA's accounting treatment is not at issue in this rate case. Fiscal Year (FY) 2018–2019 Proposed Power and Transmission Rate Adjustments[,] Public Hearing and Opportunities for Public Review and Comment, 81 Fed. Reg. 78,999, 79,001 (Nov. 10, 2016). The LOC does not affect the accrual accounting of EN expenses. *Id.* Instead, the LOC only affects BPA's cash flows. *Id.* Factors affecting cash flows are properly addressed on the statement of cash flows, which is where Staff proposes to address the treatment of the LOC. Perhaps more important is that EN is already using LOCs to provide cash for its annual operating expenses, and BPA is using the cash from its revenues to repay high-interest appropriations. Staff merely proposes to alter the statement of cash flows to incorporate transactions that are already occurring in a manner that is consistent with BPA's actual treatment of the transactions.

ICNU argues that the proposed treatment of the LOC will create rate shock for customers. ICNU Br., BP-18-B-IN-01, at 103. This concern is difficult to understand. The LOCs are part of a larger Regional Cooperation Debt (RCD) program that allows BPA to accelerate the repayment of high-interest Federal debt. In the RCD program, EN refinances and extends its debt as it comes due. BPA uses cash flows from revenues freed up by the refinancings to repay a like amount of higher-interest-rate Federal appropriations and bonds. Lennox *et al.*, BP-18-E-BPA-14, at 18. The EN refinancings allow the repayment of BPA's Federal debt because the revenue requirements for each rate period include a forecast of EN debt repayment rather than refinancing. When the EN debt is refinanced, it frees up cash flows that would otherwise have

been dedicated to repaying EN debt. BPA can repurpose the freed-up cash to repay high-interest-rate Federal debt in place of EN debt, producing significant interest rate savings over time. *Id.*; Lennox *et al.*, BP-18-E-BPA-31, at 16. The use of the LOC allows the interest savings to be accelerated by one year. *Id.* In other words, this program lowers costs that go into BPA's Priority Firm (PF) rate and, therefore, lowers the costs for utilities that supply power to ICNU's members.

ICNU's proposed treatment of the LOC in the Power revenue requirement would prevent BPA from countering dramatic swings in the Slice true-up, which in fact could produce rate shock for Slice customers. ICNU does not address this argument. Without the new lines on the statement of cash flows, there would be significant financial implications. In the year the LOC is issued, Slice customers would be charged for higher Federal debt payments even though no cash would be needed. *Id.* at 18. In the following year, Slice customers would receive large credits when non-Federal debt service declines even though no cash would be available because it had been used to repay the LOC. *Id.* BPA must address these unintended consequences, and Staff provides a solution with its proposed changes.

ICNU argues that BPA is using the LOC as a source of financing, causing BPA to exceed its self-financing authority. ICNU Br., BP-18-B-IN-01, at 104. This argument is inaccurate. BPA is not using the LOC as a source of financing and has never claimed to do so. The LOC is a transaction between EN and its bank. BPA is not a party to the transaction, nor does it have a financial stake or control over the use of the LOC. The LOC simply reduces BPA's cash obligations in the year in which the LOC is in place because it reduces the amount that BPA must pay EN through the net billing agreements. This allows the agency to use the cash that is freed up by the refinancing for different purposes. Lennox *et al.*, BP-18-E-BPA-14, at 18. In this case, the cash is used to repay high-interest debt. BPA is not using the cash that has been freed up to finance capital investments.

ICNU questions whether BPA has the same financial obligations toward the LOC as it does with other EN costs and whether an LOC even exists. ICNU Br., BP-18-B-IN-01, at 105-106. The repayment of the LOC is governed by the net billing agreements between BPA and EN. Lennox *et al.*, BP-18-E-BPA-31, at 17. The RCD program and the use of a LOC have been discussed extensively by BPA staff in public meetings. BPA can find no basis for ICNU's questioning of the applicability of the net billing agreements or if the costs even exist.

Decision

The revenue requirement statement of cash flows will be modified with the addition of the Non-Cash Expenses and Repayment of Non-Federal Obligations lines.

Issue 2.2.3

Whether BPA should provide a version of the repayment model that can be used by parties on their own computer systems.

Parties' Positions

JP02 states that BPA should provide a version of the repayment model in an executable, usable form. JP02 Br., BP-18-B-JP02-01, at 54. PPC made similar arguments in its direct case but did not pursue them in brief. Deen *et al.*, BP-18-E-PP-01, at 1-2.

BPA Staff's Position

Staff states that the repayment model meets BPA's business needs. Lennox *et al.*, BP-18-E-BPA-31, at 21–22. It is complex and relies on a proprietary debt management database for data management. *Id.* at 20. While the model is not available in an executable form, the BPA-designed computer code is available on BPA's public website. *Id.* at 21.

Evaluation of Positions

JP02 argues that it is essential that BPA's repayment model be available to parties in an executable, usable form. JP02 Br., BP-18-B-JP02-01, at 54. While BPA Staff ran the repayment model per requests of the parties, JP02 maintains that this is not adequate for parties to understand and test modeling results. *Id.* JP02 argues that without a repayment model that it can run on its own computers, it cannot rebut BPA's revenue requirement and that BPA's revenue requirement will not be supported by substantial evidence. *Id.* at 55. JP02 argues that BPA should make available an executable repayment model in time for the BP-20 rate proceeding. *Id.*

The parties have had an adequate opportunity to rebut BPA's revenue requirement determination. BPA Staff has provided all underlying data on which the repayment model relies as well as the results of the modeling. BPA Staff has also taken the extra step of performing additional modeling upon request of the parties. The Northwest Power Act requires BPA to conduct one or more hearings in which the parties are “provided an adequate opportunity by the hearing officer to offer refutation or rebuttal of any material submitted” 16 U.S.C. § 839e(i)(2). This is a procedural requirement to ensure that the parties have an opportunity to present their “views, data, questions, and argument” related to proposed rates. *Id.* In this proceeding, BPA has conducted hearings, and the Hearing Officer provided the parties an adequate opportunity to rebut material submitted by BPA. Therefore, BPA has met its obligations under Section 7(i)(2).

The Administrator has determined there is sufficient evidence in the record to support his determinations in this proceeding. BPA created its repayment model software in-house, relying on the knowledge and expertise of its skilled information technology professionals. It is reasonable for BPA to rely upon the results of BPA's repayment model as the product of agency expertise.

In the BP-16 rate case, BPA concluded that it would “explore ways to make the repayment model available to rate case parties.” Administrator’s Final Record of Decision, BP-16-A-02, at 85. BPA concluded that it could not make its current repayment model available to rate case parties in an executable format. An entirely new repayment model would need to be created. The current repayment model was developed at considerable time and expense to BPA and its customers. BPA does not have a business reason to expend the time, effort, and funds to develop an entirely new repayment model. Although the repayment model is not available as an executable piece of software, BPA has provided the source code for the model. BP-18-E-BPA-31, at 20. Additionally, manuals for use of the model as well as planning and development documents are available from BPA’s FOIA office. With this information, it is possible for the parties to mimic BPA’s repayment model. BP-18-E-BPA-31, at 21.

BPA Staff intends to continue to offer to perform repayment studies for the parties by request in future rate cases. If the manuals, planning documents, and development documents available from BPA’s FOIA office, coupled with the available software code, are not sufficient to allay the questions or concerns of the parties, BPA is willing to organize a future workshop outside of the rate case regarding the more technical aspects of the model.

Decision

BPA will not create a new repayment model for use by parties on their own computer systems.

2.3 Power and Transmission Risk

The Power and Transmission Risk Study, BP-18-E-BPA-05, identifies, models, and analyzes the impacts that key risks and risk mitigation tools have on Power Services’ and Transmission Services’ net revenue and cash flow. It also demonstrates that each business line’s rates and risk mitigation tools are sufficient for that business line to meet BPA’s standard for financial risk tolerance—the Treasury Payment Probability (TPP) standard. This study presents BPA’s analysis of quantitative and qualitative risks facing each business line’s net revenues. The study 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. Department of Treasury (Treasury). Administrator’s Final Record of Decision, 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 TPP.
- 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 Federal Columbia River Power System (FCRPS) and Federal Columbia River Transmission System (FCRTS).
- Maintain sufficient financial reserves levels to support BPA's credit rating.
- Include in the risk mitigation package only those elements that can be relied upon.
- Do not let financial reserves 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, for Power rates, prevent any risks arising from Tier 2 service from imposing costs on Tier 1 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.

In this BP-18 rate proceeding, BPA incorporated a new modification to its net secondary revenue forecasting methodology that accounts for extra-regional energy sales to California.

No party raised issues related to BPA's forecast of net secondary revenue for the BP-18 rate period.

BPA has incorporated implementation of the FRP into the Power and Transmission Risk Study. In order to implement the FRP, a Transmission Cost Recovery Adjustment Clause (CRAC) and a Transmission Reserves Distribution Clause (RDC) are included in this rate proceeding. These mechanisms are structured similarly to the Power CRAC and the Power RDC. BPA is also adding PNRR to the Power Revenue Requirement for implementation of the FRP. The FRP and its implementation are discussed further in Section 6 of this Final ROD.

3.0 POWER RATES AND POLICIES

3.1 Competitiveness and the Proposed Power Rate Increase

ICNU and WPAG are concerned that BPA's utility customers and their industrial consumers may have to pay more for power than they would have to pay other suppliers based on BPA's recent rate increases and the current proposed increase and, therefore, express concern regarding BPA's competitiveness. *See* ICNU Br., BP-18-B-IN-01, at 3-4; WPAG Br., BP-18-B-WG-01, at 4. BPA is also concerned about its competitiveness, which led BPA to significant program cost reductions in the near term and engaging in Focus 2028 with customers and stakeholders for long-term strategic planning. Rates recover costs; thus, the first step is to focus on costs. BPA's costs are established outside BPA's rate cases, and the parties' concerns about BPA's future competitiveness may be better addressed outside BPA's rate cases. It is important, however, that the parties' concerns be heard and addressed, to the extent they can be, during the ratemaking process.

ICNU argues that Staff's proposal to increase Tier 1 power rates by at least 3.5 percent is part of an unsustainable trend of dramatic rate hikes. ICNU Br., BP-18-B-IN-01, at 3. ICNU notes that in the last three rate periods, BPA averaged rate increases of nearly 8 percent. *Id.* ICNU states that unless BPA takes immediate action, a continuation of this trend may cause irreparable harm to all regional customers and end-use consumers. *Id.*

ICNU notes that preference power has historically been a source of significant competitive advantage to Northwest businesses, especially those heavily reliant on large amounts of electric power. *Id.* ICNU states that, in recent years, this advantage has all but disappeared, causing both utilities and ratepayers to lose significant amounts of money via rates that are far higher than what would have been paid on the open market. *Id.* As large end-use consumers on BPA's system consider where to site their operations, many are now faced with potentially difficult decisions to relocate energy-intensive businesses or, at the very least, to construct new facilities in areas with access to lower-cost market power. *Id.* at 3-4. Unless these trends reverse quickly, many could choose to abandon their historical connections with public power and BPA, and look elsewhere for power to maintain some semblance of cost-competitiveness in the global economy. *Id.* at 4.

WPAG expresses similar concerns. WPAG argues that BPA must take action to ensure its competitiveness. WPAG Br., BP-18-B-WG-01, at 3. WPAG states that historically and persistently low natural gas prices, the rise of renewable energy, multiplying carbon-free initiatives, and reduced demand have fundamentally changed energy markets throughout the West, significantly lowering both (1) the price BPA can receive for its secondary energy, and (2) the measuring stick by which BPA's rates are compared. *Id.* at 3-4. Meanwhile, the costs incurred and the revenues forgone by BPA to satisfy its regulatory and legal obligations, and to otherwise provide public benefits, continue to rise. *Id.* at 4. In this environment, each increment of rate increase BPA levies to recover its costs (as BPA is required to do), and to fund its many obligations under the statutes identified above, erodes the perception that BPA's PF rate is a competitive rate in today's wholesale marketplace. *Id.* Said another way, in light of current

prevailing market rates, there is a finite amount of upward rate pressure that BPA's customers can or will tolerate before they deem BPA's power rates uncompetitive. *Id.*

WPAG states there are risks to BPA when its power rates exceed the market for too long. *Id.* First and foremost is that such a circumstance can undermine BPA's capacity to balance its costs and revenues. *Id.* This, in turn, threatens BPA's ability to meet its statutory objectives, including BPA's obligations to repay the Federal Treasury, recover its costs, and to mitigate, protect, and enhance fish and wildlife. *Id.* When BPA's PF rate was similarly above market in the mid-1990s, the Administrator identified the linkage between BPA's competitiveness and its capacity to fulfill its statutory obligations as follows:

BPA must always balance its costs with its revenue generating ability. The availability of power at competitive prices from other suppliers now precludes BPA from meeting costs simply by raising rates to its customers. There is a BPA firm power rate level above which a rate increase would no longer increase BPA's revenue (due to a price-induced reduction in demand). This rate level is referred to as BPA's maximum sustainable revenue. Allowing BPA's rates to exceed this level would not be consistent with sound business principles. It would reduce BPA's total revenue and its ability to repay its U.S. Treasury debt and to fund public benefits.

Id. at 4-5 (citing Administrator's 1996 ROD Template (New Power Sales Contracts) and Amendatory Agreement No. 7, at 2) (emphasis omitted). WPAG notes that, fortunately for BPA, the current take-or-pay Regional Dialogue (RD) Contracts largely shelter it from price-induced reductions in load through FY 2028. WPAG Br., BP-18-B-WG-01, at 5. This provides BPA with some time to improve its competitive standing vis-à-vis the market. *Id.* Unfortunately, for BPA's preference customers, it appears that due to the factors identified above, including diminishing net secondary revenue and increasing fish and wildlife costs, this rate case will result in yet another substantial power rate increase, and yet another hit to BPA's perceived competitiveness. *Id.* If this trend continues, at best it may cause some of BPA's preference customers to consider less expensive non-Federal power supply options for post-2028. *Id.* at 6. This would effectively be a price-induced reduction in demand in the manner identified as a concern by the Administrator in 1996. *Id.* At worst, it may result in BPA being forced to release some of its preference customer loads to the market before 2028 if the difference between BPA and market rates becomes too large for too long. *Id.* Either event would have the potential to dangerously upend the long-term balance between BPA's costs and revenues and put BPA's compliance with its statutory obligations at risk. *Id.*

WPAG states that BPA's announcement earlier this year that there is a substantial risk of a Day 1 CRAC at the start of the BP-18 rate period and its proposal to effectively adopt another Fish CRAC to address the recent ruling from U.S. District Court for the District of Oregon in *National Wildlife Federation v. National Marine Fisheries Service*, No. 3:01-cv-0640-SI, 2017 WL 1829588 (D. Or. Apr. 3, 2017), *amending and superseding* 2017 WL 1135610 (D. Or. Mar. 27, 2017) ("*National Wildlife Federation*"), demand even more cost-cutting by BPA in order to mitigate both the need for and extent of such CRACs. *Id.* at 7. Furthermore, BPA's preference customers are already evaluating whether they believe BPA will be

competitive in 2028 and are making plans accordingly. *Id.* Waiting until 2028 to become competitive, therefore, will be too late. *Id.*

WPAG notes that when confronted with a similar situation in the mid-1990s, BPA took extraordinary action to ensure it could recover its costs while maintaining its competitiveness, and recommends that BPA use those actions as a framework for what BPA can and should be doing now, including: (1) aggressively cutting costs; (2) seeking new opportunities for fish-mitigation cost stabilization and funding; (3) redesigning basic products; and (4) exploring new opportunities to maximize revenue. *Id.* at 7-9.

WPAG concludes that BPA's ability to meet its statutory mission depends on its ability to remain competitive, both over the short and long terms. *Id.* at 9. WPAG acknowledges that BPA is working extraordinarily hard in this regard, but given the dramatic changes currently ongoing in Western wholesale energy markets, BPA will likely need to do much more to remain competitive. *Id.* Fortunately, BPA has successfully confronted this risk before, and can look to its past for examples as to how to secure its future. *Id.* WPAG looks forward to engaging BPA and other stakeholders on this important issue following the rate case. *Id.*

BPA appreciates WPAG's recognition of BPA's efforts to remain competitive. *See* Stiffler *et al.*, BP-18-E-BPA-27, at 6. Through the IPR and IPR 2 processes, BPA significantly reduced controllable costs. In the IPR process, the agency reduced spending increases by \$19 million per year on average for Power in both FY 2018 and FY 2019. *See* Integrated Program Review and Capital Investment Review, Close-out Report, October 2016, available at <https://www.bpa.gov/Finance/FinancialPublicProcesses/IPR/Pages/IPR-2016.aspx>.

On January 18, 2017, BPA issued a letter initiating the IPR 2 public process—a second round of public discussions on a limited set of spending areas for fiscal years 2018 and 2019. *Id.*; *see* January 18, 2017, IPR 2 Invitation Letter, available at <https://www.bpa.gov/Finance/FinancialPublicProcesses/IPR/Pages/IPR-2016.aspx>.

This second cost review was conducted in response to extensive feedback during the initial IPR, and in recognition that it had more work to do in its effort to fend off the unsustainable rate trajectory of the past four rate periods. *See* Administrator's Letter on IPR 2 Close-out Report, available at <https://www.bpa.gov/Finance/FinancialPublicProcesses/IPR/Pages/IPR-2016.aspx>. The IPR 2 process addressed expense and capital spending for Reclamation and the Corps, operations and maintenance (O&M) expenses for the Columbia Generating Station, the Commercial Operations Key Strategic Initiative, and workforce expenses. *Id.* While BPA took important steps to reduce spending levels during the initial IPR, the additional round of discussions in IPR 2 allowed BPA to build on that momentum of de-escalating costs and direct the agency's attention to a few consequential elements of BPA's cost structure. *Id.*

In April 2017, BPA completed IPR 2, which reduced spending levels for Power by an additional \$17 million per year on average compared to the final IPR spending levels BPA shared in October 2016. *Id.* at 10. Although program costs are not rate case issues, these efforts show BPA's continuing commitment to controlling its costs and establishing low rates.

Through the IPR and IPR 2 processes, BPA reduced the power revenue requirement by about \$35 million per year below initially proposed IPR spending levels. Additional reductions in direct hydro capital spending for FY 2017–2019, which, combined with other debt management actions, reduced the capital portion of the revenue requirement by \$91 million per year in FY 2018 and FY 2019, compared to the BP-16 Initial Proposal. See Administrator’s Preface to this Final 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. Unfortunately, many of the drivers for this rate increase involve costs that are beyond the direct control of BPA. It is also important to note that BPA often 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 struck the appropriate balance with information available at that time, and the Final Proposal will do the same as it incorporates the results of the IPR 2 process and the latest financial information available.

WPAG argues that BPA has exhausted the use of rate increases as a viable balancing tool, and that BPA customers have exhausted their own ability to absorb another substantial BPA rate increase, having cut costs and staff, and spending their own financial reserves to provide their customers with rate stability in response to BPA’s prior substantial rate increases. WPAG utilities believe that BPA cannot be competitive by simply raising rates, and urge BPA to commit to more cost cuts to keep the rate increase as low as possible. WPAG Br. Ex., BP-18-R-WG-01, at 3-5.

However, even the \$126 million per year in reductions from IPR, IPR 2 and the capital portion of the revenue requirement are substantially offset by increases in BPA’s uncontrollable costs. See Administrator’s Preface to this Final ROD. Moreover, BPA will continue to face significant pressures on its long-term cost structure beyond this rate period. 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.

BPA understands that it must set a new course and make difficult decisions on a variety of program offerings and adopt financial disciplines so that BPA is competitive in 2028. With fundamental forces changing across the utility industry, BPA now more than ever is thinking strategically and planning for the future. This new course may include solutions from the past, as this is not the first time BPA has had to confront its future competitiveness, but it will likely also need to include solutions for the future—solutions that will be successful with the changing

industry. It is because of this core understanding that BPA is committing to aggressively secure its competitiveness by: decreasing costs directly within BPA's control; finding new avenues to better control and manage BPA's indirect costs; and uncovering new methods that diversify BPA's sources of revenue and effectively reduce BPA's reliance on the short-term energy market.

BPA's intent to remain vigilant on spending levels and competitiveness is summarized in a letter from the Administrator accompanying the April 2017 IPR 2 Close-out Report:

When we launched IPR 2, we committed to presenting alternatives for your consideration and comment. We now have a better idea of what is required to provide more visibility into our spending level proposals and will be better prepared to provide you with more useful data in future spending-level engagements. Through the newly created Business Transformation Office, we are advancing our ability to prioritize and sequence work and to develop robust business cases in advance of public review. As well, the analytic capabilities we are developing in our Finance organization will support our goal of being able to share and evaluate the benefits and risks of proposed spending levels.

The steps we have taken to mitigate cost escalation for fiscal years 2018 and 2019 are significant, and we would not have been able to achieve these savings without our many partners and engaged stakeholders. The final proposed spending levels described in this document represent a focused effort to demonstrate BPA's strengthening capacity to deliver disciplined and enduring cost management practices. But there is hard work ahead of us, and I look forward to your continued engagement as we address the many other challenges and opportunities that will influence the cost of power and transmission services in the next rate period and beyond.

As we continue to focus on sustainable finances and rates, we also continue to balance the other elements of our agency strategy, which are essential to BPA's position as a motivating force of the Northwest economy and way of life. Through the talent of our people, we are maintaining and enhancing the region's investments in the federal physical assets; advancing policies and investments that result in reliable, efficient and flexible operations; and remain committed to mitigation actions and environmental enhancements that will continue to add value for years to come.

Administrator's Letter on IPR 2 Close-out Report, *available at* <https://www.bpa.gov/Finance/FinancialPublicProcesses/IPR/Pages/IPR-2016.aspx>.

BPA is committed to working with its stakeholders in strategic planning through Focus 2028 and other collaborative sessions outside the rate case, where a free exchange of ideas for controlling and reducing costs is possible and where new revenue opportunities can be explored. BPA acknowledges that maintaining our competitiveness will require long-term thinking and making

difficult choices. Those choices can best be determined through open dialogue with our customers in developing BPA's long-term strategy.

3.2 Power Loads and Resources

The Power Loads and Resources Study (Study), BP-18-FS-BPA-03, contains the load and resource data used to develop BPA's wholesale power rates for FY 2018–2019. Documentation supporting the results of the Study is presented in the Power Loads and Resources Study Documentation, BP-18-FS-BPA-03A. The Study is also described in the direct testimony of Bellcoff *et al.*, BP-18-E-BPA-19.

The 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 2018–2019. 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. If BPA's resources are greater than the amount of load forecast for the rate period, firm surplus sales are forecast to achieve load-resource balance.

The 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 Study provides inputs to various other studies and calculations in the ratemaking process: (1) the Power Rates Study, BP-18-FS-BPA-01; (2) the Power Market Price Study, BP-18-FS-BPA-04; and (3) the Power and Transmission Risk Study, BP-18-FS-BPA-05.

No party raised issues related to BPA's forecast of loads and resources for the BP-18 rate period.

3.3 Power Market Price Study

The Power Market Price Study, BP-18-FS-BPA-04, contains BPA's natural gas price and electricity market price forecasts for the BP-18 rate period, and outlines the methodologies and inputs used to develop the forecasts. The natural gas price forecast serves as an input into the electricity market price forecast, and the electricity market price forecast is used in the development of the demand rates, load-shaping rates, short-term balancing purchases and expenses, augmentation purchases and expenses, secondary energy sales and revenue, PNRR, and other components outlined in the Power Rates Study, BP-18-FS-BPA-01. The testimony of Graessley *et al.*, BP-18-E-BPA-20, provides an overview of modeling updates and states BPA Staff's reasons for employing and modifying the various methodologies used to produce the forecasts.

No party raised issues in the initial briefs related to BPA's electricity market price forecast or BPA's natural gas price forecast for the BP-18 rate period.

3.4 Power Rate Development

This section addresses issues related to the Power Rates Study and the power rate schedules, including the GRSPs. Section 3.4.1 lists changes in rate development methods, rate schedules, and GRSPs proposed by BPA Staff that were not raised in the parties' initial 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 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-18-E-BPA-01, at 1.

Section 7 of the Northwest Power Act, 16 U.S.C. § 839e, governs the allocation of BPA's 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, pt. 1, (1980). Section 7 reserves rate design (how the revenue is collected) for 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, RAM2018, for purposes of calculating power rates. BPA makes the RAM2018 spreadsheet model available to the public on its website. The Power Rates Study describes how the tiered PF Public rate (PFp) is designed following the cost of service and rate directives ratemaking steps. The rate design for the PFp rate was established in the Tiered Rate Methodology (TRM). TRM, BP-12-A-03. The TRM restricts BPA and customers with CHWM 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. *Id.* § 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* Section 1.2.2.

3.4.1 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. The parties' initial briefs contained no objections to these changes, and some parties expressed 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-18-FS-BPA-01; the 2018 Power Rate Schedules and GRSPs, Appendix C to this Final ROD;

Stiffler *et al.*, BP-18-E-BPA-22; Stiffler *et al.*, BP-18-E-BPA-27; Weekley *et al.*, BP-18-E-BPA-23; and Weekley *et al.*, BP-18-E-BPA-28.

1. **Priority Firm (PF) Rate Schedule: Product Conversion Charge.** A new charge has been added for customers switching from Slice/Block to Block only or Load Following service to compensate for Slice True-Up credits received in FY 2014 and FY 2015.
2. **Tier 2 Load Growth Billing Adjustment.** This adjustment has been removed from the BP-18 rate schedules and GRSPs because it is not applicable in this rate period.
3. **Firm Power and Surplus Products and Services (FPS) Rate Schedule.** The FPS rate schedule was slightly reorganized to give the rate schedule a more logical flow. No changes were made to the availability of products and services under this rate schedule.
4. **Adjustments, Charges, and Special Provisions (GRSP II).** The GRSPs have been grouped together by similar topic rather than alphabetical order to make them more user-friendly. The new organization allows users to find related topics in a single location.
5. **Low Density Discount (GRSP II.B).** The table has been updated from a “less than” symbol to an “equal to or less than” symbol to clarify the range for each ratio. The language is revised to clarify when additional discounts apply and how additional discounts for very low densities are applied in GRSP II.B, Sections 4 and 5.
6. **Transmission Scheduling Service (GRSP II.I.5).** Due to changes in scheduling practices, the methodology for calculating this charge has been capped to keep rates consistent with the BP-16 rate case. This product design and rate methodology will be revisited for the BP-20 rate case. Additionally, a reduction was made to the transaction assumption used to set the cap on Unspecified Resource Amounts serving Above-RHWM Load from three daily transactions to one because these transactions are generally known a year in advance, and are likely less costly to administer.
7. **Resource Shaping Charge (RSC) (GRSP II.I.2).** Billing determinant descriptions were updated to clarify the types of planned generation they apply to and to align with the CHWM contracts.
8. **Forced Outage Reserve Service (FORS) (GRSP II.I.4).** Billing determinant descriptions were updated to clarify the types of planned generation they apply to and to align with the CHWM contracts.
9. **Transmission Curtailment Management Service (TCMS) (GRSP II.I.5(b)).** Transmission Curtailment Management Service is being expanded to allow a Load Following customer serving its load with non-Federal purchases delivered at Mid-C on non-firm (rather than firm) Network Transmission schedules to qualify for the service. The rate structure for this service mirrors Transmission Services’ current Energy Imbalance charge (index plus bands, depending on size).

10. **Unanticipated Load Service (GRSP II.M.2(a)(1) and 4(a)(1)).** For Unanticipated Load Service provided under both the PF-18 and FPS-18 rate schedules, energy rates have been changed to be the greater of (1) the PF Tier 1 Equivalent energy rates or (2) the PF Load Shaping rates.
11. **Unauthorized Increase (UAI) Charge (GRSP II.N).** The demand charge description has been updated to clarify when the charge applies to customers that purchase a Block-only product or the Block portion of the Slice/Block product and to align the charge with the CHWM contract terms.
12. **Residential Exchange Program (GRSP II.T).** Section II.T.2 of the BP-16 GRSPs entitled “Change in Service Territory Due to Annexation or Load Transfer” has been eliminated because, with the adoption of the Residential Exchange Program Settlement, it is not applicable.
13. **Large Project Targeted Adjustment Charge.** This charge was designed to recover BPA’s borrowing and issuance costs associated with funding customers’ Large Project Program conservation projects. *See* BP-16 Power Rate Schedules and GRSPs, BP-16-A-02-AP02, GRSP II.A.2. However, BPA is discontinuing the Large Project Program on September 30, 2017, and therefore eliminating this associated charge.
14. **Super Peak Period (GRSP III.B.30).** The definition of the Super Peak Period is revised to be (1) October through May during HE 8 through HE 10 and HE 19 through HE 21; and (2) June through September during HE 14 through HE 19 in BP-18.

3.4.2 Demand Rate

Issue 3.4.2.1

Whether BPA should use an LMS100 or an LM6000PF SPRINT as the marginal cost resource to calculate the demand rate.

Parties’ Positions

NRU and PNGC support the use of the LMS100 simple-cycle combustion turbine (SCCT) as the marginal cost resource to calculate the demand rate. NRU Br., BP-18-B-NR-01, at 19-25; PNGC Br., BP-18-B-PN-01, at 13-15.

ICNU argues that BPA should use an aeroderivative SCCT, consistent with Appendix G of the Northwest Power and Conservation Council’s (the Council) Seventh Northwest Conservation and Electric Power Plan (Seventh Power Plan), as the marginal cost resource to calculate the demand rate. ICNU Br., BP-18-B-IN-01, at 106-110. In ICNU’s demand rate calculations for a “Proposed Aeroderivative,” ICNU uses the LM6000PF SPRINT as the marginal cost resource to calculate the demand rate. Mullins, BP-18-E-IN-01, at 35; Mullins, BP-18-E-IN-01-AT01, at 139-141; Mullins, BP-18-E-IN-01-AT02, at 7.

BPA Staff's Position

Staff proposes to use the LMS100 SCCT as the marginal cost resource to calculate the demand rate. Stiffler *et al.*, BP-18-E-BPA-22, at 11-14.

Evaluation of Positions

The demand charge is designed to send a price signal to a limited portion of a customer's overall demand on BPA and is applicable to customers purchasing Load Following and Block with Shaping Capacity Products. TRM, BP-12-A-03, at 71. 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 Section 7(i) process. *Id.* at 76. In other words, the TRM has established the design of the demand rate, and the only issue that may be litigated in rate cases through the term of the TRM is to identify the marginal capacity resource and the annual fixed costs associated with that resource. *Id.* at 76-77. The TRM provides a variety of sources upon which BPA may base this cost. *Id.* at 77. In the BP-18 Initial Proposal, BPA calculated the demand rate based on the annual fixed costs of the marginal capacity resource LMS100 SCCT using information from the Council's Microfin model 15.2.1. Stiffler *et al.*, BP-18-E-BPA-22, at 11. This is the same basis for the marginal capacity resource that BPA has used to calculate the demand rate since the start of the TRM in BP-12. Stratman & Weathers, BP-18-E-NR-02, at 2.

ICNU argues that given the rapid growth in variable energy resources deployed in the region, it is essential that any capacity resources be able to respond to rapidly changing conditions. ICNU Br., BP-18-B-IN-01, at 106-107. ICNU states that, generally, aeroderivative resources are the most flexible capacity resources available, and are significantly more responsive than the LMS100. *Id.* at 107. In response, however, ICNU is apparently unaware that the LMS100 is an aeroderivative resource (including certain frame technology) and, therefore, has significant flexibility. Stiffler *et al.*, BP-18-E-BPA-27, at 11, Attachment 6. ICNU selects a particular aeroderivative model, the LM6000PF SPRINT, and argues that because the LM6000PF SPRINT is more flexible and responsive than the LMS100 and other capacity resources, it would best be able to balance the region's increasing need for flexible capacity. ICNU Br., BP-18-B-IN-01, at 107. This argument fails, however, because selecting the proper marginal resource for BPA is not simply a matter of which resource has the greatest flexibility. The question is whether a resource has sufficient flexibility to meet BPA's needs. If the resource meets BPA's flexibility needs, BPA logically then looks for the least-cost resource that provides such flexibility. As noted above, both the LM6000PF SPRINT and LMS100 models are classified as aeroderivative SCCTs with load following capabilities. Stiffler *et al.*, BP-18-E-BPA-27, at 11, Attachment 6. In particular, the LMS100 is well suited to offer load-following service, with the ability to retain high efficiency levels at partial load. *Id.* at 10. The LMS100 is a cost-effective marginal resource that can be used for a variety of applications. *Id.*

In addition, the LMS100 provides sufficient flexibility to balance intermittent resources and ensure resource adequacy. *Id.* at 11. The LMS100, like all of GE's aeroderivative products, is engineered to serve as a flexible resource and reach full output within 10 minutes. *Id.*, Attachment 6, at 5. Consequently, the LMS100 qualifies as a non-spinning contingency reserve for use in reliability planning. *Id.*, Attachment 7, at 5. In addition, the LMS100 shares a ramp

rate of 50 megawatts (MW) per minute with the LM6000PF SPRINT, suggesting the two aeroderivatives share common regulation capability. *Id.* at 11. Although the LM6000PF SPRINT offers faster start times than the LMS100 (5 minutes as opposed to 10 minutes), this difference does not offer a material advantage sufficient to warrant a departure from the LMS100 for use in setting the demand rate, particularly given the LMS100's load-following capability. *Id.* Should BPA need to acquire the output of a marginal resource in the future, it would seek to do so in the least-cost manner consistent with its needs. *Id.* at 10. The LMS100 satisfies this criterion better than the LM6000PF SPRINT. *Id.*

ICNU argues that there are three reasons why it believes an aeroderivative SCCT is preferable to the LMS100. ICNU Br., BP-18-B-IN-01, at 107. First, ICNU argues that the use of an aeroderivative SCCT is consistent with the Council's Seventh Power Plan, where the Council noted "the best fit resource for the *region* is an Aeroderivative simple-cycle combustion gas turbine (SCCT)." *Id.* (emphasis added). However, as noted above, the LMS100 is an aeroderivative SCCT. Therefore, the LMS100 qualifies as a "best fit" resource in the Council's view.

Also, as noted above, the Council's selection of the GE LM6000PF SPRINT model as its aeroderivative SCCT reference plant in the Power Plan does not mean that the LM6000PF SPRINT is the best resource to use in determining BPA's demand rate. Stiffler *et al.*, BP-18-E-BPA-27, at 10. The TRM provides a variety of sources upon which BPA may determine this cost, including BPA's Resource Program, costs of BPA's recent capacity additions, or third-party sources, such as the Energy Information Administration, EPRI Technical Assessment Guide, the Council, or the Integrated Resource Plans of Pacific Northwest electric utilities. TRM, BP-12-A-03, at 77. For purposes of calculating the demand rate, there is simply no requirement that BPA use any specific resource the Council identifies in its Plan.

Furthermore, one must review what the Council was addressing when it referred to "the best fit resource for the region." Significantly, it was not referring to what best fits BPA's needs for calculating its demand rate. Instead, ICNU cites Appendix G of the Council's Seventh Power Plan. Mullins, BP-18-E-IN-01, at 31. Appendix G is entitled "Conservation Resources and Direct Applications Renewables" and discusses the methodology used by the Council for "estimating the conservation resource potential in the region." Seventh Power Plan, App. G at G-1, available at <http://www.nwcouncil.org/7thplan/>. Specifically, Appendix G describes how to calculate the benefit-versus-cost ratio to determine the cost-effectiveness of a particular conservation measure. *Id.* at G-4. One piece of this calculation is to include a "deferred generation credit," for which Appendix G uses an aeroderivative SCCT. Stratman & Weathers, BP-18-E-NR-02, at 5-6. ICNU relies on this reference to an aeroderivative SCCT, in particular the LM6000PF SPRINT, used in a calculation related to conservation measures, to argue that BPA should modify its demand rate calculation. A citation to a single input in an appendix to the Council's Power Plan that analyzes conservation, however, does not justify BPA modifying the basis for its demand rate, which has been used for the past three rate periods.

Furthermore, even if Appendix G were relevant to the calculation of BPA's demand rate, the Seventh Power Plan explicitly recognizes that its analyses are based on the entire Northwest region, not any particular utility. Seventh Power Plan at G-23. Appendix G specifically states

that the Council uses the “best fit resource for the *region*” when selecting the marginal generation resource to use when calculating the cost-effectiveness of a conservation measure. *Id.* (emphasis in original). Appendix G also observes that individual entities may have different input values given specific needs, but that the methodology to estimate a benefit-cost ratio should be consistent. *Id.* at G-21. BPA has determined that the best fit for its needs in calculating the demand rate is the LMS100.

Although the Council’s Plan was addressing different purposes than BPA is addressing in this rate case, the Council did not expressly reject the LMS100 as an appropriate capacity resource for the Council’s purposes. ICNU provides no information regarding why the LMS100 was not mentioned in the Council’s Plan. Stiffler *et al.*, BP-18-E-27, at 10. Logically, the LMS100 is one of the resources that the Council would have reviewed in making its selection. *Id.* The absence of a review of the LMS100 could mean that the Council forgot to review the resource, intended to review the resource but ran out of time to conduct its review, or other possibilities. *Id.* The Council’s use of the LM6000PF SPRINT, without a comparison or concurrent review of the LMS100, provides little information regarding which resource would provide the best basis for addressing the Council’s needs.

ICNU’s second argument is that a switch to an aeroderivative SCCT for the purpose of the TRM would materially improve the model, while maintaining its existing incentives and benefits—that is, customers who already pay artificially low rates under the existing TRM method would still see net benefits if an aeroderivative SCCT were used instead of an LMS100. ICNU Br., BP-18-B-IN-01, at 107. First, as noted previously, the LMS100 is an aeroderivative resource. There would not be a “switch” to an aeroderivative SCCT but instead a continued use of an aeroderivative SCCT. Indeed, the manufacturer itself, General Electric, describes the LMS100 as an aeroderivative resource. Stiffler *et al.*, BP-18-E-27, Attachment 7, at 4. Thus, the LMS100 provides the same basic benefits provided by the LM6000PF SPRINT, another aeroderivative resource.

ICNU argues that its proposed change to the capacity resource used in TRM calculations would leave existing incentives and benefits in place, and customers that pay demand charges would continue to pay artificially low rates under the terms of the TRM. ICNU Br., BP-18-B-IN-01, at 108. ICNU states that this change would slightly increase demand charges for some customers, but the TRM’s carve-out for existing contract demand ensures that individual customers’ payments would remain artificially low, relative to the actual amount of demand they impose on the system. *Id.* ICNU states that, in particular, existing customers would still be insulated from the actual cost of the demand they create on the BPA system. *Id.* ICNU’s argument, however, does not distinguish the LM6000PF SPRINT from the LMS100. As ICNU notes, there may be benefits to be gained by more directly linking TRM demand charges to a customer’s total system demand, but a change to the *type* of capacity resource would not accomplish this. *Id.* However, use of the LM6000PF SPRINT would not be a change in the basic type of resource because the LMS100 is also an aeroderivative resource and, therefore, the continued use of the LMS100 also would not accomplish a more direct linking of demand charges to a customer’s total system demand.

ICNU argues that the TRM understates demand charges for BPA customers by exempting contract demand from TRM demand charges. *Id.* at 110. This is incorrect. Contract Demand Quantities (CDQs) were developed for TRM rate design so that BPA could change the demand charge billing determinant from Generation System Peak to Customer System Peak (CSP), and to increase the demand rate to a marginal price, without creating dramatic rate impacts on customers. Stiffler *et al.*, BP-18-E-BPA-27, at 11-12 (citing Fisher *et al.*, TRM-12-E-BPA-06, at 23-24). CDQs were established in accordance with the TRM, and each customer has 12 CDQs listed in Exhibit B of the customer's CHWM contract. Stiffler *et al.*, BP-18-E-BPA-27, at 12. Except for a Joint Operating Entity (JOE), which can have its CDQs modified due to changes in the JOE's utility membership, a customer's CDQs are only subject to change due to having its load annexed by a utility with monthly CDQs, or annexing the load of a utility with monthly CDQs, in accordance with Section 2.2 of Exhibit B of the CHWM contract. *Id.* Because CDQs are not revised to account for a utility's load growth or changes to its load profile over time, any change to the demand rate directly impacts those utilities that pay a demand charge. *Id.* However, the question of CDQs is not relevant to the selection of BPA's marginal capacity resource. *Id.* There is no reason why mitigation of the rate impact of implementing a true price signal at the inception of the TRM is, in any way, relevant to the selection of the marginal resource for purposes of calculating the demand rate for the BP-18 period. *Id.* BPA should select the least-cost resource that also meets the anticipated load following needs of its customers. *Id.*

ICNU claims that if Staff's recommendation were adopted, then the TRM would effectively create a double subsidy for customers paying the demand charge—first, by exempting existing contract demand from demand charges, and then by using an artificially low-cost capacity resource, the LMS100, to determine the cost of the demand charges that those customers pay. ICNU Br., BP-18-B-IN-01, at 110. Contrary to ICNU's claims, first, as explained above, the TRM does not understate demand charges for BPA's customers. Second, the LMS100 is not an artificially low-cost capacity resource. Instead, like ICNU's proposed LM6000PF SPRINT, the LMS100 is an aeroderivative resource. The LMS100 also satisfies BPA's flexibility and other load-following needs. As explained previously, there is no need to acquire a more expensive resource if a lower-cost resource satisfies BPA's needs.

ICNU's third argument is that the use of an aeroderivative SCCT resource more accurately reflects actual peaker construction trends in the region. *Id.* at 109. ICNU claims that regional utilities place far greater emphasis on operational flexibility than cost—and, thus, so should the TRM model. *Id.* at 108. This argument is overreaching. ICNU's broad assertion that all regional utilities place far greater emphasis on flexibility than cost is based solely on the fact that PGE constructed a reciprocating engine generator, which ICNU claims is more akin to an aeroderivative SCCT in both cost and flexibility than the LMS100. The claim that all regional utilities place greater emphasis on operational flexibility than on cost, based on a single choice by a single utility at a single point in time, is poorly founded. In addition, it would make ICNU's alleged "regional trend" change willy-nilly with each new capacity resource addition. Similarly, each new capacity resource addition would indicate that regional utilities were placing more emphasis on cost than operational flexibility, or vice versa, depending only on the latest resource constructed. This is despite the fact that a utility would make its choice based on the particular

circumstances of the utility. BPA, however, is not trying to find a resource that was acquired by any particular utility based on its particular needs. Instead, BPA is trying to reflect the costs BPA would face to acquire a capacity resource to meet BPA's load and resource capacity obligations.

ICNU states that PGE actually modeled its marginal capacity assuming that it would build a low-cost, low-flexibility frame generator; but, when the time to build actually arrived, PGE chose to construct a high-cost, high-flexibility reciprocating engine. *Id.* at 109. ICNU argues that there is no reason to think that other regional utilities would not also prioritize flexibility over cost, just as PGE did. To the contrary, however, a single utility's choice for a capacity resource is based on its own particular circumstances. Simply because one utility acquired a particular type of resource does not mean that another utility in different circumstances would make the same choice. Indeed, the fact that PGE modeled its marginal capacity assuming a low-cost, low-flexibility frame generator shows that PGE considered a resource other than the reciprocating engine generator, and the choice of resource was not clear from the beginning. Also, PGE did not choose the LM6000PF SPRINT, as advocated by ICNU.

ICNU claims that any continuing argument derived from the prior rate case, *i.e.*, that the LMS100 is the "industry standard" for capacity resources in the Western Interconnect, would be inapposite. *Id.* However, the 2016 Final ROD, less than two years ago, justified the use of the LMS100 as the TRM's capacity resource of choice partly on the basis of nearly 30 LMS100 units either under construction or recently built across the Western Electricity Coordinating Council, almost all of them in California. Final Record of Decision, BP-16-A-02, at 31. In contrast to ICNU's citation of a single resource, the construction of 30 LMS100s shows a significant trend in the Western Interconnect.

ICNU claims that "other recently constructed peakers have been aeroderivative models, not lower-cost LMS100 or frame generators." ICNU Br., BP-18-B-IN-01, at 109 (citing Mullins, BP-16-E-IN-02, at 9-10). ICNU, however, cites no BP-18 record evidence to support this assertion. Instead, ICNU cites its testimony in BPA's *BP-16* rate case. *Id.* ICNU did not move this prior testimony into the BP-18 record, and no party had the opportunity in the BP-18 rate case to conduct discovery on ICNU's past assertions, to file testimony in response to such assertions, or to cross-examine witnesses on the assertions. Such extra-record testimony cannot be used to support ICNU's BP-18 claims. Even if one were to review ICNU's extra-record testimony, however, ICNU's argument is not persuasive. ICNU's cited BP-16 testimony states:

With the exception of Port Westward II, all of the other peaking resources built since 2010 in the Pacific Northwest have been based on the more-expensive, yet highly flexible, aeroderivative combustion turbine technologies. For example, the Culbertson Generating Station, placed into service in late 2010, is a General Electric LM6000 aeroderivative turbine. The Dave Gates Generating Station, placed into service in early 2011, is a Pratt & Whitney aeroderivative combustion turbine. The Highwood Generating Station, placed into service in late 2011, is a General Electric LM6000 aeroderivative turbine.

Mullins, BP-16-E-IN-02, at 9-10.

If BPA had had the opportunity to respond to ICNU's BP-16 testimony in the BP-18 rate case, BPA would have pointed out that, in fact, the Culbertson Generating Station is an *LMS100* SCCT, not an LM6000. *Culbertson Station*, Basin Electric Power Coop., <https://www.basinelectric.com/Facilities/Culbertson/> (last visited May 25, 2017). ICNU's citation to the Culbertson Generating Station therefore *supports* BPA's selection of the LMS100. Furthermore, the Highwood Generating Station in Great Falls, Montana, cited by ICNU as an LM6000, was built by Southern Montana Electric Generation and Transmission Cooperative (SMEGTC), which filed for bankruptcy one month after the Highwood Generating Station went into service. The LM6000 unit was later bought by a company in Missouri, dismantled, and sold piece by piece. *Missouri Company Buys Highwood Station*, Beartooth Electric Coop., Inc., <http://www.beartoothelectric.com/content/missouri-company-buys-highwood-station> (last visited May 25, 2017). Although BPA is not drawing a cause-and-effect relationship between SMEGTC's acquisition of an LM6000 and its bankruptcy, this event reminds utilities that they must be concerned with cost when acquiring a resource; if a resource is too expensive, it may have significant financial impacts on the acquiring utility. Thus, even if BPA were to review the extra-record resources cited by ICNU, one would conclude that BPA's use of the aeroderivative LMS100 would be consistent with other recently constructed aeroderivative peakers.

ICNU states that BPA should not consider using a resource that has never been built in the Northwest to determine demand costs; to do so would almost certainly understate the actual cost of future demand, as measured by actual past construction. ICNU Br., BP-18-B-IN-01, at 110. However, as noted above, aeroderivative resources similar to the LMS100 have been built in the region. Furthermore, if the LMS100 satisfies BPA's flexibility needs, there would be no need to acquire a more expensive resource such as the LM6000PF SPRINT. Thus, using an expensive LM6000PF SPRINT when a more affordable resource would meet BPA's needs would be financially irresponsible and almost certainly overstate the actual cost of future construction.

Decision

BPA will continue to use the LMS100 as the marginal resource to calculate BPA's demand rate for the BP-18 rate period.

3.4.3 Tier 2 and Remarketing Value

Under Section 5(b)(1) of the Northwest Power Act, BPA is obligated to sell firm power to serve the portion of a utility's retail consumer load that is not served with the utility's own resources dedicated to serve such loads. BPA forecasts the availability of firm Federal power for serving its total load obligation under this section with an annual calculation of its net requirement load obligations. For each rate period, BPA also makes an annual forecast of its loads and resources and available firm power. BPA provides firm power from the Federal Base System (FBS) for this net requirement load when firm power is available. BPA forecasts firm power from the Federal hydro system using a 1937 critical water year calculation, a standard that assures the availability of firm power from the system in almost all conditions.

To meet its total load obligation under its contracts, BPA compares its forecast of firm power to its net requirement load obligations.² If BPA does not have sufficient power from Federal system resources, then BPA would acquire or purchase power to meet its obligations. Under CHWM contracts and the TRM, BPA made a distinction in its rates for its net requirement load obligations to customers based on an amount of power that would be sold at a Tier 1 PF rate—the lesser of a customer’s net requirement load or its RHWL—and an amount of power that the customer could either supply from non-Federal resource(s) or have BPA supply at a Tier 2 PF rate—the Above-RHWL Load). Although a pricing distinction was made, the entire load served by BPA is its net requirements load obligation and, under applicable BPA statute, BPA’s obligation is to first serve customer loads with available firm power from the FBS and not by additional power purchases unless BPA has a need for the power.³ For the first year (FY 2018) of the BP-18 rate period, BPA has forecast sufficient firm system power from the FBS to meet its total load obligations for load priced at Tier 1 rates and Above-RHWL Load priced at Tier 2 rates. For the second year (FY 2019), BPA purchased power from the market to serve its Above-RHWL Load obligation. Power Rates Study, BP-18-FS-BPA-01, § 3.2.2.1.

To price its power service to Above-RHWL Loads, BPA establishes a rate termed the Remarketing Value. The Remarketing Value is a mills-per-kilowatt-hour rate and is applied in two situations. First, BPA uses the Remarketing Value to determine credits for customers with power purchased at Tier 2 rates and/or non-Federal resources in excess of need that are being remarketed by BPA in accordance with Section 10 of the CHWM contracts. Because a customer must elect to take service at Tier 2 rates and/or apply non-Federal resources to serve its load before its Above-RHWL Load is determined, Section 10 of the CHWM contract allows BPA to remarket any excess amounts. Second, BPA uses the Remarketing Value to price the “unpurchased” power needed to serve Above-RHWL Load priced at Tier 2 rates. *Id.* at 49.

In the Initial Proposal, the Remarketing Value for a fiscal year is proposed to be based on either (1) the rate case market price forecast using critical water year, called the “augmentation price,” or (2) the weighted average price of BPA’s acquisitions to support Tier 2 power sales made in FY 2017, but no later than May 31, 2017. 2018 Power Rate Schedules and GRSPs, BP-18-A-04-AP03, GRSP III.B.24.

In its Rebuttal Testimony, BPA modified its Initial Proposal for the Remarketing Value in response to customers’ concern that the risk premium for the proposed use of FBS power in FY 2018 was too high, unreasonable and not supported. BPA proposed the following modification:

² Long-term power sales contracts with customers are “to supply them with the firm power they need to meet their firm loads in the region”. H. Rep. No. 96-976, Part II, 96th Cong., 2d Sess., at 33. “[T]he term ‘firm power load’ is intended to mean the power the customer is obligated to make continuously available to its purchasers . . . , and the term ‘firm resources’ is intended to mean the electric power suitable for providing service to firm power loads.” S. Rep. No. 96-272, at 26 (1979). Power made continuously available is firm power based on critical water planning in a hydroelectric power system.

³ Under Section 11(b)(6)(i) of the Transmission System Act, the Administrator is authorized to purchase electric power on a short-term basis to meet temporary deficiencies in electric power that the Administrator is obligated by contract to supply.

Remarketing Value is the value BPA provides to customers for remarketed energy (both Tier 2 and non-Federal). This value is also used to calculate the cost of unpurchased amounts of Tier 2 energy. The Remarketing Value for a fiscal year is based on: (1) the rate case market price using the critical water year “augmentation price” when BPA has not yet acquired the power to supply Tier 2 service; (2) the weighted average price of the power purchases BPA has acquired (between October 1, 2016 and June 1, 2017) for the corresponding year to supply Tier 2 service; or (3) the average of the rate case market price using all 80 water years and the rate case market price using the critical water year “augmentation price” when BPA is using Firm Surplus from the FCRPS for Tier 2 service and BPA does not make any actual power acquisitions (between October 1, 2016 and June 1, 2017) for the corresponding year to supply Tier 2 service.

Weekley, *et al.*, BP-18-E-BPA-28, at 12. This revised definition of Remarketing Value includes a third possibility that considers BPA having the supply available from the FBS when a market purchase will not be made and prices such power using an average of the two market price forecasts.

Issue 3.4.3.1

Whether the Remarketing Value shall be based upon: (1) the augmentation price using a 1937 critical water year market price forecast, or (2) an 80-year average water market price forecast, or (3) an average of the two market price forecasts; when FBS power is used to serve Above-RHWM Load priced at Tier 2 rates and an actual power acquisition price cannot be used.

Parties’ Positions

PNGC argues that BPA’s use of the augmentation price forecast using the 1937 critical water year for calculating the Remarketing Value results in a materially higher price premium of 19 percent compared to average water and publically known forward-market pricing from available sources, such as Intercontinental Exchange (ICE). PNGC Br., BP-18-B-PN-01, at 3.

PNGC argues that BPA Staff did not provide a reason or explain why using a forecast that produces a 19 percent premium was justified other than that it is higher than a forecast based on average water conditions. *Id.* at 4. For BPA supply needs that are not filled with actual market purchases, PNGC asserts that only a price set by a market forecast using average water conditions would “ensure that Tier 2 rates more accurately reflect the price BPA could . . . achieve if it were to purchase market power to fulfill its needs for Tier 2 service [Above-RHWM Load].” *Id.* at 7.

NRU also states that BPA Staff did not present sufficient justification for using the augmentation price forecast other than it is higher than the 80-year water price forecast. NRU Br., BP-18-B-NR-01, at 9. NRU asserts that BPA Staff only stated that the 80-year forecast does not have a premium, which does not justify use of the augmentation price forecast. *Id.* NRU agreed with Staff’s assessment that if BPA plans to use power from the FBS to serve its Above-RHWM Load

obligation, it has no supply risk because the source of the power is already known and NRU supports using the average of the two market price forecasts to determine the Remarketing Value in such circumstance. *Id.* at 15-17. NRU disagrees with PNGC that BPA should purchase power on the wholesale market for any “Tier 2 open positions” (load needs) for FY 2018. *Id.* at 17-18.

JP06 opposes both the PNGC proposal to set the Remarketing Value equal to the forecast spot market price minus the “Overhead Adder,” and NRU’s proposal that BPA set the Remarketing Value at a forecast rate equal to BPA forecast of spot market prices under 80-year water conditions (firm market price or “FMP”). JP06 argues that neither proposal uses forecasts that would value the transactions for fixed amounts of firm power at fixed prices for future delivery. JP06 Br., BP-18-B-JP06-01, at 10.

JP06 also disagrees with BPA’s Rebuttal proposal to average the two market price forecasts when using Federal power to serve Above-RHWM Load priced at Tier 2 rates, contending it appears to be based on a fundamental misperception of the purpose of the Remarketing Value. *Id.* at 12. JP06 states that Federal power “should be marketable by BPA at a firm power price reflecting both the supply and price risk premium over spot market power price.” *Id.* JP06 further states that it is inappropriate “to credit the Tier 1 Cost Pool or to charge the Tier 2 Cost Pool a price for the surplus firm Tier 1 System Capability used to serve loads at Tier 2 Rates at a price below the market price which it could obtain for the surplus.” JP06 Br. Ex., BP-18-R-JP06-01, at 7. JP06 argues that BPA’s averaging causes BPA to credit the Tier 1 cost pool “by an amount less than the actual value of the surplus firm power being transferred to the Tier 2 Cost Pool”. *Id.* at 7-8. JP06 supports BPA Staff’s proposal that discussions for determining remarketing transactions be conducted in BP-20 workshops prior to the BP-20 Initial Proposal and also recommends BPA address in workshops the methodologies used to determine the Remarketing Value. JP06 Br., BP-18-B-JP06-01, at 12.

WPAG favors consistency with the TRM over the expediency of using the market price forecast based on 80 water years when setting the Remarketing Value. WPAG Br., BP-18-B-WG-01, at 22-23. WPAG notes that the TRM does not prescribe any particular methodology for setting the rate, only noting what components may be included and that BPA’s Rebuttal Testimony proposal appears to reflect a reasonable alternative to the Initial Proposal considering there is no supply risk. As such, WPAG believes it would be reasonable for BPA to adopt the proposal contained in its rebuttal. *Id.* at 23-24.

BPA Staff’s Position

When setting rates, BPA values: (1) prospective power acquisitions to serve its obligations at the augmentation price; (2) prospective surplus power sales at the market price forecast using 80 water years; and (3) power purchased or power sales secured before setting rates at the associated transaction value. Weekley, *et al.*, BP-18-E-BPA-28, at 3. In valuing prospective acquisitions using the augmentation price, BPA is accounting for two types of risk: a price risk and a supply risk. However, in valuing power that has already been sourced, particularly if it is from the FBS, there is not an associated purchase price and there is reduced supply risk. Therefore, BPA Staff supports using the average of its two market price forecasts to value FBS power used to serve Above-RHWM Load priced at Tier 2 rates.

Evaluation of Positions

PNGC and NRU both assert that it is unreasonable to set the Remarketing Value based upon the forecast augmentation price for this rate period because it results in a price that is 19-20 percent higher than short-term market pricing using an 80-year average water forecast, and because it is higher than the price BPA itself has to pay for power purchased for FY 2019.

PNGC argues that using a market power purchase price already includes an appropriate risk premium for the product and that BPA should either buy for FY 2018 (which is not allowed when there is adequate FBS power) or use an index like ICE that approximates making a similar purchase as the valuation for the FBS allocated to serve Above-RHWM Load at a Tier 2 rate. PNGC contends that prices like the ICE index offer an objective data point to evaluate BPA's supply position and represent a reasonable premium with prices very close to BPA's market price forecast using its 80-year average water conditions. PNGC Br., BP-18-B-PN-01, at 3-4.

Further, in rebutting BPA's assertion that market indices do not include any premium in their pricing for locking in price ahead of service, PNGC argues this is wrong based not only on PNGC's experience but also BPA's recent 37 average megawatt (aMW) power purchase to serve Above-RHWM Load for FY 2019. *Id.* at 5. This purchase demonstrates that forward purchases can have locked-in price risk because BPA included an obligation that the seller provides an \$8.1 million letter of credit to BPA as upward price protection in the event of default prior to delivery. *Id.* PNGC states that BPA Staff's proposed modification to the Remarketing Value methodology in its Rebuttal Testimony is preferred but still overstates the premium and results in a price that is higher than is reasonable. *Id.* at 7.

Similar to PNGC, NRU argues that the augmentation price BPA proposed does not accurately reflect the cost of a market premium to secure power in advance at a fixed price, and although BPA had not made a FY 2019 power purchase at the time of the Initial Proposal, BPA later revealed that its price was similar to forward data on ICE. NRU Br., BP-18-B-NR-01, at 12-13. NRU calculated a differential of BPA's augmentation price being 20 percent higher than actual market prices. *Id.* at 12. As with PNGC, NRU argues that no evidence in the record supports a premium of this magnitude and finds that BPA's modification presented in the Rebuttal Testimony to be a better basis for imposing a risk premium while still containing methodological issues. *Id.* at 18-19.

The rate case market price forecasts that PNGC and NRU compared to forward ICE prices in their Initial Briefs were developed in preparation for the Initial Proposal. Since then, forecasts have been updated and the Final Proposal market price forecasts have realigned to be similar to ICE prices used to calculate the 20 percent premium referenced by NRU. NRU Br., BP-18-B-NR-01, at 12. The market forecasts have dropped about \$5, bringing the Final Proposal critical water price forecast down to the Initial Proposal 80-year water price forecast. Power Market Price Study and Documentation, BP-18-FS-BPA-04, Figures 8-9.

WPAG agrees with NRU that the application of a risk premium as proposed in BPA's Rebuttal Testimony would be reasonable for FY 2018, and recognizes that BPA has discretion in establishing price in a Section 7(i) proceeding under the TRM. WPAG acknowledges that

customers benefit on both sides of the equation as in prior rate periods. WPAG affirms that the TRM anticipates BPA using Federal energy to serve load at Tier 2 rates to the extent such energy is forecast to be available for the rate period as unused, and is to be allocated to the Tier 2 cost pool at the marginal cost of such power. WPAG Br., BP-18-B-WG-01, at 22-23. WPAG acknowledges the TRM does not explicitly state how BPA is to determine the marginal cost and that the determination is left to the applicable Section 7(i) process. *Id.* at 23. WPAG points to Section 6.3.1 of the TRM and states that there is a reasonable basis to conclude that the marginal cost of power would include a risk component and BPA and JP06 persuasively argue that it should. *Id.* at 23-24.

Parties have identified various aspects of BPA's Remarketing Value that can be improved regarding the type of risks to be covered, how they might be assessed and the cost basis for such risks. BPA is willing to engage in workshops prior to the next rate period (BP-20) on these issues, as supported by JP06. However, BPA has used the same methodology using the augmentation price for evaluation of the Remarketing Value in each of the prior rate periods since BPA first set rates under the TRM without challenge by any of the parties, including the present parties. Chalier *et al.*, BP-12-E-BPA-19, at 5; Chalier *et al.*, BP-14-E-BPA-17, at 9; Stiffer *et al.*, BP-16-E-BPA-17, at 4; Power Rates Study, BP-16-FS-BPA-01, at 68, 71-72. PNGC, NRU, and JP06 all make arguments that BPA's use of the methodology is not consistent with the TRM primarily because they perceive that a cost shift might be occurring between the cost pools. While BPA addresses that issue in Section 3.4.3.2 below, it should be noted that none of these parties has challenged BPA's use of this methodology as inherently creating a cost shift when it was used for setting the Remarketing Value in any prior rate case.

As WPAG correctly points out, the TRM directs BPA to use energy from the Tier 1 System for service to loads at Tier 2 rates to the extent it is available for the rate period (TRM Section 3.7), and such allocation to a Tier 2 cost pool will be at the marginal cost of such power (TRM Section 6). As BPA stated, "the TRM does not require BPA to use a flat block market purchase or flat block market price [as PNGC argues] when pricing available Tier 1 system power for Tier 2 energy needs. Rather the TRM directs that such energy be priced at the 'forecast marginal cost of such energy.'" Weekley *et al.*, BP-18-E-BPA-28, at 5. When planning the availability of its products, BPA considers the type of product being used, the basis for the product and the type of risks associated with the product. In this case, BPA is supplying firm power from the FBS that will be available in all conditions in a flat fixed shape. The availability of this product is based upon forecasts of power from the Federal system using 1937 critical water year planning and is made continuously available to the customer. BPA's use of an augmentation price is also based on the same 1937 critical water year planning and is more than reasonably correlated to the firm flat fixed product that BPA is using in FY 2018 to meet its Above-RHWM Load obligation.

PNGC proposes in its Direct Testimony that BPA should purchase power from the market for any Tier 2 "open position." Mendonca, BP-18-E-PN-01, at 10. However, NRU recommends that BPA reject PNGC's proposal if Federal surplus power is available in 2018, correctly observing that BPA would not be within its statutory authority to purchase additional power under Section 6 of the Northwest Power Act or Section 11(b)(6) of the Transmission System Act. NRU Br., BP-18-B-NR-01, at 18. Indeed, BPA has power available from the FBS in FY 2018,

and must use such power as is needed to meet its firm power contractual obligations before it makes any sales of surplus power. Under Section 5(f) of the Northwest Power Act, BPA only has surplus power available for marketing after it has met all of its Section 5(b), 5(c) and 5(d) firm power contractual obligations. BPA's obligation to serve the net requirement load under CHWM contracts of its public utility customers constitutes BPA's Section 5(b) obligation under the statute. BPA's net requirement obligation includes its obligation to serve any Above-RHWM Load at a Tier 2 rate, which a public utility customer has placed upon BPA under the terms of its requirements contract.

Similarly, because BPA does not have a need to buy power from the market for this load, if BPA were to use strictly a spot market price, which does not consider the same type of firm power product that BPA would be providing, then BPA would have even less of a correlation of factors between its pricing and its product. *Weekley et al.*, BP-18-E-BPA-28, at 5-6. It is unlikely that PNGC's members would consider a product that has only an average water probability of being supplied in all conditions to be the equivalent to firm power service for firm power load. PNGC's referral to the risk premium in BPA's power purchase in FY 2019, PNGC Br., BP-18-B-PN-01, at 4-6, does not make that purchase the same product as firm power provided from the FBS since the Federal system has multiple sources of generation located across the region.

PNGC, NRU, and JP06 are incorrect when they describe one rate pool selling to another rate pool and comparing sales of power on the market to BPA providing power from its own system to meet load. When establishing its rates under Section 7 of the Northwest Power Act, BPA allocates costs to recover the cost of that portion of the FBS that is used to supply customer load. BPA is not engaged in transactions between market counter-parties, the Tier 1 or Tier 2 rate pools, or anyone else when it supplies FBS power to its Above-RHWM Load. BPA's Rebuttal proposal made an adjustment to the price of firm power for Above-RHWM Load for the FY 2018 year by modifying BPA's methodology for the Remarketing Value from strictly using the augmentation price to considering an averaging which would approximate a middle ground between the augmentation price that is based on a critical water year price and the 80-year average water market price. *Weekley et al.*, BP-18-E-BPA-28, at 11. The reason to average the two market price forecasts is that BPA already has in its planning for that year the amount of firm power needed to meet the Above-RHWM Load obligation and, by statute, BPA must provide that power for such load and not sell it on the market.

Because BPA may have power that is actually firm surplus power under Section 5(f) of the Northwest Power Act during FY 2018, BPA will provide the power it is pricing at Tier 2 rates for Above-RHWM Load under all conditions. Because BPA must supply the requirements load under all conditions, the risk to the availability of the power is eliminated. *Id.* Contrary to JP06, this adjustment is not under-recovering cost for service to Above-RHWM Loads but recognizing actual supply. If the premium is both for price and supply risk, then eliminating one of the risks should reduce the premium. *See id.*; Motion to Admit Data Requests and Responses into Evidence, BP-18-M-NR-02, at 11-12 (Data Response PN-BPA-26-8); Order Admitting Data Responses, BP-18-HOO-29, at 3.

While NRU still believes the augmentation price does not reflect an accurate premium for securing power in advance of need, it finds that BPA Staff's modified proposal is an

improvement. In contrast to PNGC and JP06, NRU “strongly encourages” and WPAG supports the Administrator adopting the revised definition of Remarketing Value for the BP-18 rate period. NRU Br., BP-18-B-NR-01, at 17; WPAG Br., BP-18-B-WG-01, at 24. NRU states that it would reduce the premium paid by the Tier 2 cost pool due to the averaging of the price from both forecasts and more appropriately credit the Tier 1 cost pool for “making a sale of firm surplus power.” NRU Br., BP-18-B-NR-01, at 17.

Decision

BPA will adopt its rebuttal proposal to average the two price forecasts of the 1937 critical water year augmentation price and the 80-year average water market price in calculating the Remarketing Value for FY 2018. BPA will conduct discussions in workshops for the BP-20 rate proceeding to seek customer input on this methodology.

Issue 3.4.3.2

Whether the use of the Remarketing Value will result in a cost shift under the TRM.

When BPA sets the Remarketing Value for FBS power used to serve Above-RHWM Loads priced at Tier 2 rates in FY 2018, that value becomes both a charge to the specific Tier 2 cost pool (e.g., the Tier 2 short-term rate pool) for the Federal system power provided, and a credit to the Tier 1 Non-Slice Cost Pool because it is power that would otherwise be credited as surplus secondary power for purposes of ratemaking. Three parties raised concerns with BPA’s Initial Proposal that set the value for the Remarketing Value by using the 1937 critical water year augmentation price forecast, even though BPA used the augmentation price to set the Remarketing Value for BP-14 and BP-16 rate periods. Parties asserted that unless BPA used a particular forecast or method other than the augmentation price for setting the Remarketing Value, a cost shift would occur between the Tier 1 and Tier 2 cost pools, and such a cost shift would be inconsistent with the TRM.

Parties’ Positions

NRU, PNGC, and JP06 state that the Remarketing Value needs to be set so that power service to Above-RHWM Loads does not create cost shifts between Tier 1 and Tier 2 cost pools. NRU Br., BP-18-B-NR-01, at 1; PNGC Br., BP-18-B-PN-01, at 6; JP06 Br., BP-18-B-JP06-01, at 9. NRU says the Remarketing Value is the key definition to avoiding cost shifts between cost pools. NRU Br., BP-18-B-NR-01, at 7. JP06 states that one purpose of the TRM is to prevent recovery of costs of serving Tier 2 loads through Tier 1 rates and that each cost pool should recover the cost of service to which it applies. JP06 Br., BP-18-B-JP06-01, at 9. JP06 also states that the TRM requires that “[t]he 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 Section 7(i) Processes. Unused Tier 1 System Capability forecast to provide service at Tier 2 Rates will be allocated to the appropriate Cost Pool at the marginal cost of such power.” JP06 Br. Ex., BP-18-R-JP06-01, at 8; see TRM, BP-12-A-03, at 79. JP06 asserts that marginal cost can only mean either the costs assigned to Tier 1 system capability or the opportunity cost of power that would

otherwise be sold on the market “for the benefit of Tier 1 rates.” JP06 Br. Ex., BP-18-R-JP06-01, at 8. PNGC contends BPA did not account for the shifting of cost to Tier 2 customers, contrary to the principles of the TRM. PNGC Br., BP-18-B-PN-01, at 6. PNGC contends that in setting the Remarketing Value, BPA was only concerned with limiting costs that may be shifted to Tier 1, not Tier 2. *Id.*

NRU further states that not only should the Tier 1 system not be used to subsidize the allocated costs of Tier 2 but the reverse should also be true and Tier 2 service should not subsidize the Tier 1 system, nor should there be subsidization between Tier 2 cost pools. NRU Br., BPA-18-B-NR-01, at 5.

JP06 states that the purpose of correctly determining Remarketing Value is to avoid cost shifts between rate pools and BPA fundamentally misperceived this purpose. JP06 argues that if BPA has firm surplus power then “that power should be marketable by BPA at a firm power price reflecting both the supply and price risk premium over spot market power price.” JP06 Br., BP-18-B-JP06-01, at 12. JP06 further argues that “Tier 1 will be made whole for Tier 2’s use of the power, the full cost of which has been initially allocated to the Tier 1 Cost Pools, only if Tier 1 is credited with the full opportunity cost of losing the credit it otherwise would receive in the market for the market value of the power.” JP06 Br. Ex., BP-18-R-JP06-01, at 9.

PNGC argues that BPA was concerned only with limiting costs that may be shifted to the Tier 1 cost pool but not Tier 2, contrary to the TRM. PNGC suggests that to limit the potential for cost shift between Tier 1 and Tier 2, BPA could (1) make an actual purchase in FY 2018 that provides a known purchase price, or (2) base the Remarketing Value on “as accurate assumptions as possible” to avoid causing cost shifts with respect to power provided to Above-RHWM Loads priced at Tier 2 rates. PNGC asserts that Staff focused solely on the possibility of the Remarketing Value being too low and little upon whether the price is actually consistent with what BPA is able to purchase that power for on a forward basis. If the Remarketing Value is significantly higher or lower than available and reliable market data, a high probability of inappropriate costs exist. PNGC Br., BP-18-B-PN-01, at 6-7.

BPA Staff’s Position

In Rebuttal Testimony, BPA proposed to include a new line in Table 2.3.8 of the Power Rate Study Documentation to properly credit the Tier 1 Non-Slice Cost Pool for FBS power used to serve Above-RHWM Load priced at Tier 2 rates. Weekley *et al.*, BP-18-E-BPA-28, at 13; *see* Power Rates Study Documentation, BP-18-E-BPA-01A, at 54. The credit in the new line will be calculated using the Remarketing Value to price the FBS power used to serve Above-RHWM Load priced at Tier 2 rates. With this change, BPA Staff does not find that using the Remarketing Value, as defined in the BPA Rebuttal Testimony and stated in Section 3.4.3.1 above, will result in a cost shift between the Tier 1 rate pool and the Tier 2 rate pools. Weekley *et al.*, BP-18-E-BPA-28, at 12-13.

Evaluation of Positions

BPA acknowledges that it was not consistent with the TRM in its Initial Proposal to credit the Tier 1 cost pool at a Remarketing Value set by the 80-year average water market forecast price and to charge the Tier 2 rate pools for Above-RHWM Load power service priced at a Remarketing Value set by the augmentation price. As described in BPA's Rebuttal testimony and by NRU in its initial brief, BPA's revised proposal made modifications to include revisions to the Power Rate Study Documentation stating two line items instead of a single one, so as to remove this error. Weekley, *et al.*, BP-18-E-BPA-28, at 13; NRU Br., BP-18-B-NR-01, at 16-17. By making this change, BPA believes that the Tier 1 cost pool will be credited and the Tier 2 cost pools charged at the same marginal costs and in a manner consistent with Section 3.7 of the TRM. JP06 agrees that this change is "both more appropriate and more consistent with the TRM." JP06 Br. Ex., BP-18-R-JP06-01, at 7.

BPA agrees with the parties' arguments that the Remarketing Value is primarily designed to avoid a cost shift between the Tier 1 cost pool and Tier 2 cost pools at the price set by BPA in a Section 7(i) rate proceeding. However, BPA does not agree that the Remarketing Value can only be set by reference to market indices, or reference to a method assuming transactions between counter-parties and customers as if BPA were selling power to itself or buying power from itself. Such a construct is not what was posed in the TRM, or in the CHWM contracts, nor is it consistent with BPA's obligations to serve the full net requirement loads of BPA customers which include *both* load priced at Tier 1 rates and Above-RHWM Load priced at Tier 2 rates. BPA's customers here are its utilities, not its rate pools. Rate pools do not buy and sell to each other or take or deliver power to each other.

The parties' assertions that market is the reference point fail to recognize BPA's obligation to serve the load requirements of its customers with firm power available from the Federal system at cost. JP06 states BPA's Remarketing Value desired principle as:

Both Tier 1 and Tier 2 customers should be indifferent to whether their counter-party is an anonymous market participant or another cost pool. The Tier 1 cost pool should be compensated for surplus firm power at the full market value of firm power irrespective of the projected counter-party in the transaction, and the Tier 2 cost pool should pay the market value (but no more) to acquire firm power, irrespective of the source of such power.

JP06 Br., BP-18-B-JP06-01, at 13.

JP06 asserts BPA has set the Remarketing Value at a level that is "below the market price which it could obtain for the surplus [firm power]" which means Tier 1 will be credited "less than the actual value of the surplus firm power transferred to their Tier 2 Cost Pool." JP06 Br. Ex., BP-18-R-JP06-01, at 7-8. However, as stated above, BPA's rate pools are not counter-parties or customers of each other and there are no transactions, as in the market, internally for BPA power service that goes to load priced at Tier 1 rates and power service that goes to Above-RHWM Load priced at Tier 2 rates. This is simply BPA pricing service from the FBS reflective of its costs of service. BPA is not setting a market rate. JP06's principle may be fine for the operation

of an open market but that is not what is happening when BPA meets its net requirement load obligations to its customer with Federal power priced as near as possible to cost under the directives of Section 7 of the Northwest Power Act.

NRU cites TRM Section 3.7 to contend that, when BPA allocates unused Federal power from RHWL load to serve Above-RHWL Loads at the Tier 2 rates, the TRM requires BPA to allocate the forecast marginal cost of the Federal power to the appropriate Tier 2 cost pool and credit the same marginal cost to the appropriate Tier 1 cost pool. NRU Br., BP-18-B-NR-01, at 6. NRU asserts BPA's Initial Proposal failed to follow this principle because BPA was crediting the Tier 1 cost pools at the 80-water-year forecast, but then charging the Tier 2 cost pools at the augmentation price. *Id.* at 10. In other words, NRU says, the crediting and charging should be equal.

NRU's argument that the Tier 1 system should not be used to subsidize the allocated costs of Tier 2 but the reverse should also be true and Tier 2 service should not subsidize the Tier 1 system may be a principle for the next TRM. Presently, however, only the first part of that principle can be found in the TRM. NRU Br., BPA-18-B-NR-01, at 5. The sense of the statement that Tier 1 rates should not subsidize Tier 2's allocated costs is that the Tier 2 rate pools cannot have their cost reduced by BPA revenues that are allocated to Tier 1. Parties have generally seemed to equate costs with the use of power and this TRM provision is not a limitation on the use of the FBS to meet any Federal obligation, including meeting Above-RHWL Load.

BPA is not using "Tier 1 power" to subsidize Tier 2 or vice versa because there is no "Tier 1 power." *Id.* at 5-6. Indeed, regardless of how much JP06 or other parties assert that the power transferred to Tier 2 is surplus and marketable, there is no "surplus power" that BPA could actually market in this circumstance. *Id.* at 7-11. As noted earlier, BPA is required to use available FBS power to meet its obligations and cannot buy power if BPA already has power available. Whether assigned for use to meet Above-RHWL Load priced at Tier 2 rates or load priced at Tier 1 rates, when available FBS power is meeting BPA's net requirement loads under Section 5(b)(1) there is not a "subsidization." BPA placed no limitation on its own use of Federal power in the TRM and as long as BPA is equally crediting and charging the various rate pools at the same charge as corrected above, the direction of the TRM has been met.

JP06 argues that BPA must value power available to meet Above-RHWL Load at the market value of the power. To make the power available at less than a market value, Above-RHWL Load is served at lower cost than the power would have brought on the market, and that Tier 1 is thereby under-credited. JP06 also argues that BPA has a duty to market available power to Above-RHWL Load at "its actual value in the market." JP06 Br., BP-18-B-JP06-01, at 13; *see* BP-18-R-JP06-01, at 7-9. This premise is incorrect. BPA does not have the duty to price Federal power available for its Above-RHWL Load at its actual value in the market. The TRM in Section 3.7 states that BPA is to allocate the forecasted *marginal* cost of the energy to the appropriate Tier 2 cost pool, and does not say BPA is to allocate the actual value of the power in the market. BPA could not determine actual market value of its power assigned to the Above-RHWL Load unless BPA made a sale of the power in the market. Under Section 5(f) of the Northwest Power Act, BPA is prohibited from making such a sale since BPA cannot sell power

in the market that is not otherwise surplus to its Section 5(b) net requirement load obligations. There is nothing in the TRM that directs BPA to price the cost of Federal power to the market. If BPA were simply pricing its power at market for service to Above-RHWM Load instead of at a forecasted marginal cost of service, then there would be no reason for utilities to buy power from BPA to serve their Above-RHWM Load since BPA service and market-sourced power would be priced the same.

JP06 further argues that if BPA's Remarketing Value does not include a firm power price with a premium that reflects both the price risk and the supply risk of the product, then this underpricing "would be a cost shift, pure and simple." JP06 Br., BP-18-B-JP06-01, at 12. JP06 acknowledges that BPA does not incur incremental expenditures for price risk or supply risk when Tier 1 provides power to Tier 2, but states a cost shift occurs if Tier 1 is not credited the full opportunity cost "it otherwise would have received from the market for the market value of the power." JP06 Br. Ex., BP18-R-JP06-01, at 9. Again JP06 seems to believe that BPA could establish a market price and value for the power used for Above-RHWM Load without offering a sale to a willing buyer of that power, which BPA cannot do. Because no actual sale may be made, BPA uses market price forecasts in the rate case to value the power.

However, BPA's revised proposal in its Rebuttal Testimony was an averaging of the two market price forecasts, which BPA had developed. Staff noted that averaging the two would account for part of the supply risk but not eliminate the premium for risks because that risk is still part of the augmentation price. The averaging step does reduce the amount of the premium by half and is an approximation that still includes a premium for locking down a price prior to delivery. BPA views this reduction as reasonable since the power is firm power in a block sourced from the Federal system under critical water year planning. The augmentation price is only one forecast of spot market price for firm power and may not be equivalent to what price BPA might be able to obtain by selling firm power in a fixed block on the market if BPA had any available. Weekley *et al.*, BP-18-E-BPA-28, at 11.

PNGC proposes two actions for BPA to avoid any cost shift. First, PNGC argues BPA should buy from the market for any open position in FY 2018. Both NRU and JP06 oppose such action and, as NRU correctly points out and is explained above, BPA is not able to make such a purchase if it has Federal system power available on a planned basis to serve Above-RHWM Load. However, BPA agrees that when it makes a purchase of power from the market for Above-RHWM Load as in FY 2019, then the issue of a cost shift would not be present since the charge and the credit are both based on the price of the purchase. Second, PNGC argues BPA must base the Remarketing Value on "accurate assumptions." PNGC asserts that Staff focused solely on the possibility of the Remarketing Value being too low and little upon whether the price is actually consistent with what BPA would pay for that power on a forward basis. As noted above, Staff believes that the averaging of its two forward-market forecast price models will give a reasonable valuation of the value for firm power in a fixed block at a locked-down price prior to delivery. It is not based on pricing that reflects spot market hourly power. The directive in the TRM is for the surplus Federal power not used for load priced at Tier 1 rates to reflect a marginal cost. The TRM does not say it must be the priced at full opportunity cost or any other particular price that could be obtained from the market on a forward basis.

Decision

In accordance with the TRM, and to avoid cost shifts, when BPA uses Federal system power to serve Above-RHWM Loads priced at Tier 2 rates, BPA will price such power using the Remarketing Value and the same value will be used to credit the Tier 1 Non-Slice Cost Pool for the Federal system power provided.

3.4.4 Transfer Service Delivery Charge

The Transfer Service Delivery Charge (TSDC) is a rate designed to recover BPA's costs associated with low-voltage delivery across third-party transmission providers systems at voltages below 34.5 kV. Yokota *et al.*, BP-18-E-BPA-21, at 3. The customer pays the TSDC only if the customer receives transfer service at voltages below 34.5 kV and is not paying Transmission Service's Utility Delivery Charge (UDC) for that particular point of delivery. *Id.* at 3-4.

In WP-07, WP-10, and BP-12, the TSDC was set equal to Transmission Services' UDC. *Id.* at 4. In BP-14, BPA decoupled the TSDC from the UDC in favor of the TSDC being a stand-alone rate that better reflects the actual cost of low-voltage deliveries. *Id.* Parties supported this methodology in BP-14, and no party objected to the use of the same methodology in BP-16. In BPA's Initial Proposal for BP-18, the TSDC is proposed to increase from \$0.94 per kilowatt (kW) to \$1.26/kW.

After filing its Initial Proposal, BPA staff proposed to establish a base distribution rate for NorthWestern Energy when calculating the TSDC. Yokota *et al.*, BP-18-E-BPA-29, at 20. Staff proposed this change because NorthWestern has a fixed Open Access Transmission Tariff (OATT) rate that does not include a separate distribution rate. *Id.* BPA believes it is more equitable to use a static value established in BP-14 when the TSDC was first implemented for NorthWestern rather than use an average each subsequent rate period of all other low-voltage service across third-party transmission systems. *Id.* It is BPA's intent to use a fixed rate in its Initial Proposal until the time NorthWestern changes its transmission rate or develops a unique distribution rate. *Id.* No party took issue with BPA's modification of the treatment of NorthWestern Energy in the calculation of the TSDC.

Issue 3.4.4.1

Whether the TSDC should be linked to the UDC.

Parties' Positions

In its initial testimony, PNGC argued that the BP-18 TSDC should be calculated consistent with the changes made to Transmission Services' segmentation methodology adopted in the BP-16 rate case. PNGC Br., BP-18-B-PN-01, at 11. PNGC acknowledges that conducting additional analysis would be time-consuming and administratively burdensome, so it alternatively proposed that the TSDC be linked once again to the UDC for the BP-18 rate period. *Id.* In its rebuttal testimony, Staff disagreed with PNGC's proposal to recouple the TSDC and UDC. *Id.* at 12.

However, in its initial brief, PNGC requests that the Administrator reconsider BPA’s position. *Id.*

NRU similarly argued in its initial testimony that the TSDC and UDC should be linked to better align with the Agreement Regarding Transfer Service (ARTS) and RD Policy. NRU Br., BP-18-B-NR-01, at 26. In its initial brief, however, NRU found BPA’s rebuttal testimony persuasive and agreed with BPA’s reasoning to keep the TSDC separate from the UDC. *Id.* at 29. Although ultimately agreeing with Staff’s position, NRU “urge[d] BPA to continue to adhere to its commitments to treat Transfer Service customers comparably” and emphasized that “[r]ate methodologies should be sustainable over time.” *Id.* at 29-30.

In its initial brief, Kalispel stated support for NRU’s arguments and positions related to the calculation of the TSDC for this rate period. Kalispel Br., BP-18-B-KT-01, at 4.

BPA Staff’s Position

Staff does not support recoupling the TSDC and the UDC. Yokota *et al.*, BP-18-E-BPA-29, at 16. The TSDC rate reflects the actual costs incurred by Transfer Service, whereas linking it to the UDC does not reflect the actual costs of serving transfer customers. *Id.*

Staff appreciates NRU’s support and agrees that BPA should continue to treat direct connect and transfer service customers comparably. Staff believes the current methodology used to calculate the TSDC treats customers comparably and is consistent with the obligations made under the ARTS and the RD Contract.

Evaluation of Positions

PNGC argues that the calculation of the TSDC should reflect the changes made to Transmission Services’ Segmentation Policy (Segmentation Policy). The Segmentation Policy is based on an in-depth analysis of BPA facilities and equipment. The findings of that analysis resulted in some high-side equipment being moved from the delivery segment to the network segment. Yokota *et al.*, BP-18-E-BPA-29, at 8. PNGC recognized that, “a full analysis to ensure comparable treatment of the TSDC and the [UDC] might be more time-consuming than optimal during the formal rate case process.” PNGC Br., BP-18-B-PN-01, at 11. PNGC further noted that “BPA did not have adequate time during the BP-18 proceeding to conduct a thorough analysis of how the updated definition of the Integrated Network segment should apply to the allocation of Transfer costs between those rolled-in to the PF rate and those collected by the TSDC.” *Id.* at 12-13. Due to time constraints, PNGC proposed alternatively that BPA link the TSDC to the UDC for the BP-18 rate period because it would be efficient and “it had been done before.” *Id.* at 11.

PNGC’s proposal to analyze transfer costs would be administratively burdensome and would not result in greater efficiency. As PNGC notes, and BPA Staff agrees, conducting a full analysis would be time and resource-intensive. *Id.* at 11; Yokota *et al.*, BP-18-E-BPA-29, at 15. Further, BPA lacks the information necessary to perform an analysis of third-party transmission facilities in the precise manner as is done in the Segmentation Policy. Yokota *et al.*, BP-18-E-BPA-29,

at 15. As explained below, the appropriate remedy is not to simply relink the TSDC and the UDC. *Id.* at 16.

First, PNGC’s alternative proposal to link the TSDC and UDC means that the TSDC would not be based on actual costs. The TSDC as proposed recovers the actual costs incurred in providing transfer service. *Id.* Because the methodology used to calculate the TSDC recovers the actual cost of service, BPA believes it is a sound practice that is superior to simply mirroring a rate that is not reflective of the actual charges being incurred. *Id.*

Second, by relinking the TSDC and UDC, BPA would be setting precedent that would allow a subset of customers to request BPA to couple/decouple the TSDC and UDC depending on which rate is more favorable. *Id.* at 17. BPA believes it is important to maintain the distinction between the TSDC and the UDC and to apply the TSDC as a stand-alone rate that better reflects the actual cost of low-voltage deliveries. *See Yokota et al.*, BP-18-E-BPA-21, at 3. NRU and Kalispel agreed with Staff’s concerns of setting a negative precedent, and do not support coupling the TSDC and UDC for BP-18. NRU Br., BP-18-B-NR-01, at 29; Kalispel Br., BP-18-B-KT-01, at 4.

Third, the methodology used to calculate the TSDC is consistent with the ARTS. Under the ARTS, BPA committed to continue to roll “Transmission Component Costs” into the PF rate, thereby spreading these network costs among all ratepayers. Transmission Component Costs are defined as “the costs of Transfer Service to deliver Firm Power to <<Customer Name>> over non-Federally owned facilities that have characteristics comparable to the characteristics used to define BPA’s Integrated Network Segment.” ARTS § 2(i); *see Scott & Russell*, BP-18-E-PN-01, Exhibit A, at 3. Integrated Network Segment means “those facilities of the Federal Columbia River Transmission System that are required for the delivery of bulk power supplies . . . that are identified as Integrated Network Segment, or its successor, in the BPA segmentation study for the applicable transmission rate period.” ARTS § 2(d); *see Scott & Russell*, BP-18-E-PN-01, Exhibit A, at 3. PNGC argued that based on its commitments under the ARTS, BPA must allocate costs *identically* with the revised segmentation methodology, which would require analysis of third-party proprietary information. *Yokota et al.*, BP-18-E-BPA-29, at 9, 15. BPA disagrees.

As Staff explained, “comparable” does not mean “identical,” and BPA’s methodology to calculate the TSDC is consistent with the ARTS. *Id.* at 9. One of the primary purposes of the ARTS was to provide Transfer Customers transmission service over non-Federal systems that would be comparable to service provided to directly connected customers. However, perfect symmetry is not always possible. *Id.* at 9-10.

Additionally, the ARTS specifies which costs will be rolled-in to the Network component and thereby recovered through the PF rate. However, the ARTS does not address how BPA would recover the costs associated with the low-voltage delivery across a third party’s transmission system. *Id.* at 4. The ARTS specifically leaves that issue to be resolved at a later time stating: “[l]ow voltage delivery charges will not be included in the Transmission Component Costs and consequent rolled-in treatment, and the low voltage delivery service will be addressed in a future

process.” ARTS ROD at 12, *available at* <https://www.bpa.gov/news/pubs/RecordsofDecision/rod-20041222-Proposed-Contract-With-transfer-Service-Customers.pdf>.

BPA’s RD Contract is the result of the process that addressed low-voltage delivery service. As provided in the RD Contract, “Low Voltage Segment” means “the facilities of a Third-Party Transmission Provider that are equivalent to the voltage level of the facilities excluded by Transmission Services from the Integrated Network Segment.” This Section obligates Transfer customers to pay BPA based on the voltage level of the facilities *excluded* from the Integrated Network Segment. Yokota *et al.*, BP-18-E-BPA-29, at 9. In the prior Segmentation Policy, Transmission Services applied a 34.5-kV bright-line threshold, meaning facilities below 34.5 kV were excluded from the Integrated Network Segment. However, the current Segmentation Policy did not adopt a new voltage threshold. *Id.* at 8. Rather, specific “high-side” equipment was moved from the Utility Delivery Segment and is now included in the Network Segment. *See* Final Record of Decision, BP-16-A-02, Section 4.1.

PNGC argues that because the Segmentation Policy changed in BP-16, BPA must now revise its methodology for determining the costs of the TSDC to be consistent with the ARTS and the RD Contract. PNGC Br., PB-18-B-PN-01, at 10. PNGC claims that BPA’s statement that Transmission Services did not establish a new voltage threshold for its facilities is inaccurate. *Id.* at 11. PNGC claims that the Administrator “repeatedly discussed voltage in the section of the BP-16 ROD adopting the revised segmentation definition.” *Id.* BPA disagrees with PNGC and does not find PNGC’s citation to the BP-16 ROD persuasive. Contrary to PNGC’s assertion, the ROD discusses applying a high and low-voltage determination at the equipment level, but that is not the relevant question necessary to determine the costs to include in the TSDC. Again, the Segmentation Policy and the ROD do not establish a new voltage threshold or level that is excluded from the Integrated Network Segment. Yokota *et al.*, BP-18-E-BPA-29, at 8.

NRU’s comments are supportive of Staff’s position not to perform additional analysis and not to link the TSDC to the UDC rate. NRU highlighted BPA’s arguments, stating that it found them persuasive and “recognizes that parity does not always mean exactly equal. In fact, one could argue that in some instances, an attempt to be exactly precise in the allocation of costs may have the unintended consequence of violating the principle of comparability.” NRU Br., BP-18-B-NR-01, at 28. NRU went on to argue that BPA should continue to provide parity between directly connected and transfer customers in a manner that “best adheres to the principle of comparability.” *Id.* at 29. BPA agrees and intends to continue to treat customers comparably where it is reasonable to do so.

Finally, rates must be developed in a manner that ensures long-term certainty about cost recovery and be based on a methodology that is sustainable through time and is reflective of the actual costs incurred. Yokota *et al.*, BP-18-E-BPA-29, at 17-18. It is imprudent to continually change the methodology used to calculate the TSDC in each rate case based on whichever rate is lowest. *Id.* at 17. Transfer customers have seen direct financial benefits from decoupling the TSDC and UDC. However, now that the TSDC rate slightly exceeds the UDC, PNGC would have BPA return to mirroring the UDC. BPA fundamentally disagrees with a rate construct that would allow customers to cherry-pick between rate methodologies. *Id.* NRU and Kalispel agree with BPA and state that “[r]ate methodologies should be sustainable over time and modified only

when a change in circumstances or new evidence warrants it.” NRU Br., BP-18-B-NR-01, at 29-30; Kalispel Br., BP-18-B-KT-01, at 4. BPA agrees and intends to continue to propose the existing TSDC methodology through the remainder of the RD Contract term. This will provide greater certainty and rate stability compared to a construct that varies the methodology from rate case to rate case.

Decision

The TSDC will not be linked with the UDC.

Issue 3.4.4.2

Whether the Administrator should take rate shock into account in setting the TSDC and adopt a 25 percent rate cap.

Parties’ Positions

PNGC requests that a 25 percent rate cap be applied to the BP-18 TSDC rate to help mitigate the rate shock of a 34 percent increase. PNGC Br., BP-18-B-PN-01, at 8. PNGC argues that the BP-14 ROD established a precedent for applying a temporary rate cap at 25 percent. *Id.* at 12.

BPA Staff’s Position

Staff does not support applying a 25 percent cap in setting the TSDC. Yokota *et al.*, BP-18-E-BPA-29, at 18. Staff argues that since decoupling the TSDC from UDC, transfer customers have saved \$3,551,242. *Id.* at 19. Having applied a rate cap in BP-14 did not set a precedent for doing so in BP-18. Furthermore, under the RD Contract, Transfer Customers are obligated to pay the cost of low-voltage delivery. *Id.*

Evaluation of Positions

Staff’s initial proposal for the TSDC showed a 38 percent increase from the BP-16 rate. After adjusting for a methodology revision, the revised proposed rate would increase 34 percent. (The final proposal for the TSDC reflects a 35 percent increase.) PNGC argues that, in either case, the rate increase is substantial and will have an impact on customers and that, “[f]or some Transfer customers, the TSDC is assessed on all or nearly all of their deliveries and the cost of a 34-38 percent increase would be punishing.” PNGC Br., BP-18-B-PN-01, at 13.

PNGC has offered no testimony or other evidence to support that the increase will have a “punishing” effect on customers. Further, a rate cap in this instance would mean that Transfer Service customers would not meet their obligation under the RD Contract to “pay for service over the facilities with voltages that are excluded from the Network Segment.” Yokota *et al.*, BP-18-E-BPA-29, at 19.

Second, PNGC argues that in BP-14, BPA established precedent for temporary rate caps. PNGC Br., BP-18-B-PN-01, at 12. PNGC points to the BP-14 ROD that said determining the

UDC “requires striking a balance between cost causation and the avoidance of rate shock.” *Id.* (citing Administrator’s Final Record of Decision, BP-14-A-03, at 169). BPA disagrees with PNGC’s assertion that BPA set a precedent for a 25 percent rate cap. In BP-14, BPA limited the UDC rate increase to 25 percent. BPA found this to be an equitable limitation in the BP-14 rate proceeding; however, this did not set a commitment to apply a cap going forward. Yokota *et al.*, BP-18-E-BPA-29, at 19. Nothing in the RD or ARTS commits BPA to setting rate increase caps. *Id.* Applying a 25 percent cap would be inconsistent with the commitments the Transfer Service customers made in the RD Contract to pay for service over the facilities with voltages that are excluded from the Network Segment. *Id.*

Decision

BPA will not set a 25 percent rate cap on the TSDC.

Issue 3.4.4.3

Whether BPA should conduct a series of post-rate case workshops to perform a detailed analysis of Transfer Costs.

Parties’ Positions

PNGC and Kalispel request that the Administrator host a post-rate case workshop to perform analysis of third-party transmission providers’ delivery facilities at the equipment level. PNGC Br., BP-18-B-PN-01, at 13; Kalispel Br., BP-18-B-KT-01, at 4-5.

NRU disagrees and argues that BPA should not undertake any analysis of third-party transfer facilities to develop the TSDC rate. NRU Br., BP-18-NR-01, at 30.

BPA Staff’s Position

Staff stated that conducting a detailed analysis of the low-voltage facilities owned and operated by third-party transmission providers by the end of the BP-18 rate case was not possible. Yokota *et al.*, BP-18-E-BPA-29, at 15. As for conducting such a review prior to the next rate case, Staff had no prior position.

Evaluation of Positions

PNGC argues that Transmission Services’ revisions to its segmentation policy are significant and “provides a compelling reason to take a fresh look at the TSDC methodology.” PNGC Br., BP-18-B-PN-01, at 12. Therefore, PNGC proposes that having a series of workshops would allow BPA to analyze how Transmission Services’ revised segmentation policy impacts the allocation of costs between the PF rate and the TSDC. *Id.* at 13, 15. The analysis would require obtaining information about the third-party transmission providers’ facilities and equipment. *Id.* at 13.

Kalispel supports PNGC’s positions and expresses the concern that, as-is, “customers’ charges will be based on imprecise information which could lead to inequity.” Kalispel Br., BP-18-B-KT-01, at 4. Kalispel supports holding a post-rate case process because, regardless of time, a more accurate rate with closer parity is possible by conducting the additional analysis. *Id.* at 4-5.

Staff stated that it did not have the resources or the ability to deconstruct each third party’s transfer facility schematics to perfectly mirror the segmentation methodology. Yokota *et al.*, BP-18-E-BPA-29, at 15. PNGC and NRU acknowledged that conducting the analysis would be both time-consuming and administratively burdensome. PNGC Br., BP-18-B-PN-01, at 12-13; NRU Br., BP-18-NR-01, at 30. BPA Staff addressed its ability to conduct such an analysis during this current rate proceeding. Yokota, BP-18-E-BPA-29, at 15. Other barriers to obtaining the information and data needed to perform such a review were noted, including obtaining access to transfer provider utilities’ proprietary and confidential detailed system and substation schematics along with associated costs. *Id.*

BPA does not believe having a post-rate case process to conduct the facilities analysis would be worthwhile since the issue is a matter of access to proprietary information. Accessing such information may be difficult, if not impossible, depending on the transfer provider. It is also Staff’s professional judgment that such a review would not be fruitful because the vast majority of transfer service costs concern step-down transformers and low-side feeder positions— facilities that were not the focus of the BP-16 Segmentation Study methodology changes. *Id.*

Decision

BPA will not hold a series of post-rate case workshops to perform a detailed analysis of Transfer Costs.

3.4.5 Lost Creek Correction

Issue 3.4.5.1

Whether BPA should, going forward, allocate to the Composite Cost Pool certain transmission costs associated with the Lost Creek and Green Springs hydroelectric projects.

Parties’ Positions

ICNU opposes changing the allocation of Lost Creek/Green Springs costs, even prospectively. ICNU Br., BP-18-B-IN-01, at 117. Referencing the Error Correction Guidelines proposed by BPA Staff in the Initial Proposal, ICNU reasons that the Lost Creek/Green Springs allocation should not be considered a ministerial error. *Id.* ICNU also reasons that BPA has not met the evidentiary standard in this proceeding because BPA has allegedly not provided sufficient data to demonstrate that the costs at issue are more appropriately allocated to the Composite Cost Pool than to the pool to which they have been allocated for years. *Id.*

BPA Staff's Position

BPA Staff proposes to correct the Lost Creek/Green Springs cost allocation error going forward. Stiffler *et al.*, BP-18-E-BPA-22, at 7.

Evaluation of Positions

The costs at issue are transmission costs charged to BPA by third-party transmission operators for wheeling and losses tied to Federal generation located outside BPA's system, exclusive of costs incurred to provide transfer service to customers served under various third parties' OATT. *Id.* at 6. A recent BPA internal review showed that the majority of the roughly \$2 million per year in Third-Party Transmission and Ancillary Service costs were tied to financial payments related to wheeling costs and losses associated with the transfer of Federal generation (specifically, the Lost Creek and Green Springs projects) into BPA's control area. *Id.* Lost Creek and Green Springs generation is part of the Federal system of hydropower generation. TRM, BP-12-A-03, at 139, Table 3.1. Only about \$15,000 per year (of roughly \$2 million) is associated with transfer load service. *Id.*

Since the WP-07 rate period, and perhaps earlier, these costs have been allocated to Non-Slice customer loads. *Id.* In particular, this cost allocation affected rates in BP-12, BP-14, and BP-16. *Id.* Because these costs are directly tied to Federal generation included in the RHWMTier 1 System Capability, these are Composite Cost Pool costs and should be paid by all customers. *Id.* As to the \$15,000 in transfer service costs, these costs should be allocated to the existing Composite Cost Pool on the "Third-Party GTA Wheeling" line, pursuant to the TRM. *Id.*

Addressed elsewhere in this Final ROD are the Error Correction Guidelines proposed by Staff, which will affect Staff's decisions regarding whether to propose corrections for past errors by applying a prospective rate adjustment. See Section 2.1. Although the Lost Creek/Green Springs cost allocation error is a ministerial error within the Qualifying Type encompassed by the Error Correction Guidelines, application of the Guidelines indicates that no prospective rate adjustment is warranted to account for past effects of the allocation error. Stiffler *et al.*, BP-18-E-BPA-27, at 8; Stiffler *et al.*, BP-18-E-BPA-22, at 6-7. However, BPA has consistently corrected errors prospectively in each BPA general rate case, regardless of any guidelines.

The Lost Creek/Green Springs misallocation qualifies as an implementation error under the TRM, BP-12-A-03. Stiffler *et al.*, BP-18-E-BPA-22, at 6. As such, a new line, "Power 3rd Party Trans and Ancillary Svcs (Composite cost)" should be added to the revenue requirement, and the pre-existing line should be reinstated as "Power 3rd Party Transmission and Ancillary Svcs (Non-Slice cost)." *Id.* BPA currently does not expect to pay for any Power Third-Party Transmission and Ancillary Services (Non-Slice cost) costs. *Id.*

TRM Section 2.2 states:

The Allocated Tiered Cost Table, Table 2, sets out the cost categories that will be used for allocating costs in future 7(i) Processes. Any changes to the Allocated Tiered Cost Table to accommodate New Expenses and or New Credits will be pursuant to Section 2.3. Any changes to the Allocated Tiered Cost Table to

accommodate a need to allocate a Tier 2 Cost to a Tier 1 Cost Pool will be pursuant to Section 2.6. All other changes to the Allocated Tiered Cost Table will be pursuant to Sections 12 and 13.

TRM, BP-12-A-03, at 5; Stiffler *et al.*, BP-18-E-BPA-22, at 8.

TRM Section 2.3 states “BPA will allocate New Expenses or New Credits to the Cost Pools based on the cost allocation principles in Section 2.1. BPA will propose an allocation of the New Expenses and New Credits to the appropriate Cost Pools in the applicable 7(i) Process.” TRM, BP-12-A-03, at 7; Stiffler *et al.*, BP-18-E-BPA-22, at 8.

A “New Expense” in the TRM is defined as “an expense allocable to the applicable Cost Pool under this TRM *but for which no expense category exists on [TRM] Table 2.*” TRM, BP-12-A-03, at xvii (emphasis added); Stiffler *et al.*, BP-18-E-BPA-22, at 8. Therefore, if there is an expense BPA is expected to pay, but there is no line in TRM Table 2 to allocate those anticipated expenses, a New Expense line can be created. Stiffler *et al.*, BP-18-E-BPA-22, at 8. The lines in TRM Table 2 (lines 45-50, in Section B, Composite Cost Pool) are as follows: “Transmission and Ancillary Services,” “Third Party GTA Wheeling,” “Third Party Trans & Ancillary Services (Non-Slice cost),” “Generation Integration,” “Telemetry/Equip Replacement,” and “Extra-regional Transmission Acquisitions.” TRM, BP-12-A-03, at 133; Stiffler *et al.*, BP-18-E-BPA-22, at 8. A line for “Third Party Trans & Ancillary Svcs (Composite cost)” does not exist. *Id.*

“Third Party Trans & Ancillary Svcs (Composite cost)” meets the TRM definition for a New Expense because, as stated above, a New Expense in the TRM is defined as “an expense allocable to the applicable Cost Pool under this TRM but for which no expense category exists on Table 2.” TRM, BP-12-A-03, at xvii; Stiffler *et al.*, BP-18-E-BPA-22, at 9. During the BP-18 rate period, BPA expects to pay wheeling and losses expenses for transferring Lost Creek and Green Springs generation into BPA’s balancing authority area. Stiffler *et al.*, BP-18-E-BPA-22, at 9. As such, it is an expense that can be allocated to the Composite Cost Pool, and no expense category exists on TRM Table 2 for this expense. *Id.*

The same interpretation and implementation was used in the BP-16 rate proceeding to address the treatment of PGE WNP-3 Exchange Settlement costs. *Id.* No party raised an issue in its brief with regard to that change. *See* BP-16 Administrator’s Final Record of Decision, BP-16-A-02, at 27–29; *see also* Chalier *et al.*, BP-16-E-BPA-23, § 2.

As noted earlier, ICNU opposes correcting the Lost Creek/Green Springs error, even prospectively. ICNU Br., BP-18-B-IN-01, at 117. Referencing the Error Correction Guidelines proposed by BPA Staff in the Initial Proposal, ICNU reasons that the Lost Creek/Green Springs error should not be considered a ministerial error. *Id.* ICNU also argues that BPA has not met the evidentiary standard in this proceeding because BPA has allegedly not provided sufficient data to demonstrate that the costs at issue are more appropriately allocated to the Composite Cost Pool than to the pool to which they have been allocated for years. *Id.* ICNU argues that the parties that negotiated the TRM presumably reviewed the allocation of the relevant costs and

considered the appropriateness of the allocation methodology when agreeing to the RD Contract. Mullins, BP-18-E-IN-01, at 65.

Regardless of ICNU's assertion that the Lost Creek/Green Springs error is not a ministerial error, it is an unintentional error in terms of application of the TRM and in application of generally accepted ratemaking principles, as well as within the definition of Staff's Error Correction Guidelines. Stiffler *et al.*, BP-18-E-BPA-27, at 8. Moreover, whether the error is ministerial and, therefore, encompassed by the backwards-looking Error Correction Guidelines is moot, since the issue here is whether or not to correct the error going forward. The only remaining issue is whether Staff's proposed allocation is correct on the merits. This issue was addressed at length above.

ICNU presents no citations to support its argument that the parties that negotiated the TRM reviewed the allocation of the relevant costs and considered the appropriateness of the allocation methodology when agreeing to the RD Contract. Mullins, BP-18-E-IN-01, at 65. As noted previously, however, the costs at issue are transmission costs charged to BPA by third-party transmission operators for wheeling and losses tied to Federal generation located outside BPA's system, but delivered to all PF loads. Stiffler *et al.*, BP-18-E-BPA-22, at 6. Because these costs are directly tied to Federal generation included in the RHWMTier 1 System Capability, these are Composite Cost Pool costs and should be paid by all customers. *Id.* After reviewing the Administrator's TRM RODs from 2008, 2009, and 2011, BPA has been unable to identify any instance where a party discussed this issue or suggested a different treatment. In summary, these costs are associated with Federal system generation that both Slice and non-Slice customers receive in each respective PF product. Failure to allocate these costs broadly through the Composite Cost Pool is an error, and must be corrected going forward, irrespective of the decision on the Error Correction Guidelines.

Decision

BPA will, going forward, allocate to the Composite Cost Pool certain transmission costs associated with the Lost Creek and Green Springs hydroelectric projects.

3.5 Spill Surcharge

3.5.1 Statutory Context

Section 7 of the Northwest Power Act governs the development of BPA's wholesale power and transmission rates. 16 U.S.C. § 839e. Section 7(a)(1) requires the Administrator to establish rates in order to recover BPA's costs:

The Administrator shall 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. Such rates shall be established and, as appropriate, revised 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 (including irrigation costs required to be repaid out of power revenues) over a reasonable period of years and the other costs and expenses incurred by the Administrator pursuant to this chapter and other provisions of law. . . .

16 U.S.C. § 839e(a)(1).

Section 7(a)(2) of the Act provides that BPA's rates are confirmed and approved by the Federal Energy Regulatory Commission (FERC or Commission) only if they recover BPA's costs:

Rates established under this section shall become effective only, except in the case of interim rules as provided in subsection (i)(6), upon confirmation and approval by the Federal Energy Regulatory Commission upon a finding by the Commission, that such rates—

(A) 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,

(B) are based upon the Administrator's total system costs, and

(C) insofar as transmission rates are concerned, equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing such system.

16 U.S.C. § 839e(a)(2).

In addition to requiring BPA's rates to recover its costs, the Act grants the Administrator broad discretion in the design of BPA's rates. Section 7(e) of the Act provides:

Nothing in this chapter prohibits the Administrator from establishing, in rate schedules of general application, a uniform rate or rates for sale of peaking capacity or from establishing time-of-day, seasonal rates, or other rate forms.

16 U.S.C. § 839e(e). Pursuant to this discretion to design BPA's rates, BPA has a long-established practice, going back over 30 years, of establishing formula rates and adjustment clauses. *See, e.g.*, Residential Exchange Program and Supply System Adjustment Clauses, 1985 General Rate Schedule Provisions Sections III.C.6 and 7, approved by FERC on a final basis, *United States Department of Energy – Bonneville Power Administration, Order Confirming and Approving Rates On A Final Basis And Terminating Dockets*, Docket No. EF85-2011-011 (April 29, 1987). Like adjustment clauses, formula rates enable utilities to pass through increases or decreases in certain costs, which are not known before the rate period, to ratepayers without the need to file formal rate changes or conduct formal rate hearings.

3.5.2 Procedural Context

After BPA published its BP-18 Initial Proposal in November 2016, the U.S. District Court for the District of Oregon, on March 27, 2017, issued a ruling in *National Wildlife Federation*. The

opinion stated that the court will order “increased spill” at specified Federal dams in 2018. The court directed the parties to the lawsuit to work together with regional experts to develop a spill implementation plan. Staff therefore concluded that the *National Wildlife Federation* ruling will lead to increased spill and impact Federal hydroelectric system operations during the BP-18 rate period. Because the ruling was issued after the release of the BP-18 Initial Proposal, it created a new cost risk for BPA. This new cost risk was both substantial in size (possibly multiple millions of dollars) and asymmetrical in nature, meaning that it would result in a higher net cost because it would reduce Federal generation available for sale by BPA. As a result, BPA could not ignore the potential cost impact during the BP-18 rate period. *See Golden NW Aluminum v. Bonneville Power Admin.*, 501 F.3d 1037, 1048-53 (9th Cir. 2007). Staff proposed that a Spill Surcharge be added to BPA’s PF, Industrial Firm (IP), and New Resources Firm (NR) power rates to address this new cost risk and thereby ensure that BPA’s rates recover BPA’s total forecast costs.

As noted above, based on the substantial uncertainty regarding planned annual spill levels during the BP-18 rate period that will result from the court’s ruling, BPA’s preferred method of addressing the court order was to introduce a new rate mechanism to recover the potential costs of any changes in planned annual spill operations resulting from the order and related processes, when more definitive information regarding those changes becomes available. Because BPA was proposing a new surcharge, rather than updating data and information, BPA incorporated the development of the Spill Surcharge into the BP-18 Section 7(i) rate hearing to ensure that parties had an opportunity to thoroughly review and provide input on the proposal in a Section 7(i) rate hearing.

Because the BP-18 rate hearing had been under way since November 2016, the court ruling created exigent circumstances, requiring BPA to revise the BP-18 procedural schedule to accommodate the parties’ review. On April 17, 2017, BPA held a conference with rate case parties to develop a procedural schedule for the establishment of the Spill Surcharge within the BP-18 rate hearing. No party in the conference asked BPA to incorporate cross-examination into the revised schedule. *See* BP-18-M-BPA-12. After the scheduling conference, in which the litigants reached consensus on a proposed schedule, BPA filed a motion with the Hearing Officer to amend the BP-18 procedural schedule. *Id.* On April 21, 2017, the Hearing Officer granted the motion and established the schedule. BP-18-HOO-30. Pursuant to the “supplemental phase” of the schedule, Staff filed its direct testimony on April 27, 2017. The testimony was subject to oral and written discovery by the parties. The parties filed their direct testimonies on May 11, 2017. The parties’ testimonies were subject to oral and written discovery by the litigants. On May 25, 2017, BPA and JP08 filed rebuttal testimony responding to the parties’ direct testimonies. The testimony was subject to oral and written discovery by the parties. The parties filed initial briefs on June 9, 2017.

3.5.3 National Wildlife Federation Opinion and the BP-18 Power Rate Proposal

On January 9, 2017, the plaintiffs in *National Wildlife Federation* “move[d] under the Endangered Species Act (ESA) for an injunction requiring the Federal Defendants to provide spring spill beginning in 2017 for each remaining year of the remand period at the maximum spill level that meets, but does not exceed, total dissolved gas . . . criteria allowed under state

law” *Id.* at 1. In response to the requested injunction, the court issued an amended opinion and order on April 3, 2017, stating that it will order increased spill, but not until the spring 2018 migration season. *Id.* at 11. In the meantime, the court directed the parties to the lawsuit to work together with experts in the region to develop a spill implementation plan and a proposed injunction order. *Id.*

Water that is “spilled” at a dam is not run through a generation turbine but instead is passed via a spillway or other non-turbine route (*e.g.*, an ice and trash sluiceway). Fisher *et al.*, BP-18-E-BPA-55, at 3. The consequence of additional spill is a reduction in the generation available to BPA to sell. *Id.* Reductions in generation result in reductions in revenue because BPA is unable to sell energy associated with the amount of water that is spilled. *Id.* All else being equal, reduced revenues associated with an increase in planned annual spill levels would affect the ability of BPA’s proposed BP-18 rates to recover total costs. *Id.*

The court did not prescribe the spill requirements that would apply in FY 2018 and 2019. The court stated that it “intends to order modifications[]” but deferred a ruling on actual spill levels to a later stage in order to provide time for the parties to the lawsuit to work together with regional experts to identify spill levels and patterns for the spring 2018 migration season that are “tailored to the needs of each dam” and “will not cause unintended negative consequences.” *National Wildlife Federation*, 2017 WL 1829588, at *6, *9-10.

The BP-18 Initial Proposal was issued in November 2016 and reflects revenues BPA expects to receive from selling energy in the FY 2018–2019 rate period based on the assumed spill levels specified in the current Biological Opinion. Fisher *et al.* BP-18-E-BPA-55, at 4. When the district court issued a ruling in Spring 2017 indicating it will order “increased spill” in the spring of 2018, Staff filed supplemental testimony to propose a manner in which to appropriately reflect the court’s ruling in the development of the BP-18 rates. *Id.*

At this time, BPA does not know whether or how the court’s latest ruling could impact spill operations in 2019. *Id.* Given this uncertainty, Staff proposed a Spill Surcharge, which is formula-based and will evaluate each fiscal year of the rate period independently, comparing increases in planned annual spill levels relative to the spill levels assumed in setting rates. *Id.*

The establishment of the Spill Surcharge is not intended to determine or recommend the spill levels that should be ordered by the court for FY 2018 in *National Wildlife Federation*. *Id.* at *4-5. The court instructed the parties to the lawsuit to work together with regional experts during the next year to develop “a spill implementation plan and proposed injunction order.” *Id.* (citing *National Wildlife Federation*, 2017 WL 1829588, at *24). The court will order spill levels for 2018 following this process. Fisher *et al.*, BP-18-E-BPA-55, at 5. The Spill Surcharge is designed to ensure that BPA is able to recover costs that result from potential increases in planned spill levels for FY 2018 and possibly FY 2019. *Id.* Because it is not known whether or how the court’s ruling could impact spill operations in FY 2019, the proposed Spill Surcharge evaluates each fiscal year of the rate period independently. *Id.* at 4.

Staff did not propose to model in rates any other potential effects of the court’s decision because the planned spill operations for 2018 are not yet known. *Id.* at 5. As described above, spill

assumptions for FY 2018 will be established in a court-ordered process, which will be conducted outside of the rate case and completed after rates are set. *Id.* at 4-5. Staff did not want to speculate on the outcome of this process, whether through revised hydro modeling or inclusion of a fixed-cost line item, and proposed instead to develop a targeted surcharge that would address the cost risk of increased planned spill when more information is known. *Id.* at 5.

3.5.4 Staff's Proposed Spill Surcharge

This section presents a summary description of the BPA Initial Proposal Spill Surcharge. *See* Fisher *et al.*, BP-18-E-BPA-55, for a complete description of the proposal. The purpose of the Spill Surcharge is to allow BPA to increase its revenue collection from PF, IP, and NR energy sales when the planned annual spill levels increase relative to the spill levels assumed in setting rates.

3.5.4.1 Spill Surcharge Amount

The Spill Surcharge recovers the costs calculated by the Spill Surcharge Amount, which determines the additional cost to be charged to customers. The Spill Surcharge Amount formula has three main components:

1. the Spill Cost Component determines the cost (or lost revenue) associated with an increase in planned annual spill relative to the spill assumed when setting rates;
2. the Cost Reduction Component (*CostR*) allows the Administrator to decrease the Spill Surcharge Amount when BPA observes or forecasts reductions in program spending relative to the program spending used for the purpose of setting rates; and
3. the Non-Slice Component adjusts the entire formula to reflect the operational and cost-recovery differences between Slice and Non-Slice PF power sales. Non-Slice power sales are subject to the surcharge whereas Slice power sales are not because they are directly impacted by increased spill and are subject to an annual cost and revenue true-up.

Spill Cost Component

The Spill Cost Component determines the cost (or lost revenue) associated with an increase in planned annual spill relative to the spill assumed when setting rates; *i.e.*, BPA calculates the cost of lost generation caused by additional spill. BPA first determines the difference between the Federal regulated hydro generation from two studies: (1) the hydro regulation (HYDSIM) study used in the BP-18 Final Proposal (which does not reflect additional spill); and (2) a revised HYDSIM study that will use the BP-18 Final Proposal study with the new spill assumptions for the applicable year modeled. In addition, the lack of market spill data inputs in the revised HYDSIM studies will be updated. The Federal generation data from both studies will be based on 80 historical water conditions modeled.

The resulting differences in generation between the two studies are multiplied by the BP-18 Final Proposal market price forecast for each month over the 80 historical water conditions modeled. The resulting costs in each month for every year are summed and divided by 80 to determine the Spill Cost Component.

Cost Reduction Component

The Cost Reduction Component or “*CostR*” variable used in the Spill Surcharge formula is a dollar amount of specific forecast and actual program spending reductions as determined by the Administrator, at his discretion. Generally, program spending is identified in BPA’s Integrated Program Review (IPR) process and consists of forecasts of expenses that will appear on BPA’s income statement but does not include debt management, interest, power purchase costs, revenue credits, net secondary revenue, the Residential Exchange Program, or discounts.

Non-Slice Component

The Non-Slice component of the formula determines the portion of the calculated spill cost and cost reduction that will be charged to Non-Slice power sales; this portion is approximately 75 percent. Slice sales are not subject to the Spill Surcharge, but instead are impacted by any increased spill through lower Slice generation.

3.5.4.2 Spill Surcharge Implementation

Calculation of Spill Surcharge Rate and Annual Spill Surcharge Rate

A Spill Surcharge Amount will be calculated once each fiscal year in 2018 and 2019 when there is sufficient certainty around the revised spill assumptions and any offsetting Cost Reductions. BPA expects to be able to calculate the Spill Surcharge and start the public process (described below) no later than the last day of May in each fiscal year. The Spill Surcharge Amount cannot be negative. If BPA determines the Spill Surcharge Amount for a fiscal year would result in an amount less than \$5 million, then the Spill Surcharge Amount will be deemed equal to zero. Once the Spill Surcharge is finalized for a fiscal year, it will not be revisited.

The Spill Surcharge Rate will be calculated by dividing the Spill Surcharge Amount by the forecast billing determinants under the PF Melded, IP, and NR rates, and the sum of the PF System-Shaped Loads for the unbilled remaining portion of the applicable fiscal year. The Spill Surcharge Rate will also be used to adjust the PF Tier 1 Equivalent rates for the unbilled remaining portion of the applicable fiscal year. Finally, BPA will calculate an Annual Spill Surcharge Rate to adjust the Load Shaping Charge True-up rate and the PF Melded Equivalent Energy Scalar rate.

Public Process

BPA will conduct a public process prior to finalizing and implementing the Spill Surcharge. BPA will make available the data and assumptions used to calculate the Spill Surcharge Amount, Spill Surcharge Rate, and Annual Spill Surcharge Rate, hold a public meeting to describe the calculations, and provide a public comment period before the amount, rate, and adjustment are

made final. The assumptions will include the dollar amount of any forecast and actual cost reductions identified by the Administrator for use in calculating the Spill Surcharge Amount.

Billing

The Spill Surcharge Rate will be used in billing as follows. The Spill Surcharge Rate will increase the Heavy Load Hour (HLH) and Light Load Hour (LLH) energy rates under PF Melded, IP, and NR service for the remaining portion of the fiscal year. For PF customers with a System-Shaped Load, the Spill Surcharge Rate will be applied to the sum of the HLH and LLH PF System Shaped Loads in each month for the remaining portion of the fiscal year. A customer's Low Density Discount will be applied to its share of the Spill Surcharge Amount.

To help avoid possible cash flow problems for BPA customers, the Spill Surcharge includes a provision to allow a customer's share of the FY 2018 Spill Surcharge to be spread in a flat monthly amount over the remaining months of FY 2018 plus all 12 months of FY 2019. For FY 2019, BPA proposes that BPA and its customers use the FY 2018 experience to proactively plan for FY 2019 and use other tools, if needed, to address cash flow concerns, such as the Flexible Priority Firm Power Rate Option.

Other Adjustment Clauses

BPA's adjustment clauses, the proposed Power CRAC, Power Reserves Distribution Clause (RDC), and the NFB (Biological Opinion) mechanisms will work in the context of the Spill Surcharge as follows. The Power CRAC and RDC applying to FY 2018 rates will not be affected by the Spill Surcharge. The Power CRAC and RDC that apply to FY 2019 will account for any additional revenue resulting from the Spill Surcharge. In addition, the Spill Surcharge will not change the determination of an NFB trigger event; however, revenues received from the Spill Surcharge will be included for the purpose of calculating the NFB Adjustment and the Emergency NFB Surcharge. This means that if an NFB event occurs during the rate period, Spill Surcharge revenue will be taken into account as part of the "before case" and will not be charged for again under the NFB mechanisms.

3.5.5 Issues

Before addressing issues regarding the Spill Surcharge, it should be noted that certain parties supported Staff's Spill Surcharge proposal. JP08 supported Staff's proposal for four reasons. JP08 Supp. Br., BP-18-B-JP08-01, at 4-5. First, the Spill Surcharge costs would be transparent and based on the minimum amount of changes from the BP-18 final studies. *Id.* at 4. Staff's proposed methodology and the associated public process would allow the agency to transparently address the court's order. *Id.* Second, because the approach would model spill requirements when they are known, it would minimize chances that BPA will collect unnecessary revenues. *Id.* Because BPA would not be speculating on the outcome of the 2018 spill design or the 2019 Federal Columbia River Power System Biological Opinion (2019 BiOp), it would allow those processes to proceed unhindered by any rate case assumptions. *Id.* at 4-5. Third, given that the surcharge is meant to recover costs for a single year of operations or for unknown future BiOp operations, it is appropriate from a ratemaking perspective to have a separate charge rather than to simply roll the operational assumption into the baseline hydrological studies. *Id.* at 5. Finally,

Staff's proposed approach would not bias or pre-judge the outcome of other processes. *Id.* By declining to speculate on outcomes, BPA is allowing the court process to determine spill operations for FY 2018 and the 2019 BiOp to not be hindered by any rate case assumptions. *Id.* Conversely, if Staff adopted an approach that involved predicting these outcomes, it could potentially prejudice the court and BiOp processes. *Id.*

Issue 3.5.5.1

Whether, in addition to the Section 7(i) hearing in which the Spill Surcharge was established, BPA should conduct another Section 7(i) hearing to implement the Surcharge.

Parties' Positions

WPAG argues that Section 7(i) of the Northwest Power Act requires BPA to conduct a Section 7(i) hearing to implement the Spill Surcharge, even though the Spill Surcharge has already been established in a Section 7(i) hearing. WPAG Supp. Br., BP-18-B-WG-02, at 4-10.

BPA Staff's Position

BPA Staff notes that conducting a second Section 7(i) proceeding regarding the mechanical implementation of the Spill Surcharge would be impractical, unnecessary, costly, and inefficient. Fisher *et al.*, BP-18-E-BPA-56, at 10. The Spill Surcharge proposed by Staff provides a more reasonable manner of implementing an adjustment clause. *Id.*

Evaluation of Positions

As explained above, all of the elements of the Spill Surcharge, including the manner in which the Surcharge would be implemented, were proposed and discussed in great detail in Staff's direct and rebuttal testimony, WPAG's and other parties' testimonies, and in the GRSP provisions used to implement the Spill Surcharge. Like most other formula rates and adjustment clauses, BPA is establishing the Spill Surcharge in a Section 7(i) hearing and implementing the Surcharge through an informal process occurring during the rate period. WPAG, however, would like BPA to hold a second Section 7(i) hearing to implement the Spill Surcharge. WPAG Supp. Br., BP-18-B-WG-02, at 4-10.

WPAG cites Section 7(i) of the Northwest Power Act, which prescribes the procedures BPA uses in establishing its power and transmission rates. Section 7(i) provides, in pertinent part:

In establishing rates under this section, the Administrator shall use the following procedures:

Notice of the proposed rates shall be published in the Federal Register with a statement of the justification and reasons supporting such rates. Such notice shall include a date for a hearing in accordance with paragraph (2) of this subsection.

One or more hearings shall be conducted as expeditiously as practicable by a hearing officer to develop a full and complete record and to receive public comment in the form of written and oral presentation of views, data, questions, and argument related to such proposed rates. In any such hearing—

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, and

the hearing officer, in his discretion, shall allow a reasonable opportunity for cross examination, which, as determined by the hearing officer, is not dilatory, in order to develop information and material relevant to any such proposed rate.

In addition to the opportunity to submit oral and written material at the hearings, any written views, data, questions, and arguments submitted by persons prior to, or before the close of, hearings shall be made a part of the administrative record.

16 U.S.C. § 839e(i).

WPAG argues that when BPA implements the Spill Surcharge, BPA would not (1) publish the surcharges and justifications in the Federal Register, (2) appoint a hearing officer to develop a complete record, (3) allow cross-examination, (4) provide parties the opportunity to rebut material submitted by any other party as would be required under Section 7(i), or (5) make a final decision as that term is understood in the context of Section 7(i). WPAG Supp. Br., BP-18-B-WG-02, at 5.

WPAG does not acknowledge the concept of formula rates or adjustment clauses, which are extremely common in the utility industry. When a utility conducts a hearing and establishes its rates, there may be a particular cost (*e.g.*, fuel, spill through dams, etc.) that is not known at the time of the hearing. Nevertheless, the utility would like to establish its rates for its prospective rate period without having to stop in the middle of the rate period and completely reestablish its rates through another lengthy, expensive hearing. Therefore, the utility develops a formula rate or adjustment clause, which makes a limited adjustment to rates based on the formula established in the initial hearing. Basically, once the unknown cost becomes known during the rate period, it is inserted into the formula, and a mechanical calculation determines the rate adjustment to be applied to its rates. This describes the Spill Surcharge.

Reviewing WPAG's arguments *seriatim*, first, BPA published a Federal Register Notice (FRN) for BPA's proposed BP-18 rates on November 10, 2016. *See* Fiscal Year (FY) 2018–2019 Proposed Power and Transmission Rate Adjustments, Public Hearing and Opportunities for Public Review and Comment, Bonneville Power Administration, Department of Energy (DOE), 81 Fed. Reg. 78,999 (2016). The FRN identified and justified in summary fashion all of BPA's proposed rate schedules, including: (1) the Priority Firm Power Rate (PF-18), which applies to net requirements power sales to public body, cooperative, and Federal agency customers made pursuant to Section 5(b) of the Northwest Power Act; (2) the PF Exchange rate, which applies to

the sale of power to regional utilities that participate in the Residential Exchange Program established under Section 5(c) of the Northwest Power Act; (3) the New Resource Firm Power Rate (NR-18), which applies to net requirements power sales to investor-owned utilities (IOUs) made pursuant to Section 5(b) of the Northwest Power Act for resale to ultimate consumers; direct consumption; construction, testing and start-up; and station service; and which is also applied to sales of firm power to Public customers when this power is used to serve new large single loads; (4) the Industrial Firm Power Rate (IP-18), which applies to firm power sales to direct service industrial (DSI) customers authorized by Section 5(d)(1)(A) of the Northwest Power Act; and (5) the Firm Power and Surplus Products and Services Rate (FPS-18), which applies to sales of various surplus power products and surplus transmission capacity for use inside and outside the Pacific Northwest. *Id.* Section 7(i) of the Northwest Power Act requires that a “[n]otice of the proposed rates shall be published in the Federal Register with a statement of the justification and reasons supporting such rates.” The five foregoing rates are the rates referenced in Section 7(i). Thus, BPA published all of its proposed rates in the FRN.

The Spill Surcharge is an adjustment mechanism within the PF, IP, and NR rates. The need for the Spill Surcharge, however, was not known to BPA or other parties until after the FRN had been published, when parties received the opinion and order in *National Wildlife Federation*. As noted previously, in response to exigent circumstances, the Hearing Officer established an amended procedural schedule in order to incorporate the development of the Spill Surcharge into the ongoing BP-18 Section 7(i) rate hearing.

WPAG next argues that BPA would not appoint a hearing officer to develop a complete record. WPAG Supp. Br., BP-18-B-WG-02, at 4-5. WPAG fails to mention that a hearing officer had been appointed at the inception of the BP-18 hearing, and that the Hearing Officer established the procedural schedule to review the Spill Surcharge within the BP-18 hearing. *See* BP-18-HOO-30. The Hearing Officer was therefore presiding over the filing of Staff’s Initial Proposal supporting the Spill Surcharge, the oral and written discovery regarding the Staff proposal, the filing of the rate case parties’ responding testimonies, the oral and written discovery regarding the parties’ testimonies, the filing of the litigants’ rebuttal testimonies, the oral and written discovery regarding the litigants’ rebuttal testimonies, and the filing of the parties’ briefs. In sum, a hearing officer has presided over the BP-18 supplemental Section 7(i) hearing to develop the Spill Surcharge.

WPAG next argues that BPA would not allow cross-examination regarding the Spill Surcharge. WPAG Supp. Br., BP-18-B-WG-02, at 4. Before Staff filed its initial Spill Surcharge proposal, BPA invited all rate case parties to attend a scheduling conference, where the litigants would develop a proposed procedural schedule for the Spill Surcharge within the BP-18 Section 7(i) hearing. During this conference, no party, including WPAG, requested that an opportunity for cross-examination be included in the Section 7(i) hearing schedule. The Hearing Officer adopted the litigants’ consensus schedule. The Hearing Officer’s order, which did not include cross-examination, is consistent with Section 7(i)’s direction that “the hearing officer, *in his discretion*, shall allow a reasonable opportunity for cross-examination” 16 U.S.C. § 839e(i) (emphasis added).

WPAG next argues that BPA would not provide parties the opportunity to rebut material submitted by any other party. WPAG Supp. Br., BP-18-B-WG-02, at 4. As noted previously, however, after Staff filed its initial Spill Surcharge proposal, WPAG was provided the opportunity, which it took, to file testimony in direct response to Staff’s proposal. Similarly, when rate case parties filed testimony, WPAG was provided the opportunity to file rebuttal testimony in response to each testimony. Thus, WPAG had the opportunity to rebut material submitted by any other litigant.

WPAG next argues that BPA would not make a final decision regarding the Spill Surcharge. WPAG Supp. Br., BP-18-B-WG-02, at 4. To the contrary, according to the schedule for the supplemental phase of the BP-18 Section 7(i) hearing, which concerns the establishment of the Spill Surcharge, the Administrator will release a final decision on BPA’s proposed BP-18 rates and the Spill Surcharge, on July 26, 2017. BP-18-HOO-30.

In summary, BPA has established the Spill Surcharge, which includes the manner in which to implement the Spill Surcharge, in compliance with Section 7(i) of the Northwest Power Act.

WPAG notes BPA’s position that a separate Section 7(i) hearing is not necessary because the Spill Surcharge is established through the BP-18 Section 7(i) hearing. WPAG Supp. Br., BP-18-B-WG-02, at 5. Further, BPA notes that “there is only one element that is not included in the BP-18 rate proceeding . . . (planned spill assumptions for each year),” and for this reason, “[c]onducting an entire expedited 7(i) hearing for this narrow, limited purpose would be impractical and unnecessary.” *Id.* (citing Fisher *et al.*, BP-18-E-BPA-56, at 8).

WPAG argues that simply because the Spill Surcharge is for “a narrow and limited purpose” does not absolve BPA of its Section 7(i) responsibilities. WPAG Supp. Br., BP-18-B-WG-02, at 5. This statement, however, ignores BPA’s point. BPA was not arguing that the Spill Surcharge has a limited purpose (although this is true), but rather that everything about the Spill Surcharge and its implementation will have been established in the BP-18 proceeding after review by WPAG and other rate case parties, except for planned spill assumptions for each year. In other words, the only thing WPAG would not have had an opportunity to review and challenge in the BP-18 Section 7(i) hearing regarding the Spill Surcharge would be the planned spill amount that is currently unknown and will be inserted mechanically into the Spill Surcharge formula to determine the amount of the surcharge. Fisher *et al.*, BP-18-E-BPA-56, at 22-23. However, WPAG wants BPA to hold a second Section 7(i) hearing in order to review the revised spill assumptions, once information regarding planned annual spill levels becomes available. These planned annual spill levels will be established through external processes and, once determined, are not subject to change by BPA; BPA will merely insert those revised assumptions into the Spill Surcharge formula. WPAG’s proposal therefore makes little practical sense.

WPAG argues that the Revised Federal Generation component of BPA’s proposed formula for calculating the Spill Surcharge Amount will require BPA to run a revised Federal HYDSIM study after the close of the BP-18 rate case once the revised spill assumptions are known. WPAG Supp. Br., BP-18-B-WG-02, at 5-6. WPAG claims that normally HYDSIM studies are documented in the Final Power Loads and Resource Study, and subject to the rigors of a Section 7(i) hearing so parties can review, question and contest those studies if they so choose.

Id. In response, however, WPAG and the parties have been advised numerous times that the HYDSIM studies that will be used in implementing the Spill Surcharge will be the same HYDSIM studies documented in the Final BP-18 Proposal after having undergone the rigors of the BP-18 Section 7(i) hearing. As BPA has noted previously, the only new element used to calculate the Spill Surcharge will be the planned spill amounts.

WPAG argues that BPA's proposal is to remove a revision of one of the most important and financially substantial elements of BPA's rate case methodology from the purview of the rate case. WPAG Supp. Br., BP-18-B-WG-02, at 6. In response, once again, BPA is not proposing to remove anything from the purview of the rate case; the planned spill assumptions are taken from an independent source and are not subject to change even if included in an additional Section 7(i) hearing. WPAG will have had a full opportunity to review the HYDSIM studies in the BP-18 rate case, and the final HYDSIM studies are the same studies that will be used in calculating the Spill Surcharge. The only element that will be changed in implementing the Spill Surcharge is the planned spill amounts, which are not yet available and will come from a publicly administered external process. WPAG also expresses concern that this could be used as a precedent to remove some or even all HYDSIM or other rate studies from future rate proceedings. *Id.* Although it is difficult to imagine BPA developing rates in the absence of the HYDSIM studies, WPAG is simply speculating about something that has not occurred, and in all rational likelihood would not ever occur. In the event it did occur, however, any proposal to remove studies from the rate case could be challenged by WPAG in the relevant rate case.

WPAG argues that models do not create reality, but nevertheless BPA is proposing to use a model developed today to subsequently set rates in 2018 and 2019 without considering any other factor that may be actually happening in 2018 or 2019 other than the new spill requirements. WPAG Supp. Br., BP-18-B-WG-02, at 6-7. WPAG's argument, however, would undermine fundamental principles of ratemaking. BPA is not just using its model as established today (in the BP-18 Section 7(i) hearing) to implement the Spill Surcharge during the FY 2018–2019 rate period. BPA is using all of its models and studies established today (in the BP-18 Section 7(i) hearing) to develop all of its rates that are in effect through the entire FY 2018–2019 rate period. Rates are prospective and are developed based on forecasts. The rates will be in effect for an entire rate period; they are not constantly reviewed to determine whether any facts have changed from when the rates were developed. A formula rate like the Spill Surcharge uses the same models and forecasts used to develop BPA's base rates, and simply incorporates a currently unknown factor—planned spill assumptions—to implement the surcharge.

WPAG argues that the Spill Surcharge is in contrast to other formula rates BPA has established to mitigate risk such as the CRAC and the Oversupply Rate. WPAG Supp. Br., BP-18-B-WG-02, at 7. (The CRAC is an upward adjustment to rates to respond to financial circumstances BPA experiences before the next opportunity to adjust rates in a rate proceeding; the Oversupply rate recovers the displacement costs that BPA pays out under OATT Attachment P, Oversupply Management Protocol.) WPAG acknowledges that the CRAC and Oversupply Rate are also implemented outside a Section 7(i) hearing, but claims the inputs into their respective formulas are based on near-term forecasts that incorporate observed reductions in reserve levels during the rate period in the case of the CRAC, and actual costs incurred during the rate period in the case

of the Oversupply Rate. *Id.* In this fashion, WPAG claims the CRAC and Oversupply formula rates balance the ease by which BPA can implement them with increased accuracy by use of actual or near actual (as opposed to rate case forecast) values. *Id.* WPAG argues that BPA’s Spill Surcharge proposal instead seeks to combine the ease of implementation with the use of models and forecasts (not actual values) to set the Spill Surcharge rate. *Id.*

WPAG misrepresents the Spill Surcharge as initially proposed by Staff. The only variable in Staff’s proposed formula that can increase the cost of the Spill Surcharge Amount is the planned spill assumptions for each year. Fisher *et al.*, BP-18-E-BPA-56, at 6. These planned annual spill assumptions are not determined with a forecast but rather are determined transparently through other highly visible and verifiable processes. *Id.* Therefore, the Spill Surcharge functions in much the same way as the CRAC and Oversupply formula, which WPAG appears to support, with updates based on actual or near-actual values.

Further, WPAG supports as a second-best option the adoption of ICNU’s proposal to incorporate the effect of increased spill on market prices. WPAG Supp. Br., BP-18-B-WG-02, at 13. ICNU’s proposal, however, does exactly what WPAG proposes should not be done outside a second Section 7(i) process, which is to change the Spill Surcharge Amount based on a forecast of additional secondary revenue resulting from increased forecast market prices. ICNU Supp. Br., BP-18-B-IN-02, at 3. Therefore, WPAG’s second preference undermines its primary argument. It is impossible to reconcile WPAG’s primary position—that the Spill Surcharge is in some way flawed because it relies on forecasts conducted outside the rate case (which it does not)—with WPAG’s second preference to modify the Spill Surcharge to explicitly rely on a non-rate case forecast for additional secondary revenue.

WPAG notes BPA’s observation that the context that surrounds the need for the Spill Surcharge rate more closely resembles BPA’s formula Slice True-Up Adjustment than it does the CRAC in that it has a lower magnitude than the CRAC and has a narrower scope, and BPA’s observation that two components of the Slice True-Up Adjustment are calculated in a similar fashion to the proposed surcharge. WPAG Supp. Br., BP-18-B-WG-02, at 7. WPAG quotes Staff’s testimony stating, “The Actual Firm Surplus and Secondary Adjustment from Unused RHW (2018 Power Rate Schedules and GRSPs, BP-18-A-04-AP03, GRSP II.R.1(b)) and calculation of the Actual DSI Revenue Credit (2018 Power Rate Schedules and GRSPs, BP-18-A-04-AP03, GRSP II.R.1(c)) are calculated by applying varying megawatt-hour (MWh), which are established outside the rate proceedings, to fixed forecast market prices that are established in the rate proceedings.” WPAG Supp. Br., BP-18-B-WG-02, at 7-8 (citing Fisher *et al.*, BP-18-E-BPA-56, at 7). WPAG argues that, similar to the CRAC and the Oversupply rate, those portions of the formulas for the Actual Firm Surplus and Secondary Adjustment from Unused RHW and the Actual DSI Revenue Credit that are established outside the rate proceeding are based on *actual* rather than modeled or forecasted data, so in this critical respect they are more like the CRAC than BPA’s proposal for calculating the Spill Surcharge Amount. WPAG Supp. Br., BP-18-B-WG-02, at 8.

Again, WPAG overlooks the source and nature of the only variable in Staff’s proposed formula—planned annual spill assumptions—that can increase the cost of the Spill Surcharge Amount. Fisher *et al.*, BP-18-E-BPA-56, at 6. These planned annual spill assumptions are not

based on a forecast but are, for all intents and purposes, representative of the actual planned spill operations as determined transparently through other highly visible and verifiable processes. The Spill Surcharge is simply the result of updating the rate case 80-water-year study with the determined spill plan.

WPAG also argues that the underlying context of the Slice True-Up Adjustment is that it was agreed to by customers as part of the Slice Rate, which was predicated on the customers paying their percentage share of BPA's actual costs, which are not known until the fiscal year is over. WPAG Supp. Br., BP-18-B-WG-02, at 8. WPAG asserts that the TRM establishes a robust alternative process for reviewing the basis for any adjustment (including the use of an external auditor, multiple workshops, and the ability to request a third-party review process), while the Spill Surcharge includes an "anemic" public process when compared to the process detailed in the TRM for the Slice True-Up Adjustment. *Id.* WPAG correctly points out that the Slice product and its implementation come with a significant amount of context and history. The Slice product is unique in many different ways and as a result makes comparisons to it more challenging and complex. Regardless, one need not dive into the complexities of the Slice product in search for justification of the Spill Surcharge. As previously stated, the Spill Surcharge functions in much the same way as the CRAC, and the CRAC has been a foundational component of BPA's power rate design for more than a decade. Both the CRAC and the Spill Surcharge are based on actual or near-actual values. The precedent of the CRAC supports the adoption of the Spill Surcharge.

Decision

The implementation of the Spill Surcharge, like the implementation of other formula rates and adjustment clauses, does not require BPA to conduct a Section 7(i) hearing in addition to the Section 7(i) hearing in which the Spill Surcharge was established.

Issue 3.5.5.2

Whether BPA should conduct an expedited Section 7(i) proceeding to determine the Spill Surcharge Amount and related surcharges for FY 2018.

Parties' Positions

WPAG argues that BPA should hold an expedited Section 7(i) proceeding to determine the Spill Surcharge Amount and related surcharges for FY 2018. WPAG Supp. Br., BP-18-B-WG-02, at 9-10.

BPA Staff's Position

BPA Staff notes that even if a second Section 7(i) proceeding regarding the mechanical calculation of the Spill Surcharge were expedited, it would still be unnecessary. Fisher *et al.*, BP-18-E-BPA-56, at 10.

Evaluation of Positions

WPAG argues that BPA should hold a targeted and expedited Section 7(i) rate proceeding at the start of 2018 to establish the Spill Surcharge Amount and Spill Surcharge rate for FY 2018. WPAG Supp. Br., BP-18-B-WG-02, at 9-10. However, a typical Section 7(i) rate hearing process is time consuming, costly for BPA and its customers, and generally impractical to conduct for periods shorter than two years. Fisher *et al.*, BP-18-E-BPA-56, at 8. A targeted and expedited Section 7(i) rate proceeding somewhat mitigates some of these factors, but not enough to make it the right tool in the present situation. *Id.* This is due to several reasons. *Id.* First, the BP-18 Section 7(i) process is occurring now, and this existing process allowed BPA to propose a formula rate that provides a straightforward solution to BPA's revenue recovery risk that is reasonable under the circumstances. *Id.* In contrast, WPAG is essentially suggesting that BPA should conduct an entire expedited Section 7(i) hearing even though there is only one element that is not included in the BP-18 rate proceeding that is needed in order to calculate the spill cost component of the surcharge (planned spill assumptions for each year). *Id.* Furthermore, this element is not a calculation, but is simply a matter of updating spill assumptions to reflect planned annual spill operations resulting from court orders and related processes. *Id.* at 4-5. Conducting an entire expedited Section 7(i) hearing for this narrow, limited purpose would be impractical and unnecessary. *Id.*

Second, given that there is currently an ongoing Section 7(i) process, conducting another Section 7(i) process would simply delay the implementation of the surcharge. *Id.* In certain situations, delaying a decision can make sense, especially when a reasonable solution cannot be derived with the information and time available. *Id.* at 8-9. However, this is not the case with the Spill Surcharge, where a simple formula rate adjustment calculation is available. *Id.* at 9. Even under Staff's proposal, the surcharge may not be calculated until more than 30 percent of the rate period has passed for a possible FY 2018 surcharge adjustment, and more than 80 percent of the rate period has passed for a possible FY 2019 surcharge adjustment. *Id.* This limits the time in which to incorporate the surcharge into customers' bills. *Id.*

Although Staff views the Spill Surcharge as a typical formula rate adjustment, WPAG appears to view the implementation of the Spill Surcharge as establishing a new rate and presumably would want BPA to file the Spill Surcharge with FERC for confirmation and approval. *Id.* FERC requires BPA to file its rates at least 60 days prior to the date for which interim approval is requested, which means BPA would not be able to implement the surcharge until at least 60 days later than under Staff's proposal. *Id.* But this is not the end of the delay. In addition, an expedited Section 7(i) process is typically 90 days. *Id.* Even if BPA were able to construct a presently unproven more expedited Section 7(i) process, this would delay implementation by at least an additional 30 days. *Id.* Each time the implementation date is delayed, customers would see a higher impact on their bill as the Spill Surcharge is recovered over fewer and fewer months. *Id.*

WPAG argues that a partial solution to the delay raised by its proposal would be for BPA to seek a waiver of FERC's regulations. BP-18-B-WG-02, at 9-10. WPAG cites three instances in which BPA previously received a waiver of the 60-day filing requirement. *Id.* First, however, with BPA's Spill Surcharge, like other formula rates and adjustment clauses, there would be no

need to request a waiver of FERC's regulations because the Spill Surcharge already would have been filed with the Commission for approval along with BPA's other rates. Second, although it is possible that the Commission would grant such a waiver, each request is reviewed on a case-by-case basis, and a waiver is not guaranteed. Third, even if the 60-day requirement were waived, there would still be some period between filing the rate and receiving interim approval; this would result in an implementation delay compared to the Spill Surcharge as now proposed.

Fourth, reviewing each of the cited waivers: in 1986 BPA received a waiver of the 60-day requirement so BPA could modify its non-firm rates in the face of rapidly declining gas and oil prices. *United States Dept. of Energy – Bonneville Power Admin.*, 35 FERC ¶ 61,143, at 61,335 (1986). Despite the waiver, there was still an approximately 30-day period between the rate filing and the receipt of interim approval. Also in 1986, BPA received a waiver for BPA's proposed Variable Industrial Power rate schedule VI-86, designed to guard against the loss of BPA's Direct Service Industrial load. *United States Dept. of Energy – Bonneville Power Admin.*, 36 FERC ¶ 61,142, at 61,353-54 (1986). Again, despite the waiver, there was an approximately 30-day period between the rate filing and the receipt of interim approval. In 1993, BPA received a waiver for the Power Shortage Rate (PS-93) so that the rate would be in effect in time for the 1993-94 heating season. *United States Dept. of Energy – Bonneville Power Admin.*, 65 FERC ¶ 62,179 (1993). Once again, despite the waiver, there was an approximately 30-day period between the rate filing and the receipt of interim approval. In summary, even assuming BPA received a waiver of the Commission's 60-day filing requirement, it is likely there would still be at least a 30-day delay in receiving interim approval.

WPAG also argues that BPA has previously addressed similar mid-rate period developments that may affect cost-recovery by establishing new rates outside the general rate case while still complying with the procedural requirements under the Northwest Power Act. WPAG Supp. Br., BP-18-B-WG-02, at 10. WPAG's argument is inapposite. In each of the cases cited above, BPA developed a new rate schedule: the NF-86 rate, the VI-86 rate, and the PS-93 rate. Whenever BPA establishes a new rate schedule, it conducts a Section 7(i) rate hearing. This is completely different from implementing a formula rate or an adjustment charge. BPA establishes formula rates and adjustment clauses in Section 7(i) hearings (just as the Spill Surcharge has been established in the BP-18 Section 7(i) hearing), but the implementation of the formula rate occurs during the rate period with an informal public process. Section 7(i) of the Northwest Power Act requires the establishment of rates in a Section 7(i) hearing, not the implementation of a rate already established through a Section 7(i) hearing.

Finally, WPAG argues that BPA has stated that it will allow the Spill Surcharge for FY 2018 to be spread across the remaining months of FY 2018 plus all 12 months of FY 2019, and this should alleviate the concern that an expedited Section 7(i) process would create unduly high monthly charges. WPAG Supp. Br., BP-18-B-WG-02, at 10. However, to the extent there is any required period between filing the Spill Surcharge with FERC and the granting of interim approval, there would be a greater delay than under Staff's proposal, where there is no delay whatsoever.

In summary, conducting an expedited Section 7(i) proceeding regarding the mechanical calculation of the Spill Surcharge would be impractical, unnecessary, costly, and inefficient.

Fisher *et al.*, BP-18-E-BPA-56, at 10. The Spill Surcharge proposed by Staff provides a more reasonable manner of implementing an adjustment clause. *Id.* Furthermore, the proposed approach is less costly and reduces rate shock compared to conducting an expedited Section 7(i) proceeding, which is consistent with WPAG's competitiveness argument, namely, that BPA will likely need to do much more to lower its costs and increase its revenue to remain competitive. *Id.* at 13 (citing Saleba *et al.*, BP-18-B-WG-07, at 8-9).

Decision

BPA will not conduct an expedited Section 7(i) proceeding to determine the Spill Surcharge Amount and related surcharges for FY 2018.

Issue 3.5.5.3

Whether BPA should establish a Spill Surcharge for 2019.

Parties' Positions

WPAG argues that BPA should not establish a Spill Surcharge for 2019. WPAG Supp. Br., BP-18-B-WG-02, at 10-12.

BPA Staff's Position

BPA Staff does not know whether or how the district court's recent spill ruling could affect planned annual spill operations in 2019, and therefore proposes that the formula rate also apply in FY 2019 to account for this uncertainty. Fisher *et al.*, BP-18-E-BPA-56, at 11.

Evaluation of Positions

WPAG argues that BPA is not under the same compulsion to develop a spill surcharge for FY 2019 as it faces for FY 2018 because the court's ruling in *National Wildlife Federation* only addresses spill in FY 2018, and therefore it is speculative that either the court or the 2019 BiOp will lead to an increase in planned spill for FY 2019. WPAG Supp. Br., BP-18-B-WG-02, at 10. It is precisely to account for this uncertainty that WPAG identifies that Staff proposed the Spill Surcharge also apply in FY 2019. Fisher *et al.*, BP-18-E-BPA-56, at 11. Staff saw no drawback to applying the formula rate both years and, in fact, one of the strengths of the formula rate proposal is that it allows BPA to address each year independently. *Id.* at 11-12. If spill is not increased in FY 2019 relative to the Final Proposal, then Staff's formula would not collect any additional revenue from customers. *Id.* at 12. If spill is increased, then the formula will allow for revenue recovery in proportion to the impact and allow BPA to recover its costs. *Id.* BPA has the obligation to recover its costs, and applying the spill surcharge to both years under these particular circumstances supports this obligation without unduly collecting revenue from customers when an added cost is not incurred. *Id.*

Also, in addition to being a formula rate that will only collect additional revenue in proportion to BPA's added cost, the Spill Surcharge allows the Administrator to identify forecast and actual

program spending reductions independently in both years. *Id.* at 11-12. In the event that planned annual spill levels for FY 2019 increase relative to the spill assumptions contained in the BP-18 Final Proposal, this component of the Spill Surcharge allows both cost and revenue solutions. *Id.* This is consistent with customer statements on BPA's competitiveness and could result in a less costly outcome for customers over the long run than a plan to delay the financial consequences of an increase in planned annual spill for FY 2019, if any, until BP-20. *Id.* at 12.

WPAG argues that if there were no Spill Surcharge in 2019, and in the event a future court ruling or the 2019 BiOp subsequently leads to increased spill for FY 2019, the resulting financial impact should be treated the same as any other financial difference from rate case forecasts; in other words, it would contribute to the net reduction in Power's financial reserve balance and potentially cause or contribute to the triggering of Power's CRAC. WPAG Supp. Br., BP-18-B-WG-02, at 10-11 (citing Saleba *et al.*, BP-18-E-WG-07, at 7). However, this circumstance would allow BPA's already depleted Power reserves to decline even more, which could contribute to jeopardizing BPA's credit rating. In addition, the reduction in reserves would contribute to the triggering of Power's CRAC, which would result in an automatic rate increase to customers. These are not good results.

WPAG argues that spill requirements for FY 2019 are unknown; there are other unknowns affecting BPA's cost recovery in 2019 such as gas prices, snow levels, the shape of the runoff, and new court decisions; BPA already has proven mechanisms in place to ensure cost recovery notwithstanding the host of unknowns it confronts in setting rates for a two year rate period, *e.g.*, the CRAC; BPA is likely to adopt a new financial reserves policy as part of this rate proceeding, one of the purported benefits of which is to provide rate stability in the face of unforeseen contingencies; and BPA already has a number of formula rates that mitigate the risk to BPA, including the CRAC, the Oversupply Rate, the NFB Adjustment, the Emergency NFB Surcharge, and Slice True-Up Adjustment. WPAG Supp. Br., BP-18-B-WG-02, at 12. WPAG states that while BPA's increased reliance on formula rates provides value to BPA by shifting the risk of uncertainty to its customers, it can devalue BPA's products and services by eroding customer confidence that BPA's stated rate is the rate they will actually pay, and the perception that BPA is a dependable counterparty will suffer as a result. *Id.*

BPA understands WPAG's concerns. However, as WPAG notes, "intra-rate period adjustments to rates should only happen in the most extraordinary of circumstances, such as in response to the Court's spill order affecting FY 2018." *Id.* at 12. The Spill Surcharge is an example of the proper use of a formula rate; it addresses a specific cost when BPA's other formula rates would be inadequate to recover such costs. Furthermore, the Spill Surcharge is only a temporary ratemaking approach used by BPA until issues regarding spill requirements at Federal dams have been resolved. However, while BPA must address each formula rate and policy on its own merits, WPAG is correct that BPA must also pay attention to BPA's rates as a whole and the impact such rates have on BPA's customers. To this end, instead of making speculative assumptions about spill conditions that might occur during the rate period to address an increase in planned annual spill levels, BPA developed a Spill Surcharge approach which would limit BPA's cost exposure while also protecting customers' rates from potentially excessive increases.

Decision

The Spill Surcharge will apply to FY 2019.

Issue 3.5.5.4

Whether BPA should issue a close-out letter at the conclusion of the public process implementing the Spill Surcharge.

Parties' Positions

WPAG argues that BPA should issue a close-out letter at the conclusion of the public process implementing the Spill Surcharge. WPAG Supp. Br., BP-18-B-WG-02, at 12-13.

BPA Staff's Position

BPA Staff proposed that a close-out letter could be issued by the Administrator or his designee depending on the circumstances involved with implementing the Spill Surcharge. Fisher *et al.*, BP-18-E-BPA-56, at 18.

Evaluation of Positions

WPAG argues that the Administrator should obligate the agency to issue a close-out letter at the conclusion of the public implementation process rather than reserving the right to make a case-by-case determination. WPAG Supp. Br., BP-18-B-WG-02, at 12-13. WPAG states that, unlike the CRAC, the proposed surcharge has no stated upper limit (or cap) and will not be based on near-term financial results but on modeled and forecast data prepared by BPA during the BP-18 rate case. *Id.* at 13. WPAG claims that this difference is sufficient to justify a commitment to publish a close-out letter. *Id.* However, it is not clear what the relationship is between a cap and the need for a close-out letter. Aside from the cap, which appears to be irrelevant in the context of a close-out letter requirement, WPAG states no reason why a rate adjustment, such as the Spill Surcharge, should require a close-out letter. WPAG simply points out that the CRAC includes a cap that makes it different, but WPAG does not consider other rate adjustments that do not have caps nor require close-out letters, for example, the Dividend Distribution Clause (DDC) (and as proposed for the Power Reserves Distribution Clause (RDC)) and the Load Shaping True-Up Adjustment. *See* 2018 Power Rate Schedules and GRSPs, BP-18-A-04-AP03, GRSP Sections II.P and II.E. Therefore, although there may be circumstances where a mandatory close-out letter is appropriate, each circumstance must be reviewed on a case-by-case basis; however, there is substantial evidence and precedent where formula rates and adjustment clauses do not have mandatory close-out letters.

Furthermore, the Spill Surcharge is designed in a manner that relies on existing information and studies that have been vetted in the BP-18 Section 7(i) hearing. As discussed previously, the only variable in Staff's proposed formula that can increase the cost of the Spill Surcharge Amount is the planned spill assumptions for each year. These planned annual spill assumptions are not determined by BPA alone and will be transparently established through other highly

visible and verifiable processes. For these reasons, it seems unlikely that there would be many issues regarding the implementation of the Spill Surcharge. If no issues are identified during the public process regarding the implementation of the Spill Surcharge, there would be little need for a close-out letter. Therefore, the Administrator should have discretion regarding whether a close-out letter is issued. However, it is important that customers understand the calculations and basis for any decisions that are needed to calculate the final Spill Surcharge. Thus, if needed, BPA will ensure that customers have all pertinent information through written communications or in meetings, such as BPA's Quarterly Business Review.

Decision

The Administrator will have the discretion to issue a close-out letter at the conclusion of the Spill Surcharge public implementation process.

Issue 3.5.5.5

Whether BPA should set the CostR component of BPA's formula at a minimum of \$10 million.

Parties' Positions

WPAG argues that BPA should set the *CostR* component of BPA's formula at a minimum of \$10 million. WPAG Supp. Br., BP-18-B-WG-02, at 13.

ICNU supports WPAG's proposal to set the *CostR* component of BPA's formula at a minimum of \$10 million. ICNU Supp. Br., BP-18-B-IN-02, at 4-5.

BPA Staff's Position

BPA Staff believes it is not appropriate to establish a fixed minimum amount to be included in the *CostR* component of the Spill Surcharge. Fisher *et al.*, BP-18-E-BPA-56, at 14-15.

Evaluation of Positions

The Spill Surcharge formula contains a *CostR* component, which is a dollar amount of specific forecast and actual program spending reductions as determined by the Administrator. Fisher *et al.*, BP-18-E-BPA-55, at 11. The specified program spending reductions are relative to the program spending assumed for purposes of setting the BP-18 Final Proposal rates and will be identified at or before the time the Spill Surcharge Amount is calculated. *Id.* at 11-12. This component of the formula allows the Administrator to reduce the Spill Surcharge Amount after considering observed and forecast reductions in program spending relative to the amounts assumed for the purpose of setting the BP-18 Final Proposal rates. *Id.* at 12. The *CostR* variable component is equal to the dollar sum of the specific program spending reductions identified by the Administrator when the Spill Surcharge Amount is calculated. *Id.*

As noted earlier, program spending is generally identified in BPA's IPR process. *Id.* It consists of forecasts of expenses that would appear on BPA's income statement such as those related to the Columbia Generating Station, the Corps, Reclamation, and BPA's energy efficiency and fish

and wildlife programs. *Id.* Program spending does not include debt management, interest, power purchase costs, revenue credits, net secondary revenue, Residential Exchange Program, and discounts. *Id.* The *CostR* variable is set at the discretion of the Administrator. *Id.* This allows the Administrator to consider BPA's overall financial health and use a broad range of cost categories to determine the cost savings (if any) that qualify for *CostR*. *Id.* This approach is easier to administer and implement than an approach that would require precise accounting. *Id.*

WPAG argues that the Administrator should adopt WPAG's proposal that BPA commit in the Spill Surcharge Amount formula that the *CostR* component would be no less than \$10 million/year in the form of additional undistributed spending reductions. WPAG Supp. Br., BP-18-B-WG-02, at 13. WPAG states that this is appropriate given the cost competitiveness concerns raised by WPAG and other parties in earlier pleadings. *Id.* In addition, it would demonstrate to customers that BPA is not relying solely on power customers to backstop this unexpected cost. *Id.* WPAG encourages the Administrator and BPA to find additional cost cuts to offset the amount of the surcharge if possible. *Id.* ICNU supports WPAG's proposal, and requests that the Administrator consider this as an opportunity to demonstrate, at least modestly, BPA's commitment to regaining long-term cost competitiveness. ICNU Supp. Br., BP-18-B-IN-02, at 4-5.

BPA is actively trying to address competitiveness issues through measurable spending reductions, among other things, although challenges remain. Fisher *et al.*, BP-18-E-BPA-56, at 14-15. The *CostR* component of Staff's proposed formula allows for cost solutions without arbitrarily selecting an amount of undistributed reductions, as is the case with WPAG's proposal. *Id.* at 15. It would be inappropriate, however, to lock in a minimum \$10 million amount in the *CostR* component because it is impossible to know the financial circumstances facing BPA at the time the Spill Surcharge is implemented. Ideally, BPA could identify sufficient cost reductions to offset a surcharge. However, coming after the IPR and IPR 2 processes, where BPA achieved significant cost reductions, it may be more difficult to identify additional reductions. BPA, nevertheless, will work hard to find additional cost reductions, but it would be unwise to establish a non-discretionary minimum level of cost reductions for the Spill Surcharge.

Decision

The Spill Surcharge will not include a minimum cost reduction of \$10 million in the CostR component.

Issue 3.5.5.6

Whether the Spill Surcharge should account for potential increases in secondary revenue.

Parties' Positions

ICNU argues that the Spill Surcharge should capture the effects of potential increases in secondary revenue, such as potential increases in market prices resulting from decreased supply. ICNU Supp. Br., BP-18-B-IN-02, at 1-2.

BPA Staff's Position

BPA Staff did not include a provision in the Spill Surcharge to account for potential increases in secondary revenue, but identified how such an approach could be implemented if the Administrator chose such an alternative. Fisher *et al.*, BP-18-E-BPA-56, at 2-5.

Evaluation of Positions

ICNU correctly points out that the formula initially proposed by Staff does not capture all the derivative impacts that a fully modeled increase in spill would have on BPA's rates. Fisher *et al.*, BP-18-E-BPA-56, at 2. Staff purposefully went this route in the interest of simplicity and certainty. *Id.* In the interest of simplicity, the proposed formula limits the number of moving pieces. *Id.* In the interest of certainty, the proposed formula relies almost entirely on values as determined in the Final Proposal. *Id.* For example, to support simplicity, Staff did not include in the formula an adjustment for the Low Density Discount, which would reduce recovery of the Spill Surcharge Amount by roughly 2 percent. *Id.* Similarly, for increased certainty, Staff relied on a single market forecast that would be established with the release of the BP-18 Final Proposal. *Id.*

ICNU, however, proposed adding an additional variable to the Spill Surcharge formula to account for additional secondary revenue resulting from increased market prices. Mullins, BP-18-E-IN-05, at 4. Staff believes that expanding the formula, as ICNU suggested, to capture the impact that reduced generation might have on forecast market prices would add both complexity and uncertainty. Fisher *et al.*, BP-18-E-BPA-56, at 2. In light of this added complexity and uncertainty, and in the spirit of the ratesetting principle of simplicity, the initially proposed Spill Surcharge Amount formula provided a reasonable estimate of the fully modeled impact that an increase in planned annual spill would have on BPA's revenue recovery. *Id.*

Although Staff continues to favor the simplicity inherent in Staff's proposed formula, ICNU's proposal to embed this potential impact in the *CostR* component (parameter) rather than redesign the entire formula helped to address some of Staff's concerns. *Id.* at 4. If the Administrator were to adopt ICNU's proposal, then, consistent with ICNU's reasoning, Staff would also recommend that the impact of the Low Density Discount be considered. *Id.* at 4-5. Staff suggested the addition of a new variable *SecR* (Secondary Reduction) that could reduce the Spill Surcharge Amount:

SecR (Secondary Reduction) is equal to the net impact increased spill has on BPA's forecast balancing purchase costs and forecast revenue from remaining secondary sales due to any changes in the forecast market prices using BP-18 final studies with revised planned spill assumptions. Such amount will be reduced by any Spill Surcharge Amount that is not collected due to the application of the Low Density Discount. If the resulting SecR is less than zero, the SecR is deemed to be zero.

The new formula would be:

$$\left(\left(\frac{\left(\sum_{i=1}^{1120} ((BP18FedGen_i - RevFedGen_i) \times BP18Price_i) \right)}{80} \right) - CostR \right) \times \left(1 - \sum Slice\% \right) - SecR$$

Id. at 5. ICNU reviewed Staff’s proposed language but continued to support ICNU’s earlier proposal, which would have added an additional term to the Spill Surcharge formula to account for additional secondary revenue resulting from increased market prices. ICNU Supp. Br., BP-18-B-IN-02, at 3. Nevertheless, ICNU states that Staff’s alternative proposal, as discussed in its supplemental rebuttal testimony, is an improvement over the original Spill Surcharge model. *Id.* ICNU contends that with only a minor increase in complexity, this alternative model would capture costs and benefits of an increase in planned annual spill far more accurately. *Id.*

ICNU has identified an element that should be reflected in the Spill Surcharge. Staff’s proposed approach to accommodating ICNU’s proposal is reasonable.

Decision

The Spill Surcharge will account for potential increases in secondary revenue, using Staff’s modification of ICNU’s proposal.

Issue 3.5.5.7

Whether the CostR component of the Spill Surcharge should be clarified to provide that the Spill Surcharge Amount will only be reduced if program costs decrease, not raised if program costs increase.

Parties’ Positions

ICNU supports clarifying the *CostR* component of the Spill Surcharge to note that it will not increase if program costs increase. ICNU Supp. Br., BP-18-B-IN-02, at 3-4.

BPA Staff’s Position

BPA Staff acknowledged during discovery that the *CostR* component would only allow the Administrator to decrease the Spill Surcharge Amount. Fisher *et al.*, BP-18-E-BPA-56, at 5.

Evaluation of Positions

ICNU notes that Staff’s initial Spill Surcharge proposal contained a *CostR* component, which gave the Administrator discretion to reduce the Spill Surcharge Amount if program costs decreased. ICNU Supp. Br., BP-18-B-IN-02, at 3. ICNU states that Staff’s initial proposal, however, left some uncertainty as to whether the component could also allow the Administrator to *increase* the Surcharge, if program costs grew. *Id.* at 3-4. To dispel any potential confusion,

ICNU requested that Staff clarify its understanding of the component, which Staff did by issuing an erratum correction confirming that the *CostR* component should only be allowed to *reduce* costs. *Id.* at 4 (citing BP-18-E-BPA-55-E01 at 1). ICNU recommends that any Spill Surcharge approval contain such clarification, which would ensure that the model is both simple and accurate, as well as transparent and easy to understand. ICNU Supp. Br., BP-18-B-IN-02, at 4.

Decision

The CostR component of the Spill Surcharge will be clarified to provide that the Spill Surcharge Amount will only be reduced if program costs decrease, not raised if program costs increase.

Issue 3.5.5.8

Whether the provision allowing customers to spread the impact of a fiscal year 2018 Spill Surcharge into fiscal year 2019 should be removed.

Parties' Positions

Snohomish requests that BPA remove the Spill Surcharge provision allowing customers to spread the impact of a fiscal year 2018 Spill Surcharge into fiscal year 2019. Snohomish Br. Ex., BP-18-R-SN-01, at 5-6. For customers that may experience a cash flow problem as a result of the Spill surcharge, Snohomish recommends that BPA staff work with those customers proactively to address the problem using existing tools. *Id.* at 6.

BPA Staff's Position

This issue was first raised in Snohomish's Brief on Exceptions. Therefore, Staff was not provided an opportunity to respond.

Evaluation of Positions

Snohomish argues that any situation where BPA forgoes revenue in one period, even if BPA would ultimately collect those revenues in a future period, increases the likelihood of a Power CRAC for all customers in the period where the revenues are not collected. *Id.* at 5. Snohomish points out that an increased probability of a Power CRAC being triggered affects all of BPA's customers. *Id.* at 6. Snohomish states that accommodating some customers while increasing financial uncertainty for the agency and others is not good policy. *Id.*

Given these points, Snohomish suggests removing the provision allowing customers to spread the impact of a fiscal year 2018 Spill Surcharge into fiscal year 2019 rather than increase the risk of a Power CRAC that would be incurred by all customers. *Id.* Instead, Snohomish suggests that the Administrator should direct Staff to identify customers who may experience a cash flow problem as a result of the Spill Surcharge, and work with those customers proactively to address that problem using existing tools. *Id.*

Snohomish makes a valid point that it is possible that solving a customer's cash flow problem, as proposed by Staff, could inadvertently cause a cash flow problem for BPA. These BPA cash flow problems could, as Snohomish describes, impact BPA's Power CRAC and thereby impact all customers. The inadvertent creation of a cash flow problem for BPA has been considered in BPA's other customer cash flow-related solutions, such as the Flexible Priority Firm Power Rate Option and Priority Firm Power (PF) Shaping Option. *See* 2018 Power Rate Schedules and GRSPs, Appendix C, GRSP II.W and GRSP II.X. As a remedy, both of those provisions are initiated with a customer request and are granted by BPA only if they do not have a material adverse impact on BPA's overall cash flow, as determined solely by BPA. *Id.*

As noted above, Snohomish suggests that BPA should proactively work with identified customers to address their cash flow problems. Snohomish Br. Ex., BP-18-R-SN-01, at 6. Although the magnitude of the Spill Surcharge is not yet known, the potential for a Spill Surcharge has been identified. As such, customers should attempt to proactively plan for the financial impacts of the Spill Surcharge and its impact on cash flow. It is BPA's preference to have revenue associated with the Spill Surcharge, if any, be collected in the year in which the costs were incurred. However, without the magnitude and specific billing months identified, it is possible that a customer could still find itself with a cash flow problem despite its proactive plan. Further, it is also quite likely that BPA would be able to aid a customer's FY 2018 Spill Surcharge cash flow as proposed by Staff and not impact the FY 2019 Power CRAC as described by Snohomish.

Given that Staff's proposed FY 2018 Spill Surcharge cash flow solution could provide further cash flow aid to customers that could be provided without adversely impacting BPA or other customers, BPA will leave it as a potential solution but modify the Spill Surcharge language so that it matches BPA's other cash-flow solutions. Specifically, BPA will make the Spill Surcharge billing provision as proposed by Staff an option that is available based on BPA's discretion after considering potential material adverse impacts on BPA's overall cash flow, such as its potential impact on the FY 2019 Power CRAC as described by Snohomish.

Decision

BPA will modify the billing provision that allows a customer to spread the impact of a fiscal year 2018 Spill Surcharge into fiscal year 2019. The modification will require that a customer make a request for cash flow relief from the Spill Surcharge as proposed by Staff. Such cash flow relief will be granted at BPA's discretion after considering potential material adverse impacts on BPA's overall cash flow and the Power CRAC.

3.5.6 IRU Proposal

3.5.6.1 BPA Ratemaking

The Northwest Power Act requires BPA to establish, and periodically review and revise, rates for the sale of electric energy and capacity and for the transmission of non-Federal power. 16 U.S.C. § 839e(a)(1); Fisher *et al.*, BPA-18-E-BPA-56, at 20. BPA's rates must be established and periodically revised to ensure recovery of the Administrator's total costs, consistent with

sound business principles. 16 U.S.C. § 839e(a)(1). For many decades, both before and after enactment of the Northwest Power Act, BPA has established rates on a prospective basis; that is, for a prospective number of years. Fisher *et al.*, BPA-18-E-BPA-56, at 20. These periods have ranged from one to five years, and are called rate periods. *Id.* BPA currently establishes rates for prospective two-year rate periods, and the BP-18 rates are being established for the prospective fiscal years 2018 and 2019. *Id.* Because BPA's rates are established for future years, BPA must rely heavily on forecasts to establish its rates, as is standard in the electric utility industry. *Id.*

BPA prepares a Power Rates Study which, in part, demonstrates that rates have been set at a level that recovers the allocated power revenue requirement for the upcoming rate period. Fisher *et al.*, BPA-18-E-BPA-56, at 20 (citing Power Rates Study, BP-18-E-BPA-01, at 1). The development of rates in the PRS uses inputs from a variety of sources. *Id.* These sources include: the Power Loads and Resources Study, which provides load and resource forecasts; the Power Revenue Requirement Study, which uses forecast costs expected to be incurred in the rate period to establish BPA's power revenue requirement; the Power Market Price Study, which provides the electricity market price forecasts and forecast quantities of power expected to be sold and purchased in electric markets; the Power and Transmission Risk Study, which forecasts financial risks to BPA and sets forth the tools for mitigating those risks; and the revenue forecast, which uses two forecasts (one using rates from the rate schedules currently in effect and one using proposed rates). *Id.* at 20-21. BPA uses these studies in order to test whether current rates and proposed rates will recover the power revenue requirement. Fisher *et al.*, BPA-18-E-BPA-56, at 20-21 (citing Power Rates Study, BP-18-E-BPA-01, at 1-2). In summary, forecasts are critical and central factors in establishing BPA rates. Fisher *et al.*, BPA-18-E-BPA-56, at 21.

3.5.6.2 Summary of BPA Staff Proposal and IRU Proposal

BPA Staff's Initial Proposal

Staff's proposed Spill Surcharge recovers the costs calculated by the Spill Surcharge Amount, which determines the additional cost to be charged to customers. As described above in Sections 3.5.4.1 to 3.5.4.3, the Spill Surcharge Amount, as initially proposed by Staff, is calculated using a formula with three main components: Spill Cost Component, Cost Reduction Component, and the Non-Slice Component. The proposed Surcharge calculation relies on BP-18 Final Proposal analyses, updated to reflect only the updated planned spill operation.

IRU's proposal would primarily affect the first component of the Surcharge, the Spill Cost Component, which determines the cost (or lost revenue) associated with increased spill relative to the spill assumed when setting rates.

Initial IRU Proposal

IRU's initial Spill Surcharge proposal was that, if the Administrator adopted the Staff proposal for a Spill Surcharge, the calculation of the Spill Surcharge Amount should occur following the conclusion of the spring spill period on June 20, 2018, and June 20, 2019. Heutte, BP-18-E-IR-01, at 14. This would allow the collection and use of actual hydro generation and market price data in calculating the Spill Surcharge Amount. *Id.*

Revised IRU Proposal

In its initial brief, IRU submitted a revised, “blended” proposal that draws from both BPA’s proposal and IRU’s testimony “in an effort to ensure that BPA’s customers are fairly charged for only the actual cost of any increase in . . . spring spill and that this cost is reasonably distributed over the rate period.” IRU Supp. Br., BP-18-B-IR-01, at 2. IRU claims that it proposed the use of actual hydro generation and market prices rather than estimated values in part to diminish rate instability. *Id.* at 4. IRU describes its revised blended proposal as follows:

In the first step, BPA would calculate an initial Spill Surcharge amount once the spill levels and patterns for 2018 have been established either under the process directed by the Court or by the Court itself, if necessary. The 2018 spill levels and patterns would also be applied provisionally to 2019. Thus, an initial Spill Surcharge amount for both 2018 and 2019 and the aggregate contribution to the overall power revenue requirement for the BP-18 rate period could be established sooner than May 31, 2018, based on forecasts of the impact of increased spill using the Staff method.

In the second step, BPA would levelize the initial 2018–2019 aggregate Spill Surcharge amount across the remaining number of billing months during the BP-18 rate period, and commence billing customers monthly on that basis.

In the third step, once the actual 2018 spring spill period is completed in mid-June 2018, BPA would adjust the Spill Surcharge for 2018 based on actual hydro generation and actual market prices, as proposed by IRU. The difference in the original and revised 2018 Spring Spill estimate would then be applied as a pro rata monthly adjustment, up or down as appropriate, to the Spill Surcharge for customer bills through the remainder of the BP-18 rate period.

In the fourth step, with the completion of the 2019 spring spill period in mid-June 2019, BPA would likewise adjust the Spill Surcharge for 2019 based on actual hydro generation and actual market prices. The difference in the original and revised 2019 Spring Spill estimate would then be applied as a second pro rata monthly adjustment to the Spill Surcharge for customer bills for the remaining months of the BP-18 rate period.

IRU Supp. Br., BP-18-B-IR-01, at 4-5. In summary, IRU proposes that BPA should calculate an initial Spill Surcharge amount for FY 2018 and FY 2019 based on Staff’s proposal, levelize the amount across the remainder of the billing months in the rate period and commence billing, later (after the spring fish passage spill season concludes) adjust both the market price component and the water year component of the Spill Surcharge for actual data, and then apply these actual figures to calculate pro rata monthly adjustments to customer bills. *Id.*

Issue 3.5.6.2.1

Whether the proposed Spill Surcharge should be based on the average water year impact of

increased spill (using 80 water years of data) or be based on a single water year's impact of increased spill.

Parties' Positions

IRU argues that the Spill Surcharge should be determined using both an average water and a single water year's impact of increased spill. IRU Supp. Br., BP-18-B-IR-01, at 4.

BPA Staff's Position

BPA Staff proposed using the average water year impact of increased spill. Fisher *et al.*, BP-18-E-BPA-55, at 7. Staff determined that using a single water year would recover BPA's revenue requirement, but at the expense of rate stability. Fisher *et al.*, BP-18-E-BPA-56, at 32. In addition, implementing the IRU proposal would require a significant amount of developmental analytical work, as well as require an unquantified amount of additional preparation, modeling, and public process time. *Id.* at 33.

Evaluation of Positions

IRU proposes a blended Spill Surcharge that uses two steps to determine the water year impact of increased spill. IRU Supp. Br., BP-18-B-IR-01, at 4. First, IRU's proposed Spill Surcharge would use, and bill customers based on, the average water year impact of increased spill as used by Staff. *Id.* Second, once the spring spill period in each year was completed, IRU proposes that the Spill Surcharge that uses the average water year impact be adjusted, up or down, based on a single water year impact. *Id.* IRU does not propose a specific method for determining the single water year impact, but offers an example where Staff would use the hydro year most closely matching the actual current year hydro generation. Heutte, BP-18-E-IR-01, at 13.

Staff identified a number of concerns with the use of a single water year in the Spill Surcharge and ultimately determined that the use of a single water year was not practical under the circumstances and would also impose significant rate volatility. Fisher *et al.*, BPA-18-E-BPA-56, at 30-35. To start, Staff provided an extensive and non-exhaustive list of problematic issues with IRU's proposed approach of comparing actual generation to a single year in the 80-water-year set (based on similar runoff volume): the shape of flows (*e.g.*, daily, weekly, and monthly) can vary considerably and thus can impact generation, market prices, and revenues in very different ways; the distribution of flows among tributaries and river reaches can vary considerably for years that have similar flows; the actual operation of projects, both Federal and non-Federal, can sometimes be significantly different from those modeled in rate case forecasts; actual generator outages may differ for many reasons from the planned generator outages used in rate case forecasts; actual project operations may include unrelated effects of real-time special operations such as barging, boat racing, life-saving emergency operations, and emergency dam safety measures; and market conditions, including changes in regional or West Coast energy markets related to weather, generation levels, and other factors, can considerably change operations of the system. *See* Fisher *et al.*, BP-18-E-BPA-56, at 30-31, for a complete description of these issues.

Thus, comparing actual generation that will occur in FY 2018 and FY 2019 to a single water year in the 80-water-year data set with similar water conditions, as IRU initially suggested in its direct case, would not isolate the direct and indirect effects of a change in planned spill operations. *Id.* In fact, Staff observed that IRU’s proposed approach would introduce a wide range of other variables unrelated to spill operations, which are simply the natural differences between actual operations and forecast operations. *Id.*

In addition, Staff explained that comparing “actuals” to a single year of the 80-water-year dataset would not account for the ratemaking process being based on the average of an 80-water-year dataset, and not a single year of the dataset. *Id.* Further, using an actual after-the-fact true-up of operations information, as IRU also suggested in its direct case, would require the development of a new methodology that would need to be reviewed and vetted by BPA’s customers and other rate case parties. *Id.* Staff concluded that creating, testing, and vetting of this new methodology would take a significant amount of time and work to complete and is not practical under the circumstances. *Id.* at 31-32. These circumstances include the fact that the Spill Surcharge is expected to be a temporary feature, expected to be used only in the two-year rate period, FY 2018–FY 2019, in the particular context and timing of the recent district court ruling. After this period, it is expected that BPA would be able to return to its normal ratemaking practice of modeling spill assumptions and incorporating the financial consequences of those spill assumptions into BPA’s base rates through the traditional rate setting process, without using the Spill Surcharge formula.

Moreover, Staff pointed out that IRU’s proposal of a single water year is fundamentally flawed. Staff explained that selecting the “hydro year most closely matching the actual current year hydro generation,” taken literally, would mean selecting the individual year of the 80-water-year dataset where generation is the most similar to the “actual generation” that occurred in each respective year (FY 2018 or FY 2019). Fisher *et al.*, BPA-18-E-BPA-56, at 33. Staff explained that selecting the year based on generation would not provide an estimate of the generation impacts from a change in planned spill operations. *Id.* Instead, it would provide an estimate that seeks to minimize the generation differences, with no consideration of how a change in planned spill operations actually impacted generation. *Id.* Staff described how IRU’s proposal was to simply look for a year in the 80-water-year data set that looks like what “actually” happened and not what would have happened under a different spill assumption. *Id.* at 33-34. Thus, even if the extensive list of issues identified by Staff in IRU’s proposal were resolved, implementing IRU’s proposal as described would improperly compare two similar generation outputs and not compare, as it should, the generation output difference in two similar hydrological conditions.

Staff also pointed out that compounding this fundamental flaw is the fact that IRU’s proposal was largely incomplete. Staff explained that many of the necessary details needed to implement IRU’s proposal were not worked out. *Id.* at 22. When asked how IRU proposed for BPA to calculate the hydro year most closely matching the actual current-year hydro generation, IRU stated that it had not thought through the metrics and methodology. *Id.* (citing Attachment 4, Data Response BPA-IR-26-1). IRU also acknowledged that since natural precipitation and management of the hydro system necessarily vary from year to year, no previous seasonal or yearly record would exactly match the conditions of the spring spill period of 2018 and 2019. *Id.*

IRU nevertheless asserted that a reasonable proxy could be found, but noted that the assessment would likely involve both mathematical analysis and expert judgment. *Id.* Again, this was in stark contrast to Staff’s proposal, which simply updates the spill assumptions in BPA’s established HYDSIM model used to set the BP-18 final rates. *Id.* at 22-23.

Rate stability is a key principle of sound ratemaking. *Id.* at 33. To better understand the effects of IRU’s and Staff’s proposals, Staff modeled the financial differences that a Spill Surcharge based on a single water year would have relative to a Spill Surcharge that used an average of 80 water years. *Id.* at 32. Staff explained that a single water year’s impact would invariably result in a larger or smaller impact relative to the average 80-water-year impact. *Id.* Staff’s analysis demonstrated that basing a Spill Surcharge on a single water year would, all else being equal, recover BPA’s revenue requirement, but would increase rate volatility. *Id.*, Attachment 1, Table 2 (80-Year Average Water versus Single Water Year).

Using the average water year impact is acceptable from the standpoint of setting rates. *Id.* at 32. Most of BPA’s ratemaking is set on the average impact (sometimes referred to as the “expected” impact) with full recognition that actual events will be different than forecast. *Id.* at 32-33. Indeed, it is BPA’s standard practice for the risk of forecast error to be alleviated by risk mechanisms such as financial reserves, PNRR, and BPA’s other rate adjustment clauses. *Id.* at 33. Because BPA’s rates are based largely on forecasts, the rates established for any particular rate period will under- or over-collect BPA’s actual costs for that period. If the rates under-collect BPA’s actual costs, BPA has financial reserves and ratemaking features, such as the CRAC, to help ensure that BPA can make its Treasury payment. Alternatively, if the rates over-collect BPA’s actual costs, BPA’s financial reserves will improve and help keep rates lower in future rate periods.

IRU argues that in using “estimated” values, Staff’s proposal would require more preparation, modeling, and review than it would if actual values were used. Heutte, BP-18-E-IR-01, at 6. However, IRU does not have a specific understanding of what data and analysis would be needed to actually implement its proposal. *See Fisher et al.*, BP-18-E-BPA-56, at 22. Nor had IRU thought through the metrics and methodology of determining the hydro year most closely matching the actual current year hydro generation. *Id.* In contrast, Staff’s proposal simply updates spill assumptions in BPA’s established HYDSIM model. BPA regularly runs the HYDSIM model to evaluate hydro system operations and has used this model for more than a decade. *Id.* at 23. Even the AURORAxmp[®] cycle of a HYDSIM model run is routine for BPA. *Id.* This is further emphasized by the fact that all but the HYDSIM inputs in the AURORAxmp[®] model run will have been established and fixed when BPA publishes its BP-18 final rates. *Id.* As a result, Staff’s proposal effectively amounts to an update to the planned spill, which is a minor update in HYDSIM, and a standard run of the ratemaking models that BPA previously vetted through the Section 7(i) process used to set the final BP-18 rates. *Id.*

IRU offers a flawed and incomplete proposal that, even if corrected and completed, would introduce more volatility and more complexity, and provide little compelling reason to change course from a solution that aligns with BPA’s longstanding and sound practice of setting rates and establishing cost recovery based on the average financial impacts of its operations.

Decision

The Spill Surcharge will be based on the average water year impact of increased spill, using 80 water years of data.

Issue 3.5.6.2.2

Whether the Spill Surcharge should use the rate case forecast of market prices or actual market prices.

Parties' Positions

IRU argues that the Spill Surcharge should use actual market price data. IRU Supp. Br., BP-18-B-IR-01, at 4-5.

BPA Staff's Position

BPA Staff believes the Spill Surcharge should use the rate case forecast market prices. Fisher *et al.*, BP-18-E-BPA-55, at 10; Fisher *et al.*, BP-18-E-BPA-56, at 24-29.

Evaluation of Positions

IRU argues that the Spill Surcharge should use actual market price data. IRU Supp. Br., BP-18-B-IR-01, at 4-5. IRU disagrees with Staff's contention that use of the July 2017 market forecast, nearly a year ahead of the first Spill Surcharge period ending in June 2018 and two years ahead of the second period ending June 2019, is the most appropriate approach for setting the Spill Surcharge. IRU Supp. Br., BP-18-B-IR-01, at 3 (citing Fisher *et al.*, BP-18-E-BPA-56, at 23). IRU argues that this approach would almost certainly result in either over-collection or under-collection of the actual costs of any increase in spring spill, and believes it is more likely to result in over-collection in 2018 and 2019, given that IRU believes that market prices are likely to be lower than BPA rate case estimates. *Id.*; Heutte, BP-18-E-IR-01, at 12. IRU claims that either result would lead to a corresponding shift in revenue requirements into a future rate period. IRU Supp. Br., BP-18-B-IR-01, at 3. IRU argues that using a combination of prospective (forecast) hydro generation and market price data to establish an initial Spill Surcharge, and then adjusting the formula rate for actual hydro and market data once it is available, would diminish rate instability and eliminate the prospect of spillover costs to future rate periods. *Id.*

Using actual market prices in the Spill Surcharge formula would not improve its accuracy or ability to recover BPA's costs. Fisher *et al.*, BP-18-E-BPA-56, at 24-25. Actual market prices that will occur during the rate period are not apposite for the purpose of setting a formula rate that accounts for the cost recovery impacts of changes in planned annual spill assumptions relative to those used to set rates. *Id.* From a ratemaking perspective, the forecast cost of an increase in planned spill is determined through rate case assumptions regarding hydro inventory (forecasts about available water to run through the turbines and generate megawatts) and forecast market prices. *Id.* The fact that actual market prices will be different from the forecast used to set rates has no bearing on the amount of forecast revenue BPA associated with that increase in

planned spill when it set its rates (setting aside the derivative impact actual market prices have on any remaining secondary sales). *Id.* at 25. This is because, in the process of setting rates, BPA assumes that it will receive a certain amount of revenue from selling the surplus energy that is forecast to be available during the rate period at the forecast market price, and credits the revenue requirement accordingly. *Id.*

For example, assume that at the time rates are set, BPA forecasts it will have 10 MWh of surplus energy that it could sell at \$10/MWh during the two-year rate period. *Id.* Under these circumstances, BPA would forecast \$100 in revenue from surplus energy sales, which would cause BPA to reduce its remaining revenue requirement by \$100. *Id.* In other words, BPA would effectively credit the forecast revenue from surplus sales (\$100) to reduce its rates during the rate period. *Id.* (This offset reducing the power revenue requirement is a longstanding ratemaking practice that supports BPA's ability to provide Federal power system products and services to its customers at the lowest possible rates consistent with sound business principles that enable cost recovery.) But if, in actuality, those 10 MWh were spilled rather than generated as a result of changes in planned annual spill operations, from a cost recovery perspective, BPA would be short \$100, all else being equal. *Id.* This is true regardless of whether the actual market price turned out to be \$0/MWh or \$20/MWh; in either case this would not change the fact that when BPA set its rates for power sales, it reduced its power revenue requirement by \$100. *Id.* Also, if BPA had known in advance that those 10 MWh were not going to be available for sale, BPA would not have included a forecast revenue associated with them and consequently, would have set higher rates in order to recover that additional \$100 from its customers over the course of the rate period. *Id.*

Staff analyzed the effect on cost recovery of using the rate case forecast market prices, rather than actual market prices, for determining the Spill Surcharge. *Id.*, Attachment 1, Table 1 (Forecast versus Actual Market Prices). Staff's analysis illustrated that, all else being equal, a Spill Surcharge that was based on the rate case forecast market prices recovered BPA's revenue requirement exactly. This was in direct contrast to the Spill Surcharge that was based on actual market prices that either over-collected or under-collected BPA's revenue requirement the vast majority of the time. *Id.* at 26. In fact, the only time the actual market price Spill Surcharge collected BPA's revenue requirement exactly was when Staff assumed the actual market price was equal to the rate case forecast market price.

Said another way, if BPA set its rates assuming the market price was zero, BPA could spill all of its surplus energy in a \$1000/MWh market and still recover its revenue requirement. *Id.* From a ratemaking perspective, BPA would receive exactly the amount of revenue from surplus sales that it used to set rates for its customers: zero. *Id.* From an actual cost perspective, of course, that spill had a significant opportunity cost under those actual market conditions, but this opportunity cost was not used for the purpose of setting rates. *Id.* For this reason, Staff's proposed Spill Surcharge is a ratemaking solution that solves a ratemaking problem: establishing rates that demonstrate cost recovery *ex ante*. *Id.* The "actual data" method proposed by IRU seeks to identify the opportunity cost of reduced generation after the fact, which is useful information from a public policy perspective, but is not relevant for the purpose of determining

the additional amount of revenue needed to recover costs identified through the IPR and IPR2 processes. *Id.*

IRU's suggestion that Mid-C market prices will possibly remain lower than the BP-18 estimates during FY 2018 and FY 2019 raises a procedural issue. Heutte, BP-18-E-IR-01, at 10; IRU Supp. Br., BP-18-B-IR-01, at 3, 6. By the end of March 2017, BPA and all rate case parties had completely compiled the evidentiary record on the market price forecast to be used in developing all of BPA's BP-18 power rates. IRU did not challenge BPA's market price forecast study and testimony (or any other forecasts to establish BPA's proposed BP-18 power and transmission rates) in the BP-18 proceeding when such matters were raised. Fisher et al., BP-18-E-BPA-56, at 29. On April 29, 2017, IRU filed a late motion to intervene. *Id.* at 28. On May 1, 2017, the Hearing Officer granted IRU's motion, but with certain conditions. *Id.* The order states that in IRU's petition to intervene, IRU represented that "it accepts the record as it has been developed to this point and agrees to abide by the schedule set forth in Order BP-18-HOO-30." *Id.* at 29 (citing Order Conditionally Granting IRU Motion to Intervene, BP-18-HOO-33). Despite its agreement to accept the record as developed at that point of the hearing, which included the complete record that had been developed on BPA's market price and natural gas price forecasts, IRU filed testimony questioning those forecasts. Heutte, BP-18-E-IR-01, at 9-11. To the extent IRU challenges the market price and natural gas price forecasts that had already been examined by all of the litigants in the BP-18 hearing, its testimony is improper. Nevertheless, as explained above, actual market prices are not apposite for determining the additional amount of revenue needed when BPA loses rate case forecast sales as a result of an increase in planned annual spill. Fisher et al., BP-18-E-BPA-56, at 29.

IRU also believes that actual market prices are relevant to the Spill Surcharge and likely to be lower than BPA's rate case forecasts. IRU Supp. Br., BP-18-B-IR-01, at 3. However, the data it provided, as well as its responses to data requests, do not bear this out. Heutte, BP-18-E-IR-01, at 9; Fisher et al., BP-18-E-BPA-56, at 27. IRU acknowledges that a carefully constructed market price forecast, in principle, would be equally likely to be above or below the actual market price over time. Fisher et al., BP-18-E-BPA-56, at 27. IRU also acknowledges that BPA's market price forecast is thoroughly analyzed in the BPA rate case process. *Id.* Taken together, IRU appears to agree that BPA's market price forecast, in principle, would be equally likely to be above or below the actual market price over time. *Id.* The market price forecast is an unbiased estimate (equally likely to be above or below the actual market price over time) of the market value of power during the upcoming rate period. *Id.* (citing Power and Transmission Risk Study, BP-18-E-BPA-05, at 69; Weekley et al., BP-18-E-BPA-28, at 8). Of the 10 actual versus forecast values provided in IRU's direct case, five of the actual values were higher than forecast and five were lower than forecast. *Id.* In other words, 50 percent of the actual market values that IRU provided were above BPA's market price forecast and 50 percent were below BPA's forecast. *Id.* Staff also noted that BPA's market price forecast reasonably accounts for technological and fundamental market changes affecting future prices in its forecasts. *Id.* Specifically, the gas price forecast considers continued availability of low-cost natural gas, and the market price forecast includes reasonable estimates of growth in California utility scale and distributed solar resources consistent with estimates produced by the California Public Utility

Commission, California Energy Commission, and other energy industry consultants. *Id.* (citing Power Market Price Study and Documentation, BP-18-E-BPA-04, at 10, 27-28).

In summary, while there can be potential variations between estimated and actual hydro generation and market prices, as noted and illustrated above, actual market prices are not relevant for determining the additional amount of revenue needed when BPA loses rate case forecast sales as a result of an increase in planned spill. *Id.* That is, the rates are being adjusted to what they would have been had the new spill assumptions been known when rates were set. *Id.* All else being equal, the rates will then recover the power revenue requirement. *Id.* Thus, it is appropriate to use the market price forecast to establish the Spill Surcharge because, like the establishment of other BP-18 rates, BPA would have relied on forecast data to establish its rates if the prospective change in planned spill levels were known with certainty at the outset of the BP-18 rate proceeding. *Id.* (citing Power Market Price Study and Documentation, BP-18-E-BPA-04, at 24, 28-29). Furthermore, IRU's challenge to BPA's market price and gas forecasts is untimely. Finally, BPA's market price forecast is reasonable and reflects recent market trends.

Decision

The Spill Surcharge will use the rate case forecast market prices.

Issue 3.5.6.2.3

Whether a Spill Surcharge that is based on average water impact and rate case forecast market prices would meet BPA's obligation to recover its costs.

Parties' Positions

IRU argues that its "blended" approach provides the most accurate and stable implementation of the Spill Surcharge and ensures full cost recovery within the BP-18 rate period, while providing customers with a more moderate billing impact. IRU Supp. Br., BP-18-B-IR-01, at 6-7.

BPA Staff's Position

IRU described its "blended" approach proposal for the first time in its initial brief. Therefore, Staff did not have an opportunity to respond.

Evaluation of Positions

IRU asserts that an increase in planned spring spill levels should not be converted into a source of additional revenue for BPA at the expense of its customers. IRU Supp. Br., BP-18-B-IR-01, at 1, 2, 6. IRU argues that its revised approach, which draws on both IRU and Staff testimony, would ensure that BPA's customers only pay for any actual increase in costs to BPA from incremental spring spill. IRU Supp. Br., BP-18-B-IR-01, at 6. IRU contends that BPA has so far rejected any approach that employs actual spill and cost data for 2018 and 2019 because forecast-based ratemaking is, in effect, "how we've always done it" and suggests that this is an insufficient reason to impose on customers costs IRU believes BPA is unlikely to incur. *Id.*

The evaluation of whether IRU's revised proposal resolves rate stability concerns is addressed in Issue 3.5.6.2.6, below, and will not be addressed here. In response to IRU's arguments, first, IRU has not demonstrated that Staff's proposed Spill Surcharge is likely to result in an over-recovery of costs BPA will incur. In fact, IRU's proposal does not do a better job of solving for BPA's potential under-recovery of costs, either. Fisher *et al.*, BP-18-E-BPA-56, at 36.

Second, IRU's argument overlooks a key component of BPA's ratemaking practice; namely, that BPA's ratemaking is largely based on forecasts. Fisher *et al.*, BP-18-E-BPA-56, at 23. IRU ignores that most of BPA's BP-18 rates are based on forecasts that are prepared well before the end of the prospective rate period. Using forecasts in this manner provides the Spill Surcharge with the same foundation as other aspects of BP-18 rates. Overlooking this key feature causes IRU to reach a premature and incorrect conclusion; specifically, that a Spill Surcharge based on actual data would function effectively in concert with BPA's larger rate design, which is largely based on forecasts. *Id.*

Third, IRU's argument also seems to imply that BPA would somehow "profit" from additional revenue (*i.e.*, if actual revenue exceeds forecast revenue), and that BPA's customers would be injured as a result. This demonstrates a fundamental misunderstanding of BPA's role as a Federal power marketing administration. BPA is a non-profit governmental entity; in compliance with its organic statutes, BPA only sets rates to recover its costs. Specifically, the Administrator must operate in a manner that allows BPA to recover its costs in accordance with sound business principles. 16 U.S.C. § 839e(a)(1). As is standard in the electric utility industry, BPA relies *ex ante* on forecasts to demonstrate cost recovery for the rate period when setting its rates. Fisher *et al.*, BP-18-E-BPA-56, at 24. Establishing rates for any rate period will result in either an over-recovery or under-recovery of costs at the end of the rate period. If the rates under-collect BPA's costs, BPA has financial reserves and ratemaking features, such as the CRAC, to help ensure BPA can make its Treasury payment. Alternatively, if the rates over-collect BPA's costs, BPA's financial reserves will improve and help keep rates lower in future rate periods, which serves ultimately to benefit BPA's customers. *Id.* at 21. BPA itself, however, does not benefit financially from any additional revenue, as IRU implies.

In conclusion, BPA is a non-profit government entity that must set its rates to recover its costs. In order to set the BP-18 rates to recover costs in FY 2018 and 2019, therefore, BPA is proposing a Spill Surcharge for the limited but important purpose of demonstrating *ex ante* cost recovery. *Id.* at 24. Staff's proposal is a practical, straightforward approach that closely approximates what the rates would have been if planned annual spill operations for FY 2018 and FY 2019 were known at the time the BP-18 final rates were calculated. *Id.* Staff's proposal works in concert with BPA's larger rate design and does a better job of recovering BPA's costs.

Decision

A Spill Surcharge that is based on the average water impact of increased spill and rate case forecast market prices properly applies standard ratemaking practices that limit rate volatility while also meeting BPA's statutory obligation to recover its costs.

Issue 3.5.6.2.4

Whether IRU's proposal would improve the SecR variable of the Spill Surcharge Amount.

Parties' Positions

IRU contends that its proposal would reduce forecast error associated with the *SecR* variable. IRU Supp. Br., BP-18-B-IR-01, at 5. IRU also contends that the *SecR* variable would take significant effort to calculate. *Id.*

BPA Staff's Position

This issue was raised for the first time in IRU's initial brief. Therefore, Staff did not have an opportunity to respond.

Evaluation of Positions

IRU contends that Staff has already indicated a revision of the proposed Spill Surcharge formula rate to add a new variable *SecR* (Secondary Reductions) to account for the net impact increased spill has on BPA's forecast balancing purchase costs and forecast revenue from remaining secondary sales due to any changes in the forecast market prices. IRU Supp. Br., BP-18-B-IR-01, at 5. IRU argues that, in fact, if actual hydro generation and market price data is used for this purpose, as the IRU proposal allows, the prospect of forecast error unduly affecting the *SecR* calculation and therefore the net effect on the Spill Surcharge Amount would be correspondingly reduced. *Id.* IRU also opines that the *SecR* variable would take significant effort to calculate and may require estimation based on econometric or historical data analysis, or both. *Id.*

The decision on whether to adopt the *SecR* variable is addressed in Issue 3.5.5.6 and will not be addressed here. It appears that IRU misunderstands the *SecR* calculation. IRU is incorrect in its assumptions that the new *SecR* variable would take "significant effort" and require new econometric data analysis. Although the addition of the *SecR* variable adds complexity to Staff's proposal, Staff suggested an implementation consistent with ICNU's proposal that remained fairly straightforward. Fisher *et al.*, BP-18-E-BPA-56, at 4-5. Any necessary effort is minimized because any data used as inputs to the rate models used to calculate the *SecR* variable would be set in advance when BPA sets its final rates. Similar to the other variables in the Spill Surcharge Amount, the *SecR* variable would be calculated with the same rate models that Staff regularly runs to set rates, and to evaluate hydro operations and market conditions. Fisher *et al.*, BP-18-E-BPA-56, at 23.

Further, IRU's proposal would not accomplish what IRU claims; *i.e.*, that the IRU proposal would reduce the prospect of forecast error unduly affecting the *SecR* calculation and therefore the net effect on the Spill Surcharge amount would be correspondingly reduced. IRU Supp. Br., BP-18-B-IR-01, at 5. The *SecR* variable is solving for the derivative impact that increased spill may have on balancing purchases and BPA's remaining secondary sales. Fisher *et al.*, BP-18-E-BPA-56, at 3-5. IRU's proposal, however, never considered or addressed balancing purchases

and BPA's remaining secondary sales. Because IRU's proposal clearly does not address this impact, it could not improve or reduce error associated with it.

Decision

IRU's proposal would not improve the SecR variable of the Spill Surcharge Amount.

Issue 3.5.6.2.5

Whether IRU's proposal reduces complexities involving the Load Shaping True-Up and other adjustments.

Parties' Positions

IRU states that its proposal may reduce complexities involving the Load Shaping True-Up and other adjustments. IRU Supp. Br., BP-18-B-IR-01, at 5.

BPA Staff's Position

This issue was raised for the first time in IRU's initial brief. Therefore, Staff did not have an opportunity to respond.

Evaluation of Positions

While IRU argues that its "blended" proposal would reduce complexities involving secondary effects of the Spill Surcharge on the Load Shaping True-Up and other adjustments, this is not accurate. IRU Supp. Br., BP-18-B-IR-01, at 5. The Load Shaping True-Up and other adjustments are needed when the PF Tier 1 rate and IP energy rates are effectively changed with the application of a Spill Surcharge. The Load Shaping True-Up was established through the TRM. Fisher *et al.*, BP-18-E-BPA-56, at 13 (citing BP-12-A-03, § 5.2.4). The purpose of the Load Shaping Charge True-Up is to avoid charging or crediting the market-based Load Shaping Rate for energy within a customer's Rate Period High Water Mark. Fisher *et al.*, BP-18-E-BPA-56, at 13.

The Load Shaping Charge True-up rate is effectively a measurement of the \$/MWh difference between the Load Shaping rates and the PF Tier 1 rate. *Id.* When BPA applies a Spill Surcharge to the Tier 1 rate, BPA is increasing or decreasing the Tier 1 rate relative to the fixed Load Shaping rates. *Id.* at 13-14. Given that IRU is proposing a Spill Surcharge that shares similarities with Staff's proposal, IRU's proposal would also change the Tier 1 rate. As such, IRU's proposal would not reduce the complexities involving the Load Shaping True-Up relative to the Staff proposal. Because the purpose of the PF Melded Equivalent Scalar is similar to the True-up, the same logic applies. *Id.* at 14.

Decision

IRU's proposal does not reduce complexities involving the Load Shaping True-up and other adjustments relative to the Staff proposal.

Issue 3.5.6.2.6

Whether IRU's revised proposal resolves rate stability concerns.

Parties' Positions

IRU argues that its revised "blended proposal" would diminish rate instability. IRU Supp. Br., BP-18-B-IR-01, at 6.

BPA Staff's Position

This issue was first raised in IRU's supplemental initial brief. Therefore, Staff was not provided an opportunity to respond.

Evaluation of Positions

At the outset, BPA observes that IRU's "blended approach" is a new proposal that was raised for the first time in IRU's initial brief. Although IRU's revised proposal shares some characteristics with IRU's initial proposal, it contains several new elements. These new elements include, for example, (1) applying 2018 spill levels and patterns provisionally to 2019; (2) billing a 2019 provisional Spill Surcharge once it is calculated in 2018; and (3) levelizing the 2018 and 2019 provisional spill surcharge across the remaining months of the BP-18 rate period. *Id.* at 4-5. While Staff's proposal includes a customer option to smooth FY 2018 costs, IRU's blended proposal is different in that it automatically applies to all customers and applies initially to both 2018 and 2019. *Id.* Because IRU did not present these new elements in its testimony, the parties to the BP-18 rate hearing had no opportunity for discovery on the proposal or to file rebuttal testimony addressing the new material. This is contrary to the requirements of Northwest Power Act Section 7(i), which governs BPA's rate proceedings. Without waiving objections to the timeliness of IRU's new blended proposal, an evaluation of Staff's and IRU's proposals is presented below.

As IRU notes, based on an analysis of Staff's proposal compared to the IRU proposal, Staff determined that using actual market prices in the Spill Surcharge formula would increase rate volatility and provide no additional benefit in terms of recovering BPA's revenue requirement. IRU Supp. Br., BP-18-B-IR-01, at 2 (citing Fisher *et al.*, BP-18-E-BPA-56, at 22-23). Staff also concluded that the Staff proposal was superior because it does a better job of collecting BPA's revenue requirement and does so with more stable rates. Fisher *et al.*, BP-18-E-BPA-56, at 22-23. IRU, however, argues that Staff never explains why "rate stability" is compromised by using actual rather than estimated data, when actual data are available. IRU Supp. Br., BP-18-B-IR-01, at 2.

IRU erroneously concludes that Staff did not explain why rate stability is compromised. First, Staff provided a comprehensive analysis that illustrated the extreme volatility inherent in IRU's proposal. Fisher *et al.*, BP-18-E-BPA-55, at Attachment 1, Chart 2 (Rate Volatility). Second, Staff evaluated a Spill Surcharge that used rate case forecast market prices versus a Spill Surcharge that used actual market prices. *Id.* at Attachment 1, Table 1 (Forecast versus Actual Market Prices). Staff used this analysis to reach the conclusion that actual market prices did not improve cost recovery of BPA's revenue requirement and that IRU's proposal would be unnecessarily biased by actual market volatility. *Id.* at 26, 37. Third, Staff evaluated a Spill Surcharge that used an 80-year average water spill impact versus a Spill Surcharge that used a single water year spill impact. *Id.* at Attachment 1, Table 2 (80-Year Average Water versus Single Water Year). Staff used this analysis to further illustrate its point that a single water year would invariably result in larger or smaller spill impacts. *Id.* at 32. In other words, an average will mathematically be more stable than the variability found in the data points for which it is averaging. Finally, Staff points out that IRU's proposal combines both of these sources of variability using both a single water year and actual market prices. *Id.* at 36. Staff therefore provided a thorough evaluation and explanation of the rate instability found in IRU's proposal.

Regardless, IRU attempts to resolve Staff's concerns by developing a new proposal that includes an elaborate billing implementation method to "reduce rate instability." *Id.* at 4. Despite IRU's creativity, IRU's new proposal conflates Staff's cash flow concern with its concern for rate volatility. Fisher *et al.*, BP-18-E-BPA-56, at 36-37. These are two distinct concerns and must be addressed as such. IRU's new proposal attempts to solve Staff's cash flow concern but does nothing to resolve the rate volatility found in IRU's proposal that Staff identified. *See* Fisher *et al.*, BP-18-E-BPA-56, at Attachment 1, Chart 2. Regarding the cash flow concern, BPA has other tools, such as the Flexible Priority Firm Power (PF) Rate Option, to address the potential cash flow problem. Fisher *et al.*, BP-18-E-BPA-55, at 17-18. In addition, whereas the cash flow concern is a *potential* problem, Staff has demonstrated that the IRU proposal is unnecessarily biased by actual market volatility. Fisher *et al.*, BP-18-E-BPA-56, at 26, 37. Moreover, cash flow problems are often the symptom of rate volatility and therefore IRU's potential solution inappropriately treats the symptom and not the cause.

Further, IRU provided no analysis supporting its claim that its proposal would diminish rate instability and eliminate the prospect of spillover costs to future rate periods. The facts show that the opposite is true. In Fisher *et al.*, BP-18-E-BPA-56, at 36 and Attachment 1, Chart 2, IRU's proposal was tested against Staff's proposal. In Chart 2, a flatter line demonstrates more stable rates. *Id.* at 36. As plainly shown, Staff's proposal is a solid flat line. IRU's proposal, on the other hand, is unacceptably volatile and would violate the fundamental ratemaking principle of rate stability. *Id.* Adjusting Staff's flat line Spill Surcharge proposal with IRU's erratic Spill Surcharge proposal would not diminish rate instability or eliminate the prospects of spillover costs to future rate periods. *Id.* at 38. In fact, IRU's proposal would lead to the opposite result. *Id.*

IRU states that another aspect of rate instability Staff addresses in its testimony is the compression of the Spill Surcharge into only a few months of each fiscal year. IRU Supp. Br., BP-18-B-IR-01, at 3. IRU notes that as initially described, Staff's proposed Spill Surcharge

would be collected only in July, August and September of 2018 and 2019, respectively. *Id.* IRU states that Staff also proposes that customers could receive, on request, billing for the 2018 Spill Surcharge through the end of the rate period in September 2019; but Staff did not address the compression in billing for the 2019 Spill Surcharge. *Id.* IRU argues that, in this instance, cost smoothing is desirable to reduce rate instability, and the Staff proposal for cost smoothing on request for the 2018 period makes sense and should be extended to all customers. *Id.* at 3-4.

First, Staff agrees with IRU that billing considerations should be made to address potential cash flow problems. Fisher *et al.*, BP-18-E-BPA-55, at 17-18. Staff proposed a specific billing consideration for FY 2018 but acknowledged that the compression in FY 2019 was more difficult to solve. *Id.* Staff proposed a proactive approach and the use of other cash flow tools to help solve the potential cash flow problem in FY 2019. *Id.* None of BPA's customers objected to Staff's proposed billing considerations in their testimony or Initial Briefs. Snohomish objected to Staff's proposed FY 2018 billing considerations for the first time in its Brief on Exceptions. Snohomish Br. Ex., BP-18-R-SN-01, at 4-6. Snohomish's issue is addressed above in Issue 3.5.5.8.

Second, as stated above, IRU has not provided any analysis that supports its claim that its revised blended proposal, including a true-up not only for actual market prices but also for the actual water year, is likely to aid a potential FY 2019 cash flow problem. Instead, Staff's analysis illustrates the extreme rate volatility underlying IRU's proposal. Even with its revised proposal to address cash flow concerns associated with its original proposal, increased volatility alone could make IRU's remedy inadequate. It would certainly make it more difficult to proactively plan for, thereby rendering BPA's other cash flow tools, such as the Flexible Priority Firm (PF) Rate Option, which must be applied proactively, an ineffective solution. Fisher *et al.*, BP-18-E-BPA-56, at 37.

Decision

IRU's revised proposal does not resolve rate stability concerns. IRU has not demonstrated that its new proposal improves on Staff's proposal nor does it resolve the rate volatility inherent in IRU's original proposal.

Issue 3.5.6.2.7

Whether complexity and administrative burden are appropriate factors to consider in designing a Spill Surcharge.

Parties' Positions

IRU argues that Staff's convenience is not a compelling basis for adopting or rejecting features of a Spill Surcharge. IRU Supp. Br., BP-18-B-IR-01, at 5.

BPA Staff's Position

In the context of the use of the average-water-year impact versus a single-water-year impact, Staff determined that IRU's proposal was not practical for several reasons and was not a viable option. Fisher *et al.*, BP-18-E-BPA-56, at 31-33.

Evaluation of Positions

IRU notes that, in the opinion of Staff, creating, testing and reviewing the IRU methodology would take significant effort and is not practical. IRU Supp. Br., BP-18-B-IR-01, at 5. IRU argues that Staff convenience is not a compelling basis for what IRU perceives to be a risk of over- or under-charging BPA customers for a change in planned spill operations. *Id.*

In response to this argument, first, as addressed in the above issues, Staff provided an extensive list of unresolved complications associated with IRU's proposal. These remain unresolved and would by themselves be more than enough to reach the conclusion that IRU's proposal stretches well beyond inconvenience and is, as Staff describes, an unviable option.

Second, IRU's revised "blended" proposal would add further complexity to the Spill Surcharge. As described in Issue 3.5.6.2.6 above, IRU proposes to address a cash flow concern with its original proposal by applying two separate billing adjustments in each year implemented with four separate steps. IRU Supp. Br., BP-18-B-IR-01, at 4-5. In the first step, BPA would calculate an initial Spill Surcharge amount once the spill levels and patterns for 2018 were determined, then the 2018 spill levels and patterns would be applied provisionally to 2019. *Id.* In the second step, BPA would levelize the initial 2018–2019 aggregate Spill Surcharge amount across the remaining number of billing months during the BP-18 rate period, and commence billing customers monthly on that basis. *Id.* In the third step, once the actual 2018 spring spill period is completed in mid-June 2018, BPA would adjust the Spill Surcharge for 2018 based on actual hydro generation and actual market prices. *Id.* The difference in the original and revised 2018 Spring Spill estimate would then be applied as a pro rata monthly adjustment, up or down as appropriate, to the Spill Surcharge for customer bills through the remainder of the BP-18 rate period. *Id.* In the fourth step, with the completion of the 2019 spring spill period in mid-June 2019, BPA would likewise adjust the Spill Surcharge for 2019 based on actual hydro generation and actual market prices. *Id.* The difference in the original and revised 2019 Spring Spill estimate would then be applied as a second pro rata monthly adjustment to the Spill Surcharge for customer bills for the remaining months of the BP-18 rate period. *Id.* The complexity and administrative burden of IRU's proposed approach are clear, particularly given the difficulties identified by Staff in performing many of these elements.

In contrast, Staff's proposed Spill Surcharge will not take significant effort, and as discussed above, will lend more accurate results. Staff's proposal will only require the input of planned spill assumptions, when made available, into BPA's established HYDSIM studies that were already prepared for the final BP-18 rate proposal. Fisher *et al.*, BP-18-E-BPA-55, at 7-9. This is a much simpler and more straightforward process than IRU's proposal. Furthermore, the addition of the *SecR* variable will not require any additional HYDSIM or AURORAxmp[®] model runs than would be completed under Staff's proposal, as AURORAxmp[®] will already be run to

provide lack of market spill inputs to HYDSIM. Again, this will be much less demanding than IRU's proposal. Furthermore, fully developing IRU's proposal would not only add complexity, require significant time, and require additional customer review and vetting, but would also result in less accurate results with greater rate volatility. See Fisher *et al.*, BP-18-E-BPA-56, at 31-33.

IRU admitted that it has not provided BPA the details necessary to implement its proposal and that those details would need to be developed by Staff. IRU Supp. Br., BP-18-B-IR-01, at 2. In fact, IRU's initial and blended proposals provide few details, including the foundational details that can, in and of themselves, significantly swing the size of the Spill Surcharge and the amount billed to customers. For example, IRU asserts that using actual market prices would improve the Spill Surcharge, but when asked about its proposed source and application of the market price data, IRU was unable to provide a specific suggestion. Fisher *et al.*, BP-18-E-BPA-56, at 22. Therefore, IRU's proposal is much more difficult to implement than IRU suggests and, when coupled with its significant flaw of a higher likelihood of over- or under-recovery of costs, is a more complex and less reliable method of ratemaking than Staff's Spill Surcharge proposal. Fisher *et al.*, BP-18-E-BPA-56, at 26, 35-36.

Finally, IRU's proposal would be more difficult for BPA and its customers to plan for proactively because its resulting Spill Surcharge Amount would increase rate volatility and provide no additional benefit in terms of recovering BPA's revenue requirement. *Id.* at 22. Although complexity and administrative burden are not the only factors used to determine a proper Spill Surcharge, they are certainly factors to be taken into consideration. These issues are significant and are not, as IRU suggests, a rejection based on Staff inconvenience.

Decision

Staff properly assessed IRU's proposal based on its merits. Complexity and administrative burden are appropriate factors to consider in designing a Spill Surcharge.

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4.0 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 (OATT).

BPA Staff proposes FY 2018–2019 rates for the ancillary and control area services of the BP-18 rate case that reflect the terms of the Settlement Agreement between BPA and the rate case parties. Fredrickson & Fisher, BP-18-E-BPA-18. As noted in Final ROD Section 1.1.1.3, no rate case party objected to the Settlement Agreement. The ACS-18 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 Settlement Agreement. The Settlement Agreement appears as Appendix B to this ROD; see pages B-10 through B-44.

Attachment 3 to the Settlement Agreement, Inter-Business Line Allocations, includes the forecast cost allocation for generation inputs for other products and for inter-business line costs. *Id.* at B-45. 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 the Corps and 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. Transmission Segmentation Study and Documentation, BP-18-FS-BPA-07, at 18-19.

At the time of the Settlement Agreement in Fall 2016, BPA forecast balancing reserve quantities based on estimated balancing service elections for wind, solar, and thermal resources. Fredrickson & Fisher, BP-18-E-BPA-18, at B-1. The BPA Transmission Services’ Balancing Service Elections for Dispatchable Energy Resources and Variable Energy Resources business practice allowed resources up to the first business day in April 2017 to submit elections for the FY 2018–2019 rate period. After receiving elections in April, BPA updated the balancing reserve capacity quantities. The total quantity of balancing reserve capacity increased from the forecast due to delayed dates for wind projects leaving the balancing authority area and elections to move from 30/15 Committed Scheduling to 30/60 Committed Scheduling and Uncommitted Scheduling. A table showing the resulting balancing reserve capacity quantities and a revised Inter-Business Line Allocation table that reflects the increased balancing reserves are included in the Power Rates Study Documentation, BP-18-FS-BPA-01A, Tables 9.9 and 9.10. *See also* the

Transmission Rates Study, BP-18-FS-BPA-08, Table 10.3, showing current and proposed generation inputs rates, and Table 12, showing revenue forecast at ACS rates.

The quantity of required Operating Reserves has also been updated. The BPA Transmission Services' Operating Reserve business practice allows a generator up to May 1, 2017, to notify BPA whether it will purchase spinning and supplemental Operating Reserves from Transmission Services, self-supply the reserves, or purchase the reserves from a third party for the FY 2018–2019 rate period. Based on customer decisions, there is a slight decrease in the quantity of Operating Reserves and a corresponding decrease in the Inter-Business Line Allocation. Power Rates Study Documentation, BP-18-FS-BPA-01A, Table 9.9.

The Settlement Agreement is the product of a regional consensus, and the rates established in the Settlement Agreement meet BPA's statutory ratemaking standards discussed in this Final ROD's Sections 1.1.2.1 and 1.1.2.2. The rates and cost allocations proposed in the Settlement Agreement will be adopted, including the revised revenue forecast that results from applying the terms of the Settlement Agreement to the updated customer rate period elections.

5.0 TRANSMISSION RATES

5.1 Transmission Segmentation

In the Transmission Segmentation Study and Documentation, BP-18-FS-BPA-07, transmission facilities are assigned to various groups, called segments, based on the types of services the facilities provide. Staff then calculates the investment and historical operations and maintenance (O&M) expenses associated with the facilities in each segment. This results in total existing investment and historical O&M expenses for each segment. The Transmission Segmentation Study is discussed in detail in the direct testimony of Tenney Denison *et al.*, BP-18-E-BPA-13.

BPA uses the gross investment (including forecast new investment through the upcoming rate period) and historical O&M expenses developed in the Segmentation Study as inputs to the revenue requirement associated with each segment in the Transmission Revenue Requirement Study, BP-18-FS-BPA-09, which is discussed in Section 2 of this Final ROD. This segmented revenue requirement is then used in the Transmission Rates Study and Documentation, BP-18-FS-BPA-08, to calculate transmission rates.

Staff proposes the following segments for the BP-18 rates: Generation Integration, Network, Southern Intertie, Eastern Intertie, Utility Delivery, Direct Service Industry (DSI) Delivery, and Ancillary Services. These segments are the same as those adopted for BP-16 rates.

Certain issues raised by parties and related to the Eastern Intertie and Southern Intertie segments are addressed in the following sections.

5.2 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. The Transmission Rates Study and Documentation, BP-18-FS-BPA-08, includes the results of this process, demonstrating that the rates for BPA's wholesale transmission services for FY 2018–2019 have been developed consistent with BPA's statutory and contractual obligations and will recover the transmission revenue requirement.

This section of the Final ROD addresses issues raised by the parties related to the rates for transmission service on the Eastern Intertie and the design of rates for hourly service on the Southern Intertie.

5.2.1 Eastern Intertie Rates

The Eastern Intertie is the 500-kV line and supporting substations and equipment, owned by BPA, that runs from Townsend to Garrison, Montana, where it connects with BPA's Network. The Eastern Intertie is part of the larger Montana Intertie that runs from Broadview to Garrison, Montana. Avista Corporation, NorthWestern Energy, PacifiCorp, Portland General Electric, and Puget Sound Energy (collectively, the Colstrip parties) jointly own the Broadview-to-Townsend

part of the line. Historically, the predominant use of the Montana Intertie has been to wheel Colstrip generation to BPA's Network so that it can serve loads in the Pacific Northwest.

The westbound capacity of the Eastern Intertie is 1930 MW. Pursuant to the Montana Intertie Agreement, the Colstrip parties have contracted for 1730 MW under the Townsend-to-Garrison Transmission (TGT) rate. BPA markets the remaining 200 MW pursuant to the Montana Intertie (IM) rate under its OATT. To date, BPA has sold 16 MW of its share of the Eastern Intertie on a long-term basis.

RN and SC/MEIC propose to eliminate the IM rate. Under their proposal, BPA would charge Network rates over its share of the Eastern Intertie starting at Townsend, where BPA's ownership of the Montana Intertie begins. Customers using BPA's share of the Eastern Intertie and the Network would pay only BPA's Network rate instead of both the IM and Network rates.

RN also proposes to change how costs are assigned to the IM and TGT rates. Under RN's proposal, BPA would use the segmented revenue requirement to determine the rates instead of the costs identified and methodology provided in the Montana Intertie Agreement. Alternatively, if BPA continues using the costs and methodology in the Montana Intertie Agreement to determine the TGT rate, RN proposes that BPA allocate any revenues that exceed the segmented revenue requirement to the Eastern Intertie instead of socializing them across the other segments.

Issues 5.2.1.1 through 5.2.1.7 address RN and SC/MEIC's proposal to eliminate the IM rate. (SC and MEIC chose not to participate formally as a joint party; rather, they participated collectively by filing combined briefs, testimony and evidence. Thus, they are referred to as "SC/MEIC" throughout the discussion below.) Issues 5.2.1.1 through 5.2.1.6 address specific issues raised by the parties regarding elimination of the IM rate, which culminate in BPA's overall decision not to eliminate the IM rate in Issue 5.2.1.6. Issue 5.2.1.7, regarding the precedent of eliminating the IM rate on potential roll-in of the Southern Intertie, is addressed after BPA's decision in Issue 5.2.1.6 because it is rendered moot by BPA's decision. Issue 5.2.1.8 addresses the proposal by RN to revise the TGT rate. Issue 5.2.1.9 addresses whether BPA should revise the IM and Eastern Intertie (IE) rates to be consistent.

Issue 5.2.1.1

Whether maintaining the IM rate is consistent with BPA's statutory requirement of setting rates that encourage the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles.

Parties' Positions

RN and SC/MEIC argue that elimination of the IM rate promotes the widest possible use of electric power in the region by eliminating a financial disincentive that has resulted in 184 MW of unsubscribed capacity on the Eastern Intertie. RN Br., BP-18-B-RN-01, at 6-7; SC/MEIC Br., BP-18-B-SC-01, at 13-21. They further argue that the IM rate is inconsistent with sound business principles because it has prevented additional subscription of the Eastern Intertie,

which, in turn, has resulted in less revenue to BPA. RN Br., BP-18-B-RN-01, at 8-11; SC/MEIC Br., BP-18-B-SC-01, at 25-29.

M-S-R and PPC address the substantive aspects of BPA's statutory requirement in the context of segmentation. PPC argues that BPA's segmentation regarding the Eastern Intertie and Network segments is consistent with BPA's statutory obligations. PPC Br., BP-18-B-PP-01, at 9-10. M-S-R and PPC argue that the Eastern Intertie will continue to be used as a radial line to deliver Colstrip generation to the loads in the Pacific Northwest. M-S-R Br., BP-18-B-MS-01, at 27; PPC Br., BP-18-B-PP-01, at 4-5. PPC notes that no loads or BPA customers are served directly from the Eastern Intertie facilities. PPC Br., BP-18-B-PP-01, at 4. Thus, PPC and M-S-R argue maintaining the Eastern Intertie segment is appropriate under the principle of cost-causation because its purpose is separate and distinct from Network uses on BPA's system. *Id.* at 5, 10; M-S-R Br., BP-18-B-MS-01, at 27.

BPA Staff's Position

Staff also addressed BPA's statutory requirements in the context of segmentation. Staff asserts that the facilities comprising the Eastern Intertie were constructed to integrate Colstrip generation to loads in the Pacific Northwest and are expected to continue to be used for that purpose during BP-18. Fredrickson *et al.*, BP-18-E-BPA-26, at 10-11, 12.

Evaluation of Positions

Section 10 of the Federal Columbia River Transmission System Act requires that BPA fix and establish 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." 16 U.S.C. § 838g. BPA complies with this statutory requirement largely through the segmentation of the transmission system and its policy on uniform rates. Segmentation involves assigning transmission facilities to various segments based on the types of services the facilities provide. *See* Transmission Segmentation Study and Documentation, BP-18-FS-BPA-07, at 1. The Eastern Intertie and Network segments are separate segments of BPA's system. *Id.* at 6.

BPA follows a uniform rate policy for rates on the Network segment, which was built for the benefit of all customers in the Northwest. The uniform rate policy allows customers to use BPA's Network segment by paying a single "postage stamp" rate, but the policy does not apply to the interties:

The uniform rate policy, which began 75 years ago, distributes Federal power throughout the Pacific Northwest region utilizing rates that do not distinguish among customers by size and location. Today, the purpose of the policy is to promote the widest possible diversified use of electric power at the lowest possible rates throughout the region. The policy does not extend to extra-regional deliveries and, therefore, does not include the intertie segments.

Administrator's Final Record of Decision, BP-14-A-03, at 99 (emphasis added) (internal citations omitted). The rationale for not applying the policy to the interties is that these facilities

were constructed for interregional energy transfers and do not benefit all of BPA’s customers in the Pacific Northwest. Intertie facilities were not necessary to fulfill BPA’s mission in the region of building out its transmission system to serve its customers located in the Pacific Northwest. *Id.*

SC/MEIC disagree with the conclusion that the Eastern Intertie was not built for all customers in the Pacific Northwest. SC/MEIC argue that BPA’s portion of the Eastern Intertie has always been considered distinct from the remainder of the line because it was intended to serve separate and broader purposes. SC/MEIC Br. Ex., BP-18-R-SC-01, at 7. SC/MEIC assert that the testimony of the BPA Administrator before Congress in the 1980s shows that the Eastern Intertie was intended to serve a broader purpose than just integrating the Colstrip generating plant. *Id.* at 5-9. The testimony cited by SN/MEIC states that BPA’s portion of the Eastern Intertie would “permit exchanges and sales of power between [the Western Area Power Administration (WAPA)] and BPA” contributing to the efficiency of the Columbia River hydro system. *Id.* at 6 (citing *Bonneville Power Administration and States of the Pacific Northwest: Hearing before Subcomm. on Separation of Powers of the Comm. of the Judiciary, 97th Cong. 30, 32, 58-59 (1983)*).

BPA does not find this testimony compelling for purposes of deciding how to segment the Eastern Intertie facilities for the FY 2018–2019 rate period. First, there is no evidence in the record that the Eastern Intertie will be used in a manner that contributes to the efficiency of the Federal hydro system on the Columbia River during the rate period. In fact, the evidence demonstrates that BPA is not using Eastern Intertie facilities to serve preference customer loads or effectuate transfers between BPA and WAPA. PPC Br., BP-18-B-PP-01, at 4; Fredrickson *et al.*, BP-18-E-BPA-26, at 9. Rather, the primary use of the Eastern Intertie will be to transmit power from Colstrip to the Pacific Northwest. M-S-R Br., B-18-B-MS-01, at 27-28; PPC Br., BP-18-B-PP-01, at 4-5; Fredrickson *et al.*, BP-18-E-BPA-26, at 9-11.

Second, although the Administrator’s testimony offers a general observation about the capability of the Eastern Intertie facilities, the details of the arrangement between BPA and WAPA provide the best evidence of how the parties dealt with the cost of transmitting power over the Eastern Intertie. After years of negotiation, BPA and WAPA entered into a Memorandum of Understanding (MOU) in 1984 wherein BPA assigned its capacity rights on the Eastern Intertie to WAPA. BPA Contract No. DE-MS79-84BP91627. WAPA intended to use the capacity to wheel coal-fired generation from North Dakota to loads in the Central Valley of California. *Id.* at 2-3 (recitals). WAPA’s scheduled deliveries of energy were to commence upon completion of the Eastern Intertie and terminate in 1990. *Id.* at 9 (§ 2(b)). Notably, the MOU provided for WAPA to assume BPA’s share of costs for constructing the Eastern Intertie. *Id.* at 12 (§ 6(b)). In other words, WAPA paid a charge comparable to the IM rate for its use of BPA’s share of the Eastern Intertie. Thus, to the extent the Eastern Intertie was used for energy transfers between BPA and WAPA in the early years, it was used to transmit coal-fired generation to WAPA loads in California at a charge that recovered BPA’s share of the Eastern Intertie, similar to the IM rate design employed today.

SC/MEIC requests that BPA take official notice of the Administrator’s testimony to Congress on the Eastern Intertie, which was discussed above. SC/MEIC Br. Ex., BP-18-R-SC-01, at 7 n.3.

In order to help ensure that the record on this topic is well-developed, BPA will take official notice of the Administrator’s testimony and the MOU between WAPA and BPA as well.

SC/MEIC also argue that the historical purpose of the Eastern Intertie as a whole supports eliminating the IM rate. SC/MEIC Br. Ex., BP-18-R-SC-01, at 7-8. They assert that the Colstrip transmission system (including the Eastern Intertie) was built to meet projected load growth and capacity deficits in the Northwest—presumably a benefit to all customers in the Northwest that justifies eliminating the IM rate. *Id.* In making this argument, SC/MEIC do not propose eliminating the TGT and IE rates even though their argument applies to the entire Eastern Intertie. While BPA does not dispute that the Colstrip generation station and associated transmission system were built to meet certain projected load growth and capacity deficits in the Pacific Northwest, BPA also does not find this argument persuasive in regard to eliminating the IM rate for the reasons explained below.

The Montana Intertie Agreement provides some of the best evidence of the historical purpose and use of the Eastern Intertie, because it shows the perspective of the entities that paid for the line. That agreement shows that the intertie was primarily built for the benefit of a discrete set of customers (the Colstrip parties) engaged in extra-regional transfers of power from a generation resource (Colstrip) located outside the Pacific Northwest to their loads. *See generally*, Montana Intertie Agreement, BP-18-E-BPA-53, at 432-34; Transmission Segmentation Study and Documentation, BP-18-FS-BPA-07, at 6; SC/MEIC Br., BP-18-B-SC-01, at 3-4. Even the Colstrip parties understood the discrete purpose and benefits derived from the Eastern Intertie facilities. The agreement’s recitals plainly distinguish the facilities from the rest of BPA’s transmission system:

WHEREAS Bonneville plans to construct the section of the Montana Intertie between Garrison and a point near Townsend, Montana (Townsend) and *recover the costs thereof as a separately identified portion of the Federal Transmission System*, and the Companies plan to construct the section of the Montana Intertie between Townsend and Broadview pursuant to an agreement among the Companies (Colstrip Project Transmission Agreement).

BP-18-E-BPA-53, at 433-34 (emphasis added). Including the intertie facilities in the Eastern Intertie segment ensures that the facilities remain “a separately identified portion of the Federal Transmission System” and allows BPA to recover the specific costs of building those facilities. Moreover, the methodology for recovering BPA’s costs set forth in Exhibit D of the Montana Intertie Agreement makes clear the discrete purpose and benefits derived from these facilities. *Id.* at 482-486. The methodology provides that BPA will recover the *full* amount of its costs from the Colstrip parties under the TGT rate unless BPA makes sales under the IM rate or non-firm sales (under the current IE rate) that are credited back to the TGT rate. *Id.* If BPA were to make no sales under the IM rate, the Colstrip parties would pay the full amount of the BPA’s costs.

RN and SC/MEIC assert that their proposals to eliminate the IM rate would not require a change in segmentation because BPA would still recover Eastern Intertie costs through three rates: the TGT, IE and Network rates. RN Br. Ex., BP-18-R-RN-01, at 3; SC/MEIC Br. Ex.,

BP-18-R-SC-01, at 3. The parties do not believe that eliminating the IM rate and rolling those costs into the Network segment is a change to BPA’s segmentation by itself.

Eliminating the IM rate and allocating the costs to the Network segment as RN and SC/MEIC propose is a re-segmentation of the Federal transmission system. BPA would have to reassign costs currently recovered through its sale of 16 MW under the IM rate from the separate Eastern Intertie segment to the Network segment. As the Administrator noted in BP-12, “[c]hanging the allocation of costs of transmission facilities previously classified as a separate segment in rates is a segmentation decision that must be supported by an appropriate rate case record.”

Administrator’s Final Record of Decision, BP-12-A-02, at 480. In BP-14, the Administrator again noted that “the separate segmentation of BPA’s Eastern Intertie . . . should be changed only with good reason.” Administrator’s Final Record of Decision, BP-14-A-03, at 176. For BP-18, the evidence demonstrates that BPA should not eliminate the IM rate and roll BPA’s 200-MW share of the Eastern Intertie into the Network segment.

Even if the Montana Intertie Agreement was silent on how the costs of Eastern Intertie facilities are to be recovered, the evidence in the record supports maintaining the IM rate in this rate period. As M-S-R, PPC and BPA Staff note, the primary purpose of the Eastern Intertie is to serve as a radial line between the Colstrip generation plant located in eastern Montana and BPA’s Network. M-S-R Br., B-18-B-MS-01, at 27-28; PPC Br., BP-18-B-PP-01, at 4-5; Fredrickson *et al.*, BP-18-E-BPA-26, at 9-11. Evidence in the record suggests that the Eastern Intertie will continue to be used for this singular purpose in the BP-18 rate period. *Id.* There are no loads or customers served directly from the Eastern Intertie. Fredrickson *et al.*, BP-18-E-BPA-26, at 10-11. That is, from a segmentation perspective, the Eastern Intertie has and will continue to serve a separate and discrete purpose that is different from BPA’s Network segment for the BP-18 rate period. *Id.* at 12.

RN argues that maintaining the IM rate is inconsistent with the “widest diversified use” requirement in the Transmission System Act, because it imposes an economic disadvantage on any resource seeking to use Eastern Intertie capacity. RN Br. Ex., BP-18-R-RN-01, at 8-9; 16 U.S.C. § 838g. As discussed above, moving BPA’s 200-MW portion of the Eastern Intertie into the Network segment requires a re-segmentation of the transmission system. BPA’s segmentation policy balances the widest possible diversified use requirement with elements of cost-causation. For BP-18, evidence in the record indicates that the Eastern Intertie will continue to serve a primary purpose of integrating Colstrip generation; thus, it is appropriate to maintain the IM rate. M-S-R Br., B-18-B-MS-01, at 27-28; PPC Br., BP-18-B-PP-01, at 4-5; Fredrickson *et al.*, BP-18-E-BPA-26, at 9-11.

Moreover, if BPA were to extend RN’s argument to its logical conclusion, any customer with a resource using two segments of the Federal transmission system could make the same argument regarding an economic disincentive. For example, renewable developers in California wanting south to north capacity on the Southern Intertie and then capacity on the Network segment could make the same argument—they pay a rate pancake as well. Thus, RN’s argument is an argument against BPA’s segmentation policy rather than just for eliminating the IM rate. The policy has been extensively litigated and withstood numerous challenges in prior BPA rate cases and has been approved on appellate review. *See* Administrator’s Final Record of Decision, BP-14-A-03,

at 77-119; Administrator’s Final Record of Decision, BP-16-A-02, at 67-78; *Central Lincoln Peoples’ Utility District v. Johnson*, 735 F.2d 1101 (1984); PPC Br., BP-18-B-PP-01, at 9-10.

RN also argues that maintaining the IM rate is inconsistent with “sound business principles” because BPA’s 200-MW share of the Eastern Intertie has largely gone unused since the intertie was constructed. RN Br. Ex., BP-18-R-RN-01, at 9. In other words, the IM rate is inconsistent with sound business principles because it disincentivizes subscription of BPA’s portion of the Eastern Intertie. *Id.* Similar to RN’s argument regarding “widest possible diversified use,” RN’s argument regarding “sound business principles” would require BPA to disregard the application of cost-causation principles to its transmission rates. The evidence in the record indicates that the Eastern Intertie will be used for the primary purpose of integrating Colstrip generation during the BP-18 rate period; thus, from a cost-causation perspective, it is appropriate to maintain the IM rate. M-S-R Br., B-18-B-MS-01, at 27-28; PPC Br., BP-18-B-PP-01, at 4-5; Fredrickson *et al.*, BP-18-E-BPA-26, at 9-11.

RN also cites a letter from the Montana Public Service Commission stating that the presence of the IM rate in light of the long history of unsubscribed Eastern Intertie capacity over an otherwise heavily utilized line provides “*prima facie* evidence of an uneconomic rate.” RN Br. Ex., BP-18-R-RN-01, at 9. There is not sufficient evidence in the record to support this claim. There could be a variety of other factors that contributed to the lack of subscription over the years other than the presence of the IM rate, such as lack of regional demand for additional resources that would use the Eastern Intertie, and transmission constraints on BPA’s and other regional utilities’ systems. Finally, to the extent the Eastern Intertie has been “heavily traveled” over the years, as the letter contends, the utilization appears to have occurred from a single generation resource—the Colstrip generation resource. *Id.*, Fredrickson *et al.*, BP-18-E-BPA-26, at 8.

RN and SC/MEIC’s other arguments regarding whether the IM rate provides a disincentive to the development of Montana renewable generation and additional subscriptions are addressed in Issue 5.2.1.2, below.

Decision

The IM rate is consistent with BPA’s statutory directive to encourage the widest possible diversified use of electric power to consumers consistent with sound business principles. A decision to eliminate the IM rate would require a re-segmentation of BPA’s transmission system. Facilities comprising the Eastern Intertie, including BPA’s 200-MW share, will continue serving a separate and distinct purpose from the Network segment during the BP-18 rate period.

Issue 5.2.1.2

Whether the IM rate is an impediment to Montana wind development.

Parties' Positions

RN and SC/MEIC argue that the IM rate is an uneconomic rate that serves as an arbitrary barrier to wind development in Montana. RN Br., BP-18-B-RN-01, at 6-11; SC/MEIC Br., BP-18-B-SC-01, at 13-32. They assert that the fact that BPA has only sold 16 MW is “*prima facie*” evidence that the IM rate is a strong disincentive to Montana wind development. RN Br., BP-18-B-RN-01, at 6-8; SC/MEIC Br., BP-18-B-SC-01, at 17-21.

M-S-R notes that this issue was litigated previously in BP-14 and BP-16. M-S-R Br., BP-18-B-MS-01, at 25. M-S-R and PPC contend that the IM rate is not an impediment to Montana wind development, which is already competitive based on its higher capacity factors. M-S-R Br., BP-18-B-MS-01, at 25-26; PPC Br., BP-18-B-PP-01, at 5-7. PPC argues that elimination of the IM rate will not result in additional subscriptions due to transmission constraints on BPA’s Network segment. PPC Br., BP-18-B-PP-01, at 6-7. Until the constraints are addressed, elimination of the IM rate will have no effect on subscriptions. *Id.*

BPA Staff’s Position

BPA Staff did not take a position on whether the IM rate is a significant impediment to the development of Montana wind generation. BPA Staff does assert, however, that the lack of transmission available on BPA’s Network is an impediment to customers seeking transmission service from Montana. Fredrickson *et al.*, BP-18-E-BPA-26, at 6.

Evaluation of Positions

This issue was addressed in the BP-14 and BP-16 rate cases. Administrator’s Final Record of Decision, BP-14-A-03, at 177-78; Administrator’s Final Record of Decision, BP-16-A-02, at 124-25. In those rate cases, the Administrator rejected similar arguments made by RN and SC/MEIC in this rate case. *Id.* Both M-S-R and PPC assert that there is no new evidence to support a change in wind competitiveness that would justify elimination of the IM rate in BP-18. M-S-R Br., BP-18-B-MS-01, at 25-26; PPC Br., BP-18-B-PP-01, at 5-7. In fact, PPC notes that SC/MEIC’s own witness testified in this proceeding that “[i]t is impossible to say with certainty that eliminating the Montana Intertie rate will result in greater Montana wind development.” PPC Br., BP-18-B-PP-01, at 5 (citing Fagan, BP-18-E-SC-02-V01, at 9).

While eliminating the IM rate may have some marginal benefit to Montana wind development, the record in this proceeding does not demonstrate that it would be a significant benefit or that the IM rate is an uneconomic rate preventing development. First, as PPC points out, the \$2/MWh charge added by the IM rate is negligible compared to the levelized costs of new wind resources in the region, which would have a levelized cost of energy between \$94 and \$110 per MWh. PPC Br., BP-18-B-PP-01, at 6. The Administrator came to a similar conclusion in BP-16:

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. This is a relatively small addition to the total cost of over \$100/MWh.

Administrator's Final Record of Decision, BP-16-A-02, at 124 (internal citations omitted).

Second, the balance of the evidence in the record suggests that Montana wind is competitive with other resources even with the IM rate in place. SC/MEIC argue that the relative costs of Montana wind when compared to Columbia Gorge wind are close and, therefore, the IM rate can make Montana wind uncompetitive. SC/MEIC Br. Ex., BP-18-R-SC-01, at 9 (citing Schneider, BP-18-E-SC-01-V01, at Ex. 4). However, as PPC notes, the Seventh Power Plan analyzed five plants—four in Montana and one in the Columbia River Gorge—in its study. PPC Br., BP-18-B-PP-01, at 6. The four Montana plants had lower levelized costs of energy than the Columbia Gorge plant, including the costs of transmission. *Id.* M-S-R also notes that a presentation included as an exhibit to the testimony of an SC/MEIC witness concluded that given the higher capacity factors of Montana wind generation, as compared to Northwest wind generation, the Montana wind resources could overcome higher relative transmission costs. M-S-R Br., BP-18-B-MS-01, at 25-26 (citing Schneider, BP-18-E-SC-01-V01, at Exhibit 3, 28-29 (“MT wind is cost competitive with OR and WA wind even though the cost of transmitting MT wind to PSE’s system erodes some of MT wind’s [Levelized Costs of Energy] advantage driven by higher capacity factor.”)).

Finally, given current transmission constraints, it is unlikely that eliminating the IM rate would lead to significant wind development in Montana. Both PPC and BPA Staff point out that BPA’s transmission system, particularly the West of Garrison and West of Hatwai flowgates, has significant constraints. PPC Br., BP-18-B-PP-01, at 8; Fredrickson *et al.*, BP-18-E-BPA-26, at 6. The issues impacting the development of Montana renewable generation are addressed in more detail in Issue 5.2.1.6, below. As BPA noted in the BP-16 ROD, it is willing to work with interested parties to address these and other issues impacting the development of Montana renewable generation. Administrator’s Final Record of Decision, BP-16-A-02, at 126. For transmission service requests currently in its pending queue needing Network transmission starting at Garrison, BPA will process and evaluate those requests in accordance with its OATT.

Decision

The IM rate is not a significant impediment to the development of Montana wind generation.

Issue 5.2.1.3

Whether elimination of the IM rate would increase Network rates.

Parties’ Positions

PPC and WPAG argue that the financial impacts of eliminating the IM rate will not be *de minimis* when the rate impacts of potential transmission upgrades and balancing capacity are factored in. PPC Br., BP-18-B-PP-01, at 7-8; WPAG Br., BP-18-B-WG-01, at 25.

PPC asserts that the costs of these upgrades could be in the hundreds of millions to more than a billion dollars. PPC Br., BP-18-B-PP, 01, at 8.

SC/MEIC argues that elimination of the IM rate has negligible adverse impacts to Network customers and may even result in reduced Network rates if additional sales are made. SC/MEIC Br., BP-18-B-SC-01, at 23. SC/MEIC also states that upgrades to BPA's Network segment are not at issue in this proceeding and are not a legitimate basis for maintaining the IM rate. *Id.* at 29-31.

BPA Staff's Position

Staff analyzed a number of scenarios regarding the rate impact of eliminating the IM rate. Fredrickson *et al.*, BP-18-E-BPA-26, at 5. Staff identified the impact of eliminating the IM rate as a 0-to-0.3 percent increase to Network rates if elimination does not result in additional sales. *Id.*

Evaluation of Positions

BPA Staff's analysis shows that the financial impact to Network rates of eliminating the IM rate would likely be minimal. Fredrickson *et al.*, BP-18-E-BPA-26, at 5-6. However, elimination of the IM rate by itself would likely not result in additional sales due to transmission constraints on BPA's Network. *Id.* at 6.

Customers requesting service from Montana over BPA's Network would likely need additional upgrades or reinforcements given current constraints at the West of Garrison and West of Hatwai flowgates and these could lead to additional Network costs. *Id.*; PPC Br., BP-18-B-PP-01, at 7-8; WPAG Br., BP-18-B-WG-01, at 25. The extent or costs of those upgrades are not known at this time and, thus, would require significant speculation regarding their financial impact on Network rates. Even if BPA were to eliminate the IM rate, it does not necessarily mean that BPA would build facilities used solely to integrate Montana wind into the Pacific Northwest at embedded rates. The rate treatment associated with those facilities would be determined after the plan(s) of service was identified and assessed through BPA's study process. It is premature to speculate on cost allocation or rate impacts of potential upgrades or reinforcements at this time.

Decision

Eliminating the IM rate would have minimal impact on Network rates, but investments in the Network may be necessary to enable customers to develop and integrate Montana wind into the Pacific Northwest.

Issue 5.2.1.4

Whether the shutdown of Colstrip units 1 and 2 will impact BPA's Network rates.

Parties' Positions

RN argues that BPA could see a reduction in Network transmission revenues between \$5,876,640 and \$11,753,280 when Colstrip units 1 and 2 are retired by no later than July 1, 2022. RN Br., BP-18-B-RN-01, at 21-22. RN and SC/MEIC argue that BPA should eliminate the IM rate to prepare for the closure of the units. *Id.* at 22; SC/MEIC Br. Ex., BP-18-R-SC-01, at 11. RN believes elimination of the IM rate will provide for additional subscriptions that will mitigate losses associated with this retirement. RN Br., BP-18-B-RN-01, at 22; SC/MEIC Br. Ex., BP-18-R-SC-01, at 11. RN further asserts that BPA is acting arbitrarily by increasing the hourly firm rate on the Southern Intertie to promote long-term use based on speculation while ignoring evidence that the IM rate disincentives additional long-term subscription on the Eastern Intertie. RN Br. Ex., BP-18-R-RN-01, at 9-10.

PPC argues that RN's claim of revenue loss is speculative. PPC Br., BP-18-B-PP-01, at 12-13. PPC notes that there are 1191 MW in BPA's pending queue requesting service from Montana over BPA's Network. *Id.* at 12. It is unclear what the Colstrip parties intend to do with respect to their capacity shares on the Network even if Colstrip shuts down. *Id.* These parties could repurpose this capacity to deliver different resources or transfer their rights to another customer. *Id.*

BPA Staff's Position

BPA Staff asserts that RN's argument is based on very speculative assumptions. Fredrickson *et al.*, BP-18-E-26, at 7-8. As PPC noted, the Colstrip parties could roll their Network service over and repurpose it for another resource or transfer it to another customer. *Id.* at 7. Other customers in the queue may also want the Network capacity. *Id.* at 8.

Evaluation of Positions

RN's and SC/MEIC's arguments are premised upon the assumption that the party holding the Network capacity rights associated with the portion of Colstrip units 1 and 2 will not roll over its agreement and no other customer will want the capacity. However, as BPA Staff and PPC note, it is not certain whether the customer holding those Network transmission rights will roll over or not. Fredrickson *et al.*, BP-18-E-BPA-26, at 7; PPC Br., BP-18-B-PP-01, at 12. It is possible that the customer may acquire different generation resources that will utilize the BPA Network. *Id.* There is no evidence in the record that indicates BPA's revenue forecast for the Network is inaccurate.

In regard to the Eastern Intertie, the Montana Intertie Agreement protects BPA from cost-exposure should customers taking TGT service under that Agreement seek to terminate their service before the September 30, 2027, termination date of the agreement. PPC Br., BP-18-B-PP-01, at 12; Fredrickson *et al.*, BP-18-E-BPA-26, at 8.

RN argues that BPA is acting arbitrarily by increasing the rates for hourly service on the Southern Intertie yet choosing to maintain the IM rate. BPA disagrees. The facilities, facts, and circumstances surrounding the two issues are significantly different. Section 5.2.2 discusses the facts and circumstances surrounding the Southern Intertie in detail. BPA is taking action with respect to the rates for hourly service on the Southern Intertie in large part because seams issues between the Pacific Northwest and California have created concerns about recovering the costs of the Southern Intertie. The record contains no evidence of such circumstances with respect to the Eastern Intertie.

Decision

There is no evidence in the record that indicates the closure of Colstrip units 1 and 2 will impact BPA's Network revenues for the rate period. The issues involving the Eastern and Southern Interties are separate issues.

Issue 5.2.1.5

Whether the IM and Network rate pancake violates the Commission's "Or" pricing policy.

Parties' Positions

RN argues that the IM/Network rate pancake violates the Commission's "Or" pricing policy, which allows a transmission provider to charge the higher of incremental cost or embedded rates but not both. RN Br., BP-18-B-RN-01, at 11. RN asserts that previous decisions to segment the Eastern Intertie separately from the Network should not preclude BPA from revisiting those decisions to align with Commission policy. *Id.* at 11-12.

PPC argues that BPA's segmentation resulting in different charges for use of the Eastern Intertie and Network segments do not violate the Commission's "Or" policy. PPC Br., BP-18-B-PP-01, at 9-10. The facilities comprising the Eastern Intertie and Network segments serve different purposes and include different facilities. *Id.* BPA is not charging two rates for use of the same facilities. *Id.* at 10.

BPA Staff's Position

Staff asserts that charging the IM and Network rates does not violate the Commission's "Or" policy because the segments recover the costs of different facilities serving distinct uses. Fredrickson *et al.*, BP-18-E-BPA-26, at 12. Thus, BPA does not double recover the costs of Eastern Intertie or Network facilities. *Id.*

Evaluation of Positions

As a threshold matter, the Commission's review and confirmation of BPA's rates is limited to the three criteria specified in Section 7(a)(2) of the Northwest Power Act. 16 U.S.C. § 839e(a)(2); *see also* § 1.1.3 above. As a matter of law, BPA is not subject to the Commission's "Or" pricing policy.

Even if BPA applied the Commission’s “Or” pricing policy, the evidence in the record demonstrates that BPA’s rate design for the Network and IM rates do not violate the policy. As discussed in Issue 5.2.1.1, above, the IM and Network segments serve different and distinct purposes. PPC Br., BP-18-B-PP-01, at 10; Fredrickson *et al.*, BP-18-E-BPA-26, at 12. The costs associated with service over the segments are recovered by the rates associated with those segments, respectively. *Id.* More specifically, the IM rate does not recover the costs associated with Network facilities or *vice versa*. Thus, BPA is not double recovering its costs from either segment. *Id.* Consequently, although RN asserts that BPA’s rate design is inconsistent with the Commission’s “Or” pricing policy, the evidence in the record indicates the opposite conclusion—that BPA is not recovering both embedded and incremental costs on any of the facilities comprising the Network and Eastern Intertie segments.

Additionally, RN appears to be making an argument against BPA’s segmentation policy—that customers should only pay a single rate for any use of BPA transmission. RN Br., BP-18-B-RN-01, at 11. If BPA were to adopt RN’s rationale and apply it consistently across BPA’s transmission system, there would only be a single segment and customers could use any of BPA’s facilities for a single charge—there would be no segments. As PPC notes, BPA’s segmentation methodology is long-standing, has been subject to review on various occasions, and is equitable and consistent with sound business principles. PPC Br., BP-18-B-PP-01, at 9-10.

Decision

The Commission’s “Or” pricing policy does not apply to BPA’s rate design. Nevertheless, BPA’s rate design does not violate the Commission’s “Or” pricing policy.

Issue 5.2.1.6

Whether to eliminate the IM rate and charge Network rates starting at Townsend, Montana.

Parties’ Positions

RN and SC/MEIC argue that BPA should eliminate the IM rate and charge Network rates starting at Townsend. RN Br., BP-18-B-RN-01, at 1; SC/MEIC Br., BP-18-B-SC-01, at 1. M-S-R, PPC, WPAG and NRU oppose the elimination of the IM rate, arguing that no material facts have changed since BP-16 to warrant eliminating the IM rate in BP-18. M-S-R Br., BP-18-B-MS-01, at 24-28; PPC Br., BP-18-B-PP-01, at 1-10; WPAG Br., BP-18-B-WG-01, at 25-26; NRU Br., BP-18-B-NR-01, at 30-31.

BPA Staff’s Position

BPA Staff proposed to retain the IM rate in the Initial Proposal. Fredrickson *et al.*, BP-18-E-BPA-26, at 2. The proposals made by RN and SC/MEIC to eliminate the IM rate are very similar to proposals made in BP-12, BP-14, and BP-16. *Id.* at 4. Staff does not find the reasons for RN and SC/MEIC’s proposal—the shutdown of Colstrip units 1 and 2 no later than July 1,

2022, and the adoption of additional renewable generation supply requirements in Oregon and Washington—as compelling reasons to eliminate the IM rate in BP-18. *Id.* at 12-13.

Evaluation of Positions

RN's and SC/MEIC's proposals to eliminate the IM rate and start charging Network rates at Townsend, Montana, are substantially similar to proposals made in the BP-12, BP-14, and BP-16 rate cases. Fredrickson *et al.*, BP-18-E-BPA-26, at 4; PPC Br., BP-18-B-PP-01, at 1. In each of those cases, the Administrator rejected the proposals. *Id.* The evaluation of this issue incorporates the evaluation and decisions made above in Issues 5.2.1.1-5.2.1.5.

The core issue remains transmission segmentation as the Administrator opined in BP-14. See Issue 5.2.1.1, above. The Eastern Intertie serves a discrete purpose—a radial line to transmit Colstrip generation to loads in the Pacific Northwest — and benefits a particular group of customers—the Colstrip parties. Beyond speculation that Colstrip units may shut down sometime earlier than July 1, 2022, there is no evidence in the record demonstrating that this particular use or the customers benefitting from the Eastern Intertie will change in the BP-18 rate period. M-S-R Br., BP-18-B-MS-01, at 27-28; PPC Br., BP-18-B-PP-01, at 4-5. There are no loads or customers served directly from the Eastern Intertie. PPC Br., BP-18-B-PP-01, at 4; Fredrickson *et al.*, BP-18-E-BPA-26, at 9. From a cost-causation perspective, the discrete set of customers who create these costs and benefit from the facilities comprising the Eastern Intertie segment that support extra-regional transfers of energy should bear the costs of those facilities.

The IM rate is also not a significant impediment to the development of Montana wind resources. The balance of the evidence in the record shows that the IM rate adds a very small amount to the total costs for Montana wind resources and, with a higher capacity factor, Montana wind is generally competitive with other wind resources located in the Pacific Northwest. PPC Br., BP-18-B-PP-01, at 6; M-S-R Br., BP-18-B-MS-01, at 25-26.

BPA acknowledges that the policy and regulatory environment in the Pacific Northwest is changing. As SC/MEIC notes, new state-level legislation and policy decisions promoting higher levels of renewable generation use in Oregon and Washington could benefit from the development of Montana wind generation, which has a higher capacity factor than the wind generation resources located in the Pacific Northwest. SC/MEIC Br., BP-18-B-SC-01, at 6, 16. However, that, by itself, does not justify the re-segmentation of the Eastern Intertie. BPA's segmentation policy is based on an analysis of the function of facilities. As discussed above, evidence in the record indicates that the Eastern Intertie will continue being used to deliver Colstrip generation for the BP-18 rate period. M-S-R Br., BP-18-B-MS-01, at 27-28; PPC Br., BP-18-B-PP-01, at 4-5.

BPA agrees that it is not necessary to address transmission constraints on BPA's and other utilities' transmission systems in deciding whether to eliminate the IM rate for BP-18. See RN Br. Ex., BP-18-R-RN-01, at 11; SC/MEIC Br. Ex., BP-18-R-SC-01, at 10. However, based on the record in this case, it is important to clarify that even without the IM rate, there are significant transmission impediments to the development of Montana renewable generation to serve loads in the Pacific Northwest. In the Administrator's Final Record of Decision for

BP-16, the Administrator asserted that “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.” Administrator’s Final Record of Decision, BP-16-A-02, at 126. BPA has participated in several discussions and forums on this issue since BP-16 and will continue to work with interested parties on the strategic aspects of integrating Montana renewables. As Staff notes:

There are a myriad of other issues that need to be addressed holistically. We continue to have concerns associated with service from Montana, including balancing capacity issues, allocation of costs of potential reinforcements to provide transmission service to new renewable generation in Montana, scheduling and reservation system changes and associated costs, contract issues involving the Montana Intertie Agreement, and possible additional investments (RAS/build) needed to enable service. Most of these issues need to be addressed outside of the rate case and require a discussion with parties to the Montana Intertie Agreement, as well as other stakeholders.

Fredrickson *et al.*, BP-18-E-BPA-26, at 13.

SC/MEIC maintains that the record lacks substantial evidence to support maintaining the IM rate. SC/MEIC Br., BP-18-B-SC-01, at 3, 13, 22, 29. As BPA explained in its BP-14 ROD, the substantial evidence standard applies on judicial review of BPA decisions: “the Administrator bases his decisions on his assessment of the evidence in the record. These decisions may ultimately be reviewed by the courts to determine whether there is substantial evidence to support them.” Administrator’s Final Record of Decision, BP-14-A-03, at 13–14. The preceding discussion of this issue and the other issues in this section identifies the evidence relied upon in deciding to retain the rate.

RN and SC/MEIC argue that a regional discussion outside of the rate case is not necessary to eliminate the IM rate. RN Br., BP-18-B-RN-01, at 25-26; RN Br. Ex., BP-18-R-RN-01, at 11-13; SC/MEIC Br., BP-18-B-SC-01, at 33-35; SC/MEIC Br. Ex., BP-18-R-SC-01, at 11-13. RN and SC/MEIC are correct that elimination of the IM rate is a rate case issue; it is not necessary to have a regional process after the BP-18 rate case to decide whether to change or eliminate the IM rate. As Staff has noted, however, there are myriad of issues, many of which have been discussed above and in testimony in this case, that will impact the development of Montana renewable generation, regardless of whether the IM rate is eliminated. *See* Fredrickson *et al.*, BP-18-E-BPA-26, at 13. To make decisive progress on the development and integration of Montana wind resources, these issues need to be addressed by the region. Whether, or to what extent, BPA’s rate design for the Eastern Intertie will be addressed in the process will be determined by the participants in the process.

Decision

The IM rate will not be eliminated. The Eastern Intertie segment provides a separate and distinct benefit to customers using those facilities, which is different from the benefits provided by the Network segment.

BPA wants to encourage and partner in efforts supporting economic growth in the region, including the development of renewable generation resources in Montana. BPA is willing to help establish and actively participate in a thoughtful, cohesive process to address barriers to the utility-scale development of renewables in Montana. This process will require the participation of other regional utilities, transmission planners, policymakers, and interested stakeholders. The process should result in a comprehensive commercial and policy framework that appropriately balances the opportunities, risks and costs of such development, including interconnection, provision of ancillary services, and potential upgrades to BPA's transmission system.

Issue 5.2.1.7

Whether elimination of the IM rate would set a precedent for roll-in of the Southern Intertie.

Parties' Positions

RN and SC/MEIC argue that eliminating the IM rate will not set a precedent for rolling in the Southern Intertie. RN Br., BP-18-B-RN-01, at 15-21; SC/MEIC Br., BP-18-B-SC-01, at 31-33. M-S-R, PPC, and WPAG argue that elimination of the IM rate could potentially set a precedent for rolling in the Southern Intertie. M-S-R Br., BP-18-B-MS-01, at 28-29; PPC Br., BP-18-B-PP-01, at 9; WPAG Br., BP-18-B-WG-01, 25-26. PPC and WPAG assert that roll-in of the Southern Intertie would result in a 12.5 percent rate increase, which would be rate shock to Network users; thus, BPA should avoid establishing a precedent for the roll-in of the Southern Intertie. PPC Br., BP-18-B-PP-01, at 9; WPAG Br., BP-18-B-WG-01, at 25-26.

BPA Staff's Position

Staff took no position on whether elimination of the IM rate would set a precedent for the Southern Intertie.

Evaluation of Positions

PPC and M-S-R make several arguments that elimination of the IM rate could set a precedent for roll-in of the Southern Intertie. For example, PPC suggests that renewable resource developers in California seeking cheaper export possibilities to market their power in the Pacific Northwest could make similar arguments for roll-in of the Southern Intertie as made by RN and SC/MEIC regarding Montana wind in this proceeding. PPC Br., BP-18-B-PP-01, at 9.

M-S-R suggests that a holistic review of eliminating the IM rate should include segmentation of the Southern Intertie as well. *See* M-S-R Br., BP-18-B-MS-01, at 28-29. M-S-R identifies a series of technical factors regarding bidirectional flows, linkage of developed markets and efficient dispatch of energy that could make the Southern Intertie a better candidate for roll-in than eliminating the IM rate and rolling those costs into Network rates. *Id.*

RN argues the following differences between the Eastern and Southern interties that would justify disparate treatment: the Southern Intertie consists of multiple transmission lines while the

Eastern Intertie is a single line; the Southern Intertie links two distinct markets and is optimized in real-time by an independent system operator while the Eastern Intertie is not; scheduling on the two interties is different; and, the contracts governing the two interties are different. RN Br., BP-18-B-RN-01, at 16-18. RN does not, however, explain how these differences would justify disparate treatment.

Finally, RN and SC/MEIC also state that the arguments regarding precedent are not compelling because RN's and SC/MEIC's proposals do not require a change in segmentation. RN Br., BP-18-B-RN-01, at 19-20; SC/MEIC Br., BP-18-B-SC-01, at 31. However, as explained in Issue 5.2.1.1, above, their proposals would require moving a portion of the costs associated with service on BPA's share of the Eastern Intertie to the Network segment, which is a re-segmentation of the Eastern Intertie.

Given that BPA has decided not to eliminate the IM rate, the arguments about creating precedent for roll-in of the Southern Intertie are moot.

Decision

The IM rate is not being eliminated. The arguments about creating precedent for rolling in the Southern Intertie are moot.

Issue 5.2.1.8

Whether to revise how costs are assigned to the TGT rate, or, alternatively, whether to apply all TGT revenues exceeding the Eastern Intertie's segmented revenue requirement back to the Eastern Intertie segment.

Parties' Positions

RN proposes that BPA revise the TGT rate to make it "cost-based" using the costs identified in the segmented revenue requirement instead of the Montana Intertie Agreement. RN Br., BP-18-B-RN-01, at 12. RN argues the TGT rate will exceed the segmented revenue requirement for the Eastern Intertie by approximately \$1.039 million per year during the BP-18 rate period if BPA continues basing costs on the Montana Intertie Agreement. *Id.* at 12-13. RN asserts that BPA over collected TGT revenues by approximately \$800,000 per year in BP-16 and by approximately \$3.6 million per year in BP-14. *Id.* at 13. RN claims that BPA has socialized the benefits of this over collection to all users of the system by allocating it to all other segments. *Id.* at 13-14. Alternatively, if BPA does not revise the TGT rate to make it cost-based, RN argues that BPA should apply any collection of revenues in excess of the segmented revenue requirement back to the TGT rate only, instead of the other segments. *Id.* at 14.

PPC opposes RN's proposal. PPC Br., BP-18-B-PP-01, at 13. PPC asserts that BPA's TGT rate recovers the actual costs of building and maintaining the Eastern Intertie facilities and is cost-based by definition. *Id.* PPC supports BPA Staff's position that there are multiple methods for identifying costs on which to base rates. *Id.* BPA's segmented revenue requirement is one method, as is setting costs based on contract. *Id.* To that end, there are no "surplus" revenues

generated by TGT revenues as RN purports because the rate recovers the costs identified in the Montana Intertie Agreement. *Id.* at 13-14.

BPA Staff's Position

Staff made no changes to the TGT rate structure in its Initial Proposal. Fredrickson *et al.*, BP-18-E-BPA-26, at 2. Staff does not agree with RN's characterization that TGT revenues based on the Montana Intertie Agreement will create a "surplus" in the BP-18 rate period. *Id.* at 7. The parties to the Montana Intertie Agreement negotiated and agreed as to how costs would be calculated and recovered in the Agreement. *Id.* at 6. Staff asserts that allocating costs to the TGT rate based on the costs and methodology included in the Montana Intertie Agreement is an acceptable basis on which to set rates. *Id.* at 6-7.

Evaluation of Positions

RN makes two proposals—a proposal to change what costs are recovered by the TGT rate and, alternatively, a proposal to change how revenues generated from the TGT rate are allocated if BPA does not adopt RN's first proposal. RN Br., BP-18-RN-B-01, at 12-13. Each proposal is addressed below.

Calculation of TGT Costs

RN argues that BPA should use the segmented revenue requirement instead of the costs specified in the Montana Intertie Agreement to determine the amount of costs assigned to the TGT rate. *Id.* at 13. RN asserts that using the costs set forth in the Montana Intertie Agreement to set the TGT rate results in a rate that is not cost-based. *Id.* RN asserts that using the segmented revenue requirement is consistent with the Montana Intertie Agreement. RN Br. Ex., BP-18-R-RN-01, at 3-5. If BPA were to adopt RN's proposal, it would result in reducing the TGT rate by 8 percent and increasing the Network rate by 0.1 percent. Fredrickson *et al.*, BP-18-E-BPA-26, at 6.

RN's argument that the TGT rate is not cost-based is unpersuasive. The methodology of calculating and recovering costs for the TGT rate set forth in the Montana Intertie Agreement is a valid way of identifying costs associated with BPA's construction and maintenance of the Eastern Intertie. *Id.*; PPC Br., BP-18-B-PP-01, at 13. The methodology does not provide that BPA may choose to determine costs based on the segmented revenue requirement in lieu of the formula set forth in the contract. The TGT rate is set based on BPA's costs to construct the Eastern Intertie and a methodology for recovery of those costs, as agreed to by the parties to the Montana Intertie Agreement. Montana Intertie Agreement, BP-18-E-BPA-53, at 444, 457, 482-86 (*see* §§ 9(i), 17(f), and Ex. D); PPC Br., BP-18-B-PP-01, at 13; Fredrickson *et al.*, BP-18-E-BPA-26, at 6-7. The Montana Intertie Agreement also identifies the costs associated with ownership and maintenance of the Eastern Intertie and specifies how those costs will be recovered from the Colstrip parties under the TGT rate. *See* Exhibit G of the Montana Intertie Agreement, BP-18-E-BPA-53, at 334-37. Because the TGT rate is set to recover BPA's costs for constructing and maintaining the Eastern Intertie, the rate is cost-based by definition. PPC Br., BP-18-B-PP-01, at 13. There are multiple valid methods for identifying costs on which to base

rates. Fredrickson *et al*, BP-18-E-BPA-26, at 6. Establishing the costs and methodology for the TGT rate in the Montana Intertie Agreement was done to provide clarity and certainty to the parties on how the costs of constructing and maintaining the Eastern Intertie would be allocated. *Id.* at 6-7.

RN's assertion that using the segmented revenue requirement is consistent with the Montana Intertie Agreement is incorrect. As discussed above, the agreement provides a specific formula for determining and recovering the costs of constructing the Eastern Intertie. *See* Montana Intertie Agreement, BP-18-E-BPA-53, at 482-486 (Ex. D).

Allocation of TGT Revenues

RN alternatively argues that if BPA does not revise the TGT rate to recover the Eastern Intertie's segmented revenue requirement, BPA should eliminate the IM rate and allocate any excess revenues over the requirement back to the Eastern Intertie segment instead of socializing the excess revenues to all the segments. RN Br., BP-18-B-RN-01, at 14-15; RN Br. Ex., BP-18-R-RN-01, at 4.

As set forth above in Issue 5.2.1.6, BPA is not eliminating the IM rate for BP-18. Moreover, RN's assertion that BPA is recovering "excess" revenues from the TGT rate is not compelling. BPA is collecting the revenues to which it is entitled under the Montana Intertie Agreement for constructing and maintaining the Eastern Intertie. PPC Br., BP-18-B-PP-01, at 13. The revenues collected from the TGT rate that appear to be in excess of the segmented revenue requirement are not "surplus" revenues; rather, they are revenues that are recovering BPA's costs to construct and maintain the Eastern Intertie as agreed to by the parties to the Montana Intertie Agreement.

Finally, it is worth noting that the TGT rate schedule includes a provision that requires BPA to account for surpluses or deficits in revenues collected by the TGT rate in succeeding years. 2018 Transmission, Ancillary, and Control Area Service Rate Schedules and General Rate Schedule Provisions (GRSPs), BP-18-A-04-AP04, TGT-18, § II. In this context, surpluses or deficits apply to occasions where BPA may recover more or less revenues than the costs identified in the Montana Intertie Agreement, not the segmented revenue requirement. So long as TGT revenues equal the annual costs identified in the Montana Intertie Agreement, BPA is acting in accordance with the Agreement and appropriately recovering costs.

Because BPA must fully recover its costs for all segments, the difference between revenues received from TGT rates and the Eastern Intertie segmented revenue requirement should go back into transmission rates by proportionally allocating them to all segments; this is the case whether that difference is positive or negative. The adjustment for the Eastern Intertie identified in the Transmission Rates Study accomplishes that objective. Transmission Rates Study and Documentation, BP-18-FS-BPA-08, § 3.2.1. It would be inappropriate to apply the portion of the TGT revenues that exceed the segmented revenue requirement to only the Eastern Intertie rates because the segmented revenue requirement does not reflect the agreed upon costs and recovery methodology for BPA's construction of the Eastern Intertie as set forth in the Montana Intertie Agreement.

RN argues that BPA crediting the portion of TGT revenues exceeding the segmented revenue requirement back to all the segments is inconsistent with BPA's position set forth above in Issue 5.2.1.1 that it is inappropriate to charge Network rates at Townsend yet leave the costs in the Eastern Intertie. RN Br. Ex., BP-18-R-RN-01, at 6. RN's argument conflates BPA's segmentation policy with how it accounts for revenues. The allocation of costs based on segmentation is different than the allocation of revenues that exceed the segmented revenue requirement. Under BPA's segmentation policy, if BPA were to move its 200-MW share into the Network segment, then it would have to move some, if not all, of the costs to the Network. (As explained in Issue 5.2.1.1 above, the allocation of costs in the context of the Eastern Intertie would require additional analysis not set forth in the record given that the TGT rate is contractually required under the Montana Intertie Agreement to recover all of BPA's costs if BPA does not sell its portion of the intertie.) Otherwise, users of a different segment (e.g., the Eastern Intertie) would be paying for the costs of service in a different segment (e.g., the Network segment). In regard to the allocation of revenues, BPA's general premise is that sales from each segment recover its segmented revenue requirement unless a particular segment's costs are determined using a different means, such as by contract in the case of the Eastern Intertie. When there is a surplus or deficit in revenues compared to the segmented revenue requirement, BPA applies a credit or requires an under-recovery allocation from other segments so that revenues match the segmented revenue requirement and total transmission revenues match the total transmission revenue requirement. As explained above, costs for ratemaking purposes can be set a variety of ways. In the case of the Eastern Intertie, BPA is fully recovering its costs from the parties paying the TGT rate when it recovers the costs set forth in the Montana Intertie Agreement.

Decision

The TGT rate will not be changed. The TGT rate is a cost-based rate set to recover BPA's costs identified and agreed to by BPA and the Colstrip parties in the Montana Intertie Agreement. Any revenues from TGT sales that exceed the segmented revenue requirement are not surplus revenues and will continue to be allocated to the other segments.

Issue 5.2.1.9

Whether to revise the IM and IE rates to be consistent.

Parties' Positions

RN argues that the IE and IM rates are inconsistent in regard to how costs are allocated. RN Br. Ex., BP-18-R-RN-01, at 6-7. RN asserts that the IE rate is based on the segmented revenue requirement, and the IM rate is based on the Montana Intertie Agreement. Yourkowski, BP-18-E-RN-01 at 9-11; RN Br. Ex., BP-18-R-RN-01, at 6-7.

BPA Staff's Position

Staff took no position on this issue.

Evaluation of Positions

The IM rate applies to sales of BPA's 200-MW portion of the Eastern Intertie. Customers can purchase service in annual, monthly, weekly, daily or hourly increments for firm service and hourly increments for non-firm. 2018 Transmission, Ancillary, and Control Area Service Rate Schedules and GRSPs, BP-18-A-04-AP04, IM-18, § II. The IE rate applies to hourly non-firm and is available to the Colstrip parties who pay the TGT rate. *Id.* at IE-18, § II. Both rates are applicable to service on the Eastern Intertie.

RN is correct that the IE and IM rates are inconsistent as to how costs are allocated to each rate. The IE rate is based on the segmented revenue requirement. Transmission Rates Study and Documentation, BP-18-E-BPA-08, § 5.2.3. The IM rate is based on the costs set forth in the Montana Intertie Agreement. *Id.*

Except for the IM rate, BPA's other rates applicable to OATT-based transmission service use the segmented revenue requirement. *See id.*, at 55-61. The question is whether there is sufficient justification to continue using the costs identified in the Montana Intertie Agreement for the IM rate, or change the rate to recover its portion of the segmented revenue requirement for the Eastern Intertie. In regard to the recovery of costs, the Montana Intertie Agreement addresses the costs to be recovered from the Colstrip parties (parties to the Montana Intertie Agreement). Montana Intertie Agreement, Ex. D, BP-18-E-BPA-53, at 318-22. It does not address how costs should be recovered from parties taking open access transmission service under BPA's OATT, though it does require revenues generated from the IM rate to be credited back to the TGT rate. *Id.*

Given the absence of a compelling reason to apply something other than the segmented revenue requirement to an OATT-based service, it is appropriate to change the IM rate accordingly. To calculate the IM-18 rate using the segmented revenue requirement, the segmented revenue is reduced for revenue credits and divided by the total use of the Eastern Intertie. Changing the IM rate to be based on the segmented revenue requirement will result in an approximate 15 percent reduction to the rate.

Finally, while revising the IM-18 rate to use the segmented revenue requirement, BPA Staff noticed that the segmented revenue requirement used to calculate the IE-18 rate did not include revenue credits and that the rate was calculated using the total capability of the Eastern Intertie instead of forecasted sales as done for other rates. Staff adjusted the segmented revenue requirement and IE rate calculation accordingly, so that the IM and IE rate calculations are consistent with each other. This resulted in an IE-18 rate that is .05 mills per kilowatthour (kwh) higher than if those changes were not made. In doing so, the IM and IE rate are calculated consistently with each other and BPA's other rates for OATT-based transmission service, and the IE-18 rate is equal to the IM-18 hourly rate.

Decision

The methodology used to calculate the IE and IM rates will be changed to be consistent.

5.2.2 Rates for Hourly Transmission Service on the Southern Intertie

The Southern Intertie is a system of transmission lines and substations that transmit power between the Pacific Northwest and California. The Southern Intertie transmission lines include: (1) a 1,000-kV direct current (DC) line between north-central Oregon and the Nevada-Oregon border (NOB), and (2) multiple 500-kV alternating current (AC) lines that extend between north-central Oregon and the California-Oregon border (COB). Section 2.3 of the Transmission Segmentation Study and Documentation, BP-18-FS-BPA-07, provides a full description of Southern Intertie facilities. The Southern Intertie is primarily used to export power from the Pacific Northwest and Canada to California.

In the Initial Proposal, Staff proposed to change the rate design for hourly transmission service on the Southern Intertie in an effort to address the impact of “seams” issues between the transmission systems connecting the Pacific Northwest and California in combination with the increase in the amount of solar generation capacity in California. As described below, Staff and many customers and stakeholders believe this change is needed because the combined impacts have created a disincentive to reserve long-term firm transmission service on BPA’s Southern Intertie. BPA counts on sales of long-term firm transmission service to recover 95 percent of the costs of the Southern Intertie, and it may not be able to recover those costs if customers stop taking such service.

All parties that have addressed the Southern Intertie rate proposal in this proceeding agree that seams issues exist and should be addressed. The parties disagree, however, about the extent of the issues and whether Staff’s proposal is the right solution. JP01 (Powerex and Public Power Council), Northwest Requirements Utilities, and the Kalispel Tribe support Staff’s proposal. JP03 (Sacramento Municipal Utility District (SMUD), Transmission Agency of Northern California, and Turlock Irrigation District) opposes Staff’s proposal. JP03 generally claims that circumstances have not materially changed since the Administrator declined to adopt a proposal on these issues in the last rate case (BP-16), that the evidence is insufficient to justify adopting Staff’s proposal, and that errors made by the Hearing Officer have prevented the development of a full and complete record upon which to make a decision.

As explained in this section, BPA is adopting Staff’s proposed rate design for the hourly rates for FY 2018–2019. This change increases the rate for hourly transmission service on the Southern Intertie by approximately 170 percent. This obviously is a significant increase, but it is substantially less than the increase Staff proposed in the Initial Proposal. The cost savings described in the Administrator’s preface to this Final Record of Decision, combined with the retirement of equipment and reduction in spending on the Southern Intertie during FY 2016, have reduced the segmented revenue requirement for the Southern Intertie considerably, thereby reducing the magnitude of the rate increase.

5.2.2.1 Rate Issues

Issue 5.2.2.1.1

Whether the extent of seams issues between the Pacific Northwest and California provides a basis for changing the design of hourly Southern Intertie rates.

Parties' Positions

JP03 acknowledges that seams issues exist between the Pacific Northwest and California but argues that no evidence demonstrates that these issues are altering demand for long-term firm service on the Southern Intertie and that Staff's proposed change to the rate design is not justified. JP03 states that the circumstances surrounding the seams issues have not materially changed since the end of the BP-16 proceeding. JP03 Br., BP-18-B-JP03-01, at 65.

JP01 argues that Staff's proposal appropriately responds to the seams issues. JP01 Br., BP-18-B-JP01-01, at 5-7.

BPA Staff's Position

Staff conducted an extensive public process following the BP-16 rate proceeding to discuss the extent of seams issues between the Pacific Northwest and California. Linn *et al.*, BP-18-E-BPA-25, at 5-6. Staff identified several seams issues and found that the increase in solar generation in California is making these issues worse. Data Requests and Responses Admitted into Evidence, BP-18-E-JP01-03, at 7, 90. This is making long-term firm transmission service less attractive to customers, potentially causing cost recovery issues in the future. Fredrickson *et al.*, BP-18-BPA-12, at 7.

Evaluation of Positions

The consideration of seams issues between the Pacific Northwest and California in relation to the rates for hourly transmission service on the Southern Intertie has a lengthy history. The discussion below summarizes that history before describing the seams issues and addressing JP03's arguments.

Background

In the Initial Proposal for the BP-16 rate proceeding, Staff proposed to use its long-standing rate design for hourly rates on the Southern Intertie, which sets rates at a level that ensures a customer reserving hourly transmission service for 16 hours a day, five days per week (80 hours in total), pays the same amount as a customer reserving long-term firm transmission service for all hours. Transmission Rates Study and Documentation, BP-16-E-BPA-07, at 69. This is a common design for hourly rates in the utility industry and is based on the assumption that there are 16 peak (or heavy load) hours per weekday. Administrator's Final Record of Decision, BP-16-A-02, at 110. The design is intended to encourage customers to reserve long-term service (a term of one year or more) rather than reserving hourly service for only the hours of highest demand. *Id.*

In direct testimony in the BP-16 rate proceeding, Powerex and PPC proposed changing the rate design for hourly rates on the Southern Intertie to address seams issues between the Pacific Northwest and California. Powerex and PPC claimed that seams issues lead to a “disincentive for future [long-term firm] subscriptions and renewals that, if left unchecked, could ultimately jeopardize BPA’s cost recovery for existing and future expansion projects.” JP06 Br., BP-16-B-JP06-01, at 2. They proposed to base the hourly rate on actual reservations of hourly non-firm service from customers per week from FY 2012–2014, which they calculated was approximately 23 hours per customer per week. JP06 Br., BP-16-B-JP06-01, at 10-12. In other words, Powerex and PPC proposed that a customer reserving hourly transmission for 23 hours per week would pay the same amount as a long-term firm customer.

BPA did not adopt Powerex’s and PPC’s proposal in the BP-16 rate proceeding, stating that the existing rate design “creates an adequate incentive for customers to reserve long-term firm service on the Southern Intertie.” Administrator’s Final Record of Decision, BP-16-A-02, at P-2, 112. Nevertheless, the Administrator concluded that “seams issues exist and must be addressed,” but that it was necessary to “seek clarity on the extent of the issue, conduct a broader examination of seams issues with the involved parties, and evaluate both ratemaking and non-ratemaking solutions” before deciding how to address the issues. *Id.* at P-2.

Staff subsequently examined the issues in an extensive public process from September 2015 through February 2016. Linn *et al.*, BP-18-E-BPA-25, at 5. A variety of stakeholders participated in the process. *Id.* at 5-6. Powerex, the California Independent System Operator (CAISO), and the Los Angeles Department of Water and Power (LADWP) all made presentations on seams issues. *Id.* The views and comments of the CAISO and LADWP were important because those entities’ transmission systems are interconnected to BPA’s Southern Intertie at COB and NOB. Staff requested comments from stakeholders in four separate comment periods and thoroughly considered the views and comments received. *Id.* The members of JP03 did not submit comments in the process.

Staff developed a white paper at the end of the public process that identified the seams issues, analyzed potential solutions, and presented conclusions. Data Requests and Responses Admitted into Evidence by Order BP-18-HOO-29, BP-18-E-JP01-03, at 11-103. Staff committed in the white paper to proposing a new methodology for the design of hourly rates on the Southern Intertie in the Initial Proposal in this proceeding. *Id.* at 90.

Staff’s proposal in this proceeding retains the same basic design as the existing rates, but it updates the methodology to reflect a reduction in the number of peak hours in California due to changes in the state’s generation mix. Fredrickson *et al.*, BP-18-E-BPA-12, at 3, 9-10. According to Staff, California has greatly increased the amount of installed solar generation capacity in the past several years, and the resulting solar generation has changed the state’s daily net load shape. *Id.* at 4. Net load is the total load minus in-state wind and solar generation. *Id.* It represents the energy demand that must be met from dispatchable resources within California and imports from other regions, such as the Pacific Northwest. *Id.* Staff concluded that net load in California during the hours in the middle of the day has trended downward as solar generation has increased. *Id.* This decrease in net load during daytime hours is known as the “duck curve” (because of the shape of the curve on a graph). *Id.* Traditionally, daytime hours have been

considered part of the 16 peak hours per weekday, which, as described above, is the assumption underlying the use of 80 hours per week (16 hours per day multiplied by five weekdays) to calculate current hourly rates. *Id.* at 3. The evidence of the decrease in net load during daytime hours led Staff to conclude that California now has only four to six peak hours per day. Data Responses and Requests Admitted into Evidence, BP-18-E-JP01-03, at 90. In the end, Staff designed the proposed hourly rates based on an assumption of five peak hours per day, so that a customer reserving hourly transmission service for five hours per day, five days per week (25 hours in total) pays the same amount as a customer reserving long-term firm transmission service. Fredrickson *et al.*, BP-18-E-BPA-12, at 3.

Description of the Seams Issues

The white paper developed by Staff at the end of the public process identified seams issues between: (1) the Pacific Northwest and the CAISO's day-ahead market, and (2) the Pacific Northwest and California transmission providers that are not part of the CAISO. Data Requests and Responses Admitted into Evidence, BP-18-E-JP01-03, at 17-18.

Due to the seams issues between the Pacific Northwest and the CAISO's day-ahead market, a generator or marketer without long-term firm transmission service on BPA's system can bid energy into the CAISO day-ahead market and then procure hourly transmission service later from BPA if the CAISO accepts its bid. *Id.* This creates a disincentive to reserve long-term firm service on BPA's system because long-term firm service is unnecessary to participate in the day-ahead market, and BPA sells unused long-term capacity as hourly non-firm transmission at a relatively low transmission rate. *Id.* If the CAISO does not accept the bid of a long-term firm transmission customer in the CAISO day-ahead market, it usually results in unused capacity on BPA's system that a successful bidder without long-term firm transmission service can purchase as hourly non-firm transmission. *Id.* at 19-20. Although there is some risk of not being able to purchase hourly non-firm transmission service, it is available most of the time. Holcomb *et al.*, BP-18-E-JP03-01, at 54.

The seams issue between the Pacific Northwest and non-CAISO transmission providers in California occurs because those transmission providers do not consider the "curtailment priority" of BPA transmission service when curtailing transmission schedules. Data Requests and Responses Admitted into Evidence by Order BP-18-HOO-29, BP-18-E-JP01-03, at 18, 104; Cross-Ex. Tr. at 212-14. When transmission providers curtail transmission service in response to system reliability conditions, they do so according to the "priority" associated with each form of service. Non-firm service is curtailed prior to firm service. The non-CAISO transmission providers perform the majority of curtailments on southbound transmission schedules, so the priority of BPA's transmission service is largely irrelevant on the Southern Intertie, and BPA firm transmission may be curtailed ahead of BPA non-firm transmission. *Id.* This creates a disincentive to reserve long-term firm transmission service on BPA's system because it minimizes or eliminates the additional delivery risk that would normally be associated with BPA non-firm transmission service. *See* Cross-Ex. Tr. at 212-14.

Extent of the Seams Issues with the CAISO

No party in this proceeding questions whether seams issues with the CAISO exist or whether such issues should be addressed. JP03 Br., BP-18-B-JP03-01, at 1; JP01 Br., BP-18-B-JP01-01, at 1-2; Kalispel Tribe Br., BP-18-B-KT-01, at 3-4. JP03, however, questions the extent of the issues and whether the magnitude and frequency of those issues have changed since BP-16. JP03 Br., BP-18-B-JP03-01, at 20; Holcomb *et al.*, BP-18-E-JP03-02, at 41-43.

JP03 disagrees with Staff's testimony that seams issues are causing the need for a rate change, arguing that the issues with the CAISO have existed since 2009 and that BPA found in BP-16 that the existing rate design creates adequate incentive to reserve long-term firm service. JP03 Br., BP-18-B-JP03-01, at 65. JP03 also disagrees that the evidence of the frequency and magnitude of the seams issues justifies Staff's proposal. *Id.* at 61. According to JP03, the magnitude of the issue is unclear. *Id.*

The lack of clarity surrounding the extent of the seams issues was one of the reasons why BPA did not adopt Powerex and PPC's proposal in the BP-16 rate proceeding. *See* Administrator's Final Record of Decision, BP-16-A-02, at 112. It also was one of the reasons that BPA decided to conduct a public process following the BP-16 proceeding to further examine the seams issues. The evidence developed in the public process and the evidence presented in this proceeding demonstrate that changes in California's generation mix are heightening the impact of seams issues and creating a potential loss of revenue. In other words, while seams issues have made it feasible for customers to use hourly service rather than long-term service, the impact of the increasing amount of solar generation in California on the number of peak hours has made it more economical.

Staff has testified that the significant increase in installed solar generation capacity in California has decreased net load during daytime hours. Fredrickson *et al.*, BP-18-E-BPA-12, at 4. The decrease in net load during daytime hours is the basis for Staff's conclusion that there are now five peak hours per weekday in California. *Id.* at 3. CAISO has performed similar, independent analysis that largely reaches the same conclusions about the number of peak hours in California per day. *Id.* at 4-5. In addition, Western Systems Power Pool (WSPP) has created new power products to serve this evening peak, and SMUD has traded similar products. Linn *et al.*, BP-18-E-BPA-25, Attachment 1 (Data Response BPA-JP03-26-34); Data Responses and Requests Admitted into Evidence, BP-18-E-JP01-03, at 90.

JP01 provided evidence that the duck curve is having an even more dramatic effect than previously expected. JP01 states that "the dramatic reduction in net load during the mid-day hours—the so-called belly of the duck—reached levels in 2016 that CAISO had previously anticipated would not be reached until 2020." Deen & Wellenius, BP-18-E-JP01-01, at 21. JP01 also quotes a CAISO study that utility-scale installed solar generation capacity, which was approximately 9,000 MW in 2016, is expected to grow by another 4,000 to 5,000 MW by 2020. *See id.* Similarly, rooftop solar generation capacity in California is expected to grow by more than 4,000 MW between 2017 and 2020. *Id.* at 21-22. This would result in a combined growth in rooftop and utility-scale solar generation capacity of 8,000 to 9,000 MW during the BP-18 rate

period. This projected increase in solar generation capacity will further decrease net load during daytime hours, reducing the incentive to hold long-term firm transmission service.

The evidence of the impact of the duck curve, the seams issues identified above, and the likelihood that solar generation capacity in California will continue to increase provides a strong basis for concern about the value of long-term firm transmission service on BPA's Southern Intertie and the incentive to reserve such service. Linn *et al.*, BP-18-E-BPA-25, at 3-4; Deen & Wellenius, BP-18-E-JP01-01, at 21-22. Customers need only five hours of transmission service to serve the hours of peak demand in California, and it would be cheaper under the current (BP-16) methodology to purchase hourly service for these five hours than to reserve long-term firm service for all hours.

Against this backdrop of circumstances suggesting that the value of long-term firm transmission service is in decline, BPA must consider that such service recovers 95 percent of the costs of the Southern Intertie. Data Requests and Responses Admitted into Evidence, BP-18-E-JP01-03, at 14. Long-term firm transmission service provides stable and predictable cost recovery because the contracts for such service typically last at least several years, and the customers commit to pay for that service whether they utilize it or not. Fredrickson *et al.*, BP-18-E-BPA-12, at 7.

A decrease in the reservation of long-term firm transmission service would mean that BPA would have to rely on more on revenues from sales of short-term service for cost recovery. *Id.* These revenues would be more volatile than relying on long-term firm service because customers would reserve transmission service only when they need it, and the amount they reserve would largely depend on load and resource conditions and the resulting economics of selling energy over the Southern Intertie on a short-term basis. *Id.* This may change from year to year, impacting BPA's ability to set rates to recover the costs of the Southern Intertie. *Id.* Although JP03 states that this is a "meaningless truism" and that it does not show that a "decrease in long-term firm transmission capacity is more or less likely in past rate cases," BPA believes that the incentive to reserve long-term firm transmission service is not as strong as it was during the BP-16 rate proceeding for all the reasons described above. JP03 Br. Ex. BP-18-R-JP03-01, at 16.

JP03 questions reliance on the CAISO study showing the potential increase in solar generation capacity in California in FY 2018–2019, stating that increases of that magnitude suggest there may be no need to use the Southern Intertie at all, much less purchase long-term firm transmission service from BPA. *Id.* at 15-16. JP03 argues that raising the Southern Intertie rates would be "futile" under these circumstances because increasing solar generation means that the demand for the Southern Intertie is declining. *Id.* at 16. BPA is not suggesting there will be no need to use the Southern Intertie due to increased solar generation. There will still be strong demand for use of the Southern Intertie during the evening peak when the sun is setting and solar generation is reduced. *See* Cross-Ex. Tr. at 217 (JP01 witness stating that "there continue to be periods and hours in which [long-term firm transmission service] is highly valuable."). Staff's proposed hourly rate design encourages customers to reserve long-term firm transmission service to serve this evening peak.

JP03 argues that the increase in solar generation capacity does not describe the extent of the seams issue because increasing solar generation is not, in and of itself, a seams issue. JP03 Br. Ex., BP-18-R-JP03-01, at 14-15. However, increasing solar generation is heightening the impact of seams issue because the CAISO day-ahead market makes it relatively easy for customers to obtain hourly transmission service (see above) and customers need fewer hours of transmission service. All of this makes hourly service more attractive than it was during the BP-16 rate proceeding.

Extent of the Seams Issues with Non-CAISO Transmission Providers

Seams issues between the Pacific Northwest and non-CAISO transmission providers were not discussed or identified during the BP-16 rate proceeding. JP03 Br., BP-18-B-JP03-01, at 8. In the white paper and in this proceeding, Staff and JP01 stated that non-CAISO transmission providers in California do not consider the priority of BPA transmission service when curtailing transmission schedules. Data Requests and Responses Admitted into Evidence by Order BP-18-HOO-29, BP-18-E-JP01-03, at 18, 104; Cross-Ex. Tr. at 212-14. Nearly half of the Southern Intertie is used to access markets in California other than the CAISO. JP03 Br., BP-18-B-JP03-01, at 2. The evidence of the extent of seams issues between the transmission systems of the Pacific Northwest and California is more comprehensive than during the BP-16 rate proceeding.

JP03 implies this seams issue would occur only if transmission facilities interconnected to BPA south of COB and NOB are “de-rated” (operated below typical operating limits), and this “de-rate” caused the transmission provider south of COB or NOB to curtail transmission service in accordance with their own transmission priorities, not BPA’s. JP03 Br. Ex., BP-18-R-JP03-01, at 56. This is not the case. At cross-examination, JP03’s counsel asked JP01’s witnesses if a BPA non-firm customer faced “delivery risk” if there was an issue on BPA’s portion of the Southern Intertie but there was no problem south of COB and NOB. Cross-Ex. Tr. at 213, 212 (witness clarifying that counsel for JP03 was asking about *BPA’s* Southern Intertie). JP01’s witness stated “it is not Bonneville doing the curtailment or allocating who flows” when there is an issue regarding the transmission service that BPA provides on the Southern Intertie. *Id.* at 214. Rather, it is transmission providers in California, including the non-CAISO transmission providers. *Id.*

JP03 argues that there is no evidence of the frequency or magnitude of these curtailments. JP03 Br. Ex., BP-18-R-JP03-01, at 56. This misses the point. If curtailments are rare, there is no delivery risk to using hourly non-firm service because that service is rarely curtailed. If curtailments are frequent, there is still little to no additional delivery risk to using hourly non-firm service, as opposed to long-term firm transmission service, because California transmission providers do not consider the curtailment priority of BPA transmission service. One reason long-term firm transmission service is valuable is because it is—under normal circumstances—curtailed after non-firm transmission service. JP01’s witness provided compelling testimony that is not the case on the Southern Intertie. Cross-Ex. Tr. at 212-14.

JP03 also argues that this seams issue is the result of the Commission’s pro forma open access transmission tariff and has been a longstanding issue for more than 20 years. JP03 Br. Ex.,

BP-18-R-JP03-01, at 56. Even assuming that this is the case, the tariff still makes it feasible for customers to switch from long-term firm transmission service to hourly service without being exposed to additional delivery risk. As described above, the increasing amount of solar generation in California that Staff and others have identified since the BP-16 rate proceeding has now made it more economical as well.

JP03 faults BPA for expressing concern about seams issues with non-CAISO transmission providers because the BP-16 Final Record of Decision stated that Powerex's and PPC's proposal does not recognize any value for other uses of long-term firm transmission service, such as bilateral sales outside of CAISO markets. *Id.* at 54. Yet this issue was never explored in the BP-16 rate proceeding, and the BP-16 Final Record of Decision directed Staff to "conduct a broader examination of seams issues." Administrator's Final Record of Decision, BP-16-A-02, at P-2. This directive was not limited to seams issues with the CAISO. *See id.* JP03 itself asked Staff at least one data request about this issue, and Staff responded that schedules from north to south "over the Southern Intertie are normally curtailed by the [balancing authority area] on the Southern end of the Intertie" and that these "curtailments do not follow BPA's OATT priorities." Data Requests and Responses Admitted into Evidence by Order BP-18-HOO-29, BP-18-E-JP01-03, at 104.

Finally, JP03 argues that BPA is relying on concerns about this seams issue "to plug an evidentiary gap" in Staff's case created by an increase in the size of the Southern Intertie transmission queue from 2009 to 2012. JP03 Br. Ex., BP-18-R-JP03-01, at 11-12. This argument has no basis. BPA addresses JP03's argument concerning the tripling size of the queue in Issue 5.2.2.1.5.

Conclusion

The combined impact of the increase in the amount of solar generating capacity in California and seams issues between the transmission systems connecting the Pacific Northwest and California provides a basis for changing the design of hourly Southern Intertie rates. When Powerex and PPC proposed to change the hourly rate design in the BP-16 rate proceeding, there was simply inadequate opportunity to thoroughly consider all the potential implications of the proposal, given the nature and complexity of the issues, the magnitude of the potential rate increase, and the constraints of the rate case process. Two years later, following an extensive public process to examine the extent of the seams issues, a thorough vetting of the proposed rate solution in this rate proceeding, and an examination of the growth of solar generation in California, the understanding of the extent of these seams issues is much clearer.

Decision

The extent of the seams issues between the Pacific Northwest and California provides a basis for changing the design of hourly Southern Intertie rates.

Issue 5.2.2.1.2

Whether Staff gave serious consideration to comments that ran counter to its position during the pre-rate case public process.

Parties' Positions

JP03 argues that Staff did not give serious consideration to comments that ran counter to its position during the pre-rate case public process, including those of PGE and SMUD. JP03 Br., BP-18-B-JP03-01, at 57-61.

JP01 states that Staff conducted many publicly noticed workshops, made and encouraged interested parties to make presentations, and analyzed and encouraged stakeholders to analyze available data. JP01 Br., BP-18-B-JP01-01, at 9.

BPA Staff's Position

Staff conducted an extensive public process to explore seams issues, and it requested comments from stakeholders in four separate comment periods. Linn *et al.*, BP-18-E-BPA-25, at 5. Staff gave consideration to these comments in developing its white paper, which provided the basis for the BP-18 Initial Proposal. Holcomb *et al.*, BP-18-E-JP03-01-AT01, at 74 (SM-BPA-26-107).

Evaluation of Positions

JP03 argues that Staff failed to give serious consideration to comments submitted in the pre-rate case public process if those comments ran counter to the notion that addressing seams issues require a ratemaking solution. JP03 Br., BP-18-B-JP03-01, at 57-62. JP03 claims that Staff “arbitrarily dismissed” PGE’s comments and gave conflicting accounts of how it weighed those comments. *Id.* at 57-60; JP03 Br. Ex, BP-18-R-JP03-01, at 32. As an initial matter, JP03 ignores that BPA adopted PGE’s ultimate recommendation not to initiate an expedited Section 7(i) rate proceeding in the summer of 2016 to address seams issues, and instead waited until this proceeding. Data Requests and Responses Admitted into Evidence, BP-18-E-JP01-03, at 87-89. BPA accepted PGE’s recommendation over the opposition of Powerex, which wanted an expedited rate proceeding in advance of BP-18. *Id.* at 88. This alone shows that Staff considered PGE’s comments.

JP03 questions why BPA would decide not to conduct an expedited Section 7(i) rate proceeding based, in part, on PGE’s suggestion, but reject PGE’s opposition to Staff’s rate proposal as a whole. JP03 Br. Ex, BP-18-R-JP03-01, at 33. PGE stated that a significant rate adjustment, such as the one Staff is proposing, should be made as part of a general rate case, not in an expedited proceeding that would address a single issue. Addressing the issue in a general rate case allows for more time to consider the viewpoints of all parties. An expedited proceeding can take place in as little as 90 days. Hearing Procedures, § 1010.10(a). Although Staff’s proposal had widespread support, the general rate proceeding provides more time to carefully consider the views of any stakeholders that opposed the proposal. Also, there were relatively few long-term firm reservations that were eligible for renewal during FY 2016–2017, diminishing the chances

of under-recovery on the Southern Intertie during that time. Data Requests and Responses Admitted into Evidence by Order BP-18-HOO-29, BP-18-E-JP01-03, at 20.

JP03 focuses on PGE's statement "that changes occurring in the region with respect to emerging markets and renewable resource integration will serve to increase the need for long-term firm transmission." Holcomb *et al.*, BP-18-E-JP03-01-AT03, at 25. JP03 states that Staff rejected PGE's suggestion because PGE provided no evidence to support the claim, but Staff did not hold Powerex to the same standard. *See* JP03 Br., BP-18-B-JP03-01, at 58. According to JP03, Staff accepted Powerex's claim that long-term firm customers will not renew service without requiring any evidence. JP03 also states there is no evidence Powerex is relying on hourly service as a substitute for long-term firm transmission service. JP03 Br. Ex., BP-18-R-JP03-01, at 32 n.14. Yet this is contrary to evidence in the record, which shows that Powerex cancelled long-term firm transmission reservations, has removed all of its requests from the transmission queue, and is purchasing large amounts of hourly transmission service. Holcomb *et al.*, BP-18-E-JP03-01, at 20, 95. All of this was known to Staff when the public process began in September 2015. *See* Cross-Ex. Tr. at 55, 76, 102. Furthermore, it shows that Powerex is not "bluffing" about not renewing long-term service—as JP03 states in its brief—and may not renew such service in the future. JP03 Br., BP-18-B-JP03-01, at 96.

JP03 argues that the interest PGE received when it sold capacity on its share of the Southern Intertie in 2013 is evidence of PGE's statement regarding changes occurring in the region. *Id.* at 58. Staff is correct, however, in that PGE's offer process in 2013 does not provide evidence for PGE's claim that regional changes related to emerging markets and renewable resource integration will increase the need for long-term firm Southern Intertie transmission. Holcomb *et al.*, BP-18-E-JP03-01-AT03, at 25. An offer process from four years ago does not show whether the need for long-term firm transmission will increase or decrease in the future, and it is doubtful that PGE was trying to use its 2013 experience in that way. JP03 also questions why Staff did not reach out to PGE to ask about its claim that there is an increasing need for long-term firm transmission service. *Id.* at 25-26. However, PGE submitted its comments in October 2015, and the public comment process did not conclude until February 2016. PGE knew full well how to get its comments considered in the public process. *Id.* Indeed, PGE had more opportunities to submit comments to elaborate on its views, and PGE took advantage of those opportunities. PGE has never complained that Staff did not adequately address its comments and, as stated above, BPA accepted PGE's recommendation not to conduct an expedited Section 7(i) proceeding in advance of the BP-18 rate case. Moreover, PGE is a party in the BP-18 rate proceeding, and has not filed testimony opposing Staff's proposal.

JP03 also states that Staff did not consider SMUD's comments submitted in August 2016. JP03 Br., BP-18-B-JP03-01, at 57. As described above, the Administrator called for a public process to address the seams issues in the Final Record of Decision in BP-16, which was issued in July 2015. That process, in which Staff determined its BP-18 Initial Proposal, started in September 2015 and concluded in February 2016. SMUD submitted its August 2016 comments opposing the approach adopted in the public process approximately six months after that process was over.

The public process was publicly noticed, and SMUD was welcome to participate. All stakeholders had four opportunities to comment before the conclusion of that process in February 2016. Yet SMUD did not participate and submitted no comments. Staff stated publicly at the end of the public process that it intended to propose a revised rate design for hourly Southern Intertie rates in the BP-18 Initial Proposal. Data Requests and Responses Admitted into Evidence, BP-18-E-JP01-03, at 90. After February 2016, Staff continued to develop the details of its Initial Proposal in pre-rate case workshops, which were separate from the earlier public process and addressed a wide variety of issues, including defining the number of peak hours, how BPA should set its Scheduling, System Control and Dispatch Service rate in light of Staff's proposal, and exploring the use of discounting in the south-to-north direction for hourly service on the Southern Intertie. *See* Powerex Comments on BP-18 Southern Intertie Rate, BP-18-X-03, at 2. However the direction that Staff was heading for the Initial Proposal was a result of the public process. Linn *et al.*, BP-18-E-BPA-25, at 3. Consequently, a change to Staff's position at that point would have disrupted the outcome of the public process, burdened the parties that participated in that process, and threatened to unravel the broad coalition supporting the proposal.

JP03 states that it could not have known that comments submitted six months late would not be considered. JP03 Br. Ex., BP-18-R-JP03-01, at 34. Yet every other BPA customer and stakeholder adhered to the timelines set forth by Staff. JP03 argues that Staff's white paper was labeled "pre-decisional," and this shows Staff had not made a decision as to what to propose in the rate proceeding. *Id.* However, the white paper was labeled "pre-decisional" because BPA was not taking a final agency action. It was only deciding what to propose in this ratemaking proceeding, and key elements of the proposal, such as the exact number of peak hours, were missing at that point. Data Responses and Requests Admitted into Evidence by Order BP-18-HOO-29, BP-18-E-JP01-03, at 90.

JP03 also states the process was "patently unreasonable" because BPA would not consider late comments criticizing Staff's proposal. JP03 Br. Ex., BP-18-R-JP03-01, at 84. JP03 seems to disregard that Staff provided more process and opportunity for stakeholders to discuss the seams issue than is required under the Northwest Power Act. The Act does not require Staff to hold public processes to discuss rate case issues or to conduct pre-rate case workshops before commencing a rate proceeding. BPA decided, however, to conduct a process to examine the issues on the Southern Intertie, and it was necessary for Staff to establish the timeline for that process to provide certainty for Staff and stakeholders. No stakeholder objected to ending the process in February 2016, and BPA staff had no reason to believe that new stakeholders would come forward six months later and oppose Staff's proposal. It is regrettable the members of JP03 did not participate in the public process.

Regardless of the missed opportunity to participate in the pre-rate case public process, JP03 has had ample opportunity to raise its concerns with Staff's proposal during this proceeding and has availed itself of that opportunity. JP03 submitted more than 200 data requests to Staff and JP01, filed approximately 140 pages of written testimony, cross-examined Staff and JP01 witnesses for approximately six hours, made a 30-minute oral argument to the Administrator, and filed briefs

exceeding 200 pages. JP03's arguments that it was denied adequate process are unpersuasive. JP03 Br., BP-18-B-JP03-01, at 57.

JP03 complains that the results of the public process have been treated as a "gigantic thumb on the scales in favor of Staff's proposal." JP03 Br. Ex., BP-18-R-JP03-01, at 85. However, Staff made no mention of the public process in its testimony on the proposed rate design in the Initial Proposal. See Fredrickson *et al.*, BP-18-E-BPA-12, at 2-11. The materials from the public process, including Staff's white paper analyzing seams issues, have made their way into the record since that time by other means. JP03 included almost 30 pages of documents from the public process in its direct case. Holcomb *et al.*, BP-18-E-JP03-01-AT03, at 11-27, 42-54. Data requests from JP03 also required Staff to refer to the public process, and JP03 has included the responses in the record. See, e.g., Holcomb *et al.*, BP-18-E-JP03-01-AT01, at 17 (SM-BPA-26-14), 61 (SM-BPA-26-91), 72 (SM-BPA-26-103). JP03 has argued at length about the contents of comments in the public process and asked BPA to take official notice of certain comments, including Powerex's, that were not otherwise in the record. JP03 Br., BP-18-B-JP03-01, at 57-62; See Issue 5.2.2.2.5. It is not credible for JP03 to raise issues concerning BPA's public process, submit evidence from that process into the record, and then fault BPA for considering such evidence in its decision. Similarly, it is not credible for JP03 to ask BPA to take official notice of Powerex's comments and then complain that BPA "references the 'public process' and the comments of stakeholders made during the public process, a process in which Powerex was very vocal." JP03 Br. Ex., BP-18-R-JP03-01, at 79.

The stakeholders expressing support for a ratemaking solution in the public process represented a broad and diverse group consisting of Northwest public power customers, power marketers, and renewable energy developers. Linn *et al.*, BP-18-E-BPA-25, at 5-6. The group included Tacoma Power, PPC, Morgan Stanley, Powerex, Avangrid, NRU, and the ICNU. *Id.* Since the public process, the Kalispel Tribe has also supported the rate design change. Kalispel Tribe Br., BP-18-B-KT-01, at 3-4. Of BPA's long-term firm transmission customers, only Exelon opposed the rate design change during the public process. Data Requests and Responses Admitted into Evidence, BP-18-E-JP01-03, at 39. The majority of hourly customers also support making the rate design change, with only Exelon, Southern California Edison, and PGE submitting comments in the public process opposing Staff's proposal. *Id.* at 39-46. Turlock Irrigation District, which did not submit comments in the public process, is the only Southern Intertie customer that opposes Staff's proposal in this proceeding. SMUD and the Transmission Agency of Northern California do not purchase Southern Intertie transmission service from BPA.

Such a broad and diverse group in support of a rate design change was not apparent during the BP-16 rate case. It is also relatively rare. For instance, in this rate case, renewable energy developers and interest groups are encouraging BPA to change its rate design on the Eastern Intertie, whereas Northwest public power utilities oppose it. See Section 5.2.1 above. Various customer groups have different perspectives on BPA's proposed FRP. See Section 6. Aside from the opposition of JP03, there is a high degree of consensus among BPA's Southern Intertie customers (both long-term firm customers and hourly customers) that BPA should change its rate design for hourly rates on the Southern Intertie. BPA attaches meaningful significance to the broad coalition of support for this change.

JP03 discounts this broad and diverse group because PPC and Powerex are the only parties that testified in support of the rate change in the BP-16 proceeding and they are the only customers testifying in support of a rate change in this proceeding. JP03 Br. Ex., BP-18-R-JP03-01, at 47-48. However, BPA cannot ignore comments indicating a high level of support for this change. After conducting workshops and learning more about these issues, it was apparent that many stakeholders and Southern Intertie customers have the same concerns expressed by Powerex and PPC. JP03 discounts “a change in headcount supporting a previously rejected proposal.” *Id.* However, as stated below, Staff’s proposal is materially different from Powerex’s and PPC’s proposal. See Issue 5.2.2.1.6. Furthermore, this broad and diverse group includes those that purchase almost all long-term firm transmission service on the Southern Intertie. It is not prudent for BPA to ignore these customers, face the risk of cost-recovery issues on the Southern Intertie, and hope JP03 is correct these customers are all “bluffing.” JP03 Br., BP-18-B-JP03-01, at 96.

JP03 discredits the support of all these stakeholders because their “economic interests are all aligned.” JP03 Br. Ex., BP-18-R-JP03-01, at 83. JP03 provides no evidence to support this statement. Moreover, this statement actually contradicts JP03’s own testimony. JP03 witnesses testified that Northwest consumers would be made worse off by Staff’s proposal and that “[m]any Northwest utilities are net sellers of energy,” at prices established by the Mid-Columbia index, which lists wholesale power prices in the Northwest, and “will see lower revenue as a result [of Staff’s proposal].” Holcomb *et al.*, BP-18-E-JP03-01, at 70-71. If JP03 is correct that Northwest utilities will see lower revenues as a result of Staff’s proposal, it is reasonable to conclude that at least some entities are supporting Staff’s proposal not because of the opportunity for financial gain, but rather because of genuine concern that BPA might not recover its Southern Intertie costs from its Southern Intertie customers. This is especially true for customers supporting Staff’s proposal that hold little to no Southern Intertie capacity, such as the Kalispel Tribe and members of NRU. As the Kalispel Tribe stated, “reduced demand [for long-term firm transmission service] jeopardizes the stable recovery of costs.” Kalispel Tribe Br., BP-18-B-KT-01, at 3. BPA shares these concerns.

Finally, in response to JP03’s claim that there have been “no material changes in circumstances” since the BP-16 rate proceeding, BPA notes that the public process conducted prior to this proceeding provided Staff and other stakeholders a better understanding of the seams issues between the Pacific Northwest and California, including how increased solar generation is affecting those issues. Although BPA held several workshops prior to the BP-16 rate proceeding, it did not examine this issue in detail. JP03 Br. Ex., BP-18-R-JP03-01, at 18 n.4. This was one reason why the BP-16 Final Record of Decision directed Staff to spend more time examining this issue.

Decision

Prior to this rate proceeding, Staff considered all timely submitted comments on this issue. This included comments that were opposed to a ratemaking solution and those that advocated for such a solution.

Issue 5.2.2.1.3

Whether Staff meaningfully evaluated non-rate alternatives prior to the Initial Proposal in this rate case.

Parties' Positions

JP03 argues Staff did not meaningfully evaluate non-ratemaking alternatives and failed to explain why BPA did not pursue non-rate alternatives that would have had a lesser impact on hourly customers. JP03 Br., BP-18-B-JP03-01, at 70-71. JP03 states that this contravenes the Hearing Officer's directive that testimony "fully explain the consequences of adopting the proposed methods." *Id.*

JP01 states that "[t]he entirety of the work done since the conclusion of the BP-16 rate proceeding led BPA Staff to believe that the agency must address the seams issues on the Southern Intertie with a targeted rate solution." JP01 Br., BP-18-B-JP01-01, at 11.

BPA Staff's Position

Staff evaluated both ratemaking and non-ratemaking alternatives when it developed its white paper in the public process following BP-16. Linn *et al.*, BP-18-E-BPA-25, at 35. However, the purpose of this rate case is to set rates, not to adopt or implement non-ratemaking alternatives such as changes to business practices or operating procedures. *Id.*

Evaluation of Positions

As stated above, the BP-16 Final Record of Decision directed Staff to evaluate both ratemaking and non-ratemaking solutions to seams issues before BPA would adopt a ratemaking solution. In its brief, JP03 asserts that Staff did not meaningfully evaluate non-rate alternatives. JP03 Br., BP-18-B-JP03-01, at 70-71. Despite its assertion, JP03 relies upon Staff's white paper, where Staff evaluated non-rate alternatives, including an alternative to change BPA's scheduling software. JP03 quotes Staff's evaluation, which concluded that a change to BPA's scheduling software would be "more effective in preserving the advantages of long-term firm [transmission service] in the CAISO [day-ahead market]." JP03 Br., BP-18-B-JP03-01, at 64 (quoting Holcomb *et al.*, BP-18-E-JP01-01-AT03, at 56). JP03 also faults Staff for not ranking the effectiveness of non-ratemaking alternatives in numerical order. *Id.* at 64. These assertions lack merit.

First, JP03's arguments related to non-rate solutions are untimely. The proper forum for the discussion regarding non-rate solutions was the public process, not this rate case. As described above, JP03 did not participate in the public process.

Second, Staff did evaluate whether the alternatives (both rate and non-rate) were more effective or less effective. Cross-Ex. Tr. at 105. JP03 fails to acknowledge critical portions of Staff's evaluation of non-ratemaking alternatives. For example, JP03 claims that Staff failed to explain why it did not pursue making changes to its scheduling system that JP03 believes would have a

lesser impact on hourly customers. JP03 Br., BP-18-B-JP03-01, at 70-71. JP03 states that this contravenes the Hearing Officer’s directive that testimony “must fully explain the consequences of adopting the proposed methods.” *Id.* at 71. However, Staff’s evaluation shows that changes to the scheduling system would have a greater negative impact than a ratemaking change. Staff found that the scheduling change is only effective “[i]f a customer is unable to acquire [hourly non-firm (HNF)] transmission to deliver power or has to buy HNF in excess of what it needs.” Data Requests and Responses Admitted into Evidence, BP-18-E-JP01-03, at 70. In other words, this alternative is effective only if it makes hourly transmission service unavailable at any price or if a customer must buy more hourly transmission than it needs. Therefore this alternative adds a great deal more risk than today for customers utilizing hourly service, where such service is available “most of the time.” Holcomb *et al.*, BP-18-E-JP03-01, at 54.

JP03 takes issue with this conclusion, stating that the white paper did not conclude non-rate alternatives are effective only if they reduce the availability of non-firm transmission service or if a customer must buy more transmission than it needs. JP03 Br. Ex., BP-18-R-JP03-01, at 35. This is incorrect. If a non-rate alternative did not reduce transmission availability or require a transmission customer to buy more hourly service than it needs, it would not solve the seams issue. Hourly service would still be available “most of the time” and not have priority over long-term firm transmission service. See Issue 5.2.2.1.1.

Despite JP03’s arguments to the contrary, paying more for a service has less negative impact than not being able to have the service at any price. JP03 believes this is not the case. It claims Staff’s proposal makes hourly transmission service uneconomical compared to long-term firm transmission service. JP03 Br. Ex., BP-18-R-JP03-01, at 35-36. JP03’s statement must be put in the context of Staff’s methodology. If a customer reserves fewer than 25 hours a week of transmission service, hourly transmission service is more economical (cheaper) than long-term firm transmission service. If a customer reserves more than 25 hours a week of transmission service, then long-term firm transmission service is more economical than hourly transmission service. However, JP03’s preferred non-ratemaking alternative would make it less likely for a customer to reserve hourly transmission service, even for a few hours a week, because there is a greater chance it might not be available. In the example above, a customer that reserves hourly transmission service for fewer than 25 hours a week would be worse off with little to no hourly transmission service than with hourly transmission service that is more expensive.

Similarly, forcing the customer to purchase more transmission than it needs effectively raises the price of transmission service and reduces the amount available for other customers to purchase. BPA’s ratemaking alternative raises the price of hourly transmission service to create the desired incentives. JP03 states that even if a customer had to buy twice as much hourly transmission service than it needs at current rates, it would still be cheaper than buying the actual amount of transmission service that it needs under Staff’s proposed rates. JP03 Br. Ex., BP-18-R-JP03-01, at 36. Buying twice as much transmission service as needed, however, results in half of that transmission service going unused. The unused half would not be available for other customers to purchase, even if other customers requested such service, resulting in the potential under-utilization of the Southern Intertie.

JP03 states that this description only explains the consequences of a single non-ratemaking alternative, not the consequences of other non-ratemaking alternatives that are in the white paper. *Id.* at 34. However, this is the alternative that JP03 specifically mentions in its brief and testimony. JP03 Br., BP-18-B-JP03-01, at 70-71. The consequences of other non-ratemaking alternatives are described in the white paper as well. JP03 faults the white paper for being “pre-decisional.” JP03 Br. Ex., BP-18-R-JP03-01, at 34. Yet nothing in the white paper was a final agency action; therefore, it was “pre-decisional.” JP03 argues Staff concluded that releasing hourly non-firm transmission service at noon of the pre-schedule day might increase the certainty of some customers’ ability to acquire hourly non-firm service. *Id.* Although Staff did arrive at this conclusion, it also said that this was a risk that would have to be mitigated and proposed a method for mitigating this risk. Data Responses and Requests Admitted into Evidence by Order BP-18-HOO-29, BP-18-E-JP01-03, at 70.

JP03 argues that Staff’s testimony contravenes the Hearing Officer’s directive that testimony “fully explain the consequences of adopting the proposed methods.” JP03 Br., BP-18-B-JP03-01, at 70-71. But the Hearing Officer’s order requires only that Staff fully explain the consequences of its rate proposal, not the consequences of non-rate proposals that Staff did not propose. Special Rules of Practice Governing this Proceeding, BP-18-HOO-02, at 2. JP03 asks how “it is possible to ‘fully consider’ the consequences of a rate hike without considering the impact of alternatives?” JP03 Br. Ex., BP-18-R-JP03-01, at 33-34. Again, however, Staff must explain only what would occur if *its* proposal was adopted, not the proposals of other parties. Nor is Staff (or any other party) required to brainstorm a number of proposals and explain what would happen if BPA adopted each one. Most importantly, Staff is not required to identify non-rate proposals, which are outside the scope of this rate proceeding. Nonetheless, Staff did evaluate ratemaking and non-ratemaking alternatives through its testimony and in the public process prior to this rate proceeding. These materials are part of the record.

Finally, JP03 asserts Staff first proposed a bundle of ratemaking and non-ratemaking solutions and is now proposing only a ratemaking solution. JP03 Br., BP-18-B-JP03-01, at 64. This argument is misplaced. BPA’s focus in this rate case is on the first piece proposed by Staff—the ratemaking solution. The purpose of this rate case is to set rates, not implement changes to business practices or operating procedures. Linn *et al.*, BP-18-E-BPA-25, at 35. As discussed above, Staff’s evaluation demonstrated that the non-ratemaking alternative that appears to be favored by JP03 (*i.e.*, the scheduling system change) would negatively impact hourly customers more than a ratemaking alternative. Although JP03 makes the unsupported assertion that Staff’s evaluation of such alternatives was inadequate, JP03 had an opportunity to raise its concerns in the public process that evaluated those non-ratemaking alternatives but chose not to do so.

Decision

Staff conducted a meaningful evaluation of non-ratemaking solutions before the Initial Proposal in this rate case.

Issue 5.2.2.1.4

Whether the evidence of subscription levels and renewal rates for long-term firm transmission service provides a basis for changing the hourly rate design.

Parties' Positions

JP03 states that the Southern Intertie is fully subscribed and that renewal rates of long-term firm service have increased to 100 percent during the FY 2016–2017 rate period. JP03 Br., BP-18-B-JP03-01, at 69. JP03 argues that BPA has not proven the renewal rates or the incentive to purchase long-term firm transmission service has declined since the BP-16 rate proceeding. JP03 Br. Ex., BP-18-R-JP03-01, at 4. JP03 also claims that Staff and JP01 agree that customer decisions to renew long-term firm transmission service are evidence that the value of long-term firm transmission service is greater than hourly service. JP03 Br. Ex., BP-18-R-JP03-01, at 19.

JP01 argues that BPA can no longer be confident that long-term firm customers will continue to renew service. Multiple customers have declined long-term firm service when it was offered, and 2,801 MW of long-term firm transmission service (out of a total of 5,715 MW of BPA's north-to-south capacity) will terminate by the end of the BP-18 rate period unless customers decide to renew service. JP01 Br., BP-18-B-JP01-01, at 14.

BPA Staff's Position

Staff believes the 100 percent renewal rate in FY 2016 is attributable to the Administrator's commitment to address seams issues in the BP-16 Final Record of Decision. Linn *et al.*, BP-18-E-BPA-25, at 9-10. Staff also believes it is more prudent to respond to concerns expressed by a wide variety of customers, rather than waiting for cost recovery issues to materialize. *Id.*

Evaluation of Positions

One of the reasons that BPA did not adopt the rate proposal by Powerex and PPC in the BP-16 rate proceeding was that the Southern Intertie was fully subscribed at that time, meaning that BPA had no capacity available to offer to new requests for service. Administrator's Final Record of Decision, BP-16-A-02, at 111. Today BPA has 20 MW of unsubscribed capacity. JP03 Data Responses Admitted Into Evidence by BP-18-HOO-29, BP-18-E-JP03-17, at 332. According to JP03, Staff stated that BPA is in the process of executing a contract for this 20 MW of unsubscribed capacity. JP03 Br. Ex., BP-18-R-JP03-01, at 4. This is incorrect. Staff stated that BPA is in the process of executing a contract with a customer for 8 MW of long-term firm transmission service. This 8 MW is separate from the remaining 20 MW of unsubscribed capacity on the Southern Intertie. BPA is still attempting to find a purchaser for the remaining 20 MW of Southern Intertie service. *See* JP03 Data Responses Admitted Into Evidence by BP-18-HOO-29, BP-18-E-JP03-17, at 332. In any event, subscription levels remain high at this time; 20 MW is a relatively small amount compared to BPA's overall capacity on the Southern Intertie.

Renewal of long-term firm transmission service is governed by BPA's Open Access Transmission Tariff (OATT). Under the OATT, a customer that signs a contract for long-term firm transmission service (sometimes referred to as "reserving" service or having a "reservation") has the right to renew that service at the end of the reservation, subject to conditions that are not relevant here. Linn *et al.*, BP-18-E-BPA-25, at 9-11; JP03 Br., BP-18-B-JP03-01, at 69. As JP03 asserts, customers continually have reservations coming up for renewal, and there is always at least a theoretical risk that customers will not renew. JP03 Br., BP-18-B-JP03-01, at 69. Although this is nothing new, the decision of one customer to not renew service can quickly change the amount of unsubscribed capacity on the Southern Intertie. If just one or two customers decide not to renew service, BPA potentially faces an under-recovery of Southern Intertie costs in FY 2018–2019 and in future rate periods.

JP03 argues that customers renewed every Southern Intertie reservation eligible for renewal since the end of the BP-16 rate proceeding, and that this shows long-term firm service is more valuable than hourly service. *Id.* JP03's argument, however, only looks back at renewal rates from a limited time period to attempt to predict what renewal rates may be in the future. It does not account for the circumstances and timing surrounding BPA's treatment of the seams issues. A more complete look at renewals involves examining: (1) the renewal rates during the BP-16 rate proceeding, (2) the renewal rates since the end of the BP-16 rate proceeding, (3) any potential changes during the BP-18 rate period that may influence renewal rates, and (4) the facts and circumstances during all of these periods.

Shortly before the issuance of the BP-16 Final Record of Decision in July 2015, Powerex, BPA's largest Southern Intertie customer, and PacifiCorp decided not to renew service. Linn *et al.*, BP-18-E-BPA-25, at 12; Holcomb *et al.*, BP-18-E-JP03-01, at 95. These non-renewals were not captured in JP03's limited focus on renewals since the end of the BP-16 rate proceeding, although JP03 did acknowledge in its testimony that Powerex has cancelled some Southern Intertie reservations in the past. At the same time, Powerex is using far more hourly service than any other customer. Holcomb *et al.*, BP-18-E-JP03-01, at 94-95. Powerex has 1,579 MW eligible for renewal in the FY 2018–2019 rate period, and it would be imprudent to dismiss the possibility that Powerex might not renew some of its reservations in favor of continuing a move towards hourly service. Linn *et al.*, BP-18-E-BPA-25, at 9.

JP03 claims that the "objective evidence" shows that Powerex has partially renewed two reservations in recent years. JP03 Br. Ex., BP-18-R-JP03-01, at 68. BPA agrees that this evidence is uncontroverted, but BPA interprets the evidence differently than JP03. From BPA's perspective, this evidence highlights a troubling trend. Powerex has either refused to renew or partially renewed its eligible long-term firm transmission service reservations on the Southern Intertie since 2015. Holcomb *et al.*, BP-18-E-JP03-01, at 95; JP03 Br. Ex., BP-18-R-JP03-01, at 68; JP03 Data Responses Admitted Into Evidence by BP-18-HOO-29, BP-18-E-JP03-17, at 332. It has not fully renewed a single reservation. It also has removed all of its requests from the queue during this time, and, as stated above, has purchased large amounts of hourly transmission service. Holcomb *et al.*, BP-18-E-JP03-01, at 94-95. Although the amount Powerex did not renew in FY 2017 is relatively small (20 MW), BPA cannot discount the possibility that this trend will continue, and potentially accelerate, if BPA fails to take action in

this rate proceeding. Powerex's 1,579 MW of reservations eligible for renewal in FY 2018–2019 is more than the 1,303 MW of reservations that all customers had up for renewal in FY 2016–2017. BPA wants to incentivize its long-term firm transmission customers to fully renew transmission service due to the decrease in the size of the queue and customers not accepting offers of new transmission service on the Southern Intertie. See Issue 5.2.2.1.5.

As to the fact that all customers with expiring reservations renewed during FY 2016–2017, no party disputes the 100 percent renewal rate since the end of the BP-16 rate proceeding. Viewing that piece of evidence in isolation would provide no basis for changing the hourly rate design, but also provides an incomplete view of customer behavior with respect to renewals. The evidence shows that while customers have renewed 100 percent of reservations since the end of the BP-16 rate proceeding, customers have not renewed all reservations during other relevant periods. BPA does not draw any firm conclusions based on that evidence alone. BPA attaches significance, however, to the fact that the non-renewals prior to the end of the BP-16 rate proceeding occurred at a time when customers had raised the seams issues to BPA but BPA had made no commitment to address or even examine the issues. The renewals since the end of the BP-16 rate proceeding, on the other hand, coincided with BPA's commitment in the BP-16 Final Record of Decision to examine the issue, Staff's commitment in the public process that followed the BP-16 rate proceeding to pursue a rate design change, and Staff's follow-through on its commitment by proposing the change in this proceeding. Given the evidence of the broad coalition of support for a change that emerged from the public process that followed the BP-16 rate proceeding, it is reasonable to conclude that customers with renewal decisions since the end of that proceeding would take into account the efforts to actively address this issue. Cross-Ex. Tr. at 111; *see also* Linn *et al.*, BP-18-E-BPA-25, at 10.

JP03 argues that customers did not know the outcome of this rate proceeding when making renewal decisions since the end of the BP-16 rate proceeding and, therefore, could not have relied on it when making these decisions. JP03 Br., BP-18-B-JP03-01, at 12. Although this is true, it assumes that customers would have a singular focus on the lack of certainty about the outcome of the BP-18 rate proceeding rather than taking into account all of the best information available at the time. The best information available at the time would have included the uncertainty about the BP-18 rate proceeding, but it also would have included BPA's commitment to examine and address the issues through ratemaking or non-ratemaking solutions, and Staff's proposal to change the hourly rate design in this proceeding. BP-16 Administrator's Final Record of Decision, BP-16-A-02, at P-2; Linn *et al.*, BP-18-E-BPA-25, at 10. It is reasonable to conclude that customers took BPA's commitment to address seams issues into consideration when they made their renewal decisions and that this limited the amount of long-term firm transmission that was not renewed by Powerex and other long-term firm transmission customers. Similarly, it is reasonable to conclude that if BPA took no action to address the seams issue, customers would take that into consideration when making their renewal decisions in FY 2018–2019 and that would cause more customers to not renew transmission service.

BPA acknowledges that all the positions and conclusions on this topic, including those of JP03 and Staff, involve speculating to some extent about what customers are thinking. This issue plainly leaves room for disagreement, and BPA views customers' perception of the history of

BPA's treatment of this issue differently than JP03. The issue of customer perception highlights an important point. The members of JP03 purchase no long-term firm transmission service on the Southern Intertie from BPA, and JP03's theories about the value of long-term firm transmission service at times reflect a different perception than customers that actually purchase that service from BPA. For example, JP03 states that the emerging CAISO energy imbalance market (EIM) "should serve to enhance the value of BPA's long-term firm service on the Southern Intertie." Holcomb *et al.*, BP-18-E-JP03-01, at 14. The EIM is a real-time wholesale energy market that includes participants in the Pacific Northwest, California, Nevada, and Arizona. PacifiCorp participates in the CAISO EIM, yet PacifiCorp chose not to renew some of its long-term service in 2015. PacifiCorp's action provides more objective and compelling evidence of the value of long-term firm transmission service to EIM participants that actually purchase such service from BPA. Moreover, it shows that customers purchasing long-term firm transmission service from BPA view circumstances differently than JP03. For all of these reasons, BPA disagrees with JP03's argument that the 100 percent renewal rate since the BP-16 rate proceeding shows that a rate design change is unnecessary.

JP03 argues that Staff has conceded that market certainty about renewals has increased since the BP-16 rate proceeding. JP03 Br., BP-18-B-JP03-01, at 31-33. This mischaracterizes Staff's position. For purposes of forecasting sales for the Initial Proposal, Staff assumed that customers would renew all of the long-term firm reservations that would otherwise terminate in the BP-18 rate period, but Staff's sales forecast also assumed that BPA would adopt Staff's proposed hourly rate design. Cross-Ex. Tr. at 97. The sales forecast that Staff prepared for the Initial Proposal included assumptions that are consistent with the rate design and other policies in the Initial Proposal. Based on the results of the public process following the BP-16 rate case, it was reasonable to assume that long-term firm customers concerned about the value of their service were satisfied with Staff's proposal to change the rate design and would renew their service if Staff's proposal were adopted. Contrary to JP03's claims, this is, in fact, what Staff assumed. JP03 Br. Ex. BP-18-R-JP03-01, at 18 n.4; Linn *et al.*, BP-18-E-BPA-25, at 14. Furthermore, Staff's testimony states that "the risk of under-recovering the costs of the Southern Intertie segment has increased since the BP-16 rate proceeding" due "to the reliance on sales of long-term firm service to recover the costs of the majority of the Southern Intertie." Fredrickson *et al.*, BP-18-E-BPA-12, at 4. This again shows that Staff did not concede that market certainty has increased since the BP-16 rate proceeding.

JP03 faults Staff for not conducting "market intelligence" to support its sales forecast as that term is described in the Transmission Rates Study. JP03 Br., BP-18-B-JP03-01, at 31. Staff acknowledged this on cross-examination. Cross-Ex. Tr. at 99. JP03 ignores, however, the value of the information gleaned from the public process, in which a large and diverse group of customers expressed concern with the status quo.

JP03 also states that Staff refuses to speculate on future uses of the Eastern Intertie after Colstrip units 1 and 2 are shut down, but is willing to speculate that customers may not renew long-term firm transmission service on the Southern Intertie. JP03 Br., BP-18-B-JP03-01, at 69-70. The circumstances on the Eastern Intertie are different from those on the Southern Intertie. Most importantly, the Montana Intertie Agreement protects BPA against cost recovery issues on the

Eastern Intertie. It does not expire until 2027, which is well after the FY 2018–2019 rate period covered by this proceeding. BPA does not have such an agreement for its 5,715-MW share of Southern Intertie capacity. In addition, most Southern Intertie customers believe that BPA needs to adopt a rate design change. This consensus among Northwest public power utilities, renewable developers, and power marketers does not exist on the Eastern Intertie. This shows that Staff’s concerns regarding the Southern Intertie are more than just speculation.

JP03 argues that BPA “improperly shifted the burden of proof” by requiring JP03 to conclusively demonstrate that renewal rates reflect adequate incentive to purchase long-term firm transmission service. JP03 Br. Ex., BP-18-R-JP03-01, at 3-4. JP03 claims that BPA must prove that the renewal rate has declined to adopt Staff’s proposal. *Id.* at 4. BPA must support its ratemaking decisions with “substantial evidence in the rulemaking record . . . considered as a whole.” Northwest Power Act, § 9(e)(2), *codified at* 16 U.S.C. § 839f(e)(2). Given this standard, BPA cannot base its decision solely on the fact that customers have renewed service during FY 2016–2017. BPA has not shifted any burden to JP03, but BPA cannot focus on one piece of evidence alone to assess the meaning of customer renewals. As described above, BPA has considered evidence of renewals from all the relevant time periods and the facts and circumstances during those periods as well.

Finally, potential changes in California’s generation mix during the FY 2018–2019 rate period may also influence renewal rates. Installed solar generation capacity in California is projected to increase by up to 9,000 MW by 2020. Deen & Wellenius, BP-18-E-JP01-01, at 21. This amount of solar generation will continue to decrease net load in California during daylight hours. Fredrickson *et al.*, BP-18-E-BPA-12, at 5. The decrease in net load during daylight hours further reduces the incentive for customers to hold long-term firm transmission service because customers will not need as much capacity during these hours. Customers could, therefore, purchase hourly transmission service at a lower cost, unless BPA changes its hourly rate methodology.

Decision

The evidence of subscription levels and renewal rates from all the relevant time periods, considered in connection with the facts and circumstances at the time, provides a basis for changing the hourly rate design.

Issue 5.2.2.1.5

Whether the evidence of BPA’s decreasing queue of pending requests for service on the Southern Intertie provides a basis for changing the hourly rate design.

Parties’ Positions

JP03 argues that there is no substantial evidence the queue is declining in size. JP03 Br. Ex., BP-18-R-JP03-01, at 25-27. It claims that the queue has gone up, down, and then up again since the 2009 CAISO rule changes. *Id.* at 26. It also states that there is no causal correlation between the size of the queue and seams issues. *Id.* at 27. JP01 states that “past behavior of customers in

the queue makes it evident that BPA’s actual ability to sell [long-term firm] service may be well below the amount of requests in the queue, which itself is already greatly diminished.” JP01 Br., BP-18-B-JP01-01, at 14. Furthermore, BPA’s public process sufficiently ties the concerns about the value of long-term firm service to the decreased appetite for this service, reflected in the diminishing queue for long-term firm service. *Id.* at 15.

BPA Staff’s Position

The pending requests in the queue for long-term firm service on the Southern Intertie have decreased by thousands of megawatts since 2015. Linn *et al.*, BP-18-E-BPA-25, at 4-5. This decline is attributable to a combination of the CAISO’s market rules and the duck curve. Holcomb *et al.*, BP-18-E-JP03-01-AT01, at 25-26 (SM-BPA-26-31). If long-term firm customers do not renew service, BPA’s queue is likely not large enough for BPA to sell all available capacity, especially because customers have rejected more than 500 MW of offers since January 2015. Linn *et al.*, BP-18-E-BPA-25, at 7.

Evaluation of Positions

Under BPA’s OATT, when a customer submits a request for new long-term firm transmission service on the Southern Intertie or a request to renew long-term firm transmission service, BPA places that request in a queue with all other pending requests. *Id.* at 8. BPA grants renewal requests subject to several conditions that are not relevant here. *Id.* at 9-10. Requests for new service are placed in the queue in the order in which they are submitted. Linn *et al.*, BP-18-E-BPA-25, at 4. BPA then determines if it has available capacity for these new requests. JP03 Br., BP-18-E-BPA-08, at 28-29. If it has available capacity, it offers service in queue order, and the customer can either accept or reject that offer of service. *Id.* If the customer accepts the offer, its request is granted and removed from the queue. Customers that accept service are said to have “reserved” service. If the customer rejects the offer, its request is rejected and removed from the queue. *Id.*

At the end of the BP-16 proceeding, BPA had a queue of approximately 2,167 MW of pending requests for long-term firm transmission service on the Southern Intertie. Linn *et al.*, BP-18-E-BPA-25, at 14. This “long queue of customers waiting for capacity” on the Southern Intertie was one of the reasons for not adopting Powerex’s and PPC’s rate proposal in that case. Administrator’s Final Record of Decision, BP-16-A-02, at 111.

Since the end of the BP-16 proceeding, the number of requests in the queue has declined by roughly half. Although JP03’s Brief on Exceptions states “there is no substantial evidence the queue is declining in size,” this is contrary to JP03’s testimony which concluded that the “net size of the queue has decreased since the end of the BP-16 case.” JP03 Br. Ex., BP-18-R-JP03-01, at 27; Holcomb *et al.*, BP-18-E-JP03-01, at 18.

The queue now has either 762 MW per Staff’s calculation, or 1,099 MW per JP03’s calculation. JP03 Br., BP-B-JP03-01, at 27 n.67. JP03’s calculation includes a pending request from Powerex to renew 337 MW of an expiring 357-MW reservation, whereas Staff’s does not. Requests to renew service are technically placed in the pending queue. If one counts Powerex’s

renewal request to be in the pending queue, it means that the entire amount of Powerex's 357-MW expiring reservation has not been sold. In terms of how the queue works, a customer cannot be waiting in the queue for service that it has already purchased. Therefore, JP03's calculation would mean that a significant amount of Southern Intertie capacity (357 MW) is unsold. However, it is reasonable to assume that Powerex will renew service for 337 MW because it submitted a renewal request for that amount. This would leave BPA with a queue of 762 MW, and 20 MW of unsubscribed capacity. JP03 argues that the 337 MW must be considered to be "in the queue." JP03 Br. Ex., BP-18-R-JP03-01, at 26. If this is the case, then this would leave BPA with a queue of 1,099 MW and 357 MW of unsubscribed capacity. As described above, the lack of unsubscribed capacity was one of the reasons why BPA did not adopt the Powerex and PPC proposal in the BP-16 proceeding. If there currently is a substantial amount of unsubscribed capacity on the Southern Intertie, this would provide additional support for Staff's proposal.

JP03 argues that BPA "contrives to redefine" the way that Staff has calculated the amount of requests in the queue. *Id.* This is not the case. BPA has tried to reflect JP03's arguments about the queue size by presenting both calculations (762 MW and 1,099 MW) and by granting JP03's request to take official notice of the snapshot of the queue that JP03 attached to its Initial Brief. JP03 apparently remains unsatisfied. The important point, however, is that the amount of requests in the queue has declined in recent years. Using either Staff's or JP03's calculation, the queue is roughly half of what it was at the end of the BP-16 proceeding.

The number of megawatts in the queue is important because it represents the offers of new service that BPA could make to customers if capacity becomes available. Although JP03 argues that "[n]othing prevents BPA from offering long-term firm transmission capacity it has available, even if the offer exceeds the size of the queue," this is not correct. *Id.* at 28. Under BPA's OATT, a customer must submit a request in BPA's transmission queue to receive an offer of service from BPA. Deen & Wellenius, BP-18-E-JP01-02, at 4. Also, entering the queue gives customers the option—but not the obligation—to purchase long-term transmission service. *Id.*

The 762 MW of requests (or 1,099 MW, using JP03's calculation) currently in the queue is small compared to the 2,801 MW of long-term firm transmission service on the Southern Intertie that is up for renewal during FY 2018–2019. Again, this is more than double the amount up for renewal during FY 2016–2017. Linn *et al.*, BP-18-E-BPA-25, at 14-15. The reduction in the amount of megawatts in the queue increases the risk that capacity would not be fully subscribed (and BPA would face cost recovery issues) if customers do not renew long-term firm service.

This risk is compounded by the fact that pending requests in the queue are held by only a few customers. Five customers have a total of eight pending requests for service (two requests on the AC path and six requests on the DC path). JP03 Br., BP-18-B-JP03-01, Attachment; *see* description of the Southern Intertie at Fredrickson *et al.*, BP-18-E-BPA-07, at 4. This is a small number of customers, and it indicates that the actions of only a few customers could result in a cost recovery issue. If one or more long-term firm reservations on the Southern Intertie are not renewed, thus freeing up capacity for offers to customers with pending requests, and then a few customers in the queue refuse a subsequent offer of service, this capacity would be unsold. Depending on the amount, this could cause a cost recovery issue. Customers in the queue have

rejected offers for a total of 510 MW of new service since January, 2015. Linn *et al.*, BP-18-E-BPA-25, at 7. Several customers rejecting service since January, 2015, currently have requests in the queue. Therefore, BPA cannot discount the possibility of customers rejecting new service.

JP01, JP03, and Staff have debated why customers have left the queue. These arguments are discussed below, but the most important point is that the queue has declined considerably by almost any measure. In September 2014, the queue was at 6,228 MW. Fredrickson *et al.*, BP-18-E-BPA-12, at 7. It is now a fraction of that amount. At the same time, virtually all long-term firm customers have told BPA that an hourly rate design change is necessary. Linn *et al.*, BP-18-E-BPA-25, at 6.

JP03's arguments that Staff has failed to pinpoint why the queue is decreasing falls flat given the concerns that BPA is facing. For instance, JP03 points out that the queue tripled in size from 2009 to 2012, and it argues that this increase shows that the 2009 CAISO market rules could not be responsible for a decrease in the queue. JP03 Br., BP-18-B-JP03-01, at 26. JP03 also argues that Staff stated that the "2009 market rule changes had the *immediate* effect of reducing the value of [long-term firm transmission service]." JP03 Br., BP-18-B-JP03-01, at 25 (emphasis in original). This paints an incomplete picture of the circumstances about which BPA is concerned. Although Staff states that the 2009 market rules led to a decline in value of long-term firm transmission service relative to hourly transmission service, it does not necessarily follow that the 2009 market rules—by themselves—would cause an increase or a decline in the queue. As stated in Issue 5.2.2.1.1, the 2009 CAISO market rules made it feasible for customers to switch from long-term firm transmission service to hourly service. The increasing amount of solar generation in California that Staff and others have identified since the BP-16 rate proceeding has made it more economic.

Since the BP-16 rate proceeding, however, Staff has analyzed the duck curve and found that the combination of the duck curve and 2009 CAISO market rules is causing the decline in the queue. Holcomb *et al.*, BP-18-JP03-01-AT01, at 25-26 (SM-BPA-26-31). The duck curve has reduced the peak number of hours in California to five per weekday. This makes hourly transmission service an economic choice because it is cheaper to reserve transmission service for 25 hours per week than to purchase long-term firm transmission service under BPA's existing hourly rate structure.

Since solar generating capacity was less than 1,000 MW in the CAISO at the beginning of 2013, it would have caused a very minor reduction in net load during the middle of the day. Linn *et al.*, BP-18-E-BPA-25, at A-1. In other words, the trend seen in the duck curve was not present from 2009 to 2012, and it would have little to no effect on the queue. Since that time, solar generating capacity in the CAISO has increased to over 10,000 MW. *Id.* This has reduced net load in California during daytime hours, thereby undermining the economic incentive to purchase long-term firm transmission service. Fredrickson *et al.*, BP-18-E-BPA-12, at A-1 to A-5.

The 2009 CAISO market rules contribute to this problem because they effectively eliminated much of the priority that long-term firm transmission normally has had over hourly non-firm transmission when selling into the CAISO market. See Issue 5.2.2.1.1. Therefore, the

combination of customers needing to reserve hourly transmission only for the five-hour peak in California and the lack of priority of firm transmission over non-firm transmission service make long-term firm transmission service less attractive than it was in the BP-16 rate proceeding.

JP03 also argues that the queue has declined because, for a number of months, BPA had an “odd-lot” of 8 MW available to sell. JP03 Br., BP-18-B-JP03-01, at 29. In accordance with its OATT, BPA offered this capacity to customers, and customers rejected it. *Id.* JP03 speculates that this is because the amount of capacity offered was less than customers had requested. *Id.* Even if that is true, it still does not explain the decline in the queue. If customers still wanted service on the Southern Intertie for their requested amount, they could have submitted a new request for service after they were removed from the queue. This did not happen.

JP03 argues that customers whose requests were removed may be waiting to submit a request for long-term firm transmission service until there is enough capacity available to meet the full amount of their requests. JP03 Br. Ex., BP-18-R-JP03-01, at 28. This is extremely unlikely. If customers wanted Southern Intertie service, BPA must assume that they would ask for it. It is not prudent for BPA to assume the risk of an under-recovery due to customers not renewing transmission service and hope that customers will enter the queue to take this service.

JP03’s argument is further undermined by its statement that Staff has “concede[d]” that customers have been in the queue for a long period of time and, in the interim, their needs have changed. JP03 Br., BP-18-B-JP03-01, at 27; Holcomb *et al.*, BP-18-E-JP03-01-AT01, at 62 (SM-BPA-26-92). If that is the case, the queue is declining because customers’ needs are changing, not because they are reluctant to enter the queue for fear of receiving less than a full offer of service. If long-term firm transmission service is as valuable as JP03 claims, it is hard to see why customers’ needs for that service would have changed. Rather it is probable that customers’ lack of interest in the queue reflects the questions about the need for long-term firm transmission, which has to do with the seams issues and the duck curve. Even if the decline in the queue is not due to seams issues or the duck curve, the amount of requests in the queue has declined precipitously since the last rate case. As a result, if customers decide not to renew existing reservations, there is an insufficient number of requests and megawatts for BPA to make offers to replace them, even if one assumes that the customers in the queue would accept service if offered.

Similarly, JP03’s statement that customers in the queue that are in the act of competing for long-term firm service with others in the transmission queue shows that long-term firm transmission service is valuable. JP03 Br. Ex., BP-18-R-JP03-01, at 31. JP03’s argument on this point is confusing, because it seems to cut against JP03. Since the beginning of FY 2016, customers had the option to compete for 230 MW of long-term firm transmission service but chose not to do so. Fredrickson *et al.*, BP-18-E-BPA-12, at 8. This again shows the lack of interest in long-term firm transmission service.

JP03 argues that BPA refused to adopt Powerex and PPC’s proposal in the BP-16 rate proceeding, even though Powerex removed 4,000 MW from the queue. JP03 Br., BP-18-B-JP03-01, at 29. But Powerex was only one customer, and BPA still had more than 2,000 MW in the queue at the time of the BP-16 Final Record of Decision. The risk associated with customers

potentially deciding not to renew all or part of 1,303 MW of reservations (the amount up for renewal in FY 2016–2017) is more acceptable when BPA has “a long queue of customers” with more than 2,000 MW of pending requests for service on the Southern Intertie. Administrator’s Final Record of Decision, BP-16-A-02, at 111. Since the end of BP-16, an extensive public process has revealed that concerns about long-term firm service are widely shared among BPA’s Southern Intertie transmission customers. At the same time, the queue continues to decline. See discussion above at Issue 5.2.2.1.2. It is now down to 762 MW (or 1,099 MW), and 2,801 MW is up for renewal in FY 2018–2019. JP03 Br., BP-18-B-JP03-01, at 27, n.67; Linn *et al.*, BP-18-E-BPA-25, at 14-15.

In the BP-16 rate proceeding, the “long queue of customers” provided some comfort that the risk of customers not renewing service was within acceptable limits, because there were plenty of requests in the queue to offer service if capacity became available. Administrator’s Final Record of Decision, BP-16-A-02, at 111. As explained above, circumstances have changed significantly in recent years. The amount of requests up for renewal in the rate period is significantly greater than the amount of requests in the queue. This provides no comfort when weighing BPA’s concerns about cost recovery.

Decision

The decline in BPA’s queue provides a basis for changing the design of hourly Southern Intertie rates.

Issue 5.2.2.1.6

Whether BPA should reject Staff’s proposal in this case for the same reasons it rejected Powerex’s and PPC’s proposal in the BP-16 rate proceeding.

Parties’ Positions

JP03 argues that Staff’s proposed rate design would increase rates by essentially the same amount as Powerex’s and PPC’s proposal in the BP-16 rate proceeding, and the reasons why BPA rejected those customers’ proposal still apply today. JP03 Br., BP-18-B-JP03-01, at 65-67. Specifically, JP03 states that BPA: (1) did not accept Powerex’s and PPC’s argument that the proposed rate increase is comparable to rates charged by SMUD, TANC, and LADWP; (2) found that a long-term firm customer pays more for transmission service than an hourly customer because it can use more transmission service; (3) found long-term firm service is superior because hourly service is often unavailable; and (4) found that Powerex’s and PPC’s proposal overlooks non-CAISO uses of the Southern Intertie. *Id.* at 65-70.

JP01 argues that Staff’s proposal in this proceeding differs materially from Powerex’s and PPC’s proposal in BP-16. JP01 Br., BP-18-B-JP01-01, at 22. Specifically, JP01 states that Staff’s proposal is based on a well-documented, uncontroverted change in the high-value hours in California and not on historical usage of hourly service on the Southern Intertie. *Id.*

BPA Staff's Position

Nothing decided in the BP-16 rate proceeding precludes adoption of Staff's proposal in this case.

Evaluation of Positions

In BP-16, Powerex and PPC proposed to establish the rate for hourly non-firm transmission service on the Southern Intertie based on actual reservations of hourly non-firm service from FY 2012–2014. Administrator's Final Record of Decision, BP-16-A-02, at 108. They calculated the actual use of hourly non-firm service to be approximately 23 hours per customer per week. *Id.* at 108-109. Based on that calculation, they proposed setting the hourly non-firm rate so that a customer that reserves 1 MW of hourly non-firm service for 23 hours per week pays the same amount as a customer that reserves 1 MW of long-term firm service. *Id.* This would have resulted in a rate of 12.97 mills per kWh in the FY 2016–2017 rate period. *Id.* at 109.

In the Final Record of Decision in the BP-16 proceeding, BPA rejected the Powerex and PPC proposal in part because the calculation of the average amount of hourly transmission reservations did not take into account hourly reservations that were denied. Administrator's Final Record of Decision, BP-16-A-02, at 110. BPA found that Powerex's and PPC's proposal did not reflect hourly demand for hourly service and, even if it did, BPA's hourly rate design "is not an attempt to anticipate the number of hours that the average customer will use hourly non-firm transmission in a given week." *Id.*

Staff's proposal in this proceeding is not based on the average number of hourly reservations made by customers. Staff's proposal is to update the number of peak hours per week in California used to calculate the hourly rate. As described above, Staff argues that the amount of solar generation in California has reduced the number of peak hours in California to 25 hours per week (5 hours per day multiplied by five days), which is significantly less than the 80 hours per week (16 hours per day multiplied by five days) assumed in the existing rate design. *See* Fredrickson *et al.*, BP-18-E-BPA-12, at 4-5. Staff proposes to set the rate for hourly transmission service on the Southern Intertie so that a customer that reserves 1 MW of hourly service for 25 hours per week pays the same amount as a customer that buys 1 MW of long-term firm service. This results in a rate of 9.56 mills per kWh. Like BPA's existing methodology, Staff's proposal is not an attempt to anticipate the number of hours that customers will use hourly transmission. *Id.* It is meant to provide an incentive to purchase long-term firm service. *Id.*

JP03 argues that Staff's proposal is unnecessary, because the existing rate design provides adequate incentive to reserve long-term firm transmission service. *See* JP03 Br. Ex., BP-18-R-JP03-01, at 52-53. JP03 points out that BPA concluded in the BP-16 rate proceeding that hourly non-firm service on the Southern Intertie was unavailable in a significant number of hours and that this lack of availability created adequate incentive to continue reserving long-term firm transmission service. *Id.*; *see* Administrator's Final Record of Decision, BP-16-A-02, at 111. JP03 argues the risk that hourly service will be unavailable in FY 2018–2019 means that the existing rate design continues to create adequate incentive to reserve long-term firm transmission service. JP03 Br. Ex., BP-18-R-JP03-01, at 52-53.

The evidence in this proceeding supports a different conclusion about the availability of hourly service than the one reached in the BP-16 rate proceeding. In its direct testimony, JP03 examined hourly data on denied requests for southbound hourly service on the Southern Intertie from October 2009 through August 2016 and concluded that hourly requests were granted “most of the time.” Holcomb *et al.*, BP-18-E-JP03-01, at 54. JP03 has not squared the arguments in its brief that the existing rate design creates adequate incentive to choose long-term firm service with its testimony that hourly service is available most of the time.

Furthermore, the conclusion that hourly transmission is available most of the time may actually understate the amount of hourly transmission service that is available. Even though most hourly requests are granted, Staff’s analysis since the BP-16 rate proceeding has shown that denial of a customer’s initial request for hourly service does not mean that the customer will be unable to obtain hourly service at all. In a response to a data request from JP03, Staff explains that many customers submit multiple requests for the same amount of demand. Holcomb *et al.*, BP-18-E-JP03-01-AT1, at 59 (Data Response SM-BPA-26-88). For instance, if a customer requests 50 MW of service for 23 hours and that request is denied, it may subsequently request 50 MW of service for 22 hours to see if that request is granted. *Id.* JP03’s analysis of denied hourly requests did not take into account that customers whose initial requests for hourly service were denied may have ultimately obtained service through a subsequent request.

In addition, the market for resales of long-term firm transmission service shows relatively little unmet demand for hourly service. Customers may resell long-term firm transmission capacity for periods as short as one hour. Only one resale transaction in FY 2016 had a price greater than the hourly rate. Holcomb *et al.*, BP-18-E-JP03-01, at 31-32. Since the prices for resale transactions are almost always lower than the hourly rate, it is reasonable to conclude that hourly service is widely available. If hourly service was not widely available, long-term firm transmission customers would be able to sell hourly capacity in excess of the hourly rate. The record in the BP-16 rate proceeding did not include this resales data.

JP03 states that Staff’s proposal “confuses a customer’s incentive with its ability to purchase transmission service over a number of peak hours.” Holcomb *et al.*, BP-18-E-JP03-01, at 42 (emphasis omitted). But this is true of BPA’s existing rate design, which JP03 wants BPA to retain. That is to say, there is no guarantee that customers will be able to reserve hourly transmission service for 80 hours per week, 25 hours per week, or any other number of hours per week, and, as stated above, hourly service is often available either from BPA or on the resale market. BPA is more concerned that “not providing an adequate incentive for long-term firm use increases the chance that customers will not reserve long-term service, thereby making short-term use readily available.” Linn *et al.*, BP-18-E-BPA-25, at 22. This would result in no longer having a stable and predictable source of revenue to recover Southern Intertie costs and make cost recovery much more volatile. See Fredrickson *et al.*, BP-18-E-BPA-12, at 7.

JP03 argues that BPA found in the BP-16 Final Record of Decision that it was appropriate for long-term firm transmission users to pay more than hourly customers “because they can use the Southern Intertie more.” JP03 Br., BP-18-B-JP03-01, at 66. JP03 references the finding that a customer reserving transmission 23 hours per week should not pay more, in total, than a long-term firm customer. Administrator’s Final Record of Decision, BP-16-A-02, at 109. However,

under Staff's proposal, an hourly customer reserving transmission 23 hours per week would still pay less, in total, than a long-term firm customer. Similarly, an hourly customer pays more on a per-hour basis than a long-term firm customer under either BPA's existing methodology or Staff's proposed methodology. More importantly, the statement in the BP-16 Final Record of Decision was made in the context of fairly allocating costs between long-term and hourly customers. BPA's existing methodology and Staff's proposed methodology are intended to ensure that a customer that reserves service for the peak hours of the day pays the same contribution to fixed costs as a customer that reserves service on a long-term basis. Fredrickson *et al.*, BP-18-E-BPA-12, at 3. Staff has shown the number of peak hours in California is 25 hours per week. See Issue 5.2.2.1.7. Given this finding, customers that use transmission for 25 hours per week should make the same contribution to fixed costs as customers that reserve service on a long-term basis.

JP03 is incorrect that the BP-16 Final Record of Decision concluded that long-term firm transmission customers should pay more than hourly customers because long-term firm transmission service is superior. JP03 Br. Ex., BP-18-R-JP03-01, at 48. As stated above, the existing methodology makes hourly service more expensive than long-term firm service on a per-hour basis. A customer that uses 80 hours of hourly service per week pays the same as a customer that has long-term firm service for 168 hours per week. In any event, whether one service is superior to another largely depends on customer preferences in terms of flexibility, cost, and availability. See Linn *et al.*, BP-18-E-BPA-25, at 24 (discussing the attributes of hourly and long-term firm service).

JP03 states that Staff has attempted to justify its proposal by comparing Staff's proposed rate to SMUD's, TANC's, and LADWP's rates. In the BP-16 Final Record of Decision, BPA found that although the absolute levels of SMUD's, TANC's, and LADWP's rates are close to the rates under Powerex and PPC's proposal, "their [hourly] rates are only meaningful when compared to their long-term rates." Administrator's Final Record of Decision, BP-16-A-02, at 110. This comparison revealed that a customer that reserves 1 MW for 60 hours on TANC's system, for example, pays the same amount as a customer that reserves 1 MW of TANC's long-term firm transmission service. This result is much more similar to BPA's existing assumption of 80 peak hours per week than Powerex's and PPC's proposal to use 23 hours. *Id.*

In this proceeding, Staff did not compare the absolute level of its proposed rate with SMUD's, TANC's, and LADWP's rates to demonstrate the reasonableness of its proposal. Staff made that comparison to respond to JP03's argument that wholesale markets—and JP03—would be harmed by Staff's proposal. Cross-Ex. Tr. at 161. Staff stated "it seemed relevant to us that there were a number of rates out there [SMUD, TANC, LADWP] at about the same level that don't seem to be causing that kind of harm." *Id.* The potential harm of Powerex's and PPC's proposal on wholesale markets was not an issue in the BP-16 rate proceeding.

JP03 alleges that Staff, like Powerex and PPC in the BP-16 rate proceeding, ignored the substantial non-CAISO uses of the Southern Intertie. JP03 Br., BP-18-B-JP03-01, at 70. This is incorrect. Both JP01 and Staff state that non-CAISO transmission providers in California do not recognize the tagging priority of neighboring OATT transmission providers such as BPA. Data Requests and Responses Admitted into Evidence, BP-18-E-JP01-03, at 18; Cross-Ex. Tr. at 214.

Staff states that non-CAISO transmission providers “perform the curtailments on the majority of tags moving [north to south] across the Southern Intertie; therefore, the transmission priority of the product used on their systems [not BPA’s] determines the order of curtailment.” Data Responses and Requests Admitted into Evidence, BP-18-E-JP01-03, at 18. As a result, “the transmission priority of the service used on BPA’s system is irrelevant and BPA firm transmission may be curtailed ahead of BPA non-firm transmission.” *Id.* This information was not part of the record in the BP-16 rate proceeding, and it shows that the seams issues are larger than just those with the CAISO. Similarly, Staff has shown that increased solar generation is not limited to the CAISO because California’s renewable portfolio standards apply to California utilities that are not members of the CAISO. Linn *et al.*, BP-18-E-BPA-25, at 11. JP03 itself has described how participants outside of the CAISO market have had to adjust trading activities because of decreasing net load in the middle of the day, including using power products that focus on the evening peak identified by Staff. *Id.* at 19.

JP03 argues repeatedly that circumstances have not changed since BPA rejected the PPC and Powerex proposal in the BP-16 rate proceeding. At the end of the BP-16 rate proceeding, BPA simply was not ready to adopt a significant rate increase to address the seams issues identified by Powerex and PPC based on its knowledge of the issues at that time. The public process following the BP-16 rate proceeding and this proceeding have allowed all parties and stakeholders to examine this issue in a much more comprehensive manner. Based on the more thorough understanding that BPA has now, including how the increasing amount of solar generation in California heightens the effect of the seams issues, BPA is not in the same situation that it was two years ago. In addition, Staff’s proposal in this proceeding is materially different from Powerex’s and PPC’s proposal in the BP-16 rate proceeding in terms of both underlying rationale and overall magnitude of the rate increase. In short, the decision in the BP-16 rate proceeding addressed a different proposal, different evidence, and a different level of knowledge about the seams issues between the Pacific Northwest and California.

Decision

None of the findings in the BP-16 Final Record of Decision preclude BPA from adopting Staff’s proposal in this rate proceeding.

Issue 5.2.2.1.7

Whether evidence in the record supports a conclusion that there are 25 peak hours per week in California.

Parties’ Positions

JP03 argues that there is no evidence supporting Staff’s claim that the number of peak hours in California has been reduced to five hours per day, five days per week. JP03 Br., BP-18-B-JP03-01, at 42-43. JP03 faults Staff for not determining the precise number of peak hours in California in the BP-14 and BP-16 rate periods to demonstrate a reduction. *Id.* JP03 also argues

that “high Southern Intertie use continues to occur in a large number of hours” and that there are heavy load hours seven days per week. *Id.* at 52.

JP01 agrees with Staff that demand in California is highest only in a relatively small number of evening hours during weekdays. JP01 Br., BP-18-B-JP01-01, at 22.

BPA Staff’s Position

Staff’s analysis and independent analysis performed by the CAISO demonstrate that there are five peak hours per day in California. Linn *et al.*, BP-18-E-BPA-25, at 1-4. Staff based its findings on its analysis of the increase in renewable resources in California since 2013, the decrease in net load in California during that time, hourly requests for transmission service becoming increasingly concentrated in the evening peak, line loadings on the Southern Intertie, and new power products being developed to meet evening peak demands. *Id.* at 3-4.

Evaluation of Positions

JP03 argues that there is no evidence to support Staff’s testimony that the number of peak hours (or heavy-load hours) in California has declined to five hours in the evening. JP03 Br., BP-18-B-JP03-01, at 42-43. JP03 claims that Staff has not defined “peak hours” or analyzed whether the number of peak hours has declined. JP03 Br. Ex., BP-18-R-JP03-01, at 20. This is incorrect. BPA’s existing hourly rate methodology assumes that there are 80 peak hours per week in California. Fredrickson *et al.*, BP-18-E-BPA-12, at 3. Staff defined these hours as those when demand was historically the highest. *Id.* Staff’s proposal is to continue to use this same cost-based methodology, including the definition of peak hours, in the FY 2018–2019 rate period, but to revise the number of hours per week from 80 hours to 25 hours based on changes in California. *Id.* at 3-4.

Despite JP03’s claims about a lack of analysis, Staff’s analysis shows that the number of peak hours started to decrease in FY 2013 and that the decline became pronounced in FY 2016, after the BP-16 rate proceeding. JP03 Data Responses Admitted Into Evidence by BP-18-HOO-29, BP-18-E-JP03-17, at 320; *see* Fredrickson *et al.*, BP-18-E-BPA-12, at A-1. This decrease in the number of peak hours is consistent with the growth of solar generation capacity in California during this time, which increased from less than a thousand megawatts in 2013 to more than 10,000 MW today. Fredrickson *et al.*, BP-18-E-BPA-12, at A-1 to A-5; Linn *et al.*, BP-18-E-BPA-25, at A-1 to A-2. The evidence also shows that the reduction in net load during the mid-day hours in California reached levels in 2016 that CAISO did not anticipate reaching until 2020. Deen & Wellenius, BP-18-E-JP01-01, at 21-22. Again reductions in net load decrease the number of peak hours of demand in California.

JP03 points out that Staff stated in cross-examination that it did not study the exact number of peak hours at the end of the BP-16 rate proceeding. JP03 Br., BP-18-B-JP03-01, at 42 (citing Cross-Ex. Tr. at 50). Yet Staff did not need to determine the appropriate number of peak hours at the end of the BP-16 rate proceeding because the existing rate design is based on the traditional assumption of 16 peak hours per day, five days per week in California. *See* Linn *et al.*, BP-18-E-BPA-25, at 2 (peak hours are “traditionally considered to be the 16 hours in the

middle of the day . . .”). As a result, Staff had no need to study the number of peak hours for purposes of setting rates in the BP-16 rate proceeding.

Analysis performed by the CAISO confirms that the hours of highest demand in California are limited to a handful of hours in the evening. Fredrickson *et al.*, BP-18-E-BPA-12, at 4-5. The CAISO’s analysis shows five peak hours per day in each month except July and August. Data Responses and Requests Admitted into Evidence, BP-18-E-JP01-03, at 103. During July and August, the CAISO’s analysis shows four peak hours in the afternoon and five super peak hours in the early evening each day. *Id.* JP03 faults Staff for not including the four peak hours in the afternoon in July and August as part of Staff’s number of peak hours per day, even though the CAISO classified them as peak hours. JP03 Br. Ex., BP-18-R-JP03-01, at 23. However, Staff did not simply adopt the CAISO’s analysis as its own. Staff independently examined the CAISO’s net load, hourly reservations on the Southern Intertie, and long-term schedules, among other measures. Fredrickson *et al.*, BP-18-E-BPA-12, at 5, A-1 to 8; Linn *et al.*, BP-18-E-BPA-12, at 3-4, A-1 to -11. Staff’s analysis shows five peak hours per weekday in California throughout the year. Fredrickson *et al.*, BP-18-E-BPA-12, at 3-4. The CAISO is the grid operator for most of California, and its analysis provides a valuable perspective independent from Staff. The fact that the CAISO’s findings are largely consistent with Staff’s findings shows that Staff’s analysis is reasonable.

JP03 argues that the CAISO’s analysis included peak hours for seven days per week, not five. JP03 Br. Ex., BP-18-R-JP03-01, at 23. Although this is correct, other California transmission providers, such as SMUD and TANC, set their own hourly transmission rates based on a five-day week. Linn *et al.*, BP-18-E-BPA-25, at 24. JP03 maintains BPA simply assumes that weekend hours should not be part of the peak number of hours. JP03 Br. Ex., BP-18-R-JP03-01, at 49. This is not correct. Staff’s data supports this conclusion. Fredrickson *et al.*, BP-18-E-BPA-12, at A-3. Loads in California are still lower on the weekends than on weekdays; therefore it is reasonable not to include these weekend hours in the peak hour calculation. *See id.*

In addition, JP03’s claim that the CAISO’s analysis was published prior to the BP-16 Final Record of Decision is immaterial. JP03 Br. Ex., BP-18-R-JP03-01, at 23 n.7. The CAISO’s analysis was not in the record in the BP-16 rate proceeding, nor was any discussion or analysis of increased renewable generation reducing the number of peak hours in California. Similarly, JP03 faults the CAISO’s analysis because it uses data from 2013 and 2014. JP03 Br. Ex., BP-18-R-JP03-01, at 23 n.7. Yet, if anything, this shows that the CAISO’s analysis is too conservative and may include too many peak hours, especially between noon and 4 p.m. in July and August, because the reduction in net load during daytime hours due to solar generation has occurred more quickly than CAISO anticipated. *See Deen & Wellenius*, BP-18-E-JP01-01, at 21-22. JP03’s statement that the purpose of the CAISO study was to establish time-of-use rates, not to set hourly transmission rates, does not explain why that difference is material. *See JP03 Br. Ex.*, BP-18-R-JP03-01, at 23.

Aside from the analysis conducted by Staff and the CAISO, WSPP has created a new power product for a six-hour peak in the evening. SMUD, a member of JP03, has begun trading similar products as a result of “shifting load patterns from increased renewable generation.” Linn *et al.*, BP-18-E-BPA-25, Attachment 1 (Data Response BPA-JP03-26-34). The development of this

new product is largely consistent with Staff’s conclusions about five peak hours per day and, unlike the CAISO’s analysis, it does not distinguish four peak hours in the afternoon in July and August.

JP03 claims that SMUD’s use of WSPP’s six-hour peak power product is augmented by SMUD’s use of a separate power product from 8 a.m. to 4 p.m. JP03 Br. Ex., BP-18-R-JP03-01, at 23-24. It is difficult to determine the exact point JP03 is trying to make. JP03 asserts in the same portion of its brief that there are two peaks and it provides a chart that shows demand is substantially lower from 8 a.m. to 4 p.m. than during other times of day. *Id.* Multiple products being offered across hours that have traditionally been traded through one product demonstrates that customer demand to buy and sell energy during the period of the day when net load is the lowest (the “duck belly”) and the evening peak are different enough to warrant changes within the industry. *See* Attachment to Data Response SM-BPA-26-30, BP-18-X-05, at 1; *see also* Issue 5.2.2.2.5. In short, demand is declining during the daytime hours that JP03 cites.

JP03 seems to fault Staff for not explaining the conclusion about 25 peak hours per week in California in precise, mathematical terms. In the white paper that Staff developed in the public process following the BP-16 rate proceeding, Staff concluded that there were approximately four-to-six peak hours in the evening per day in California. Data Responses and Requests Admitted into Evidence, BP-18-E-JP01-03, at 90. After conducting further analysis, Staff proposed basing the Southern Intertie hourly rate on five peak hours per day, five days per week. As explained above, this is similar to the CAISO’s conclusions (five peak hours per day in each month except July and August) and the new power products developed by WSPP (year-round six-hour peak). *Id.* Stakeholders in the public process that followed the BP-16 rate proceeding advocated using a four-hour peak. *Id.* at 39-46. Calpine, a major power generator in California, summarized these stakeholders’ sentiments by stating that “even the most casual observers of the CAISO market will conclude that as a result of the rather dramatic solar growth, there are only 4, or so, premium hours of each weekday” *Id.* at 39. All of this evidence shows that Staff’s conclusion about the number of peak hours per day in California falls in the range established by others that have considered this topic. This evidence also shows that Staff’s proposal is more precise than continuing to use the traditional assumption of 16 hours per day. Although Staff’s proposal does not reflect all of these ways of calculating peak hours, it is consistent with the analysis and approach taken by others that have considered this topic, and it results in a reasonable assumption for ratemaking purposes.

JP03 argues that there are two distinct peaks rather than a single five-hour peak. JP03 also claims that, although the increase in solar generation has shifted the amount of peak hours, the total number has not declined. JP03 supports the claim about two peaks by citing a chart from the CAISO. JP03 Br. Ex., BP-18-R-JP03-01, at 24; Holcomb *et al.*, BP-18-E-JP03-02-AT03-CC02, at 16. According to JP03, the CAISO’s chart shows a morning peak and an evening peak. Yet there are three problems with JP03’s use of this chart. First, the CAISO has not acknowledged a morning peak in its analysis cited above. Data Responses and Requests Admitted into Evidence, BP-18-E-JP01-03, at 103. Instead, these hours are defined as off-peak in all months of the year. *Id.* Second, the chart only represents one day in January. A chart of a typical spring day does not show this apparent morning peak. Holcomb *et al.*, BP-18-E-JP03-02-

AT03-CC02, at 17. Third, there is no evidence in the record that WSPP (or anyone else) has developed a power product to cope with this purported morning peak.

JP03 states that there is no demonstrated link between the number of peak hours and the demand for use of the Southern Intertie because the use of hourly service has remained flat. JP03 Br. Ex., BP-18-R-JP03-01, at 25. This is misleading. Staff notes that requests for hourly transmission service on the Southern Intertie are increasing during the few evening peak hours and decreasing during daytime hours. Linn *et al.*, BP-18-E-BPA-25, at 3-4. This provides further evidence that there are five peak hours per day in the evening in California, and that it is affecting the use of the Southern Intertie.

JP03 states that peak load in California is growing and will continue to grow over the next few years. Holcomb *et al.*, BP-18-E-JP03-02, at 33. This may be true, but it is not the issue here. BPA is not concerned about the absolute growth in peak loads in California. BPA is concerned about the duration of the peak each day (the number of peak hours per day) because that is the basis for designing rates for hourly transmission service on the Southern Intertie. Linn *et al.*, BP-18-E-BPA-25, at 1-2. If BPA's rate design does not take into account the duration of the peak, it encourages customers to purchase hourly service to serve the peak hours rather than purchasing long-term firm service.

Decision

The evidence supports a conclusion that there are 25 peak hours per week in California.

Issue 5.2.2.1.8

Whether an increase in total line loadings from one year to the next on the Southern Intertie reflects an increase in demand for long-term firm transmission service.

Parties' Positions

JP03 argues that total line loadings on the Southern Intertie have increased since the end of the BP-16 rate proceeding. JP03 Br., BP-18-B-JP03-01, at 35-36. According to JP03, the increase in total line loadings contradicts Staff's claims about reduced demand for long-term firm transmission service due to increased solar generation.

JP01 cites Staff's evaluation of line loadings as another piece of evidence showing that the number of peak hours has declined in California. JP01 Br., BP-18-B-JP01-01, at 11.

BPA Staff's Position

Southern Intertie line loadings are a useful measure of how customers are utilizing existing long-term firm reservations across the day, and they reflect the decline in net load in daytime hours and a resulting reduction in peak hours in California. Linn *et al.*, BP-18-E-BPA-25, at 18.

Evaluation of Positions

Total Southern Intertie line loadings measure the total amount of power flowing on the Southern Intertie. JP03 points out that total line loadings on the Southern Intertie have increased since the end of the BP-16 rate proceeding, and it argues that this reflects the high demand for long-term firm transmission service on the Southern Intertie. JP03 Br., BP-18-B-JP03-01, at 35-36. JP03 claims that Staff has acknowledged that total line loadings are a useful measure of demand, but that Staff nevertheless did not examine whether total line loadings increased in FY 2016 relative to prior years. *Id.* at 36.

Staff's pre-filed testimony stated that total line loadings are a "useful measure of demand" because it shows "how customers are utilizing existing long-term reservations *across the hours of the day.*" Fredrickson *et al.*, BP-18-E-BPA-12, at 18 (emphasis added). Chart 5 in Staff's testimony depicted the hourly shape of loadings dating back to FY 2010. *Id.* at A-6. Staff concluded that hourly line loadings are useful because the data shows whether loadings are increasingly being shaped into a few hours in the evening due to increased solar generation in California. Based on Staff's analysis, it appears that this is the case. *Id.*

JP03 questioned Staff about this point in cross-examination, and it portrays Staff's acknowledgment that its analysis only measures the shape of Southern Intertie loadings, not the total line loadings, to be a "major concession." JP03 Br., BP-18-B-JP03-01, at 37. It is not. Staff's chart is titled, "Southern Intertie Loadings Hourly Shape." Fredrickson *et al.*, BP-18-E-BPA-12, at A-6. The title clearly states that the chart measures only the shape of hourly loadings. That is to say, the chart "reflects how flows are shaped into different hours." Cross-Ex. Tr. at 18.

JP03 faults Staff for not measuring whether total hourly line loadings were higher or lower than in the BP-16 rate proceeding. JP03 Br. Ex., BP-18-R-JP03-01, at 7. JP03 also argues that total line loadings on the Southern Intertie were higher in FY 2016 than in FY 2015, and that this shows that the demand for long-term firm transmission service is increasing. The explanation is not so simple. Use of the Southern Intertie and, therefore, total line loadings, depends in part on how much power customers have to sell. A considerable amount of generation in the Pacific Northwest is hydroelectric. As a result, the amount of streamflow affects the power that long-term firm transmission customers have to sell to California, and the amount of power that long-term firm transmission customers sell to California affects the total flows over the Southern Intertie. Year-over-year variation in the total amount of power flowing on the Southern Intertie does not demonstrate whether increased solar generation is having an effect on long-term firm transmission service. Cross-Ex. Tr. at 168. It just demonstrates that customers use the Southern Intertie more in years when they have more power to sell and less in years when they have less power to sell. *Id.* As JP03 acknowledges, the costs of long-term firm transmission service are "sunk." JP03 Br., BP-18-B-JP03-01, at 46. In other words, the customer must pay for long-term firm service whether it uses the service or not. Therefore, in times of high streamflow, customers will attempt to maximize use of long-term firm transmission service.

Factors other than streamflow also affected total line loadings on the Southern Intertie during the period on which JP03 is focused. The Southern Intertie had a prolonged de-rate in FY 2015,

which decreased flows relative to other years. Linn *et al.*, BP-18-E-BPA-25, at 11. This de-rate was associated with a \$400 million upgrade to the DC portion of the Southern Intertie. Holcomb *et al.*, BP-18-E-JP03-01-AT03, at 64.

JP03 claims that Staff stated that “an increase in total line loadings would reflect an increase in demand” for long-term firm transmission service. JP03 Br. Ex., BP-18-R-JP03-01, at 7, 42 (citing Cross-Ex. Tr. at 13) (emphasis omitted). Staff did not say this. Instead Staff agreed with the hypothetical posed by JP03’s counsel during cross-examination that “if you were to see increases in Southern Intertie loadings across all hours of the day, that would reflect an increase in Southern Intertie demand.” Cross-Ex. Tr. at 13. Staff did not equate an increase in total line loadings to an increase in the demand for long-term firm transmission service. Staff stated that total line loadings reflect an increase in the demand for the Southern Intertie in general. JP03 extends Staff’s conclusion to the service that BPA offers. *See* JP03 Br. Ex., BP-18-R-JP03-01, at 7, 42. In any event, Staff subsequently clarified that factors such as streamflow affect total line loadings in a given year. Cross-Ex. Tr. at 168.

JP03’s claims about an increase in total line loadings from FY 2015 to FY 2016 are unconvincing because other factors, such as streamflow and the capacity available on the Southern Intertie, were likely at play. Staff’s analysis controlled for variables like streamflow and line de-rates by measuring the percentage of flows that occurred in each hour, rather than year-over-year changes in line loadings. Fredrickson *et al.*, BP-18-E-BPA-12, at A-6. This is a reasonable approach that shows that flows are increasingly being shaped into evening hours. *Id.* Staff also examined measures of demand other than hourly line loadings, including confirmed hourly reservations on the Southern Intertie, which are increasingly concentrated into the evening peak, the development of new power products to manage the evening peak, and the general downward trend in net load in the middle of the day. Linn *et al.*, BP-18-E-BPA-25, at 3-4.

JP03 states that raising rates for hourly service would not logically drive customers to use long-term firm transmission service “if the increased penetration of solar capacity is expected to continue to reduce the need for the Southern Intertie at all.” JP03 Br. Ex., BP-18-R-JP03-01, at 8; *see also* JP03 Br., BP-18-B-JP03-01, at 44. This is not Staff’s position. Staff maintains that use of the Southern Intertie is being shaped into fewer hours of high demand due to increasing solar generation in California. Fredrickson *et al.*, BP-18-E-BPA-12, at 4. As stated above, many factors affect the overall use of the Southern Intertie.

JP03’s argument that total line loadings show increasing solar generation is not affecting the demand for long-term firm transmission service is without merit. As noted earlier, solar generation capacity within the CAISO has grown from less than a thousand megawatts in 2013 to more than 10,000 MW today. Fredrickson *et al.*, BP-18-E-BPA-12, at A-1–5; Linn *et al.*, BP-18-E-BPA-25, at A-1–2. Looking at California as a whole, this has led to a large decrease in demand for other types of power in daytime hours, such as imports of hydroelectric generation from the Pacific Northwest using transmission service on the Southern Intertie. Linn *et al.*, BP-18-E-BPA-25, at A-3. Solar generation is expected to further increase during the FY 2018–2019 rate period, which will further decrease demand for long-term firm transmission service on the Southern Intertie unless BPA takes action. Given the weight of this evidence, it is unlikely

that long-term firm transmission service is so valuable that it is immune to these forces. Instead, it is more likely that other variables, such as streamflow and transmission line de-rates, affect total line loadings, and that this explains any increase in total line loadings from FY 2015 to FY 2016.

JP03 states that the findings about declining demand for long-term firm transmission service on the Southern Intertie contradict comments that BPA submitted to the CAISO regarding CAISO's market design and renewable integration. JP03 Br. Ex., BP-18-R-JP03-01, at 8. According to JP03, BPA's comments "proclaimed" the Southern Intertie to be "one of the most valuable assets in the West Coast energy market." *Id.* The comments to the CAISO are consistent with BPA's message in this proceeding. BPA has never stated that the Southern Intertie is not valuable. BPA's concern is that customers may choose hourly transmission service on the Southern Intertie over long-term firm transmission service, causing cost recovery issues.

JP03 also misrepresents a quote from BPA's comments, stating that long-term firm transmission service "continues to have great value at the duck curve's two peak periods for ramping assistance." *Id.* BPA's comments never mention two peak periods or long-term firm transmission service. They refer to "firm transmission service," but BPA offers short-term firm service in addition to long-term firm.

Contrary to JP03's claims, the comments highlight the need for Staff's proposal. They state that CAISO "places the highest value on the day-ahead fixed energy schedules," not on ramping assistance. BPA's January 6, 2017 comments to the CAISO, BP-18-X-04, at 2; see also Issue 5.2.2.2.5. As stated above, the CAISO's day-ahead market does not recognize BPA's transmission priorities, and it is relatively easy to ensure that hourly service will be available to facilitate such transactions. See Issue 5.2.2.1.1.

Decision

An increase in total line loadings from one year to the next does not reflect an increase in demand for long-term firm transmission service. Many factors affect total line loadings on the Southern Intertie, including streamflow and de-rates.

Issue 5.2.2.1.9

Whether unique attributes or uses of long-term firm transmission service demonstrate that such service is highly valuable and that Staff's rate design proposal is unnecessary.

Parties' Positions

JP03 argues that long-term firm transmission service has specific uses or other attributes that will always make it more valuable than hourly transmission service. JP03 points to the value of long-term firm transmission to deliver energy from renewable resources to meet California's renewable portfolio standard, to use for 15-minute scheduling, and to import operating reserves into California. JP03 Br., BP-18-B-JP03-01, at 60. It also maintains that Powerex's statement

that “total congestion value has never been higher” is at odds with Staff’s statement that the duck curve is reducing value. JP03 Br., BP-18-B-JP03-01, at 43.

JP01 states that dynamic scheduling is necessary to meet California’s renewable portfolio standard and the DC portion of the Southern Intertie does not currently support dynamic scheduling, or even 15-minute schedules. JP01 Br., BP-18-B-JP01-01, at 19. The AC portion of the Southern Intertie has only limited dynamic scheduling capacity. *Id.*

BPA Staff’s Position

Long-term firm transmission service has unique attributes that have value, but there are limiting factors to almost all the attributes or uses cited by JP03. *See* Linn *et al.*, BP-18-E-BPA-25, at 11-12.

Evaluation of Positions

JP03 argues that long-term firm transmission service has a number of unique uses associated with meeting California’s renewable portfolio standard and for California utilities purchasing operating reserves from the Pacific Northwest. JP03 Br., BP-18-B-JP03-01, at 60. In addition, JP03 quotes Powerex, which states that “total congestion value between the Pacific Northwest and California has never been higher,” to show that long-term firm transmission service is very valuable. Cross-Ex. Tr. at 215.

No party disputes JP03’s assertion that California’s renewable portfolio standard is increasing. Holcomb *et al.*, BP-18-E-JP03-02, at 21. Also no party disputes JP03’s claim that renewable resources outside of California must be dynamically scheduled into the state to meet the renewable portfolio standard requirements, and that this requires long-term firm transmission service. JP03 Br., BP-18-B-JP03-01, at 60. Although dynamic scheduling is a valuable use of long-term firm transmission service, only 400 MW of the Southern Intertie capacity can be used in that way. Linn *et al.*, BP-18-E-BPA-25, at 11. This 400 MW is available only on the AC portion of the Southern Intertie and is split among the Pacific Northwest transmission owners of the Southern Intertie. *Id.* When equally allocated among all owners, BPA’s share is only 225 MW. *Id.* These 225 MW have value, but BPA has 10 times that amount of transmission up for renewal in the BP-18 rate period. As Staff stated during cross-examination, “there’s such a limited amount of dynamic scheduling available over the Intertie that it does not . . . provide a significant incentive for customers to renew their long-term firm contracts.” Cross-Ex. Tr. at 146. Dynamic scheduling is not available over the DC portion of the Southern Intertie, so it provides no incentive at all. Linn *et al.*, BP-18-E-BPA-25, at 11-12.

Next JP03 states that “uncontradicted evidence” that customers can use 15-minute scheduling on the Southern Intertie shows another use of long-term firm service. This is partially correct but not significant. JP03 Br., BP-18-B-JP03-01, at 60. All customers, not just long-term firm customers, can use 15-minute scheduling on the AC Intertie. Cross-Ex. Tr. at 168. There is nothing particularly special about this ability to use 15-minute scheduling. Fifteen-minute scheduling is not allowed on the DC portion of the Southern Intertie, so it provides no incentive

to long-term firm customers. *Id.* at 168-169. Even if it was allowed, all customers could schedule on a 15-minute basis, not just long-term firm customers.

JP03 argues that firm transmission is necessary to import operating reserves under “regional reliability rules.” JP03 Br., BP-18-B-JP03-01, at 60. This argument may have some merit, but it applies to all types of firm transmission service, including hourly service. JP03 also provides no evidence that a substantial amount of long-term firm transmission service is used to import operating reserves.

JP03 argues that BPA power (and hydroelectric power in general) is more valuable to California purchasers because it has a low carbon-emission factor. *Id.* at 61. Although it is true that BPA markets low-carbon, renewable hydropower, BPA and others should receive the premium that JP03 refers to regardless of whether hydropower is delivered using long-term firm or short-term transmission service. Large hydroelectric resources are not considered to be renewable under California’s renewable portfolio standard and do not need to be dynamically scheduled. Motion to Admit Evidence, BP-18-M-BPA-08, Exhibit A at 6.

JP03 points out that Powerex concluded in late 2015 that “total congestion value between the Pacific Northwest and California has never been higher,” and that this is at odds with Staff’s position that the duck curve is reducing value of long-term firm transmission service. JP03 Br., BP-18-B-JP03-01, at 43. However, Powerex’s witness stated on cross-examination that he had not revisited these numbers since late 2014. Cross-Ex. Tr. at 215-216. Since 2014, nameplate solar generation in the CAISO has increased by over 4,400 MW. Linn *et al.*, BP-18-E-BPA-25, at A-1. This amount of generation alone has likely decreased the congestion value between the Pacific Northwest and California during daytime hours.

JP03 claims Powerex’s witness admitted in cross-examination that “as of 2014 ‘transmission capacity between the Northwest and California is limited and highly valuable,’ and that the capacity *remains* limited and highly valuable today.” JP03 Br. Ex., BP-18-R-JP03-01, at 10 (quoting Cross-Ex. Tr. at 217:11-14) (emphasis in original). The witness’ conclusion about the value today was not so broad. He stated: “I believe that there continue to be periods and hours in which it is highly valuable.” Cross-Ex. Tr. at 217. The witness did not know whether there are more hours and more value since 2014. *Id.* Again, Staff’s analysis shows a decline in value during daytime hours due to increased solar generation in California. Linn *et al.*, BP-18-BPA-25, at 3-5.

Finally, JP03 criticizes BPA’s analysis of the attributes of long-term firm service because it alleges that BPA has the burden to demonstrate that the attributes identified in the BP-16 rate proceeding are no longer present. JP03 Br. Ex., BP-18-R-JP03-01, at 8. BPA addresses these issues in Issue 5.2.2.1.6.

Decision

The unique attributes of long-term firm transmission service identified by JP03 do not obviate the need for changes to BPA’s Southern Intertie hourly rate design.

Issue 5.2.2.1.10

Whether the evidence in the record shows that the impacts of Staff's proposal would constitute rate shock.

Parties' Positions

JP03 states that Staff did not address rate shock in its testimony and that Staff has considered less significant rate increases to be “rate shock” in the past. JP03 Br., BP-18-B-JP03-01, at 50.

JP01 does not address rate shock, but it does claim that JP03's predictions of dramatic price increases in California and a lack of liquidity in the wholesale market are “unrealistic and without support.” JP01 Br., BP-18-B-JP01-01, at 20-21.

BPA Staff's Position

Staff's testimony did not address rate shock, but JP03's claim of financial harm to SMUD between \$1.3 million and \$4.2 million per year is likely excessive. Linn *et al.*, BP-18-E-BPA-25, at 27-29. SMUD purchases no Southern Intertie hourly transmission from BPA and, even if SMUD's analysis were correct, it would only have a 0.1 to 0.31 percent impact on SMUD's retail ratepayers. *Id.* at 27.

Evaluation of Positions

Staff's proposed change to the hourly rate design will result in a rate increase of approximately 170 percent. This obviously is a significant increase, and BPA does not take it lightly. The thorough examination of the seams issues in the public process following the BP-16 rate proceeding demonstrated the need for a rate solution and resulted in broad support for Staff's proposal. This included customers that would be subject to the increase. This thorough examination of the need and broad support for the proposal is one of many factors to weigh in evaluating concerns about rate shock.

JP03 looks to BPA's discussion of rate shock in past rate case decisions and points to examples where BPA declined to adopt rate increases much less than 170 percent because of concerns about the impacts on customers. JP03 Br., BP-18-B -JP03-01, at 50. “Rate shock” has no specific quantitative value. In each case, including this one, it is a judgment based on consideration of specific facts and circumstances, including the impacts on the affected customers. As discussed below, although the rate increase proposed by Staff in this case is significant, it is justified based on the facts and circumstances at hand.

JP03 points out that BPA concluded that 25 percent rate increases over successive rate periods would cause utility delivery customers to experience rate shock. *Id.* Utility 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.” Administrator's Final Record of Decision, BP-16-A-02, at 71. BPA concluded that its initial proposal for utility delivery service in BP-16 would have caused its customers “significant economic harm.” *Id.* For example, the utility delivery

charge would have been 40 percent of the Town of Steilacoom’s total transmission bill to serve its entire retail load, even though—as stated above—it is only for a few feet of transmission service. *Id.* After the rate increase was fully phased in, it would represent 56 percent of Steilacoom’s total transmission bill. *Id.* at 70-71. This would have represented 8 percent of Steilacoom’s annual budget. *Id.* at 72. BPA also concluded that Steilacoom was “not unique” among its utility delivery customers. *Id.*

JP03 also points out that the BP-16 Record of Decision states that rolling in the costs of the Southern Intertie to the Network rate would result in a 12.5 percent Network rate increase and this “could result in rate instability and rate shock.” Administrator’s Final Record of Decision, BP-16-A-02, at 125; *see also* JP03 Br., BP-18-B-JP03-01, at 50 (discussing Staff testimony about potential impacts of rolling in the Southern Intertie). However, the statement in the BP-16 Record of Decision was made in the context of hypothetical discussion of the precedent that potentially could be set by rolling in the Eastern Intertie into BPA’s network. *See* Administrator’s Final Record of Decision, BP-16-A-02, at 125. The Record of Decision theorized that this increase could result in rate shock, but there was no proposal to roll in the Southern Intertie in BP-16, so the issue was not before the Administrator. Moreover, there was no analysis showing the potential impact of such a change on customers. As described below, the analysis JP03 has provided in this proceeding suggests that the impact of the change to the hourly rates is relatively minor.

SMUD and TANC do not purchase transmission service on the Southern Intertie from BPA. Holcomb *et al.*, BP-18-E-JP03-01-AT02, at 15, 17. Turlock buys some hourly Southern Intertie transmission service from BPA, but it is a relatively small amount and does not represent its entire retail load. *Id.* at 17. JP03 contends that its members will feel the impact of Staff’s proposal through power prices, arguing that the rate increase will either increase power prices on the Southern Intertie or force purchasers in California to buy more expensive power elsewhere. It estimates the financial impact to SMUD to be between \$1.3 million and \$4.4 million per year. Holcomb *et al.*, BP-18-E-JP03-02, at 26. JP03 expects similar impacts on Turlock, although it did not study them. Holcomb *et al.*, BP-18-E-JP03-01, at 12.

Staff and JP01 claim that SMUD’s estimate of financial harm appears excessive. JP03’s analysis assumed that the price of all Pacific Northwest exports to California, even those that do not use hourly transmission service, will increase by roughly \$8/MWh, which is the amount of the proposed increase in the hourly rate in the Initial Proposal. Holcomb *et al.*, BP-18-E-JP03-01, at 62; Linn *et al.*, BP-18-E-BPA-25, at 26. JP03 believes that power prices will rise by \$8/MWh because long-term firm customers will either be able to re-sell their transmission for nearly \$8/MWh more than they do today, or sell bundled energy for almost \$8/MWh more because purchasing hourly transmission will increase by that amount. Linn *et al.*, BP-18-E-BPA-25, at 26; Holcomb *et al.*, BP-18-E-JP03-01, at 62. For JP03’s claim to be true, the difference in the cost of power between the Pacific Northwest and California should have some correlation to BPA’s rate for hourly service on the Southern Intertie. Linn *et al.*, BP-18-E-BPA-25, at 28. Staff, however, found none. *Id.* The price difference between the Pacific Northwest and California is below BPA’s hourly rate for a significant amount of SMUD’s and other customers’ transactions on the Southern Intertie. *Id.* Under JP03’s theory, these transactions should not

occur because the difference in price is below the hourly rate. That said, the weighted average of the differences in price between the Pacific Northwest and California for SMUD's transactions is more than double the amount of BPA's hourly rate. *Id.* In other words, the price of imports from the Pacific Northwest using the Southern Intertie is often volatile, and there is no discernable correlation to BPA's hourly rate.

JP03 also testified that the market may become illiquid if Staff's proposal is adopted. Holcomb *et al.*, BP-18-E-JP03-01, at 12. The claims about an illiquid market are hard to accept, given that only 2 to 6 percent of transactions on the Southern Intertie are hourly reservations. JP01 Br., BP-18-B-JP01-01, at 20; JP03 Br., BP-18-B-JP03-01, at 5. Instead the overwhelming majority of energy is not delivered using original hourly service. JP01 Br., BP-18-B-JP01-01, at 20-21. To the extent that the increased hourly rate reduces liquidity, this impact will be minimal. *Id.* at 21. Finally, the increase in the hourly rate in BPA's Final Studies is \$2/MWh less than the increase assumed in JP03's analysis, which will further limit any impact of the increase on the members of JP03 and on market liquidity.

JP03 states that the 2 to 6 percent figure only accounts for hourly service sold by BPA, and that it does not include transactions in which long-term firm transmission is resold for hourly use. JP03 Br. Ex., BP-18-R-JP03-01, at 60. JP03's analysis on resales of long-term firm transmission service does not seem to back up its claims about the impacts. JP03 found that customers usually receive less than the hourly rate for re-sale transactions. Holcomb *et al.*, BP-18-E-JP03-01, at 31-32. In fact, JP03 found only one re-sale transaction in FY 2016 at a price that exceeds the hourly rate. *Id.* This shows that customers will not be able to increase their re-sale prices by the amount of the rate increase. Linn *et al.*, BP-18-E-BPA-25, at 28-29.

In addition, SMUD's, TANC's, and LADWP's hourly transmission rates to import Northwest power are roughly the same as Staff's proposal. Cross-Ex. Tr. at 161. Yet these rates are not causing the kind of harm that JP03 suggests in wholesale power markets. *Id.*

None of this discussion is to say that Staff's proposal will have no effect on power prices in the Pacific Northwest or California. Rather, it means that the impact to JP03, according to JP03's own analysis, appears relatively minor (see above) and not even as severe as JP03 claims. This suggests that the impacts of Staff's proposal will not lead to rate shock.

Finally, the fact that BPA does not own the entire Southern Intertie helps mitigate the potential impacts of Staff's proposal. *See* Data Requests and Responses Admitted into Evidence, BP-18-E-JP01-03, at 92-93. Several other Pacific Northwest transmission providers offer service on this path, which provides alternatives to purchasing service from BPA. *Id.* This is not the case for BPA's utility delivery and network transmission customers, where customers typically have long-term commitments to purchase transmission service from BPA and there is no other transmission provider that can provide the service. Customers that purchase hourly transmission service have, by definition, no long-term commitment and have flexibility that many network and utility delivery customers do not have. JP03 states that BPA's proposal may cause customers to buy transmission service from these other providers. JP03 Br. Ex., BP-18-R-JP03-01, at 61. Although this could occur, BPA believes that not addressing the incentive to purchase long-term firm transmission service poses a greater risk given the amount of such

service that is eligible for renewal in FY 2018–2019 and the views of its Southern Intertie customers.

Decision

Although Staff’s proposal is a significant rate increase, the evidence in the record shows that the impacts of Staff’s proposal would not constitute rate shock.

Issue 5.2.2.1.11

Whether Staff’s proposal would undermine rate stability.

Parties’ Positions

JP03 states that Staff’s rate proposal undermines rate stability. JP03 Br., BP-18-B-JP03-01, at 50-52. It argues that Staff has inconsistently stated whether its proposal is a change to BPA’s rate design, and that BPA concluded in BP-16 that “[a] rate based on actual usage . . . could quickly become inaccurate unless it is regularly revisited.” *Id.* at 51 (citing Administrator’s Final Record of Decision, BP-16-A-02, at 114).

JP01 states Staff’s proposal is “based on the changes in California’s net load shape” and does not rely on usage patterns or on anticipating the numbers of hours that the average customer will use hourly service in a given week, as proposed in the BP-16 rate proceeding. JP01 Br., BP-18-B-JP01-01, at 23. As a result, “the concern about the hourly rate spiraling upward is misplaced.” *Id.*

BPA Staff’s Position

Unlike Powerex and PPC’s proposal in the BP-16 rate proceeding, Staff is not proposing to set its hourly rate using actual transmission reservations over the Southern Intertie. Linn *et al.*, BP-18-BPA-25, at 15. Instead Staff proposes to set rates based on the number of peak hours per week in California. *Id.* This will ensure that hourly rates on the Southern Intertie will be relatively stable in future rate periods. *Id.*

Evaluation of Positions

JP03 is correct that Staff’s proposal is a change in the rate design for hourly transmission service on the Southern Intertie. Staff is proposing to change the rate design by updating the number of hours used to calculate the rate to reflect the number of peak hours in California. *Id.* at 1. This is a relatively minor change to the methodology, but it would increase the Southern Intertie hourly rate significantly.

JP03 argues that such a dramatic rate increase would “trample” rate stability. JP03 Br., BP-18-B-JP03-01, at 51. JP03 points out the Administrator’s statement in the BP-16 Final Record of Decision that a rate based on actual usage could become inaccurate unless it is revisited regularly. *Id.* JP03 suggests that Staff’s proposal in this proceeding suffers from the same

defect, but Staff's change is not tied to actual usage by hourly customers. *Id.* Staff testified that using 25 peak hours per week "is not an attempt to anticipate the number of hours the average customer will use hourly transmission in a given week. Rather using 25 hours is intended to create an economic incentive to purchase long-term firm service." Linn *et al.*, BP-18-E-BPA-25, at 16. This is the same reasoning behind BPA's existing methodology. Conditions in California have changed, and BPA must adapt to such changes.

JP03 also is incorrect that hourly customers "are subject to the caprice of the agency if it later claims a still different number of 'heavy load hours' [peak hours] in California in the next rate case." JP03 Br., BP-18-B-JP03-01, at 52. Staff's proposal is different from Powerex's and PPC's proposal in BP-16. Powerex's and PPC's proposal would have based the hourly rate on the actual number of hourly reservations in previous years. Administrator's Final Record of Decision, BP-16-A-02, at 113-14. The rate increase from Powerex's and PPC's proposal would have likely reduced the number of hourly reservations, which would have increased the rate even more in future rate periods. *Id.* The number of hourly reservations, on the other hand, will not increase or decrease the number of peak hours per week in California. Linn *et al.*, BP-18-E-BPA-25, at 15. In other words, Staff's proposal, unlike the proposal made by Powerex and PPC in BP-16, will not lead to a "vicious cycle" where hourly reservations decline due to an initial rate increase, and that decline in hourly reservations is subsequently used to increase rates in future rate proceedings. *Id.* at 15-16.

Decision

Staff's proposal does not undermine rate stability.

Issue 5.2.2.1.12

Whether Staff's proposal is consistent with cost-based ratemaking, not unduly discriminatory, and reasonable.

Parties' Positions

JP03 claims that Staff's proposal is not cost-based because there is no evidence that the cost to provide hourly service has increased. JP03 Br., BP-18-B-JP03-01, at 52-53. It also argues that enhancing the value of long-term firm transmission service is not an objective of cost-based ratemaking and that attempting to do so is unduly discriminatory. *Id.* at 53-57.

JP01 argues that JP03's criticism of the Southern Intertie rate calculation using the 25 heavy-load hour divisor is the same as criticism for using the current 80 hour divisor. JP01 Br., BP-18-B-JP01-01, at 17.

BPA Staff's Position

The proposed hourly rate is cost-based because it is designed to recover the costs of the Southern Intertie as a whole. Linn *et al.*, BP-18-E-BPA-25, at 20. Staff is only proposing to change how costs are allocated within the Southern Intertie segment. *Id.*

Evaluation of Positions

JP03 casts its argument in terms of compliance with cost-based ratemaking principles, but in reality JP03 expresses a concern with how Southern Intertie costs are allocated between long-term firm and hourly transmission customers. *See* JP03 Br., BP-18-B-JP03-01, at 52-53; JP03 Br. Ex., BP-18-R-JP03-01, at 48. Under Staff’s proposal, BPA would recover Southern Intertie costs, and it would not over-recover those costs. The fact that Staff’s proposal would change how those costs are allocated among customers does not violate cost-based ratemaking requirements established in BPA’s statutes. Staff’s proposal is trying to create a financial incentive for long-term firm transmission service, which is what the existing rate design methodology tries to do as well.

JP03 argues that “hourly service is priced lower under a cost-based methodology because it is not always available,” and that enhancing the value of long-term firm transmission service is not an objective of cost-based ratemaking. JP03 Br., BP-18-B-JP03-01, at 53. Both arguments are incorrect. Under BPA’s existing methodology, hourly service is not priced lower than long-term firm transmission service, and the Commission has approved BPA’s rates using this methodology many times. A customer that reserves hourly service for 80 hours pays the same as a long-term firm customer that can schedule service for all 168 hours of the week. SMUD and TANC use similar methodologies. Linn *et al.*, BP-18-E-BPA-25, at 36-37. In all of these methodologies, an hourly customer pays more on a per-hour basis than a long-term firm customer. Such a methodology enhances the value of long-term firm transmission service and creates a financial incentive to reserve that service. If the premise that hourly service is priced lower under a cost-based methodology is correct, then TANC’s, SMUD’s, and BPA’s existing rate methodologies are not cost-based.

Although Staff’s proposal might result in long-term firm transmission customers increasing revenues, this additional revenue is likely to be minor because the hourly rate has little bearing on power prices in California. *See* Issue 5.2.2.1.10. JP03 argues, however, that BPA “fails to meet the agency’s obligation to set reasonable rates [and it] is not excusable merely because the harm might only put a ‘small dent in the consumer’s pocket.’” JP03 Br. Ex., BP-18-R-JP03-01, at 40. To support its position, JP03 cites cases dealing with the Commission’s obligation to ensure that rates are “just and reasonable” under Sections 205 and 206 of the Federal Power Act and Section 7(b) of the Natural Gas Act.

Sections 205 and 206 of the Federal Power Act do not apply to BPA’s transmission rates. Neither does Section 7(b) of the Natural Gas Act. Although Section 212(i) of the Federal Power Act states that BPA’s rates cannot be “unjust” or “unreasonable,” that standard only applies when the Commission orders BPA to provide transmission or interconnection services in accordance with the applicable provisions of the Federal Power Act. *See* 16 U.S.C. § 824k(i). Section 212(i) does not apply to the Commission’s review of BPA’s rate filings under the Northwest Power Act. Administrator’s Final Record of Decision, BP-12-A-02, at 202.

JP03 condemns BPA for having the “concern of a monopolist,” but BPA does not have a monopoly on Southern Intertie capacity. JP03 Br., BP-18-B-JP03-01, at 55; Data Requests and Responses Admitted into Evidence, BP-18-E-JP01-03, at 92-93. Other transmission providers

offer service on the Southern Intertie, providing alternatives to BPA transmission to transfer power from the Pacific Northwest to California. *Id.* This further diminishes JP03's concerns that long-term firm transmission customers will receive a windfall.

In its Brief on Exceptions, JP03 argues that pointing out that BPA has no monopoly on the Southern Intertie distorts its point and that JP03 is referring to "BPA's role as a *regulator*." JP03 Br. Ex., BP-18-R-JP03-01, at 40 (emphasis in original). BPA is not a regulator, and JP03 provides no law or citations to support its assertion. BPA is a transmission provider that is setting rates for service on its own transmission system.

JP03 states that "maximizing profitability of a regulated service is not the legitimate concern of an agency that's supposed to set reasonable rates." *Id.* Although Staff's proposal is reasonable, JP03 provides no support for the statement that BPA is obligated to meet a just and reasonable standard in its ratemaking. BPA is charged with setting rates to recover its costs, and BPA is doing that. BPA is not seeking to maximize the profitability of long-term firm transmission service, but it is adopting a rate design that creates incentive for customers to continue purchasing that service.

In addition to all the reasons supporting Staff's proposal discussed above, Staff's proposal is necessary to help ensure that hourly customers are paying their fair share of BPA's costs. BPA's hourly rate methodology has always been premised on the principle that customers that reserve hourly transmission service for the peak number of hours should pay the same amount as a long-term firm transmission customer. Linn *et al.*, BP-18-E-BPA-25, at 4. Since there are now five peak hours per weekday in California, Staff's proposal ensures that customers that reserve service for only those hours appropriately contribute to BPA's fixed costs.

Although JP03 believes that Powerex, BPA's largest long-term firm transmission customer on the Southern Intertie, will benefit the most from Staff's proposal, Powerex also is the largest hourly customer on the Southern Intertie, representing nearly 40 percent of all hourly sales. Holcomb *et al.*, BP-18-E-JP03-01-AT02, at 17. Powerex will pay the increased hourly rate more than any other customer. Any benefits that may accrue to Powerex do not come without costs. This is not to claim, as JP03 suggests, that Powerex will receive no benefit from Staff's proposal, but rather that Powerex will incur additional costs from buying hourly transmission service and that these costs are likely to be higher than those of any other customer. *See* JP03 Br. Ex., BP-18-R-JP03-01, at 41.

JP03 also argues that Powerex will benefit from Staff's proposal because "there will be times when not all the demand for use of the Southern Intertie can be met without reliance on Powerex's share of that capacity." JP03 Br., BP-18-B-JP03-01, at 72. According to JP03, this will result in Powerex becoming a "pivotal supplier" on the Southern Intertie. *Id.* JP03 cites Commission precedent for its pivotal supplier test but acknowledges that the Commission uses the test in the context of generating capacity, not transmission service. Holcomb *et al.*, BP-18-E-JP03-01, at 73. This undermines the credibility of JP03's analysis because it is using a test in a way not intended by the Commission. One must look at all substitute generation to determine if Powerex is influencing price and not just focus on one way that energy can be delivered to California. Linn *et al.*, BP-18-E-BPA-25, at 34-35. JP03's analysis does not do this.

In addition, JP03's witnesses reached this conclusion based on the mistaken belief that Powerex had over 4,000 MW of long-term firm capacity on the Southern Intertie. Linn *et al.*, BP-18-E-BPA-25, at 35. Both Staff and JP01 corrected this mistake in rebuttal testimony. Although JP03 simply swaps out the incorrect number (over 4,000 MW) for the correct one (2,035 MW) in its brief, JP03 offers no explanation how this affects the analysis. JP03 states that the Hearing Officer struck its rebuttal testimony, and this barred a purported correction by JP03. JP03 Br. Ex., BP-18-R-JP03-01, at 41. However, the revised analysis that JP03 provided in rebuttal testimony still incorrectly showed that Powerex had more than 4,000 MW of transmission service on the Southern Intertie. Holcomb *et al.*, BP-18-E-JP03-02, Attachment 2.

JP03's Brief on Exceptions also reflects a misunderstanding of some basics about the Southern Intertie. JP03 states that Powerex holds more than 2,000 MW of firm capacity on the Southern Intertie and offers that this is "nearly forty percent" of Southern Intertie capacity. JP03 Br. Ex., BP-18-R-JP03-01, at 41. Although JP03 correctly notes in this instance that Powerex's capacity is just over 2,000 MW, this is roughly 40 percent of the amount of BPA's Southern Intertie capacity (2,035 MW of Powerex's reservations divided by 5,715 MW of BPA's Southern Intertie capacity is approximately 35 percent), not the capacity of all transmission facilities between the Pacific Northwest and California. The proper comparison would include the capacity on all the transmission facilities, because all that capacity is available to serve California's load. Powerex's 2,000 MW of capacity is a little more than 25 percent of the 7,790 MW of capacity on all the facilities on the Southern Intertie. It also does not reflect that there are other sources of generation to serve California load than the Southern Intertie. Linn *et al.*, BP-18-E-BPA-25, at 34-35. These types of misunderstandings or errors make it harder to accept a party's analysis over the course of a proceeding, especially when errors are identified but go uncorrected. In this instance, JP03's assertion is dramatically different than what a proper comparison would show, and it highlights the importance of alternative service arrangements between the Pacific Northwest and California.

JP03 argues that Staff's proposal is unduly discriminatory, but this standard does not apply to BPA ratemaking under the Northwest Power Act. Although Section 212(i) of the Federal Power Act includes an undue discrimination standard, it only applies when the Commission orders BPA to provide transmission or interconnection services in accordance with the applicable provisions of the Federal Power Act. *See* 16 U.S.C. § 824k(i). JP03 asserts that BPA has adopted a policy of adhering to the Commission's open access principles to set rates. JP03 Br. Ex., BP-18-R-JP03-01, at 48. To support its position, JP03 argues that BPA has "committed to aligning its tariff with [the Commission's] pro forma open access tariff as closely as possible" JP03 Br., BP-18-B-JP03-01, at 56. However, BPA's tariff contains only the terms and conditions of transmission service. It does not establish rates, which are set through this proceeding and are published as a separate rates schedule. 2018 Transmission Rate Schedules and GRSPs, BP-18-A-04-AP04. Furthermore, "open access principles . . . do not form part of either the Commission or Ninth Circuit review of BPA's rates." Administrator's Final Record of Decision, BP-12-A-02, at 202.

JP03 appears to argue that BPA is discriminating against hourly customers, but most of these customers support Staff's proposed change in the rate design. JP03 Br. Ex., BP-18-R-JP03-01,

at 48-50. JP03 states that it is unaware of any case law indicating that customers taking the service have a voice in determining whether that service is discriminatory. *Id.* at 49. Even if JP03 is correct about the case law on this subject, it is reasonable to take into consideration the opinion of BPA's hourly customers on the subject. Similarly, BPA, itself, is the second largest user of hourly transmission service. Holcomb *et al.*, BP-18-E-JP03-01-AT02, at 17. Therefore, for JP03's argument to be correct, BPA would be discriminating against itself.

Furthermore, JP03's undue discrimination argument equally applies to BPA's existing hourly rate design, as well as those of TANC and SMUD. All three transmission providers charge long-term firm customers, which can schedule transmission for all 168 hours of the week, the same amount as hourly customers that can schedule 80 hours (in BPA's and SMUD's case) or 60 hours (in TANC's case). Linn *et al.*, BP-18-E-BPA-25, at 36-37. Accordingly, it is neither unusual nor unduly discriminatory to ensure that there is an incentive to reserve long-term firm transmission service.

JP03 next argues that it is unduly discriminatory to charge similarly situated customers different rates without evidence that the costs to serve them are different, and that it is unduly discriminatory to charge Southern Intertie customers different hourly rates than BPA's hourly customers on different transmission segments. JP03 Br. Ex., BP-18-R-JP03-01, at 50. Yet BPA's Southern Intertie customers and hourly customers on the rest of its transmission system are not similarly situated. They are taking transmission service on different parts of BPA's transmission system that have a unique set of costs. As described in the rest of this section, specific circumstances in California are prompting the change in the rate design.

JP03 complains that Staff proposes to continue to set BPA's hourly Scheduling, System Control, and Dispatch (SCD) rate based on 80 hours of peak hours, not 25. *Id.* at 49. This is an odd argument, as Staff's proposal to continue to use 80 hours for hourly SCD rates results in lower overall costs to reserve hourly transmission on the Southern Intertie. More importantly, Staff stated that only 15 percent of the SCD revenue requirement is anticipated to come from Southern Intertie uses. Linn *et al.*, BP-18-E-BPA-25, at 19-20. Therefore, a fairly drastic reduction in long-term firm reservations on the Southern Intertie would have to occur before there would be a significant risk to cost recovery. *Id.* Staff's hourly rate proposal also addresses this risk by making long-term firm transmission service more attractive. It is reasonable to not raise the SCD rate simply to achieve consistency with the hourly rate.

Charging the same amount for hourly firm transmission and hourly non-firm transmission service also is not unduly discriminatory. *See* JP03 Br., BP-18-B-JP03-01, at 56. As stated by JP03, Commission precedent indicates that non-firm transmission service should be priced "up to" the rate for firm service. Holcomb *et al.*, BP-18-E-JP03-01, at 90. This has been BPA's practice for a number of years across all transmission segments, and Staff does not propose to change that.

JP03 argues that Schedule 8 of BPA's Open Access Transmission Tariff, unlike the pro forma tariff, does not cap the hourly rate at the daily rate. JP03 Br., BP-18-B-JP03-01, at 56-57. JP03 concludes that this results in BPA moving farther away from the pro forma tariff if it adopts Staff's proposal. It does not. BPA has never capped the hourly rate at the daily rate.

Decision

Under the Northwest Power Act, BPA's rates are not subject to the undue discrimination standard or the just and reasonable standard. Nevertheless, Staff's proposal, as adopted in this final Record of Decision, is consistent with cost-based ratemaking, is not unduly discriminatory, and is reasonable.

Issue 5.2.2.1.13

Whether discounting transmission service addresses the potential for unexpected negative outcomes of Staff's proposal.

Parties' Positions

JP03 argues that discounting would cause customers to continue to choose hourly transmission service over long-term firm transmission service and that it would not alleviate any undue harm already caused by Staff's proposal. JP03 Br., BP-18-B-JP03-01, at 72-74.

JP01 states that "in the unlikely event that adverse unintended consequences arise, in the near-term BPA retains the ability to discount the hourly rate at its discretion." JP01 Br., BP-18-B-JP01-01, at 22.

BPA Staff's Position

BPA can discount transmission service between rate proceedings. Linn *et al.*, BP-18-E-BPA-25, at 36.

Evaluation of Positions

In a data response, Staff stated that discounts would mitigate the risk of unintended consequences of the proposed rate increase. Holcomb *et al.*, BP-18-E-JP03-01,AT1 (SM-BPA-26-83). JP03 is correct that discounting the hourly transmission rates would not undo harm caused while the rates were in effect. Once the discount is put in place, however, any unintended consequences of the rate increase would be mitigated going forward. BPA can discount its rates relatively quickly because it does not have to go through a separate rate proceeding to establish the discount. Linn, *et al.*, BP-18-BPA-25, at 36. If unintended consequences occur and BPA discounts its hourly transmission service, BPA agrees with JP03 that it would have to find other ways of mitigating seams issues.

Decision

Discounting would not completely address any unexpected negative effects of Staff's proposal.

Issue 5.2.2.1.14

Whether BPA should adopt Staff's proposed rate design for hourly transmission rates on the Southern Intertie for FY 2018–2019.

Parties' Positions

JP03 opposes Staff's proposed rate design for all the reasons stated in the previous issues in this section. In general, JP03 argues that Staff and JP01 have not provided evidence that BPA's risk of under-recovering its Southern Intertie costs has materially increased since the BP-16 rate proceeding and that the Hearing Officer committed errors that have prevented the development of a full and complete record. JP03 Br., BP-18-B-JP03-01, at 14-18.

JP01 supports Staff's proposed rate design, arguing that changes in California have put in jeopardy BPA's ability to recover costs on the Southern Intertie. JP01 Br., BP-18-B-JP01-01, at 3-4. JP01 argues that Staff's proposal appropriately responds to these changes and strengthens incentives for customers to invest in long-term firm transmission service. *Id.* at 5-7.

The Kalispel Tribe supports Staff's proposal, stating that "BPA should strengthen incentives for transmission customers to choose long-term service on the Southern Intertie so that this segment of the BPA system continues to recover its costs." Kalispel Tribe Br., BP-18-B-KT-01, at 3. NRU supports the proposal as well, joining JP01's arguments on the issues. NRU Br., BP-18-B-NR-01, at 31.

BPA Staff's Position

BPA should adopt Staff's proposal because seams issues between the Pacific Northwest and California combined with increasing amounts of solar generation in California have reduced the incentive to reserve long-term firm transmission service. Fredrickson *et al.*, BP-18-E-BPA-12, at 7. A reduction in long-term firm reservations and sales would mean that BPA would have to rely more on short-term sales to recover its Southern Intertie costs, and short-term sales are much more volatile and driven by market conditions that vary from year-to-year. *Id.* Staff's proposed rate design is intended to create an incentive to reserve long-term firm transmission service and mitigate the cost recovery risk created by the impacts of the seams issues.

Evaluation of Positions

Since the BP-16 rate proceeding, customers, stakeholders, and Staff have thoroughly examined the seams issues between the Pacific Northwest and California and discussed both ratemaking and non-ratemaking alternatives. See discussion above at Issues 5.2.2.1.1 to 5.2.2.1.3. This gives the record in this proceeding a factual basis and perspective on the issues that was missing in BP-16. BPA appreciates the thoughtful participation of all parties throughout the process.

BPA has made considerable investments in the transmission facilities that make up the Southern Intertie, including, most recently, a \$400 million project to upgrade the DC path. Some of BPA's transmission customers have likewise made considerable investments in long-term firm

transmission service on the Southern Intertie. The issues raised with respect to Staff's proposal in this proceeding are, in part, about protecting BPA's investments and providing appropriate incentives for customers to continue purchasing long-term firm transmission service from BPA. Creating those incentives aligns with BPA's goal to set rates that recover the costs of the investment in long-life transmission assets primarily through the sale of long-term firm transmission service.

Staff has made a convincing argument that using the assumption of 16 peak hours per day in California for purposes of setting rates for hourly service on the Southern Intertie no longer furthers BPA's goal of recovering the costs of the Southern Intertie through sales of long-term firm service. See Issues 5.2.2.1.4 to 5.2.2.1.9. The evidence, based on a variety of metrics, supports the conclusion that there are now five peak hours per weekday in California during the evening. See Issue 5.2.2.1.7. The CAISO's independent analysis of the number of peak hours and the development of new power products to serve this evening peak corroborate Staff's conclusion. *Id.* The evidence showing the impact of solar generation on the net load in California during daytime hours, along with the projected increase in solar generation in California in the next several years, make a compelling case for taking action now rather than waiting to address a cost recovery issue after it develops. *Id.*

Staff's proposed change also is necessary to help ensure that hourly customers are paying their fair share of BPA's costs. BPA's hourly rate methodology has always been premised on the principle that customers that reserve hourly transmission service for the peak number of hours should pay the same amount as a long-term firm transmission customer. Linn *et al.*, BP-18-E-BPA-25, at 4. Since there are now five peak hours per day in California, Staff's proposal ensures that customers that reserve transmission service for only those hours will make an appropriate contribution to BPA's fixed costs. This issue is separate from the concerns about creating the proper incentives and the cost recovery risk and is an independent basis for adopting Staff's proposal.

JP03 essentially asks BPA not to take action until after a cost recovery problem has materialized. Holcomb *et al.*, BP-18-E-JP03-01, at 95-96. Given BPA's significant investment in the Southern Intertie, and the large amount of existing reservations that are up for renewal in FY 2018–2019, a “wait and see” approach is unnecessarily risky and imprudent. The evidence shows that customers that purchase long-term firm transmission service on the Southern Intertie from BPA are expressing concern about the diminishing value of that service. Linn *et al.*, BP-18-BPA-25, at 6. At the same time, customers have rejected offers of such service and removed requests for such service from the queue. *Id.* at 7. A large and diverse group of BPA's customers and stakeholders support the proposed change to the rate design, and BPA agrees for all the reasons discussed in this Final Record of Decision.

Decision

BPA will adopt Staff's proposed changes to the rate design for hourly transmission service on the Southern Intertie for FY 2018–2019.

5.2.2.2 Procedural Issues Raised by JP03

JP03 requests that the Administrator review the Hearing Officer's decisions on various procedural or evidentiary matters in this proceeding, and it requests that the Administrator take official notice of certain documents and other information. This section focuses primarily on JP03's arguments about the Hearing Officer's decisions. The last issue in this section addresses the requests for official notice.

In its initial brief, JP03 alleges that the Hearing Officer erred in rulings on JP03's motion to compel JP01 to respond to certain data requests, an "asked and answered" objection to a question of JP01's witness during cross-examination, and an exhibit that JP03 sought to use in cross-examination. In a petition submitted after JP03 filed its initial brief, JP03 alleges the Hearing Officer erred in his decision on BPA's motion to strike a portion of JP03's initial brief. JP03 effectively requests that the Administrator review and reverse the Hearing Officer's decisions on all of these issues. The discussion below individually addresses each of JP03's requests for review. Offering some general perspective at the outset on the relief that JP03 seeks may help to provide context for the discussion and decisions that follow. The Northwest Power Act prescribes the procedures the Administrator must use to establish rates. 16 U.S.C. § 839e(i). Those procedures require a hearing to be "conducted by a hearing officer" to develop a full and complete record, and for the Administrator to make a final decision based on that record once the hearing is complete. *Id.* §§ 839e(i)(2), (i)(5). Although the Administrator has ultimate authority over all issues in a BPA rate proceeding, nothing in the Northwest Power Act suggests that the Administrator should be routinely involved with resolving evidentiary disputes or procedural issues, or serve an appellate function during the evidentiary phase of the rate proceeding.

JP03 first requested review of one of the Hearing Officer's decisions in its petition for interlocutory appeal of an order denying the motion to compel mentioned above. Petition for Interlocutory Appeal of Hearing Officer's Order Denying Motion to Compel, BP-18-M-JP03-09, at 3. BPA's procedural rules provide no explicit right or procedure to seek immediate review of a hearing officer's order and no standard or procedure to apply to such a request. Although the parties ultimately were directed to address the issue in their initial briefs, the lack of procedural guidance remains. Order on Petition for Interlocutory Appeal of Hearing Officer's Order Denying Motion to Compel, BP-18-A-01, at 1. Nothing in the rules addresses if or when it might be appropriate to review and reverse a hearing officer's decision during the evidentiary phase of the rate proceeding or what standard to apply.

Reviewing the Administrator's decisions on hearing officers' alleged errors in previous BPA rate proceedings provides little guidance in the resolution of JP03's requests. The vast majority of previous alleged errors addressed motions to strike portions of testimony or briefs for various reasons. Requests for review of orders on motions to compel or objections in cross-examination have been rare.

The Administrator appears to have reversed a hearing officer's order only three times since passage of the Northwest Power Act in 1980. In WP-93, the Administrator found that a hearing officer erred in denying a Staff motion to strike testimony regarding BPA programs and program levels. Administrator's Final Record of Decision, WP-93-A-02, at 329. Contrary to the hearing

officer's finding, the Administrator concluded that BPA's programs and program levels are not ratemaking issues. *Id.* In WP-07, the Administrator reversed an order striking certain passages of testimony on river operations for the rate period. Administrator's Final Record of Decision, WP-07-A-02, at 17-7 to 17-9. The Administrator found that some portions of the testimony at issue had been struck inadvertently due to a typographical error in the order and that other portions were relevant to issues in the case. *Id.* at 17-5 to 17-7. In BP-12, the Administrator reversed a decision granting a motion to strike because an error in the Federal Register Notice had provided the hearing officer with incorrect guidance about the scope of the case. Administrator's Final Record of Decision, BP-12-A-02, at 30-31. The limited number of times that orders have been overturned in the past, and the fact that two of those decisions corrected administrative errors and one addressed the scope of the proceeding, provide little guidance in addressing JP03's requests.

The advocacy of JP03 and other parties in this proceeding has highlighted a need to update BPA's procedural rules. Issues in this proceeding have raised questions about the need for rules to address the treatment of confidential information in discovery and filings, the scope of and any limitations on discovery, the length of briefs and testimony, hearing and oral argument procedures, and other topics. BPA Staff has committed to review the procedural rules after the BP-18 proceeding is complete. *See* Bonneville Power Administration's Answer to JP03's Petition for Protective Order, BP-18-M-BPA-03, at 2. Updating the rules hopefully will help provide clarity and certainty for Staff, parties, hearing officers, and the Administrator in future rate cases.

Issue 5.2.2.2.1

Whether the Administrator should reverse the Hearing Officer's order denying JP03's motion to compel.

Parties' Positions

JP03 argues that the Hearing Officer's order on the motion to compel includes errors with respect to the standard for relevance under BPA's discovery rule and upholding JP01's claims of confidentiality and privilege. JP03 Br., BP-18-B-JP03-01, at 79-80, 92. JP01 states that the Hearing Officer correctly upheld its objections in denying the motion to compel. JP01 Br., BP-18-B-JP01-01, at 25.

BPA Staff's Position

Staff has not taken a position on this issue.

Evaluation of Positions

The Hearing Officer's order denying the motion to compel addressed a discovery dispute over data requests submitted by JP03 to JP01. Order on JP03 Motion to Compel JP01's Response to Data Requests, BP-18-HOO-21. JP03 summarizes the requests as seeking internal studies or communications related to Powerex's (1) continued willingness to invest in long-term firm

transmission service, (2) reasons for continuing to renew long-term firm service in the face of the decline in value alleged by Powerex, and (3) whether either the profitability of its sales or the value of its long-term firm service holdings had, in fact, declined. JP03 Br., BP-18-B-JP03-01, at 79.

JP01 objected to the requests on various grounds. The written responses include the specific objections to particular requests. In general terms, JP01 objected that the requests were outside the scope of the testimony, were overly broad and unduly burdensome, sought public information, or sought confidential information that is proprietary or privileged.

After the parties were unable to resolve the matter informally, JP03 submitted a motion to compel. Motion of JP03 to Compel Responses to Data Requests, BP-18-M-JP03-01. JP01 responded to JP03's motion, JP03 replied to JP01's response, and JP01 answered JP03's reply. Response of Joint Party 1 to Joint Party 3's Motion to Compel Responses to Data Requests, BP-18-M-JP01-01-V01; Reply of JP03 to Answer of JP01 to Motion to Compel, BP-18-M-JP03-05; Answer of Joint Party 1 to Joint Party 3's Reply, BP-18-M-JP01-02. At that point, the Hearing Officer declined any additional pleadings. Order Authorizing Submission of Response to JP03 Reply, BP-18-HOO-20.

The Hearing Officer's order denied JP03's motion in its entirety. Order on JP03 Motion to Compel JP01's Response to Data Requests, BP-18-HOO-21, at 12. In general terms, the Hearing Officer applied BPA's procedural rule governing discovery and denied the motion on the basis that the information sought was (1) outside the scope of the testimony and therefore not relevant, (2) privileged, or (3) publicly available. *Id.* at 6, 7, 9, 11, and 12; Hearing Procedures, § 1010.8.

Soon after the order was issued, JP03 submitted a petition for interlocutory appeal, seeking immediate review of the order by the Administrator. Petition for Interlocutory Appeal of Hearing Officer's Order Denying Motion to Compel, BP-18-M-JP03-09. JP01 submitted a response to JP03's petition. Response of Joint Party 1 to Joint Party 3's Petition for Interlocutory Appeal, BP-18-M-JP01-01-V01. After considering the petition, the Administrator issued an order directing the parties to address the issues in their initial briefs. Order on Petition for Interlocutory Appeal of Hearing Officer's Order Denying Motion to Compel, BP-18-A-01, at 1. Both JP03 and JP01 addressed the issue in their briefs.

JP03 takes issue with two aspects of the order. First, JP03 claims that the Hearing Officer erred in concluding that "relevant" information is that which falls within the scope of the witness's testimony and was relied on by the witness to produce that testimony. JP03 Br., BP-18-B-JP03-01, at 80. JP03 claims that this finding is contrary to BPA's procedural rule governing discovery and an order granting a motion to compel in the WP-10 rate proceeding, both of which JP03 maintains place the responsibility for responding to discovery on the party and not the witness. *Id.* Second, JP03 argues that the decision to uphold the objections based on claims of confidentiality and privilege lacked explanation, was unsupported, and ran afoul of basic discovery principles. *Id.* at 92-94.

The discovery dispute at issue involved eight data requests, each with multiple sub-parts consisting of individual questions or requests for information. Altogether, the dispute involves

approximately 25 individual questions. JP01 objected to each request on multiple grounds. In fact, most sub-parts of a request received multiple objections. The parties submitted multiple pleadings on the issues with lengthy arguments about detailed procedural and evidentiary issues and disagreements about the decisions of hearing officers in previous rate cases. Resolution of a discovery dispute such as this falls squarely within the BP-18 Hearing Officer's expertise and responsibility under the Northwest Power Act, and nothing in the Northwest Power Act or BPA's procedural rules establishes the procedures to follow or the standards to apply if the Administrator undertakes review of the Hearing Officer's decision.

Standard for Relevance under Rule 1010.8(b)

JP03's primary argument is that the Hearing Officer incorrectly interpreted and applied Rule 1010.8(b) of BPA's procedural rules. The rule states:

Any relevant information may be requested that is not privileged or unduly burdensome to produce. BPA or any party may request data in hard copy or computer tape, studies or admissions; however, no party shall be required to perform any new study or to run any analysis or computer program.

Hearing Procedures, § 1010.8(b). BPA has discretion to establish the discovery rules that govern its rate case proceedings. *See Pac. Gas & Elec. Co. v. F.E.R.C.*, 746 F.2d 1383, 1386–88 (9th Cir. 1984) (“The extent of discovery to which a party to an administrative proceeding is entitled is primarily determined by the particular agency,” and “agencies need not observe all the rules and formalities applicable to courtroom proceedings.”). Although BPA is bound to follow the rules it has adopted, a court should give deference to BPA's interpretation of the rules unless the interpretation is plainly erroneous. *See id.* at 1386.

The Hearing Officer pointed out how rare motions to compel have been in BPA's rate proceedings, and an order issued in the WP-10 rate proceeding appears to be the only decision interpreting and applying Rule 1010.8(b) in any detail. Order on JP03 Motion to Compel JP01's Response to Data Requests, BP-18-HOO-21, at 5-6 (discussing Order on PNGC Motion to Compel Alcoa's Response to Data Requests, WP-10-HOO-27). JP03 argues that the WP-10 order properly applied Rule 1010.8(b), and that the BP-18 Hearing Officer's interpretation of this order was “clearly erroneous.” JP03 Br., BP-18-B-JP03-01, at 81. The parties' pleadings on JP03's motion to compel, the Hearing Officer's order, and JP03's initial brief reflect a wide range of interpretations of the WP-10 order. *Id.* at 81-83. On its face, however, the data requests at issue in WP-10 are distinguishable, and the WP-10 order supports the Hearing Officer's decision.

In WP-10, Alcoa proposed that BPA should establish an industrial rate according to what a Northwest aluminum smelter could afford to pay for power, and PNGC submitted data requests seeking the information used to determine the ability of a smelter to pay and details about the definition of ability to pay. Order on PNGC Motion to Compel Alcoa's Response to Data Requests, WP-10-HOO-27, at 2. Alcoa objected on the basis that the information sought was confidential, proprietary, and unduly burdensome to produce, and it argued that the testimony about what an aluminum smelter could afford to pay was based on the “professional judgment”

of the witness rather than his review of voluminous internal documents that would have to be produced to respond to the requests. *Id.* at 3-4. The WP-10 hearing officer granted the motion to compel, finding that the requests were relevant to testimony about Alcoa's assessment of what an aluminum smelter could afford to pay. *Id.* The WP-10 hearing officer concluded that Alcoa had "opened the door" to the requests by putting aluminum smelters' ability to pay at issue. *Id.*

The BP-18 Hearing Officer distinguished the facts in WP-10 on the basis that the JP01 witness "does not discuss past or planned actions of its specific members not publicly available." Order on JP03 Motion to Compel JP01's Response to Data Requests, BP-18-HOO-21, at 6. JP03 disagrees with that distinction, arguing that Alcoa's witness in WP-10 did not discuss past or planned actions either. JP03 Br., BP-18-B-JP03-01, at 81. The WP-10 order demonstrates otherwise. Alcoa's witness had stated that he used professional judgment as to what Alcoa "would be willing to pay" during a down cycle as the definition of "could afford to pay." Order on PNGC Motion to Compel Alcoa's Response to Data Requests, WP-10-HOO-27, at 3 n.8. This is a discussion of Alcoa's willingness or other plan to pay in the future.

The WP-10 order includes another distinction that diminishes JP03's argument about the proper interpretation of Rule 1010.8(b). The data requests in WP-10 sought the "documentation *used* to determine the estimated ability of a smelter to pay" and assumptions embedded in the definition of ability to pay. Order on PNGC Motion to Compel Alcoa's Response to Data Requests, WP-10-HOO-27, at 2 (emphasis added). In other words, the only documents at issue were those that Alcoa's witness had "used" in formulating his professional judgment. The discussion of the alleged burden of production in the WP-10 order confirms the limited scope of the documents at issue. *See id.* at 4. The hearing officer ordered Alcoa to produce only those documents that were "actually used" by the witness in formulating his judgment about the ability to pay, and the hearing officer assumed that the witness had those documents in his possession. *Id.*

Given the data requests at issue in WP-10, the order does not support the standard of relevance that JP03 suggests. The order supports the conclusion that documents used by a witness to develop testimony are relevant, but it does not necessarily support a conclusion about documents that a witness did not use in preparing testimony. That category of documents was not at issue in the WP-10 order. In this regard, the findings in the WP-10 order are consistent with the conclusion in the BP-18 order that relevant information is the information "used by" the witness to produce the testimony. Order on JP03 Motion to Compel JP01's Response to Data Requests, BP-18-HOO-21, at 2. JP01 has repeatedly made clear in this proceeding that its witnesses relied on review of publicly available information to develop their testimony. Response of JP01 to JP03's Motion to Compel Responses to Data Requests, BP-18-M-JP01-01-V01, at 7; Cross-Ex. Tr. at 174. Despite JP03's contention, the BP-18 Hearing Officer's reading of the WP-10 order is not "clearly erroneous." *See* JP03 Br., BP-18-B-JP03-01, at 81. The Hearing Officer's interpretation of Rule 1010.8(b) is consistent with what appears to be the only other decision applying the rule in any detail, and this is the type of decision that falls within the Hearing Officer's responsibility and expertise. The Hearing Officer's decision will not be overturned under these circumstances.

In making this finding, BPA is not adopting the standard applied by the Hearing Officer for use in the review of the rules that will follow this proceeding. BPA recognizes the issues that JP03

has identified with respect to the arguments about reading Rule 1010.8(b) in context and the potential for shielding information from discovery by not providing it to a witness. JP03 Br., BP-18-B-JP03-01, at 80. Staff and stakeholders should consider these arguments in the review of BPA's procedural rules after the BP-18 proceeding has concluded. BPA is not, however, endorsing JP03's proposed interpretation of Rule 1010.8(b) either. JP03 states that "the basic concept of discovery" under the standard it advocates would provide for compelling a "non-party" to produce relevant evidence (that is not privileged). *Id.* at 87 (citing *Jaffee v. Redmond*, 518 U.S. 1, 9 (1996)). Such a far-reaching standard has no basis in the Northwest Power Act or BPA's procedural rules and is overly broad for a BPA rate proceeding. A BPA rate proceeding is not a trial. The interpretation of the discovery rules should reflect that fact.

Nevertheless, given JP03's arguments about the implications of a discovery rule that focuses on evidence relied on by a witness rather than in the possession of a party, the limited BPA rate case precedent on the standard to apply under Rule 1010.8(b) and similar issues, and the importance of ensuring effective discovery, the decisions on the proposed rates for hourly transmission service on the Southern Intertie in this Final ROD have not relied on the testimony cited in the disputed data requests. The decisions in this Final ROD are based on the remaining evidence in the record.

JP03 maintains that BPA's reference to JP01's Initial Brief for JP01's position on issues related to the disputed data requests demonstrates that BPA has relied on JP01's testimony. JP03 Br. Ex., BP-18-R-JP03-01, at 79. JP01 is a party to this proceeding, and BPA summarizes the position of each party at the beginning of the discussion of each issue in this Final ROD. Even though BPA may have cited JP01's Initial Brief for the summary of JP01's position on an issue, that does not mean that BPA has relied on the JP01 testimony cited in the disputed data requests in the resolution of that issue.

JP03 also offers specific examples where BPA has reached conclusions in this Final ROD that allegedly resemble statements in JP01's testimony cited in the disputed data requests. *Id.* at 78. For example, JP03 claims that BPA's comparison of the 762 MW of requests in the queue to the 2,801 MW of reservations eligible for renewal in FY 2018–2019 is similar to JP01's testimony. *Id.* The comparison of these amounts is based on evidence other than JP01's testimony. JP03 itself has provided evidence on both these topics, including requesting that BPA take official notice of the queue. BPA has not relied on the JP01 testimony cited in the disputed data requests for the examples in JP03's Brief on Exceptions or for its decisions on any other issue.

Confidential and Proprietary Material

According to JP03, the data requests at issue in the motion to compel primarily seek information and materials from Powerex, because Powerex is the only member of JP01 that holds long-term firm transmission service on the Southern Intertie. Petition for Interlocutory Appeal of Hearing Officer's Order Denying Motion to Compel, BP-18-M-JP03-09, at 1 n.1. JP03 argues that its requests would "allow BPA to ascertain whether Powerex's claim that it might not renew its existing contracts was a bluff and whether its decision to withdraw 4,000 MW from the queue during the BP-16 rate case was part of a strategy to create fake 'facts on the ground.'" JP01 Br., BP-18-B-JP03-01, at 76. JP03 urges BPA to test that claim by requiring disclosure of what JP01

describes as a “broad array of highly-sensitive commercial documents,” including profitability analyses, internal communications, and documents concerning Powerex’s commercial decision-making. JP01 Br., BP-18-B-JP01-01, at 24. When addressing disclosure of confidential information, it makes sense to weigh the burden on the responding party with the probative value of the evidence, that is, its value in assisting the agency’s determination of the matter at issue.

Powerex advanced its concerns about the impact of seams issues between the Pacific Northwest and California in the BP-16 rate proceeding, reiterated those concerns and played a primary role in the public process on the issues following the BP-16 proceeding, and has supported Staff’s proposal to adjust the rate design to address those issues in this proceeding. Powerex is the largest purchaser of both long-term and hourly capacity on the Southern Intertie. Objective evidence shows that Powerex has partially renewed certain long-term reservations in recent years but has not renewed others. Holcomb *et al.*, BP-18-E-JP03-01, at 95. Given all of these facts, it is unlikely that Powerex is “bluffing” about its concerns and has undertaken a multi-year effort to persuade other customers, regional stakeholders, and BPA Staff into supporting an unnecessary change to the hourly rates on the Southern Intertie.

JP01 expresses concern about the chilling effect on customers’ participation in future rate cases that compelling disclosure of business sensitive information in this case could cause. Response of JP01 to JP03’s Motion to Compel Responses to Data Requests, BP-18-M-JP01-01-V01, at 19. BPA shares those concerns. If participation in a BPA rate proceeding is going to mean that parties may be subject to potential discovery of business sensitive internal documents, analyses, communications, and decisions, then all parties should know that beforehand. BPA’s Hearing Procedures do not explicitly address the treatment of business sensitive information of rate case parties’ in discovery. The rules do, however, permit BPA to withhold confidential information in its possession on the basis of exemptions in the Freedom of Information Act, 5 U.S.C. § 552, or the Trade Secrets Act, 18 U.S.C. § 1905. Hearing Procedures § 1010.8(f). There is some logic to applying a similar standard for obtaining information from rate case parties. Staff, customers, and interested parties should discuss these issues in the review of BPA’s procedural rules after the BP-18 proceeding is complete.

Given that BPA’s procedural rules do not address the treatment of business sensitive information in discovery, it is unlikely that Powerex intervened in the BP-18 proceeding believing that internal materials it considers highly sensitive would be subject to discovery. The protection of business sensitive information is extremely important because the release of such materials has the potential to cause competitive harm. The potential for harm is not limited to Powerex, but applies to nearly all rate case parties. In this instance, however, the potential for harm to Powerex is particularly acute because members of JP03 are counterparties to transactions with Powerex for power and transmission services from time to time. Response of JP01 to JP03’s Motion to Compel Responses to Data Requests, BP-18-M-JP01-01-V01, at 19. Competitive harm from disclosure of business sensitive materials directly to a counterparty is a significant possibility.

In contrast to these interests, JP03 seeks information to probe whether Powerex’s claims are a “bluff” and whether Powerex has created “fake” facts. JP03 Br., BP-18-B-JP03-01, at 76. JP03’s reason for seeking discovery is speculative. JP03 assumes bad intent with no independent

evidence of such intent. Furthermore, the decisions in this proceeding are based on the evidence in the record as a whole. This includes the evidence that Powerex and other customers have not renewed existing reservations in recent years and have removed pending requests for service from the queue. Holcomb *et al.*, BP-18-E-JP03-01, at 95; Linn *et al.*, BP-18-E-BPA-25, at 12. In other words, even assuming that evidence exists to support JP03's theory, that evidence would not be dispositive. Other evidence contradicts JP03's claims. Under these circumstances, BPA would deny the motion to compel with respect to the requests to which JP01 objected based on confidentiality for reasons independent from the decision of the Hearing Officer. The burden on Powerex from disclosure of business-sensitive information outweighs the benefit of additional discovery on this issue.

JP03 points out that it proposed and the Hearing Officer adopted a protective order under which JP01 could produce confidential information. JP03 Br., BP-18-B-JP03-01, at 94. JP01 describes the protective order as "toothless" in its lack of meaningful penalties for unauthorized disclosure. Response of JP01 to JP03's Motion to Compel Responses to Data Requests, BP-18-M-JP01-01, at 12; JP01 Br., BP-18-B-JP01-01, at 19. The parties' disagreement about the merits of the protective order adopted by the Hearing Officer once again reflects that BPA's procedural rules do not address the treatment of confidential information. BPA also has no "model" protective order that parties could have reviewed prior to intervening in the BP-18 proceeding. JP03 is correct that JP01 could have opposed adoption of the proposed protective order when it was filed with the Hearing Officer, but JP01 had already objected to the data requests on the basis of confidentiality and privilege at that point. In any event, adoption of the protective order is no reason to compel disclosure in the context of the issues in this proceeding.

Attorney-Client Privilege and Work Product Doctrine

JP03 argues that JP01 had the responsibility to produce a log listing all the documents that JP01 withheld based on attorney-client privilege. JP03 Br., BP-18-B-JP03-01, at 93-94. BPA's procedural rules, however, do not require a party that objects to a data request on the basis of privilege to provide such a log.

A privilege log is unnecessary for purposes of the data requests and dispute at issue in this proceeding. Attorney-client privilege is one of the oldest recognized privileges for confidential communications and BPA will respect that privilege. There is no reason to doubt that the members of JP01 asserted the attorney-client privilege in good faith. A privilege log in this case would simply add a burden to the responding party and would provide no evidentiary value for the record. As described above, a BPA rate proceeding is a rulemaking, not a trial or adjudication, and BPA is not bound to follow all the formalities of discovery in court proceedings.

Decision

JP03's motion to compel will not be granted; however, the Powerex testimony cited in the disputed data requests has not been relied on by BPA for the decision regarding proposed rates for hourly service on the Southern Intertie in the BP-18 proceeding.

Issue 5.2.2.2.2

Whether the Hearing Officer’s decision sustaining an “asked and answered” objection at the hearing was clear error.

Parties’ Positions

JP03 maintains that the Hearing Officer erred in sustaining an “asked and answered” objection by counsel for JP01 during cross-examination. JP03 Br., BP-18-B-JP03-01, at 94-95. According to JP03, the hearing transcript shows that the witnesses never answered the question and the Hearing Officer interposed his own objection. *Id.*

BPA Staff’s Position

Staff has not taken a position on this issue.

Evaluation of Positions

JP03 argues that the Hearing Officer committed clear error in sustaining an objection during cross-examination that JP01’s witnesses had “asked and answered” a question posed by counsel for JP03. *Id.* at 94-95. During JP03’s cross-examination of JP01’s witness Kevin Wellenius, counsel for JP03 repeatedly posed the question whether the witness had asked “Powerex’s or PPC members about what their plans were for whether they would renew or would not renew their existing firm contracts.” Cross-Ex. Tr. at 175. The witness did not give a “yes” or “no” answer but explained that his testimony “relies on an extensive review of all public information related to reservation and request for reservation of transmission, and that would include any such reservations made by JP01 members.” *Id.* at 174. After counsel for JP03 asked this same question a number of times and the witness provided variations of the same answer, the Hearing Officer determined the question was “asked and answered” and did not allow further questioning on the topic. *Id.* at 178.

JP03 argues that the Hearing Officer “committed clear error in failing to require the Powerex witness during cross-examination to answer whether he had spoken to Powerex about its [long-term firm] renewal plan.” JP03 Br., BP-18-B-JP03-01, at 17. JP03 states initially that the Hearing Officer’s order appeared to be under the impression at the outset that Powerex’s witness had not been privy to internal analyses regarding the company’s plans to renew service. *Id.* According to JP03, the Hearing Officer had asserted, “without any basis,” in his order on the motion to compel that, “[a]s a consultant, [Mr. Wellenius] does not participate in or have knowledge of Powerex’s internal decisionmaking processes leading up to the business decisions about which JP03 seeks discovery.” *Id.* at 94 n.352 (quoting BP-18-HOO-21, at 1 [sic]); *see also id.* at 18 (the Hearing Officer “assumed, without evidence, that the Powerex witness was not privy” to Powerex’s LTF renewal plans.”)). The basis for the Hearing Officer’s conclusion appears to have come from JP01’s response to the motion to compel, which makes the same statement as the order: “Mr. Wellenius does not participate in, and is not privy to Powerex’s internal decision-making sessions and corporate deliberative processes leading up to the types of business decisions on which JP03 seeks discovery.” Response of Joint Party 1 to

Joint Party 3's Motion to Compel Responses to Data Requests, BP-18-M-JP01-01-V01, at 7. JP03's suggestion that the Hearing Officer was somehow uninformed or predisposed on this issue at the time of cross-examination is incorrect.

The Northwest Power Act provides that "the hearing officer, *in his discretion*, shall allow a reasonable opportunity for cross examination, which, as determined by the hearing officer, is not dilatory, in order to develop information and material relevant to any such proposed rate." 16 U.S.C. § 839e(i)(2)(B) (emphasis added). The Hearing Officer has broad discretion to determine the extent of cross-examination, whether cross-examination has become "dilatory," and what is relevant to the scope of testimony.

The transcript is the only record available to consider JP03's claims, and it conveys nothing about the demeanor of the witnesses, attorneys, or Hearing Officer, or the other circumstances in the room. Rulings on procedural or evidentiary issues during cross-examination are within the Hearing Officer's responsibilities as contemplated in the Northwest Power Act.

In this case, the Hearing Officer was within his discretion in resolving the "asked and answered" objection. Although JP03 cites to three pages of the cross-examination testimony to support its argument that the witness never answered the question (Cross-Ex. Tr. at 175-78), the transcript shows that counsel for JP03 started this line of questioning much earlier by asking about a quote from JP01's response to JP03's petition for interlocutory appeal. *Id.* at 173 ("So there's a statement there. It says that the [JP01] witnesses did not attest to Powerex's or PPC members' specific beliefs, behaviors, business expectations, internal analyses, or the like. I take it that's an accurate statement about your testimony. Is that correct?"); *see also id.* at 172. What follows is counsel for JP03 repeatedly asking the same or very similar questions multiple times and in various forms, counsel for JP01 interjecting that the questions have been asked and answered, argument about whether the witnesses have provided their "best answer," and the witnesses repeating the same basic answer each time: the testimony was only based on public information and comments. *Id.* at 172-75.

After multiple exchanges among the Hearing Officer, counsel for JP01, and counsel for JP03, the Hearing Officer instructed the witnesses to provide "as direct an answer" as possible, and the witnesses ultimately stated that "our testimony is not based on private conversations with any transmission customers." *Id.* at 178. At that point, it appears that the Hearing Officer had decided the witnesses had provided their best answer and that it was time to move on. *Id.* (Hearing Officer: "The question has now been answered."). Although JP03 is correct that the Hearing Officer subsequently added that the question is outside the scope of the testimony, that conclusion appears to be based on the witness's statement that the testimony was not based on private conversations and the rationale applied by the Hearing Officer in the order denying JP03's motion to compel. *See* Order on JP03 Motion to Compel JP01's Response to Data Requests, BP-18-HOO-21, at 2.

JP03 maintains that a direct answer to the question might have informed BPA whether Powerex was "bluffing" about its plans to renew. JP03 Br., BP-18-B-JP03-01, at 96. As described previously, JP03's speculation that Powerex has undertaken a lengthy effort to deceive BPA and its customers about Powerex's transmission service concerns is entitled to little weight. Given

the extended line of questioning on this topic, the Hearing Officer was within the discretion vested in him by statute to limit additional cross-examination on this topic.

Decision

The Hearing Officer's decision sustaining an "asked and answered" objection at the hearing was not clear error.

Issue 5.2.2.2.3

Whether the Hearing Officer's decision regarding JP03's cross-examination exhibit departs from the Special Rules of Practice Governing this Proceeding.

Parties' Positions

JP03 argues that the Hearing Officer's refusal to permit questions about a cross-examination exhibit posed by JP03 departed from the Hearing Officer's Special Rules of Practice governing such exhibits. JP03 Br., BP-18-B-JP03-01, at 98.

BPA Staff's Position

JP03 established no foundation for its proposed cross-examination exhibit, which means there was no basis to conclude that the exhibit was accurate, relevant, or reliable. Cross-Ex. Tr. at 23-24. In addition, the proposed exhibit does not comply with the provisions of the Special Rules of Practice Governing this Proceeding that apply to cross-examination exhibits. *Id.*

Evaluation of Positions

Prior to cross-examination in this proceeding, JP03 filed on the BP-18 rate case website a number of exhibits that it proposed to use during its questioning of witnesses for BPA Staff and JP01. One of those exhibits is a Microsoft Excel workbook. *See* ISNF Workbook - First Tab, BP-18-E-JP03-12; ISNF Workbook, BP-18-E-JP03-12-AT01. The workbook contains multiple "tabs." The first tab is a cover page, three of the tabs include data, and two other tabs include graphs. *See id.*

During cross-examination of BPA Staff, counsel for JP03 began to describe this exhibit for the record, and counsel for BPA stated that BPA objected to the admission of the exhibit and the discussion of it on the record. Cross-Ex. Tr. at 21-22. What follows is a lengthy argument about the exhibit between counsel for JP03 and counsel for BPA, and discussion and questions about the exhibit by the Hearing Officer. *Id.* at 22-34. The Hearing Officer ultimately directed counsel for JP03 to proceed with cross-examination "without reference to the charts and tables." *Id.* at 34. Counsel for JP03 subsequently requested to make an offer of proof with respect to the exhibit, which the Hearing Officer permitted. *Id.* at 48.

In its initial brief, JP03 argues "the Hearing Officer departed, without any explanation, from his own rules" by "refusing even to entertain preliminary questions about the calculations JP03 had

asked BPA Staff to perform, much less confirm the accuracy of the data depicted in the charts provided to the Staff in advance of the hearing.” JP03 Br., BP-18-B-JP03-01, at 19. According to JP03, the Hearing Officer’s decision is inconsistent with the procedural rule that states: “Witnesses may not be asked to perform calculations on the stand. If calculations and their results are submitted to a witness on cross-examination, the submissions must be in writing, must state the source of the data used, and must explain how the results were obtained.” *Id.* at 98 (quoting Special Rules of Practice Governing this Proceeding, BP-18-HOO-02, at 3). JP03 states that the rules require this information be provided two days in advance of the hearing. *Id.*

JP03 claims that it complied with the requirements in the Special Rules of Practice, but the record shows that JP03 is incorrect. *Id.* at 99. The exhibit filed by JP03 on the BP-18 rate case website prior to cross-examination, which consists of ISNF Workbook – First Tab, BP-18-E-JP03-12 and ISNF Workbook, BP-18-E-JP03-12-AT01, does not contain any written description of the source of the data used and how the results were obtained. Although JP03’s offer of proof includes a written description of the exhibit, and JP03 claims that the descriptive document was provided at the hearing, that document was not included with the exhibit filed on the BP-18 website prior to the hearing. JP03 Offer of Proof, BP-18-M-JP03-16, at 1 n.1. Moreover, Staff’s response to JP03’s offer of proof raises questions whether that document was provided at the hearing. Bonneville Power Administration Response to Joint Party 3 Offer of Proof, BP-18-M-BPA-11, at 2. On its face, the cross-examination exhibit consisting of BP-18-E-JP03-12 and AT01 does not include the written explanation called for in the Hearing Officer’s Special Rules of Practice. Even if the written explanation was later provided at the hearing, it was not provided to counsel for BPA two days in advance of cross-examination as required by the rules. The Hearing Officer’s decision on the exhibit was consistent with the procedural rules and within his discretion.

The Hearing Officer’s Special Rules of Practice provide a limited set of rules that supplement BPA’s Hearing Procedures. The Special Rules of Practice do not, and were never intended to, provide an exhaustive list of evidentiary rules or to replace existing rules of evidence. A party must still provide a proper foundation for an evidentiary exhibit by having a witness attest to the validity of the proposed evidence. The Hearing Officer is correct that, by attempting to introduce new analysis late in the evidentiary phase of the proceeding with no opportunity for testimony of the expert that prepared the exhibit, a decision maker has no way to know whether the analysis was accurate and reliable and deserves any weight. Cross-Ex. Tr. at 32. The record shows that in discovery JP03 asked Staff to verify and confirm the results of JP03’s analysis regarding the same dataset that counsel for JP03 referred to during the argument at cross-examination. *See* JP03 Data Responses Admitted into Evidence by Order BP-18-HOO-29, BP-18-E-JP03-17, at 357-59. Staff was unable to confirm basic aspects of the analysis. *Id.* Under these circumstances, even if the Hearing Officer had allowed the exhibit into evidence, there would have been no basis to deem the information in the exhibit reliable, and the exhibit would have deserved no weight.

Decision

The Hearing Officer’s decision regarding JP03’s cross-examination exhibit was consistent with the Special Rules of Practice Governing this Proceeding.

Issue 5.2.2.2.4

Whether the Administrator should reverse the Hearing Officer's order granting Staff's motion to strike portions of JP03's initial brief.

Parties' Positions

JP03 maintains the Hearing Officer's decision to strike a portion of JP03's initial brief was "clearly erroneous." Appeal to Administrator of Hearing Officer's Order Partially Granting BPA Staff Motion to Strike Portions of the JP03 Brief, BP-18-M-JP03-21, at 3. JP03 argues that the Hearing Officer was mistaken in finding that JP03 included a "fictitious reference" to the cross-examination transcript. *Id.* at 2. JP03 also claims that the Hearing Officer erred in striking a graph and related text. *Id.* at 3.

BPA Staff's Position

Staff has not taken a position on this issue.

Evaluation of Positions

After JP03 filed its initial brief in this proceeding, Staff moved to strike from the brief a graph titled "Total Hourly Southern Intertie Flows for FY 2010–2016" and certain text that referred to the graph. Motion to Strike the Initial Brief of JP03 and Request for Expedited Consideration, BP-18-M-BPA-13, at 1. Staff argued that this graph and text were improperly included in the initial brief because the graph was the same one that the Hearing Officer had not allowed JP03 to use during cross-examination and had excluded from the record. *Id.* JP03 submitted an answer to Staff's motion, arguing that the text that Staff sought to strike was based on evidence that is already in the record and that JP03 included the graph in its brief "simply [as] a convenience that helps illustrate our argument." JP03 Parties' Answer to Motion to Strike Portions of Brief, BP-18-M-JP03-19, at 3-4. The Hearing Officer granted the motion in part, striking the graph and some related text from the brief but leaving text that was based on evidence already in the record.

JP03 subsequently filed a motion to appeal the Hearing Officer's order regarding the following portions of the initial brief: the graph on page 40, text on page 37 and associated footnotes, and text on pages 39-41. Appeal to Administrator of Hearing Officer's Order Partially Granting BPA Staff Motion to Strike Portions of the JP03 Brief, BP-18-M-JP03-21.

The Graph on Page 40

As an initial matter, the graph that JP03 included in its initial brief is the same one that JP03 included in the proposed cross-examination exhibit that was disallowed by the Hearing Officer, as discussed in the preceding issue. *See* ISNF Workbook – First Tab, BP-18-E-JP03-12; ISNF Workbook, BP-18-E-JP03-12-AT01; Cross-Ex. Tr. at 21. Including the graph in its initial brief after the Hearing Officer's ruling during cross-examination suggests a disregard for the Hearing Officer's decision and the procedural rules. JP03 knew that the Hearing Officer had excluded the graph from evidentiary record at the point it submitted its initial brief. JP03 Parties' Answer to Motion to Strike Portions of Brief, BP-18-M-JP03-19, at 4. Section 1010.13(a) of the BPA's

Hearing Procedures states that “materials not admitted into evidence shall not be attached to any brief.” Based on that rule, the Hearing Officer’s decision to strike the graph from the initial brief will stand.

JP03 complains that the Hearing Officer failed to address its argument that the graph should not be struck because a “literal reading” of Section 1010.13(a) would bar any reference to the graph, including in JP03’s offer of proof or its arguments about the Hearing Officer’s errors. JP03 Parties’ Answer to Motion to Strike Portions of Brief, BP-18-M-JP03-19, at 4; Appeal to Administrator of Hearing Officer’s Order Partially Granting BPA Staff Motion to Strike Portions of the JP03 Brief, BP-18-M-JP03-21, at 3-4. JP03 calls this an “absurd” result. JP03 Parties’ Answer to Motion to Strike Portions of Brief, BP-18-M-JP03-19, at 5. Notably, Staff did not move to strike the portion of JP03’s initial brief that alleges error by the Hearing Officer in disallowing the graph at cross-examination. Staff focused only on the portions of JP03’s initial brief that present the graph as evidence, discuss the graph, or cite the graph as evidentiary support for other statements. The absurd result that JP03 speculates about is not at issue in this proceeding.

JP03 suggests that its appeal of the Hearing Officer’s decision disallowing use of the graph in cross-examination somehow made it acceptable to present and rely on the graph as evidence in its initial brief. *Id.* at 4. JP03’s procedural maneuvering to place before the Administrator a graph that the Hearing Officer has already excluded from evidence does not change the evidentiary status of that graph. It is not in the evidentiary record. By JP03’s rationale, a party could include any piece of evidence in the record simply by attaching it to a pleading and filing it in this proceeding. Such a result would contravene the procedural rules.

Text on Page 37 and Associated Footnotes

The original version of JP03’s initial brief included the following statement: “Over the last several years, the volume of original hourly service has been flat¹²⁸ while use of LTF has increased.¹²⁹” Staff moved to strike this sentence because footnote 129 cited the disputed graph (on page 40, discussed above) as the basis for the statement. JP03 subsequently filed a “correction” to its initial brief to add citations to footnote 129 and remove the reference to the chart. Erratum Correction to Initial Brief of JP03, BP-18-B-JP03-01-E01, at 1.

JP03’s answer to the motion to strike included the following passage about the text on page 37 of the initial brief:

There is no basis to argue that this sentence does not address materials in the record. Indeed the *BPA Staff witnesses* admitted that over the last several years (1) “the volume of original hourly service has been flat,” Tr. 72:17-25 and (2) that “use of LTF has increased.” *See, e.g.*, JP03-BPA-26-22 (agreeing that “holders of long-term from [sic] service have increased their overall scheduled use of their rights since the BP-16 rate case concluded” and that “overall use of original hourly service has not increased since the BP-16 rate case concluded.”). *See also* BP-18-E-JP03-02-AT02-CC01, Chart 1.

JP03 Parties' Answer to Motion to Strike Portions of Brief, BP-18-M-JP03-19, at 1 (*italics in original, underline added*). Apparently based on the text of JP03's answer, the Hearing Officer concluded that the underlined portion of the statement above was a quote from the cross-examination transcript. The Hearing Officer found that the quoted text did not appear in the transcript on the pages cited by JP03 and concluded that it was a "fictitious reference." Order on Motion to Strike Portions of JP03 Initial Brief, BP-18-HOO-39, at 4. The Hearing Officer found that the statement was not otherwise supported in the record and struck a portion of the sentence as follows: "~~Over the last several years, the volume of original hourly service has been flat~~¹²⁸ while use of LTF has increased.¹²⁹". *Id.* at 4-5.

In reality, the underlined quote above was JP03 quoting text from page 37 of its initial brief, not JP03 quoting the hearing transcript. JP03 states in its appeal that its answer to the motion to strike "may have been" the source of the Hearing Officer's confusion. Appeal to Administrator of Hearing Officer's Order Partially Granting BPA Staff Motion to Strike Portions of the JP03 Brief, BP-18-M-JP03-21, at 2 n.1. This seems highly likely. When the end of a statement in quotation marks is followed directly by a citation, the typical understanding is that the statement will be found in the document identified by the citation. In this case, it appears that unclear drafting caused the confusion.

Although the Hearing Officer's mistake was likely due to the lack of clarity in JP03's answer, it nevertheless was an error. In other decisions in the order, the Hearing Officer declined to strike portions of the initial brief that were supported by evidence in the record. JP03 points out other evidence in the record that supports the statement that the volume of original hourly service has been flat. The order is reversed with respect to the portion of the statement struck by the Hearing Officer.

Text on Pages 39-41

Staff's motion asked the Hearing Officer to strike the section of JP03's initial brief in which JP03 included the aforementioned graph, because that section described the graph and discussed how the graph was created. Motion to Strike the Initial Brief of JP03 and Request for Expedited Consideration, BP-18-M-BPA-13, at 2. The Hearing Officer granted Staff's motion with respect to the paragraphs that appeared immediately before and after the graph, finding that they asserted statements of fact (not previously entered into the record) rather than argument. Order on Motion to Strike Portions of Initial Brief of JP03, BP-18-HOO-39, at 5-6. Specifically, the Hearing Officer found the statements before the graph included "testimony describing the means to prepare the stricken graph" and the statements after the graph sought "to incorporate the stricken graph by references in order to make its argument." *Id.* at 6.

The Hearing Officer's order will stand. The Hearing Officer articulated a clear rationale for his decision, there is no mistake or administrative error, and JP03 created a controversy about the text by submitting an initial brief that included information that is not in the evidentiary record. JP03 maintains that its arguments in the section containing the graph are independently supported by the record. Appeal to Administrator of Hearing Officer's Order Partially Granting BPA Staff Motion to Strike Portions of the JP03 Brief, BP-18-M-JP03-21, at 4. If that is the

case, then the Hearing Officer's order does not exclude valuable information that cannot be found elsewhere.

Decision

The Hearing Officer's decision striking the statement "Over the last several years, the volume of original hourly service has been flat¹²⁸" was due to a mistake apparently caused by unclear drafting in JP03's answer to Staff's motion. That aspect of the Hearing Officer's decision is reversed. The remainder of the order will stand.

Issue 5.2.2.2.5

Whether BPA should take official notice of certain documents referenced or attached to JP03's Initial Brief and Brief on Exceptions.

Parties' Positions

JP03 requests that BPA take official notice of various documents or other materials. JP03 Br., BP-18-B-JP03-01, at 4 n.4, 27 n.67, 63 n.249, 70 n.283; JP03 Br. Ex., BP-18-R-JP03-01, at 8, 24 n.8.

BPA Staff's Position

Staff has not taken a position on this issue.

Evaluation of Positions

Rule 1010.11(c) of BPA's Hearing Procedures allow the Administrator to take official notice of any matter that may be judicially noticed by federal courts, or any matter about which BPA is expert. In its Initial Brief, JP03 asks BPA to take official notice of Staff's white paper, the queue of requests for long-term firm transmission service on the Southern Intertie, a reliability standard (BAL-002-WECC-2), and Powerex's comments during workshops prior to the BP-18 rate case. JP03 Br., BP-18-B-JP03-01, at 4 n.4, 27 n.67, 63 n.249, 70 n.283. In its Brief on Exceptions, JP03 asks BPA to take notice of comments that BPA submitted to the CAISO in January 2017 and the attachment to Data Response SM-BPA-26-30. JP03 Br. Ex., BP-18-R-JP03-01, at 8, 24 n.8. All of these materials fall within the standards in Rule 1010.11(c) of the Hearing Procedures. The discussion below individually addresses each of JP03's requests for official notice.

Both Staff's white paper and the reliability standard, BAL-002-WECC-2, are already in the record. See Data Requests and Responses Admitted into Evidence, BP-18-E-JP01-03, at 11-103; Holcomb *et al.*, BP-18-E-JP03-02-AT03 at 21-22. Therefore, there is no need to take official notice of them. In addition, a party can cite to a law or a regulation, like BAL-002-WECC-2, without it being in the record or officially noticed.

The evidentiary record and this Final Record of Decision include a considerable amount of discussion of the Southern Intertie queue. BPA will take official notice of the attachment in JP03's brief showing the queue. *See* JP03 Br., BP-18-B-JP03-01, at 103; Southern Intertie Queue attached to JP03's Initial Brief, BP-18-X-06.

BPA will also take official notice of Powerex's June 3, 2016 pre-rate case comments. *See* Powerex's June 3, 2016 comments on BP-18 Southern Intertie Rate, BP-18-X-03. These comments were discussed on the record during cross-examination and help provide context for that discussion. *See* Cross-Ex. Tr. at 112–16.

BPA's January 6, 2017, comments to the CAISO concern the CAISO's market design and renewable integration. *See* BPA's January 6, 2017 comments to the CAISO, BP-18-X-04. According to JP03, these comments contradict Staff's testimony in this proceeding that increased installed solar generation capacity in California was reducing the demand for long-term firm transmission service. JP03 Br. Ex., BP-18-R-JP03-01, at 8. BPA addresses JP03's claims in Issue 5.2.2.1.8. BPA will take official notice of its comments to provide some context for the resolution of JP03's arguments.

Finally, BPA takes official notice of the attachment to SM-BPA-26-30, which is a widely circulated email from WSPP advertising new power products. *See* Attachment to Data Response SM-BPA-26-30, BP-18-X-05. According to JP03, this email shows that the WSPP power product is for six hours a day, six days a week. JP03 Br. Ex., BP-18-R-JP03-01, at 24 n.8. BPA addresses this email in Issue 5.2.2.1.7. BPA will take official notice of the attachment to Data Response SM-BPA-26-30 to remove any doubt that the attachment is in the record and to provide some context for the resolution of JP03's arguments.

Decision

BPA will take official notice of the attachment in JP03's Initial Brief showing the Southern Intertie queue, Powerex's June 3, 2016, comments in the pre-rate case public process, BPA's January 6, 2017, comments to the CAISO, and of the attachment to SM-BPA-26-30.

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6.0 FINANCIAL RESERVES POLICY

6.1 Introduction

Financial reserves are a keystone of BPA’s long-term financial health. Harris *et al.*, BP-18-E-BPA-33, at 8. Financial reserves are used to meet payment obligations and to provide liquidity to fill financial gaps when expenses are paid before revenues are received or when expenses are simply greater than revenues. Harris *et al.*, BP-18-E-BPA-17, at 3. In these and other ways, financial reserves are a financial safeguard against delay between disbursements and receipts and against short and long-term financial uncertainty. *Id.*

Financial reserves also play a key role in supporting BPA’s credit rating. Harris *et al.*, BP-18-E-BPA-33, at 8. Credit rating agencies give BPA a credit rating each time BPA-backed debt is sold into private third-party markets. Harris *et al.*, BP-18-E-BPA-17, at 13. By industry standards, BPA has earned a strong credit rating. *See id.* at 14. This strong credit rating ensures that there is high demand and very competitive interest rates for BPA-backed debt. Harris *et al.*, BP-18-E-BPA-33, at 60-61. Accessing these markets is now, more than ever, critically important to BPA’s mission of providing power and transmission services to the region. *Id.* at 2. Over the next 10 years, BPA-backed debt (*e.g.*, bonds) that is indirectly issued through third parties is expected to exceed \$9.9 billion in order to support regional power and transmission infrastructure. Harris *et al.*, BP-18-E-BPA-17, at 13-14. This will be the most debt BPA has relied on since the agency was established in 1937. Harris *et al.*, BP-18-E-BPA-33, at 2. BPA’s debt-backed capital programs ensure that the agency continues to operate and maintain the Federal Columbia River Power System (FCRPS) and the Federal Columbia River Transmission System (FCRTS). *Id.* at 2-3. BPA’s revenue from power and transmission sales also funds a number of statutorily mandated programs, such as fish and wildlife mitigation and energy efficiency. In addition to other factors, credit rating agencies examine BPA’s financial reserves levels and policies to determine BPA’s credit rating, which in turn strongly influences the interest rates BPA pays for third-party debt. *Id.* at 3.

Financial reserves provide these (and other) valuable benefits to BPA’s customers. To date, however, BPA has had no formal policy to ensure that it retains levels of financial reserves above its needs for solvency. *Id.* at 54. BPA’s Treasury Payment Probability (TPP) standard works to ensure that reserves attributed to each business line are sufficient to remain solvent over the rate period. The TPP standard does not, however, take into account the effect of financial reserves levels on BPA’s credit rating or the relative contribution to BPA’s financial reserves from each business line, and does not have a methodology for determining when BPA or business line reserves are more or less than sufficient. See Section 6.2.3 (existing policies on financial reserves).

As a result of this gap in BPA’s policies, BPA’s financial reserves are allowed to fluctuate significantly. BPA’s financial reserves have, in fact, varied widely over the past 10 years, from a high of over \$1.2 billion in FY 2008, to a current projection of just over \$395 million in FY 2017. Harris *et al.*, BP-18-E-BPA-33, at 8; Power and Transmission Risk Study, BP-18-E-BPA-05, at 114-115, Tables 11 and 12. BPA’s current policies would allow financial reserves to decline even further—to as low as \$230 million—which, as explained later in this

section, could harm BPA’s strong credit rating. Harris *et al.*, BP-18-E-BPA-17, at 12, 16; see also Section 6.4.3 (credit rating and FRP). A decline in BPA’s credit rating due to low financial reserves would increase BPA’s interest expense for years and would be detrimental to the agency’s overall financial health. Harris *et al.*, BP-18-E-BPA-33, at 3.

This gap in BPA’s financial policies has also allowed significant fluctuations in the relative contribution of BPA’s business lines to total agency financial reserves. In the most recent projections for FY 2017, Power Services’ contribution to total agency financial reserves is projected to be \$2 million, and Transmission Services’ is projected to be \$394 million. Harris *et al.*, BP-18-E-BPA-33, at 8-9; *id.*, Attachment 1, at 15. That is, Transmission Services is forecast to supply approximately 99 percent of the financial reserves held by BPA in FY 2017. While short-term imbalances between Power Services’ and Transmission Services’ contributions to agency financial reserves are acceptable, no current policy would prevent the present disparity from turning into a long-term, systemic imbalance between business line contributions to financial reserves funding. *Id.* at 35-36, 136. Indeed, under BPA’s current policies, Power Services’ financial reserves could continue to decline to \$0, while Transmission Services’ reserves could fall to \$230 million, and still no directed rate action would be taken to restore financial reserves. Harris *et al.*, BP-18-E-BPA-17, at 12.

The Financial Reserves Policy (FRP) described in this section is intended to address these gaps in BPA’s existing policies. At a high level, the FRP provides a consistent, transparent, and financially prudent method for determining financial reserves levels for BPA. The policy defines upper and lower financial reserves thresholds for BPA’s Power Services, BPA’s Transmission Services, and the agency as a whole. The policy also provides guidance for the actions BPA may take when financial reserves levels fall below a lower threshold or exceed an upper threshold. The policy does not change BPA’s existing risk mitigation measures or prevent BPA from experiencing negative net revenue. Instead, BPA’s newly established FRP builds upon BPA’s existing policy structure to establish a framework for managing financial reserves levels for credit rating support, business line equity, and the opportunity for rate stability.

6.2 Background

6.2.1 Overview of Financial Reserves

Financial reserves are composed of cash, market-based investments, and deferred borrowing. Harris *et al.*, BP-18-E-BPA-17, at 2. BPA defines two forms of financial reserves: encumbered and unencumbered.

Encumbered financial reserves, which are also referred to as Reserves Not Available for Risk, are financial reserves that have been deposited with BPA for a specific purpose. BPA uses encumbered reserves for purposes such as capital expenses to interconnect customers to BPA’s transmission grid, and as collateral for certain trading agreements. *Id.* at 4. Since these financial reserves are committed to specific purposes, they are considered unavailable for risk mitigation. *Id.*

Unencumbered financial reserves, also referred to as Reserves Available for Risk, result from revenues being greater than expenses over time. *Id.* Because Reserves Available for Risk are not obligated for any specific future purpose, they are available for use and function as BPA's primary source of liquidity for planning and ratesetting. *Id.*

This Final ROD discusses BPA's decisions regarding unencumbered financial reserves (hereafter referred to as financial reserves) because, as explained above, encumbered reserves are not available for risk mitigation as they are already committed to specific purposes.

6.2.2 How BPA Holds Financial Reserves

All of BPA's financial reserves are held within the U.S. Department of the Treasury (Treasury) in the BPA Fund. *Id.* at 2. All of BPA's cash from Power Services and Transmission Services is deposited into this account. *Id.* Likewise, all of BPA's disbursements necessary to operate its business units and repay the Federal investment in the Federal Columbia River Power and Transmission Systems are made from this account. *Id.* The Administrator has access to all funds in the Bonneville Fund to meet payment obligations. *Id.*

While BPA's financial reserves are held in this account, BPA's power revenues and expenses are applied to the Power Services business unit, and transmission revenues and expenses are applied to the Transmission Services business unit. *Id.* BPA's revenues and expenses typically result in receipts and disbursements of cash, and these receipts and disbursements are attributed to the applicable business units. *Id.*

6.2.3 Existing Policies on Financial Reserves

Under the TPP standard, BPA sets rates for Power and Transmission Services to ensure a 95 percent probability of making BPA's year-end Treasury payment for each year of the two-year rate period. *Id.* at 5-6; *see also* Administrator's Final Record of Decision, WP-93-A-02, at 72. The TPP standard was established in 1993, after BPA missed several Treasury payments in the early 1980s, as a means to rebuild trust in BPA's ability to meet its statutory requirement to repay the Federal investment within a reasonable number of years. *Harris et al.*, BP-18-E-BPA-17, at 6. The primary purpose of the TPP standard is to ensure a very high probability that BPA will have sufficient liquidity over the rate period to meet its payment obligations to the Treasury on time and in full, particularly since BPA is required by law to meet its other financial obligations before it makes its Treasury payment. *Id.* Through the TPP standard, BPA can ensure that in a two-year rate period there is at least a 95 percent probability that Treasury payments will be made in full while maintaining certainty that all other payments throughout the year will be made. *Id.* With the support of the TPP standard, BPA has made 34 consecutive Treasury payments in full and on time. *Id.*

While the TPP standard can require BPA to hold additional financial reserves, it does so only when the chance of paying Treasury falls below 95 percent. The TPP standard itself looks only at the probability of paying the Treasury on time and in full. *Id.* at 9. If a business line can meet the 95 percent TPP standard without holding additional financial reserves, then the TPP standard would not direct that business line to raise its rates to increase its financial reserves. In this way, the 95 percent TPP standard ensures BPA's ultimate solvency over a two-year rate period, but it

does not establish prudent targets or goals for financial reserves for Power Services, Transmission Services, or the agency as a whole to meet other objectives. *Id.* at 11; Harris *et al.*, BP-18-E-BPA-33, at 54.

To date, the 95 percent TPP standard has provided important policy guidance for when BPA should intentionally increase liquidity to ensure a 95 percent probability of making Treasury payments. Harris *et al.*, BP-18-E-BPA-17, at 10. However, the standard does not provide policy guidance for other important issues related to BPA's financial reserves amounts, such as guidance on target ranges for financial reserves for the business lines or the agency, the minimum level of financial reserves BPA would allow before taking ratemaking action to protect its credit rating, the maximum amount of financial reserves BPA would allow before repurposing such reserves, or how to allocate responsibility for financial reserves between business lines. *Id.*

For these reasons, something in addition to the TPP standard is needed to support BPA's other financial policy objectives. Harris *et al.*, BP-18-E-BPA-33, at 26. Therefore, BPA is creating an additional financial policy to meet financial objectives the TPP standard does not address. Harris *et al.*, BP-18-E-BPA-17, at 16.

6.2.4 How Financial Reserves Accumulate

BPA's power and transmission rates are established to recover all costs over a rate period on a prospective basis. That is, receipts from revenues are planned to be as great as disbursements for expenses. *Id.* at 3. Actual revenues and expenses often differ from forecasts, and thus actual receipts and disbursements can be different from what was planned when setting rates. *Id.* As a consequence of the variation between forecasts and actual results that utilities experience when setting and recovering rates, receipts will be either greater than, the same as, or less than disbursements. *Id.* Therefore, financial reserves attributed to a business line increase when receipts for that business unit are greater than disbursements in a fiscal year, and financial reserves decrease when disbursements are greater than receipts. *Id.* at 2-3.

For instance, in the last three rate periods, Power Services' cash flow in a single rate period has been above the expected value by as much as \$213 million and below the expected value by as much as \$337 million. This variation can be attributed to factors such as water volume variation, load changes, the impact of weather on demand, and market conditions. *Id.* at 3. Transmission Services' cash flow has been as much as \$16 million over and \$73 million under rate case expected value calculations. *Id.* This variation can be attributed to factors such as changing market conditions, unexpected construction costs, and load variation. BPA's accumulated financial reserves have been used to fill the gap when cash flow was negative. *Id.*

6.2.5 How Financial Reserves Decline

In the absence of an express policy on financial reserves, BPA's financial reserves have varied widely over the past decade. Over the past 10 years, agency financial reserves have declined from a high of \$1.268 billion in 2008, to \$603 million in 2016. Arthur, BP-18-E-MS-12, Exhibit 12, at 10 (showing actual financial reserves from 2008–2015); *see also* Harris *et al.*, BP-18-E-BPA-33, at 36 (noting actual financial reserves for FY 2016 were \$159 million for Power Services and \$444 million for Transmission Services). That is a decline of nearly

\$900 million in nine years. Most recently, financial reserves have continued to decline, with projections of agency financial reserves of approximately \$395 million for FY 2017. *See Harris et al.*, BP-18-E-BPA-33, Attachment 1, at 16.

The lack of a financial reserves policy has also allowed the financial reserves of BPA's business lines (Power Services and Transmission Services) to vary widely. During the past decade, financial reserves attributable to Power Services have varied from \$852 million in 2008, to \$159 million in 2016 (a decline of \$693 million). Arthur, BP-18-E-MS-12, Exhibit 12, at 10 (showing actual financial reserves from 2008–2015); *see also Harris et al.*, BP-18-E-BPA-33, at 36 (actuals for FY 2016). Transmission Services' financial reserves have seen similar volatility, with financial reserves reaching a low of \$179 million in 2004 and a high of \$606 million in 2010. *Id.* At various times, each business line has held more financial reserves than the other. However, since FY 2010, the bulk of the financial reserves held in the Bonneville Fund have been attributed to Transmission Services. *Id.* This trend is expected to continue through FY 2017; the current expected value for the end of FY 2017 for Power Services' financial reserves is a mere \$28 million, while the current expected value for Transmission Services' reserves is approximately \$413 million. Power and Transmission Risk Study, BP-18-FS-BPA-05, at 127, 129, Tables 3, 8.

The decline in total BPA financial reserves is primarily due to market forces over which BPA has no control, and which can vary widely after rates have been set. *Id.* at 3, 104. These market forces underscore the fact that establishing a sound FRP is foundational to BPA's ability to remain competitive now and in the future. *Id.* at 3. The energy industry is in the midst of many dramatic changes. For example, energy prices have remained level or declined for several years; loads have remained flat, leaving fewer megawatts over which to spread rising power and transmission costs; renewable generation is adding unprecedented amounts of energy to the market; and new market entities and structures, such as the Energy Imbalance Market (EIM), stand to change the way power is bought and sold in the region. *Id.*

Despite these many challenges, BPA must be prepared in the coming years to weather uncertainty and remain steadfast in fulfilling its statutory objectives. *Id.* To ensure this firm foundation, BPA has determined that the agency must develop additional financial tools to fill current gaps. *Id.* BPA is establishing the FRP to provide a transparent, public framework for how low and high BPA's financial reserves may go before BPA must take action. *Id.* at 3-4.

6.2.6 Development of the Financial Reserves Policy

Developing a formal FRP was first discussed in the BP-16 rate proceeding. During the BP-16 rate period, which established FY 2016 and FY 2017 rates, Transmission Services' financial reserves were expected to significantly exceed the amount necessary to meet Transmission Services' TPP. Administrator's Final Record of Decision, BP-16-A-02, at 88, 95. At the time, BPA was proposing to use \$15 million of Transmission Services' financial reserves to fund capital investments in lieu of borrowing. *Id.* at 86. Certain transmission customers asked BPA to return a significant portion of financial reserves attributable to Transmission Services to transmission customers through rate reductions. *Id.* at 88. BPA declined to adopt the parties' proposal, explaining that "[u]sing a significant amount of reserves for rate relief could threaten

BPA’s credit rating.” *Id.* Transmission customers argued that BPA was disproportionately relying on financial reserves attributable to Transmission Services to support BPA’s credit rating. *Id.* at 99. Parties argued that power rates should be increased to support BPA’s financial reserves since both business lines relied on the credit rating. *Id.* at 99-100. BPA did not agree that additional rate relief was necessary or warranted, but BPA recognized that the current approach was not satisfactory and deferred the issue to after the rate case to “develop a financial reserves policy.” *Id.* at 89.

Following the publication of the BP-16 Final Record of Decision, BPA held three public workshops in the spring of 2016 to provide information to stakeholders and to receive their feedback. Harris *et al.*, BP-18-E-BPA-17, at 23. In the first workshop, BPA discussed the background, context, and history of BPA’s financial reserves-related practices. *Id.* In the second workshop, BPA discussed options for establishing target financial reserves levels and lower and upper financial reserves thresholds. *Id.* In the third and final workshop, BPA proposed a draft policy and asked for stakeholder comments. *Id.* BPA received 14 written comments and used those comments to inform the FRP. For reference, the workshop materials from these workshops may be viewed at <https://www.bpa.gov/Finance/FinancialPublicProcesses/Pages/Access-to-Capital.aspx>.

Several issues remained outstanding at the close of the FRP workshops held in spring and summer of 2016. Since BPA financial policies are generally not rate case issues, Staff considered developing the FRP concurrent with, but outside of, the BP-18 rate case. Harris *et al.*, BP-18-E-BPA-17, at 24. BPA Staff ultimately decided that including this issue within the rate case would provide the timeliest and most transparent opportunity for all interested stakeholders to express their views on the proposal. *Id.* Thus, BPA included the FRP in the scope of the BP-18 rate proceeding. Fiscal Year (FY) 2018–2019 Proposed Power and Transmission Rate Adjustments Public Hearing and Opportunities for Public Review and Comment, 81 Fed. Reg. 78,999, 79,002 (Nov. 10, 2016).

6.3 Procedural Issues Related to the Financial Reserves Policy

6.3.1 Introduction

Because the context of BPA’s rate proceeding is an important backdrop to these issues, a brief overview of Northwest Power Act Section 7(i) and BPA’s procedural rules follows.

BPA’s rate proceedings are subject to Section 7(i) of the Northwest Power Act, which provides in relevant part:

One or more hearings shall be conducted as expeditiously as practicable by a hearing officer to develop a full and complete record and to receive public comment in the form of written and oral presentation of views, data, questions, and argument related to such proposed rates.

16 U.S.C. § 839e(i)(2). BPA’s Section 7(i) proceedings, in turn, are governed by BPA’s Rules of Procedure Governing Rate Hearings, 51 Fed. Reg. 7,611-01 (Mar. 5, 1986) (“Hearing

Procedures”). These proceedings are presided over by a hearing officer, who is the person “designated by the Administrator to conduct a hearing pursuant to Northwest Power Act Section 7(i)(2).” *Id.* § 1010.2(e).

The hearing officer may issue Special Rules of Practice in each rate case. *Id.* § 1010.6(b). These rules are established by the hearing officer in each rate case through an Order and provide additional procedural guidance to the litigants. *See* Special Rules of Practice Governing This Proceeding, BP-18-HOO-02 (“Special Rules”). The Special Rules include a variety of administrative and housekeeping matters that are common in BPA rate proceedings, such as “Forming Joint Parties,” clarifying rules specific to discovery, and directing parties on the presentation of evidence. *See* Special Rules, BP-18-HOO-02, at 1-2.

The BPA rate proceeding rules provide an orderly process for developing material that will be submitted as evidence in the administrative record. The Hearing Officer has a duty to administer the rate setting process as described in these rules, and to conduct the proceeding to ensure that a “full and complete record” is developed on the proposed rates. *See* Hearing Procedures, § 1010.9(a).

During the rate proceeding, all parties have an opportunity throughout the hearing phase of the case to object to, or move to strike, any submitted material which they believe fails to meet the requirements of the Hearing Procedures or Special Rules. In addition, any material that is not otherwise objected to or struck by the close of cross-examination is admitted into the record and is considered evidence under BPA’s rules. Any and all evidence submitted to the administrative record may be relied upon by parties and BPA in making arguments regarding the issues in each case. *See* Order on Motion to Confirm or Admit Evidence, BP-18-HOO-31, at 3.

6.3.2 Issues

Issue 6.3.2.1

Whether Staff’s testimony violates the procedures governing the BP-18 rate hearing.

Parties’ Positions

ICNU argues that Staff violated BPA’s rate hearing procedures by presenting evidence in a manner that was not “self-explanatory” or “expressly stated.” ICNU Br., BP-18-B-IN-01, at 11. In addition, ICNU argues that Staff’s rebuttal should be afforded little weight because it introduced new material. *Id.* at 12.

BPA Staff’s Position

This is a legal issue ICNU raises for the first time in its brief.

Evaluation of Positions

ICNU argues that Staff's proposed FRP cannot be adequately justified on the basis of its supporting testimony, or based on the information used by Staff's witnesses in preparing such testimony. *Id.* at 10. ICNU argues that it rebutted the purported factual bases for the FRP in its direct testimony. *Id.* Staff responded in rebuttal, but ICNU claims this rebuttal was deficient because BPA either: (1) chose not to rebut ICNU's direct case on factual grounds, in favor of unsupported "belief" statements and/or unilateral assertions; or (2) introduced new affirmative matter. *Id.* at 10-11. ICNU claims that BPA should afford "little if any weight" to Staff's rebuttal testimony because neither of these approaches is appropriate under the "specific set of rules" governing the BP-18 rate case. *Id.* at 11-12.

As explained below, ICNU's arguments are procedurally and legally defective because (a) they are untimely and should have been argued and addressed during the hearing phase of this proceeding, and (b) Staff's direct and rebuttal testimony fall squarely within the requirements of BPA's procedural rules.

ICNU's Procedural Challenge to Staff's Evidence

ICNU first contends that Staff's rebuttal testimony was defective because it did not rebut ICNU's direct case on factual grounds. ICNU argues that BPA relied on "unsupported 'belief' statements and/or unilateral assertions." *Id.* at 10-11. ICNU argues that these "belief" statements fail to meet the procedural requirements under the "specific rules" governing the BP-18 rate case. *Id.* at 11. ICNU further explains the consequences of these alleged deficiencies. ICNU therefore asserts that approval of the FRP by the Administrator would constitute an "agency action in direct violation of the 'special rules' explicitly 'governing this proceeding.'" *Id.* at 4.

At first blush, ICNU appears to argue that Staff's evidence should not have been admitted into the record because it violates the Special Rules on the submission of evidence. ICNU readily admits, however, that it is not challenging the *admissibility* of the evidence Staff has submitted, but rather it is challenging the *weight* of the evidence submitted by Staff. *Id.* at 13. This statement means ICNU does not intend to challenge *whether* the evidence submitted by Staff should have been included in the record as a matter of BPA's procedures, but whether the Administrator should give any weight to the evidence when making a decision regarding establishment of the FRP. Insofar as ICNU presents arguments in this manner, its arguments are properly before BPA (rather than the Hearing Officer) because they go to the weight rather than to the admissibility of the evidence. Therefore, BPA will consider ICNU's arguments regarding whether Staff's testimony comprises unsupported belief statements or unilateral assertions in the context of the issues where the alleged statements were made.

ICNU, however, does not limit its challenge to the merits of Staff's evidence. Instead, throughout its brief, ICNU argues that Staff's evidence should be discounted because it allegedly fails to meet the requirements of "evidence" set forth in the Hearing Procedures and the Special Rules. *Id.* at 4. ICNU's central claim is:

The Administrator is being asked by Staff to commit the agency to a 10-year FRP, either in the form presented in Staff’s initial proposal, or in a slightly modified “Alternative Option” version, presented on rebuttal. Yet, given the *acute evidentiary deficiencies* in how Staff has gone about actually supporting its proposed FRP, approval by the Administrator would likely constitute an *agency action in direct violation of the “special rules” explicitly “governing this proceeding.”*

Id. (emphasis added) (footnote omitted).

There are similar references throughout ICNU’s brief. *See, e.g., id.* at 1 (“Staff has not sufficiently supported the FRP *in accordance with BPA’s own procedural requirements*”), 21 (“Staff’s proposal would still fall short of meeting the ‘quite explicit’ evidentiary rules which specially govern this proceeding”), 35 (noting that “the special rules governing this proceeding would have to be *violated* [if Staff’s testimony is interpreted other than as viewed by ICNU], since all evidence must meet the ‘clarity of evidence’ standard of being ‘expressly stated.’”) (emphasis added).

As these references make clear, ICNU appears to make the legal argument that Staff’s evidence violates the Hearing Procedures and Special Rules and, as a consequence, should not be considered as valid “evidence” when the Administrator considers whether to adopt the FRP. Indeed, ICNU argues that because of this procedural violation, relying on Staff’s evidence would, in and of itself, be a reversible error on appeal, stating that “any record of decision which adopts FRP results and conclusions, *contrary to BPA’s own rules*, would positively require a reversal, if review is sought at the Ninth Circuit.” *Id.* at 14 (emphasis added).

To the extent ICNU challenges the admissibility of Staff’s testimony, ICNU’s argument is procedurally defective and legally barred. At this point in the BP-18 rate proceeding, the factual record is closed, and Staff and all other parties’ evidence has been admitted into the administrative record. If ICNU wished to raise arguments regarding admissibility, ICNU should have filed a motion to strike Staff’s testimony. It did not. Therefore, objections that Staff’s evidence is inconsistent with the Hearing Procedures or the Special Rules are untimely because they should have been raised during the hearing phase of this process. Thus, for example, if ICNU believed that Staff’s evidence violated the Special Rules requirement that evidence be “self-explanatory,” “fully explain the consequences of adopting the proposed methods,” or be “supported by data and reasoning,” Special Rules, BP-18-HOO-2, at 2, then ICNU’s opportunity to object to Staff’s evidence was *before* it was admitted into evidence. The hearing phase is now over, and Staff’s evidence is now on the record. As the Hearing Officer made clear:

Unless material has been removed from the record by an order in response to a motion to strike, withdrawn by a party without objection by other parties, [or] rejected by a ruling of the hearing officer at hearing or similar action, it *becomes part of the record* which is, at the appropriate time, certified by the hearing officer in its totality.

Order on Motion to Confirm or Admit Evidence, BP-18-HOO-31, at 3 (emphasis added). ICNU's arguments regarding alleged "procedural errors," which were not raised before the Hearing Officer, are untimely and legally deficient and, therefore, must be denied.

This leaves ICNU the opportunity to argue that, as a general matter, Staff's evidence is not "self-explanatory" or not supported by "data and reasoning." In making such arguments, ICNU would simply be making *merit* arguments as to the validity of Staff's testimony. However, ICNU may not convert these merit arguments into *procedural* violations. Thus, ICNU is barred from arguing that Staff's evidence fails to be "self-explanatory," and as such, must be given less weight *because it violates BPA's procedural rules on evidence*. Special Rules, BP-18-HOO-02, at 1-2. As stated above, such procedural arguments would have to be raised during the hearing phase of the case, where arguments about whether evidence comports (or does not comport) with BPA's procedural rules are considered and addressed.

BPA employs a Hearing Officer for the specific purpose of managing the hearing process and addressing evidentiary issues. The Hearing Officer, usually an administrative law judge with extensive legal experience, has both the expertise and the time to address the specific procedural legal questions raised by parties. The Hearing Officer is familiar with BPA's ratesetting procedures and adopts Special Rules as he or she deems necessary. Thus, the Hearing Officer is best positioned to evaluate concerns over whether evidence meets the rules governing BPA's rate hearings. Requiring the Administrator to address, in the first instance, whether evidence submitted by a party comported with the Special Rules' requirement that evidence be "self-explanatory" or "supported by data and reasoning," Special Rules, BP-18-HOO-02, at 2, would be extremely burdensome and wasteful of his or her time, as well as make the position of the Hearing Officer essentially pointless.

ICNU seems to appreciate that the "practical realities of the Administrator's workload . . . do not permit him to create the Draft and Final Records of Decision alone." ICNU Br., BP-18-B-IN-01, at 14. Those same "practical realities" require the Administrator to rely upon the judgment and expertise of the Hearing Officer to address the evidentiary issues in the case, including compliance with the Hearing Procedures and Special Rules.

ICNU suggests that BPA's procedural rules should be fairly applied to BPA. *Id.* at 12. BPA agrees. The Hearing Procedures and Special Rules governing this proceeding should be, and always have been, applied to Staff's evidence. No party objected to the inclusion of this evidence as violating the rules of procedure, and consistent with the Hearing Officer's order, Staff's evidence is now "part of the record." Order on Motion to Confirm or Admit Evidence, BP-18-HOO-3, at 2.

In this same way, fundamental fairness requires parties to the case to raise during the hearing phase the argument that evidence submitted by Staff (or any other party) violates the procedural rules. That way, any party can make the case that its analysis comports with the rules. Waiting until the briefing phase to raise alleged procedural defects in the evidence as an independent basis of weighing evidence violates basic due process in that no party would have an opportunity to respond to such an allegation until after the Draft ROD was issued.

Moreover, waiting until the initial briefs are filed to raise such procedural issues is legally improper in that it takes an end-run around the Hearing Officer, who is the individual designated by statute to conduct the evidentiary proceeding and address evidentiary and procedural issues in the hearing phase of the case. *See* Hearing Procedures § 1010.2(e) (citing 16 U.S.C. § 839e(i)(2)).

Finally, permitting ICNU to raise procedural issues with Staff’s testimony in its brief, without having raised those issues before the Hearing Officer, would set a dangerous precedent in BPA’s rate proceedings and fundamentally undermine the hearing phase of the case. By the briefing stage of the case, the factual record is supposed to be established, leaving only the parties’ arguments to explain why the evidence and law support a particular conclusion. (This does not preclude a challenge to the admission of evidence that has been properly preserved for the Administrator’s review.)

Following ICNU’s logic, parties could argue for the first time in their briefs that evidence already admitted into the record is defective because it did not follow a requirement in the Special Rules that evidence “fully explain the consequences of adopting [a] proposed method,” and thereby contend that it should be ignored—not on its merits—but on the grounds *of a procedural violation*. Under this logic, the extensive evidentiary hearing that had already been held and which resulted in the admission of evidence into the record would be meaningless. These are precisely the types of issues the Hearing Officer is required to resolve. ICNU’s argument would allow parties to bypass the hearing and would result in the very “sandbagging” that ICNU decries in its brief. ICNU Br., BP-18-B-IN-01, at 12.

For the foregoing reasons, ICNU’s claims that Staff’s evidence should be given “little weight” because of an alleged violation of the Hearing Procedures or Special Rules lack merit. As to ICNU’s more general critique that Staff chose to respond to ICNU’s direct case with “belief” statements or “unilateral assertions,” *id.* at 10-11, BPA will address the *merits* of these assertions in the context of the issues where the alleged statements were made.

ICNU Objections to Staff’s Rebuttal Testimony

ICNU argues that Staff improperly supplemented the record in its rebuttal testimony. *Id.* at 12. Specifically, ICNU notes that BPA’s procedural rules prohibit “[n]ew affirmative matter . . . in rebuttal testimony.” *Id.* Thus, ICNU argues that to the extent the FRP might purportedly be supported by “new” studies or analyses not originally presented in Staff’s initial proposal, but filed only in rebuttal testimony, “little if any weight” should be afforded to such evidence. *Id.* ICNU asserts that the FRP “should not be justified on any ‘alternative facts’ which Staff later alleged, as a means to bypass deficiencies of the initial proposal.” *Id.*

ICNU’s claim that it was in any way inappropriate for Staff to file rebuttal and include new evidence is incorrect. The Hearing Procedures permit the filing of rebuttal testimony if it is “limited to the parties’ direct case.” Hearing Procedures § 1010.11(a)(2). The Hearing Officer’s order clearly indicates that rebuttal may include new material if provided in reply to a litigant’s case:

Rebuttal evidence must refer to the specific evidence being refuted (pages, lines, topic). New affirmative matter (*not in reply to another litigant's direct case*) may not be included in rebuttal testimony.

Special Rules, BP-18-HOO-2, at 3 (emphasis added).

In rebuttal testimony, Staff responded to the parties' direct cases. As such, anything the parties raised in their direct cases may be rebutted by Staff. ICNU's recitation of the prohibition on "[n]ew affirmative matter" omits the parenthetical exception noted above. ICNU Br., BP-18-B-IN-01, at 12. Staff's rebuttal testimony was in reply to all parties' direct cases, *including ICNU's*, and as such *may* include "new affirmative matter" as necessary to *reply* to the parties' cases. This rule makes sense since Staff must be given an opportunity to reply to the direct cases of the parties. Otherwise, the record would be incomplete, with parties' alleging certain deficiencies in BPA's direct case, and BPA left with no ability to reply.

ICNU then attempts to draw a correlation between Staff's rebuttal testimony supporting the FRP and Staff's opposition on a different issue to another party's attempt to supplement the record in its rebuttal testimony. *Id.* ICNU argues that BPA filed extensive arguments against another party for allegedly following a "sandbagging" practice. *Id.* The two situations are not comparable. Staff opposed JP03's evidence because, in Staff's view, it responded to BPA's direct case rather than to the parties' direct cases. As the hearing rules provide, parties' rebuttal testimonies may only address other parties' direct testimonies, not Staff's. Thus, Staff was concerned that JP03 was *not* responding to another party's direct case in its rebuttal, but to BPA's direct case, which it already had an opportunity to rebut in its direct case. Motion to Strike the Rebuttal Testimony of JP03, BP-18-M-BPA-05, at 3.

In contrast, Staff's rebuttal testimony, including any new analysis it performed, was entirely made in response to the litigants' direct cases. For example, in Staff's rebuttal testimony, Staff notes that parties opposed the FRP on the grounds that they believe it will not result in a net customer benefit. Harris *et al.*, BP-18-E-BPA-33, at 55 (citing Saleba *et al.*, BP-18-E-WG-01, at 20–21; Deen *et al.*, BP-18-E-JP05-01, at 12–14, 21–22; Mullins, BP-18-E-IN-01, at 39–40, 62). In response, Staff argues:

In the Initial Proposal we performed a very broad cost-benefit analysis that looked at the quantifiable costs of a downgrade, and considered the qualitative benefits of financial reserves providing rate stability, increasing interest income, and generally providing operational flexibility. Several parties criticized us for not performing a narrower, stand-alone, cost-benefit analysis. In response, we have conducted such an analysis and included it in this testimony.

Harris *et al.*, BP-18-E-BPA-33, at 55; *see also* Harris *et al.*, BP-18-E-BPA-33, at 106 (performing new analysis to determine "the relative strengths and weaknesses of the various proposals" offered in parties' cases). In this regard, any ICNU insinuation that Staff has "electively withh[eld] evidence" or engaged in "sandbagging" lacks merit. *See* ICNU Br., BP-18-B-IN-01, at 12.

Nevertheless, ICNU argues that Staff was not “directly engaging with the facts undermining and refuting its original FRP position” but instead “chose to improperly ‘supplement’ the initial proposal” and “alter[] the facts.” *Id.* As noted above, Staff’s analysis was a procedurally proper response to the parties’ cases. Moreover, ICNU would place an essentially impossible standard on Staff. In effect, to avoid ICNU’s “sandbagging” claim, Staff would have to anticipate every study, analysis, and argument parties might make and structure the Initial Proposal accordingly. BPA’s procedures, however, do not and should not require this approach. Instead, as outlined under the current BPA procedures, Staff may respond to objections and arguments in its rebuttal, which it did.

Furthermore, even assuming Staff’s proposal was procedurally deficient, which it was not, ICNU should have raised this issue during the procedural phase of this case. ICNU’s options were, as it notes, “myriad” for responding to Staff’s rebuttal. *Id.* at 13. For instance, ICNU could have sought to strike Staff’s testimony or sought supplemental testimony responding to Staff’s analysis. Either of these options would have afforded the other parties to the BP-18 proceeding an opportunity to weigh in. ICNU did none of these things. Therefore, the allegedly deficient Staff material is now “part of the record” because it was not challenged during the administrative hearing and was admitted into evidence. Order on Motion to Confirm or Admit Evidence, BP-18-HOO-31, at 3. As such, the BPA Administrator is free to consider such evidence when making his decision regarding the FRP.

The only remaining avenue available to ICNU is to challenge the weight of the evidence. ICNU Br., BP-18-B-IN-02, at 13. Thus, ICNU may argue that Staff’s analysis is substantively deficient, but ICNU has no procedural or legal basis left at this stage of the case to object on procedural grounds that the analysis in Staff’s rebuttal testimony is an improper supplement to Staff’s direct testimony. *See id.* at 12. Any and all procedural arguments regarding evidence should have been raised before the Hearing Officer during the hearing.

For the foregoing reasons, ICNU’s contention that Staff’s rebuttal testimony should be given “little weight” because it included “new affirmative” information is both procedurally untimely and unpersuasive. Any implication that Staff’s testimony should have been deemed inadmissible is also hereby denied. ICNU’s arguments regarding specific factual statements made by Staff in its direct and rebuttal testimonies are addressed below.

Decision

Staff’s testimony is consistent with the procedures governing the BP-18 rate hearing.

6.4 Need for a Financial Reserves Policy

6.4.1 Introduction

The record in this case requires BPA to answer two foundational questions regarding a financial reserves policy: (1) whether BPA would benefit from adopting a financial reserves policy; and if so, (2) what objectives should that policy meet?

To answer the first question, whether BPA would benefit from adopting a financial reserves policy, Staff considered whether BPA’s existing policies supported financial reserves. Harris *et al.*, BP-18-E-BPA-17, at 10. Staff found that the 95 percent TPP standard has provided important policy guidance for when BPA should intentionally increase liquidity to ensure a 95 percent probability of making its Treasury payment, and thereby ensure BPA’s ultimate solvency over a two-year rate period. *Id.* However, the standard does not provide policy guidance for other important issues related to BPA’s financial reserves amounts, including:

- the minimum level to which BPA should allow financial reserves to decline before BPA takes action to replenish them;
- the maximum level to which BPA should allow financial reserves to rise before taking action to use such reserves for other high-value purposes; and
- how to allocate the responsibility for maintaining financial reserves thresholds between Power Services and Transmission Services.

Id.; Harris *et al.*, BP-18-E-BPA-33, at 26. Indeed, Staff found that under BPA’s existing financial policies, financial reserves for the agency could decline to as little as \$230 million. Harris *et al.*, BP-18-E-BPA-17, at 12. Of this amount, all \$230 million would be attributed to Transmission Services. *Id.* Current policies would permit financial reserves attributed to Power Services to be \$0. *Id.*

Staff then identified four areas that would benefit from the development of a financial reserves policy: credit rating support, liquidity, rate stability, and equity. Harris *et al.*, BP-18-E-BPA-17, at 13-21; Harris *et al.*, BP-18-E-BPA-33, at 8-42. These factors are identified in Staff’s testimony as supporting the “need” for a financial reserves policy. Harris *et al.*, BP-18-E-BPA-17, at 10-21; Harris *et al.*, BP-18-E-BPA-33, at 8-42.

BPA finds that the record supports developing a financial reserves policy. For the reasons articulated below, developing a financial reserves policy will support BPA’s credit rating, address equity between BPA’s business lines, support BPA’s liquidity, and provide an opportunity for rate stability. Thus, BPA finds that the answer to the first question is in the affirmative: yes, it would be beneficial to BPA to develop a financial reserves policy. The second question, what objectives should a financial reserves policy meet, is addressed in Section 6.5 (objectives used to measure an FRP).

6.4.2 Overview of Parties’ Positions

Many parties agree with Staff’s assessment that a financial reserves policy is needed. *See* Powerex Br., BP-18-B-PX-01, at 2-5; M-S-R Br., BP-18-B-MS-01, at 1, 5-6; M-S-R Br. Ex., BP-18-R-MS-01, at 1. These parties generally agree that BPA’s existing policies are insufficient to establish prudent levels of financial reserves, and that a financial reserves policy would support BPA’s credit, liquidity, equity, and rate stability. M-S-R Br., BP-18-B-MS-01, at 1; Powerex Br., BP-18-B-PX-01, at 2-4; JP02 Br., BP-18-B-JP02-01, at 4-7. For instance, M-S-R contends that “a Financial Reserves Policy is necessary to ensure the agency has sufficient

financial resources to support its Power and Transmission operations, consistent with sound business principles.” M-S-R Br., BP-18-B-MS-01, at 1. Powerex agrees, noting “BPA Staff and rate case parties have presented compelling evidence that the agency needs a financial reserves policy.” Powerex Br., BP-18-B-PX-01, at 2. JP02 similarly argues that “BPA’s historical approach to financial reserves has resulted in inequity between the BPA Power and Transmission business lines.” JP02 Br., BP-18-B-PX-01, at 4.

Public power customers similarly acknowledge that a financial reserves policy should be developed. JP07 notes that the “lack of formal guidance on financial reserves can lead to ad hoc decision-making and inconsistent outcomes, which may not be in the best interest of BPA’s long-term financial health.” JP07 Br., BP-18-B-JP07-01, at 5. Thus, JP07 agrees that a financial reserves policy that is transparent and equitable between business lines, minimizes rate instability, and presents a solid business case for customers may aid the agency’s long-term financial health. *Id.* at 8. JP07 also agrees that liquidity, credit rating support, and rate stability are relevant aspects of BPA’s financial health that could be supported by a financial reserves policy, though JP07 notes that BPA’s liquidity needs are met primarily by the TPP standard. *Id.* at 5. JP07 encourages BPA to consider how the FRP may affect the credit rating factor of cost-competitiveness. *Id.* at 11.

WPAG expressed general concern that a financial reserves policy would place additional rate pressure on the already difficult task of maintaining competitive rates and ensuring that BPA sets the lowest possible rates consistent with sound business principles. WPAG Br., BP-18-B-WG-01, at 10. WPAG also expressed concern that such rate pressure is unnecessary when agency reserves are already high enough to support the agency’s credit rating. *Id.* WPAG notes that the primary basis for the FRP is credit-rating support. *Id.* at 13. Nonetheless, WPAG notes that it could support a policy if certain features of Staff’s Alternative Option are modified. *Id.* at 12.

ICNU contends that the evidentiary record does not support developing a financial reserves policy in this proceeding. ICNU Br., BP-18-B-IN-01, at 4, 10-11. ICNU suggests that BPA should defer a decision on a financial reserves policy to a separate “holistic” regional process. *Id.* at 5. ICNU argues that, while Staff offered six objectives in support of the FRP, the record confirms ICNU’s assertion that “the sole purpose of the FRP essentially boils down to a single objective: ‘Maintain sufficient financial reserves levels to support BPA’s credit rating.’” *Id.* at 15. ICNU then argues that none of the six objectives identified by Staff support developing a financial reserves policy. *Id.* at 4-88.

In the following sections, BPA addresses the concerns parties raise regarding whether the record supports the development of a financial reserves policy. In Section 6.5 (Staff’s objectives and the FRP), BPA discusses the six policy objectives and criteria that Staff used to develop the FRP. In most instances, the need for a financial reserves policy is addressed separately from whether the policy achieves the objectives identified by Staff. However, in the context of credit rating support, ICNU presents arguments challenging both the need for a financial reserves policy and the FRP’s ability to meet the credit support objective. BPA responds to both of these issues in Section 6.4.3 (credit rating and FRP)—that is, BPA responds to both whether a financial reserves

policy *is needed* for credit support *and* whether the FRP *will provide* that support. BPA addresses ICNU’s other concerns with Staff’s policy objectives in Section 6.5.

6.4.3 Credit Rating and a Financial Reserves Policy

6.4.3.1 Overview

BPA accesses private capital markets indirectly through debt issued by third parties (Non-Federal Debt). Non-Federal Debt enables BPA to make needed capital investments and to efficiently manage its aggregate debt portfolio. Obtaining Non-Federal Debt at favorable terms and rates is now, more than ever, critically important to BPA’s mission of providing power and transmission services to the Region at the lowest rates possible consistent with sound business principles. Harris *et al.*, BP-18-E-BPA-33, at 3. BPA is currently relying on third-party debt to finance its capital programs more than at any other time in its history. *Id.* at 2; Harris *et al.*, BP-18-E-BPA-17, at 14.

With regard to Power Services, Energy Northwest issues debt, supported by BPA’s credit, to fund new capital investments at the Columbia Generating Station (CGS) nuclear power plant and to refinance existing debt associated with CGS or Washington Public Power Supply System (WNP) Projects 1 and 3. Harris *et al.*, BP-18-E-BPA 17, at 13. Over the next 10 years, Energy Northwest is expected to issue \$3.9 billion in debt backed by BPA. *Id.* BPA’s credit rating is the primary factor determining the interest rate on that debt. *Id.* The higher the credit rating, the lower the interest rate, and thus the lower the interest expense in BPA’s Power revenue requirement. *Id.*

BPA’s credit rating is also critical to operating and maintaining BPA’s transmission assets. Third parties issue debt, supported by BPA’s credit, for the “lease purchase capital program,” which allows BPA to access short-term lines of credit and long-term financing from non-federal sources to fund Transmission construction projects. *Id.* at 14, 17. Over the next 10 years, BPA plans to back \$5.4 billion in lease purchase-related debt. *Id.* at 14. BPA’s credit rating is the primary factor determining the interest rate on this debt. *Id.* The higher the credit rating, the lower the interest rate, and thus the lower the interest expense in BPA’s Transmission revenue requirement. *Id.*

These capital programs ensure that BPA can continue to operate and maintain the FCRPS consistent with BPA’s statutory mandates. Harris *et al.*, BP-18-E-BPA-33, at 2-3. BPA’s credit rating, ranging from Aa1 (Moody’s), AA (Fitch), AA- (Standard & Poor’s), is very strong by industry standards. Harris *et al.*, BP-18-E-BPA-17, at 14. The interest rates that BPA pays for third-party debt and BPA’s ability to access the third-party debt market are strongly influenced by BPA’s credit rating, which is in turn heavily influenced by BPA’s financial reserves levels and policies. Harris *et al.*, BP-18-E-BPA-33, at 2-3; Harris *et al.*, BP-18-E-BPA-17, at 17.

As discussed throughout this section, BPA’s strong credit rating is in jeopardy. The credit rating agencies—Fitch, Moody’s, and Standard & Poor’s—are the independent entities that evaluate and rate BPA’s creditworthiness. The credit rating agencies have signaled that BPA’s credit rating may be negatively affected because of BPA’s declining financial reserves. Harris *et al.*,

BP-18-E-BPA-17, at 14. While there is much dispute over the interpretation of these warnings, and significant disagreements over what actions BPA should take in response, there can be little dispute that a credit rating downgrade would negatively impact BPA and its customers. M-S-R notes that “BPA’s credit rating is important to both business lines.” M-S-R Br. Ex., BP-18-R-MS-01, at 2. Some action must be taken to ensure that BPA’s credit rating, and, by extension, BPA’s long-term financial health and fiscal independence, is protected.

As discussed below, BPA believes the appropriate action to be taken is to establish the FRP.

6.4.3.2 Issues

Issue 6.4.3.2.1

Whether a financial reserves policy would support BPA’s credit rating.

Parties’ Positions

ICNU argues that the objective to support BPA’s credit rating does not justify adopting the FRP in this rate case. ICNU Br., BP-18-B-IN-01, at 39-78.

BPA Staff’s Position

Financial reserves are a key component of BPA’s credit rating. Harris *et al.*, BP-18-E-BPA-17, at 14. The credit rating agencies have expressed concern with BPA’s declining financial reserves and have stated that establishing a financial reserves policy would be a credit rating positive. *Id.* at 14, 16; Motion to Take Official Notice of Credit Rating Agency Reports, BP-18-M-BPA-09, Attachment A, at 3. A financial reserves policy would fill a policy gap that currently exists at BPA and would allow BPA to address the areas of concern identified by the credit rating agencies. Harris *et al.*, BP-18-E-BPA-33, at 8.

Evaluation of Positions

ICNU argues that the objective to support BPA’s credit rating does not justify adopting a financial reserves policy. ICNU Br., BP-18-B-IN-01, at 39-78. ICNU contends that BPA has not analyzed the problem sufficiently and, therefore, BPA’s solution may exacerbate the problem BPA is attempting to solve. *Id.* at 76. BPA disagrees with ICNU’s assessment for several reasons.

First, the credit rating agencies have been clear that the problem (and the solution) lies with BPA’s financial reserves. Harris *et al.*, BP-18-E-BPA-33, at 10. The Fitch rating agency noted “[t]he maintenance of strong reserves is essential to the ratings and a sustained and sizable reduction in reserves could result in downward rating pressure.” *Id.*, Attachment 4, Fitch BPA Credit Rating Report (Mar. 23, 2016), at 1. Additionally, Moody’s noted “BPA’s rating could be negatively pressured if BPA’s internal liquidity drops below 30 days’ cash on hand on a sustained basis” *Id.*, Attachment 5, Moody’s BPA Credit Rating Report (June 14, 2016), at 3. Standard & Poor’s noted, “[i]f, during our two-year outlook horizon, Bonneville’s robust

liquidity cushion erodes meaningfully whether due to hydrology conditions, capital needs, or weak market for its surplus power, we could lower the stand-alone credit profile.” *Id.*, Attachment 6, S&P BPA Credit Rating Report (Mar. 14, 2016), at 6. As each of these reports indicates, the problem is with BPA’s financial reserves—which is BPA’s primary source of liquidity. Harris *et al.*, BP-18-E-BPA-17, at 4.

Second, the problem of declining financial reserves is not addressed through BPA’s existing policies. BPA’s current policies and tools have allowed the agency’s financial reserves position to degrade swiftly and materially from an agency high of \$1.268 billion in 2008 to a current end-of-fiscal-year 2017 projection of \$395 million. Harris *et al.*, BP-18-E-BPA-33, at 8-9 (citing Harris *et al.*, BP-18-E-BPA-17, Attachment 1, January 2017 Quarterly Business Review, at 16). This is a decline of nearly \$900 million in nine years. *Id.* at 9. Current policies would allow financial reserves to continue this decline, with Power Services’ financial reserves allowed to fall to \$0. *Id.*; Harris *et al.*, BP-18-E-BPA-17, at 12.

Third, the harm that declining financial reserves can have on BPA’s credit rating is not theoretical. In 2011, BPA experienced a credit rating downgrade due in part to a decline in financial reserves. Harris *et al.*, BP-18-E-BPA-33, at 11 (citing Attachment 3, Moody’s BPA Credit Rating Downgrade Report (Aug. 31, 2011), at 1). Both the material decline of financial reserves over recent years, and the decision to use additional financial reserves for rate relief resulting in a modest expected decline in BPA’s total financial reserves available for risk, were cited as key factors for this downgrade. *Id.* at 9. The material decline in financial reserves would have been mitigated by the FRP. *Id.* at 12. In addition, the FRP would have disallowed a rate proposal that incorporated a modest expected decline in BPA’s total financial reserves available for risk because BPA’s total financial reserves available for risk were insufficient to be repurposed at that time. *Id.* Thus, the FRP would have mitigated two of the cited reasons for the downgrade BPA received in 2011. *Id.*

Fourth, there is a benefit to BPA’s credit rating from having a financial reserves policy. The record demonstrates the FRP would support BPA’s credit rating, which, in addition to other benefits, justifies its adoption. Two of the 2016 credit rating agency reports expressly noted the importance of developing a financial reserves policy, and assign a “positive” impact on BPA’s credit rating if such a policy is developed. *Id.* at 19. Both Fitch and Moody’s viewed the development of a financial reserves policy as a “positive” factor in evaluating BPA’s credit rating. *Id.* at 12. Fitch noted that BPA’s management “has initiated planning efforts with preference customers to develop more robust financial policies and forecasting methodologies, which could include a financial reserves policy and a rate forecast that looks out beyond the current rate case.” *Id.*, Attachment 4, Fitch BPA Credit Rating Report (Mar. 23, 2016), at 3. Fitch viewed “the initial steps toward the development of more formalized policies and forward-looking forecasts as positive.” *Id.* at 4. Moody’s similarly viewed the development of a financial reserves policy as positive: “We understand BPA is considering a reserves policy and we would view a robust policy that emphasized robust internal reserves to be credit positive.” *Id.*, Attachment 5, Moody’s BPA Credit Rating Report (June 14, 2016), at 6.

More recently, Moody’s affirmed the benefit of adopting a financial reserves policy. Moody’s stated, “[i]mplementation of a reserves policy would be a credit positive” Motion to Take

Official Notice of Credit Rating Agency Reports, BP-18-M-BPA-09, Attachment A, at 3. Therefore, establishing a reasonable policy for a central element of BPA’s credit rating—financial reserves—is a clear case of something BPA can and should do. Harris *et al.*, BP-18-E-BPA-33, at 24. The benefit of having such a policy is not theoretical or uncertain; there is a concrete basis for expecting it will help ensure BPA’s access to low-cost capital. *Id.* at 25.

Fifth, ICNU contends that raising rates is bad for BPA’s overall competitiveness, ICNU Br., BP-18-B-IN-01, at 48-62. Competitiveness is a factor in BPA’s credit rating, but raising rates to support sound financial metrics is also a factor in BPA’s credit rating. Motion to Take Official Notice of Credit Rating Agency Reports, BP-18-M-BPA-09, Attachment A, at 8. Further, as described more fully in Section 6.6.4.3 (phase-in), the phase-in feature of the FRP will begin this rate period by adding \$20 million PNR to Power rates. This one-time rate increase will be included in future rates, but will not create additional incremental rate pressure beyond this rate period. BPA’s proposal is to also phase in over many years the increase of the Power CRAC threshold to Power Services’ lower financial reserves threshold, thereby mitigating as much as possible any near-term negative impacts to BPA’s customers and overall competitiveness. See Section 6.6.4.3 (phase-in).

Sixth, the most recent credit rating reports, issued in March of 2017, remove any doubt that BPA’s financial reserves are key to its credit rating (or that a financial reserves policy would benefit that credit rating). See Motion to Take Official Notice of Credit Rating Agency Reports, BP-18-M-BPA-09. The changes made in the most recent credit rating agency reports confirm that BPA’s interpretation of prior credit reports was correct regarding the risk of a downgrade under BPA’s current policy gap and that a financial reserves policy would support BPA’s credit rating.

For example, where Moody’s had stated that “BPA’s rating could be negatively pressured if BPA’s internal liquidity drops below 30 days cash on hand on a sustained basis,” Moody’s now says that “BPA’s ratings could be lowered . . . if we expect internal liquidity to fall below 60 days” Harris *et al.*, BP-18-E-BPA-33, Attachment 5, Moody’s BPA Credit Rating Report (June 14, 2016), at 3; Motion to Take Official Notice of Credit Rating Agency Reports, BP-18-M-BPA-09, Attachment A, at 3. Moody’s most recent report also stated, “BPA’s rapid decline in its reserves for risk is a credit negative and an inability to ensure internal reserves at or near current levels could lead to a negative rating action.” Motion to Take Official Notice of Credit Rating Agency Reports, BP-18-M-BPA-09, Attachment A, at 4.

In a section titled “DECLINING CASH RESERVES,” Fitch stated, “cash reserves are at their lowest level since 2007, which is a concern even with the \$750 million federal line of credit that provides additional liquidity.” *Id.*, Attachment B, at 2.

S&P also updated its characterization of BPA’s liquidity in its most recent report:

If, during our two-year outlook horizon, Bonneville’s ~~robust~~ **sound** liquidity cushion erodes ~~meaningfully~~ **further** whether due to hydrology conditions, capital needs, or weak market for its surplus power, **or debt acceleration that saps its liquidity**, we could lower the stand-alone credit profile.

See Harris *et al.*, BP-18-E-BPA-33, Attachment 6, at 6; Motion to Take Official Notice of Credit Rating Agency Reports, BP-18-M-BPA-09, Attachment C, at 5 (deletions from prior report in strikethrough; additions in bold italic).

These credit reports confirm that BPA has correctly analyzed the problem—unrestrained declines in financial reserves—and that BPA’s FRP is the correct policy solution.

Decision

A financial reserves policy would support BPA’s credit rating.

Issue 6.4.3.2.2

Whether BPA must address other factors affecting BPA’s credit rating when developing a financial reserves policy and whether BPA should wait to develop such a policy until a credit rating downgrade is imminent.

Parties’ Positions

ICNU argues that BPA did not properly analyze the FRP as a credit rating policy, and that the credit rating agencies’ reports do not demonstrate an imminent threat that justifies adopting the FRP now. ICNU Br., BP-18-B-IN-01, at 41-48.

BPA Staff’s Position

Staff considered all credit rating factors relevant to the decision to adopt a financial reserves policy. Harris *et al.*, BP-18-E-BPA-33, at 29. The credit rating agencies’ reports conclude that if BPA’s policies are not improved, reserves would be allowed to drop to levels at which BPA’s credit rating could be downgraded. *Id.* at 10-11.

Evaluation of Positions

As discussed above in Issue 6.4.3.2.1 (FRP support for BPA’s credit rating), the credit rating agencies indicated in a series of reports that BPA’s financial reserves were a cause for concern. These concerns with BPA’s financial reserves were not the isolated view of one credit rating agency or credit rating analyst, but discussed in all three reports. Harris *et al.*, BP-18-E-BPA-33, at 17-18. Fitch, Moody’s, and S&P all warn that further erosion of BPA’s financial reserves could result in “downward rating pressure,” *id.*, Attachment 4, Fitch BPA Credit Rating Report (Mar. 23, 2016), at 1; “negative[] pressure” on BPA’s credit rating, *id.*, Attachment 5, Moody’s BPA Credit Rating Report (June 14, 2016), at 3; or a “lower . . . stand-alone credit profile,” *id.*, Attachment 6, S&P BPA Credit Rating Report (Mar. 14, 2016), at 6. Taking the overall tone of the written reports, combined with oral discussions during meetings Staff had with the rating agencies (which confirmed the statements made in the reports), Staff recognized that concerns of a downgrade were sincere and, as such, BPA has a sound basis for pursuing action now to protect its credit rating. *Id.* at 17-18.

ICNU makes two arguments regarding how the credit reports are used to justify the FRP. First, ICNU takes issue with Staff’s rebuttal testimony, which stated, “[Staff] do not believe [the FRP] must be evaluated as if it were ‘a credit support policy,’” and “simply because other factors may affect BPA’s credit rating does not make those factors relevant in establishing a policy.” ICNU Br., BP-18-B-IN-01, at 55-56 (citing Harris *et al.*, BP-18-E-BPA-33, at 29) (emphasis omitted). ICNU interprets this to mean BPA believes that a policy primarily designed to support its credit rating does not need to be evaluated on the basis of the factors that impact its credit rating. *Id.* at 56.

ICNU is incorrect. Staff’s testimony draws an important distinction between a *financial reserves* policy and a *credit rating* policy. BPA developed the FRP in response to a policy gap that, in part, allowed financial reserves to decline to levels that could hurt BPA’s credit rating. Harris *et al.*, BP-18-E-BPA-33, at 29. BPA agrees with ICNU that BPA should analyze whether the FRP itself could also hurt BPA’s credit rating. BPA also agrees that, if the FRP might impact a factor important to the credit rating agencies, BPA should consider this impact in deciding whether to adopt the FRP. BPA did not ignore these relevant factors. *Id.* For example, in addition to the factors included in credit rating reports, BPA *also* considered factors raised by BPA’s customers regarding equity issues, and also addressed liquidity support and rate stability. Harris *et al.*, BP-18-E-BPA-17, at 13-20. These considerations are all impacted by BPA’s financial reserves. In adopting a policy on financial reserves, BPA analyzed the FRP’s impact on these considerations. *Id.*; Harris *et al.*, BP-18-E-BPA-33, at 8-42.

BPA did not perform an in-depth analysis on every factor considered by the credit rating agencies because it did not need to. *Id.* at 29. This is because some credit rating factors are not impacted by the FRP, and thus are not relevant to deciding whether to adopt the FRP. *Id.* For example, Moody’s evaluates “the wealth indicators of the population that a utility serves Affluent residential customers generally have a higher tolerance for higher overall rates, since the electric bill is a small part of their disposable income.” *Id.*, Attachment 14, at 11. No party suggested that BPA is required to analyze residential customers’ affluence or the FRP’s impact on that affluence in order to justify adopting the policy. But ICNU’s logic would require BPA to analyze such factors.

Many factors that could affect BPA’s credit rating are beyond BPA’s direct control. Instead, BPA focused on factors that BPA could affect. BPA knew, for instance, that having a financial reserves policy is a credit positive. *Id.* at 12. BPA also knew that such a policy could prevent financial reserves from falling to levels that would likely result in a downgrade. *Id.* at 10. Finally, BPA knew that being willing to raise rates is a credit positive, and that being unwilling to raise rates is a credit negative. Harris *et al.*, BP-18-E-BPA-17, at 16-17 (“Moody’s also assigns 25 percent of the overall rating to its assessment of the entity’s management’s willingness to recover costs to support sound financial metrics.”). The FRP addresses such factors.

Second, ICNU argues that “BPA does not face an imminent threat of credit downgrade sufficient to justify a major rate increase.” ICNU Br., BP-18-B-IN-01, at 41. That is, “the facts on record demonstrate that significant rate increases have not been justified by an immediate ‘need’ for Staff’s proposed FRP over the BP-18 rate period.” *Id.* at 44.

BPA disagrees that an “imminent threat,” *Id.* at 41, is necessary to justify adopting the FRP. The FRP fills a gap in BPA’s existing policy framework in order to “provid[e] needed guidance on how low (and high) BPA’s financial reserves may go before BPA must take action.” Harris *et al.*, BP-18-E-BPA-33, at 4. While current circumstances underscore the fact that BPA should fill this gap, the FRP is not a short-sighted reaction to an imminent threat and should not be analyzed as such. Current policy gaps would allow agency financial reserves to decline to \$230 million, with the Power business line holding \$0. Harris *et al.*, BP-18-E-BPA-17, at 12. This “amounts to only 34 days cash on hand for BPA, which is far less than the number of days cash on hand BPA was holding when the rating agencies previously affirmed BPA’s high credit rating.” Harris *et al.*, BP-18-E-BPA-33, at 21. Moreover, these policy gaps have in fact allowed BPA’s reserves to significantly decline. *Id.* at 11; see Issue 6.4.4.2.1 (equity issue between business lines). As discussed at length in Section 6.6.6 (FRP and policy objectives), BPA is directed to operate with a business-oriented philosophy. See Issue 6.6.6.2 (FRP and sound business principles). BPA fails to see how its statutory mandate to operate consistent with sound business principles would require BPA to wait until a downgrade of its strong credit rating is “imminent” before taking prudent measures to protect that rating.

Further, even if an “imminent threat” to BPA’s credit rating were necessary to justify action to protect that rating, the record supports taking action now. As discussed above in Issue 6.4.3.2.1 (FRP support for BPA’s credit rating), the credit rating agencies’ March 2017 reports confirm that concerns over BPA’s financial reserves are *growing*, not diminishing. As noted in the March 2017 Fitch credit report:

FAILURE TO REVERSE CASH DECLINES: The failure of Bonneville Power Administration to adopt sufficient rate increases to reverse the decline in cash reserves, given the magnitude of variation in revenues that occurs within the power business line, would result in downward rating pressure.

Motion to Take Official Notice of Credit Rating Agency Reports, BP-18-M-BPA-09, Attachment B, at 2. Therefore, there is a very real risk that the warnings about BPA’s credit rating identified in the rating agencies’ reports will become a rating downgrade if BPA’s current policies are allowed to operate unchanged, and financial reserves drop to the bare minimum permitted by TPP. Harris *et al.*, BP-18-E-BPA-33, at 21. BPA needs a policy that prevents such a decline.

BPA could, theoretically, wait and see if its credit rating is downgraded if financial reserves decline further. But doing so would be perilous given the difficulty of building up a downgraded credit rating. A downgrade by a rating agency is usually triggered when an entity is experiencing a challenge to its business that alters the rating agency’s original assessment of the entity’s ability to repay bondholders. Harris *et al.*, BP-18-E-BPA-17, at 18. This means that even short-term negative changes in a business’s operations, finances, or industry can affect an entity’s credit rating if the rating agencies believe the changes are significant. *Id.* In contrast, rating agencies usually require a long period of positive performance before considering an upgrade to an entity’s credit rating. *Id.* Once downgraded, there is no guarantee that reserves of 60 days cash would be sufficient to return BPA to its current credit rating. Given that Moody’s credit rating agency has set “at least 250 days cash on hand on a sustainable basis” as a factor

that could lead to an upgrade (Mullins, BP-18-E-IN-01-AT01, at 113; Motion to Take Official Notice of Credit Rating Agency Reports, BP-18-M-BPA-09, Attachment A, at 3), the criterion for returning to BPA's current rating may be significantly higher than 60 days. The key point is this: a downgrade in BPA's credit rating can happen quickly, but it may take years of sustained positive performance to return BPA to the credit rating it had prior to the downgrade. Harris *et al.*, BP-18-E-BPA-17, at 18. Thus, it is in BPA's and its customers' best interests to act now to protect BPA's credit rating instead of waiting until a downgrade in BPA's credit rating is imminent.

Decision

BPA considered the relevant factors in developing a financial reserves policy that properly addresses BPA's financial reserves levels in support of BPA's credit rating. BPA need not wait until a credit rating downgrade is imminent to develop a financial reserves policy.

Issue 6.4.3.2.3

What weight should be given to the credit rating agencies' March 2017 reports regarding BPA?

Parties' Positions

ICNU recommends that BPA give the most recent credit reports little weight. ICNU Br., BP-18-B-IN-01, at 42-44.

BPA Staff's Position

The credit rating agencies' March 2017 reports were issued after Staff filed its rebuttal testimony.

Evaluation of Positions

As noted earlier, in late March 2017, the three credit rating agencies issued new credit opinions in response to the issuance of new debt associated with Energy Northwest, which BPA backs with its revenues. BPA moved for these reports to be officially noticed in the record. Motion to Take Official Notice of Credit Rating Agency Reports, BP-18-M-BPA-09. No party objected, and the reports were admitted. Order Taking Official Notice of Credit Rating Agency Reports, BP-18-HOO-27.

Nevertheless, ICNU frames Staff's consideration of the most recent reports as being a tactic to switch standards at the last minute in an attempt to render moot all potentially relevant opposition evidence in the record, and recommends that BPA give the reports little weight. ICNU Br., BP-18-B-IN-01, at 43. ICNU discounts the reports' probative value based on their timing and shift in content from prior reports. *See id.* at 42 ("timing and dramatic shift"), 44 ("lateness of the filing and the material alterations within"). ICNU argues the process was not transparent if BPA can bring in and rely on the 2017 reports, and that the rating agencies are not reliable if their reports can so change. *Id.* at 41.

Although ICNU challenges the weight and not the admissibility of the evidence, BPA correctly considered the most recent credit rating agency reports, and their timing is not a reason to discount their probative value. Further, the timing of the reports was determined solely by Energy Northwest's \$588 million bond offering that closed on May 3, 2017. The reports were all issued in late March 2017 in advance of the bond offering so that investors would have the most up-to-date information about BPA's financial health prior to the sale of bonds.

Because BPA does not determine when the credit reports become publicly available, BPA had no earlier opportunity to move them into the record. Motion to Take Official Notice of Credit Rating Agency Reports, BP-18-M-BPA-09. This was not a "tactic." See ICNU Br., BP-18-B-IN-01, at 43. Instead, BPA has a duty to base its decision on "the information available at the time." *Golden Nw. Aluminum, Inc. v. BPA*, 501 F.3d 1037, 1053 (9th Cir. 2007). Neither ICNU nor any other party objected to admission of this evidence, and the Hearing Officer found good cause to take official notice and admit it into the record. Order Taking Official Notice of Credit Rating Agency Reports, BP-18-HOO-27. The reports contain information within the scope of this proceeding and directly relevant to the development of BPA's FRP. Motion to Take Official Notice of Credit Rating Agency Reports, BP-18-M-BPA-09 (see Harris *et al.*, BP-18-E-BPA-17; Power and Transmission Risk Study, BP-18-E-BPA-05; Harris *et al.*, BP-18-E-BPA-33). As the Hearing Officer recognized, "[i]ncluding the 2017 rating agencies' reports will ensure that the record contains the agencies' most up-to-date information." Order Taking Official Notice of Credit Rating Agency Reports, BP-18-HOO-27, at 1.

ICNU argues that, if the FRP cannot be justified by the earlier 2016 credit reports, then the FRP should not be adopted now based solely on the 2017 reports. ICNU Br., BP-18-B-IN-01, at 43-44. Alternatively, ICNU argues that, if the FRP can be justified by the 2016 reports alone, it is unnecessary to attach weight to the 2017 reports. *Id.* at 44. ICNU argues the updated reports "materially alter certain rating agency statements, in comparison to 2016 reports relied upon by Staff in formulating and later attempting to support the FRP." *Id.* at 41. As an example, ICNU states:

[L]ess than a year ago, [Moody's] explained that 'BPA's rating could be *negatively pressured* if BPA's internal liquidity drops below 30 days cash on hand *on a sustained basis.*' Then, after several parties contested the need for Staff's FRP—e.g., contesting a proposal supported merely upon a specter of ratings 'negatively pressured,' in the event of the unlikely prospect of agency reserves levels falling below 30 days cash on hand on a sustained basis—Moody's fundamentally altered its standard. Now, Moody's opines: 'BPA's ratings could be *lowered* ... if we expect internal liquidity to fall below 60 days'

Id. at 41-42 (internal citations omitted) (original emphasis).

This is no reason to discredit the 2017 reports. Although the FRP is justified based on the record even without the 2017 reports, the most recent reports confirm BPA's interpretation of the 2016 reports and underscore the importance of adopting the FRP now. In ICNU's example, Moody's 2017 report validates BPA's reading of how significant reserves levels are to credit rating

agencies. It also cautions against a policy aimed at the minimum requirements to avoid a downgrade.

BPA notes that consistent themes run through all three independent rating agencies' reports, which counters concerns that such opinions are unreliable. For example, all three rating agencies added new statements in their most recent reports expressing concern with BPA's declining reserves. Motion to Take Official Notice of Credit Rating Agency Reports, BP-18-M-BPA-09, Attachment B, at 2 (Fitch) ("cash reserves are at their lowest level since 2007, which is a concern even with the \$750 million federal line of credit"); *id.*, Attachment A, at 4 (Moody's) ("BPA's rapid decline in its reserves for risk is a credit negative"); *id.*, Attachment C, at 4 (S&P) ("The liquidity cushion is vulnerable to hydrology conditions, power market volatility, and accelerated debt reduction, as the nearly \$500 million decline in 2016's unrestricted cash and investments relative to 2015 illustrated.").

All three agencies also added new statements that BPA's failure to take action to address declining reserves would be a credit negative. *Id.*, Attachment A, at 4 (Moody's) ("an inability to ensure internal reserves at or near current levels could lead to a negative rating action."); *id.*, Attachment C, at 4 (S&P) ("Biennial rate proceedings and the high threshold for triggering the utility's cost recovery adjustment mechanism limit the flexibility to respond to pressures on liquidity and DSC."); *id.*, Attachment B, at 2 (Fitch) ("The failure of [BPA] to adopt sufficient rate increases to reverse the decline in cash reserves . . . would result in downward rating pressure."). The consistency of the rating agencies' messages confirms BPA's interpretation of prior reports and supports the fact that the reports are based on objective factors, not merely the opinion of an individual credit rating agency or analyst.

Further, ICNU recommends that, given the timing and change in content of the recent reports, BPA should conduct an additional post-rate-case process to more fully consider adopting a financial reserves policy. ICNU Br., BP-18-B-IN-01, at 44. BPA's reasons for including this issue within the rate case are explained in Issue 6.6.5.4 (reasons for deciding FRP in rate case). Circumstances will continue to change, but BPA must be allowed to make decisions now based on the best available information. This proceeding has developed a detailed record. The parties have had the opportunity to address the reports, and have not been prejudiced by the Hearing Officer taking official notice of the reports. *See* Order Taking Official Notice of Credit Rating Agency Reports, BP-18-HOO-27, at 1.

Finally, ICNU characterizes the most recent credit rating agency reports as "coincidentally (or not) seem[ing] to either mimic Staff rate case positions or be presented in a fashion apparently designed to counter the FRP arguments of other parties . . ." ICNU Br., BP-18-B-IN-01, at 41. To the extent ICNU's characterization implies collusion between BPA and the credit rating agencies, this is simply another unfounded attack by ICNU. The credit rating agency reports represent those entities' independent evaluation and opinion of BPA's credit risk. BPA has no authority over the rating agencies, and the rating agencies have no stake in BPA's credit rating.

Decision

The credit rating agencies' March 2017 reports are the most recent information provided by the agencies and should be given significant weight.

Issue 6.4.3.2.4

Whether there is sufficient evidence in the record to support a finding that a policy on financial reserves would support BPA's credit rating.

Parties' Positions

ICNU makes four arguments that the evidence regarding BPA's financial reserves levels does not justify adopting a financial reserves policy:

- (1) ICNU claims that BPA has robust liquidity and its decline in reserves can be characterized as the "shedding of excess reserves." ICNU Br., BP-18-B-IN-01, at 44-45.
- (2) ICNU contends the record contains evidence that reserves will not continually fall. *Id.* at 47.
- (3) ICNU asserts that BPA did not analyze why reserves fluctuate and, therefore, no reliable reserves forecast can be made, which counters any weight placed on declining reserves predictions. *Id.*
- (4) ICNU argues that Staff misrepresented ICNU's position. *Id.* at 74-75.

BPA Staff's Position

The credit agencies' concerns with BPA's financial reserves levels justify adopting the FRP. Harris *et al.*, BP-18-E-BPA-17, at 13-15.

Evaluation of Positions

ICNU makes four arguments that the evidence regarding BPA's financial reserves levels does not justify adopting the FRP. ICNU Br., BP-18-B-IN-01, at 44-45, 47, 74-75. These will be addressed in turn.

1. Robust Liquidity and Shedding Excess Reserves

First, ICNU points to the credit rating agencies' description of BPA's robust liquidity to characterize BPA's reserves decline as "the shedding of excess reserves." ICNU Br., BP-18-B-IN-01, at 44-45. ICNU argues that BPA's reserves levels are adequate to retain BPA's credit rating and avoid a downgrade. *Id.* at 45. ICNU cites Standard & Poor's (S&P) description of BPA's robust liquidity as evidence that BPA does not immediately need the FRP. *Id.* at 44.

ICNU, however, does not consider that the rating agencies have expressed concern over BPA's levels of financial reserves *and* have indicated that further deterioration of BPA's reserves (which BPA's current policies and practices allow) could lead to negative rating pressure. Harris *et al.*, BP-18-E-BPA-33, at 19; *see, e.g.*, Harris *et al.*, BP-18-E-BPA-33, Attachment 4, Fitch BPA Credit Rating Report (Mar. 23, 2016), at 1. Moody's most recent report stated, "BPA's rapid decline in its reserves for risk is a credit negative and an inability to ensure internal reserves at or near current levels could lead to a negative rating action." Motion to Take Official Notice of Credit Rating Agency Reports, BP-18-M-BPA-09, Attachment A, at 4. S&P also updated its characterization of BPA's liquidity in its most recent report:

If, during our two-year outlook horizon, Bonneville's ~~robust~~***sound*** liquidity cushion erodes ~~meaningfully~~***further*** whether due to hydrology conditions, capital needs, ~~or~~ weak market for its surplus power, ***or debt acceleration that saps its liquidity*** we could lower the stand-alone credit profile.

See Harris *et al.*, BP-18-E-BPA-33, Attachment 6, at 5; Motion to Take Official Notice of Credit Rating Agency Reports, BP-18-M-BPA-09, Attachment C, at 5 (deletions from prior report in strikethrough; additions in bold italic). Thus, while still characterizing BPA's liquidity as "sound," S&P implies that BPA's liquidity has eroded. Motion to Take Official Notice of Credit Rating Agency Reports, BP-18-M-BPA-09, Attachment C, at 5. The rating agencies would not have included these statements, or established a general tone of caution, if they believed further declines in BPA's financial reserves would be of little importance to BPA's credit rating. Harris *et al.*, BP-18-E-BPA-33, at 19.

Moreover, BPA's current policy gap has allowed the agency's financial reserves position to degrade swiftly and materially from an agency high of \$1.268 billion in 2008 to a current end-of-fiscal-year 2017 projection of \$395 million. *Id.* at 8; *see also* Section 6.4.4 (equity and FRP). Declining reserves can lead to a credit rating downgrade. Harris *et al.*, BP-18-E-BPA-33, at 11. Indeed, the last time BPA's credit was downgraded, a decline in financial reserves was cited as part of the basis for the change. *Id.* Moody's stated in the downgrade report that the credit downgrade was due in part to:

[S]ignificant hydrology and market price risk in BPA's power services business that has led to credit quality deterioration over the last several years. Driven by low regional hydrology, low wholesale market prices and rising non-Federal debt service, total reserves available for risk dropped a cumulative 36% over a two year period

Id. (citing Attachment 3, Moody's BPA Credit Rating Downgrade Report (Aug. 31, 2011), at 1).

In addition, ICNU does not consider that the credit rating agencies' positive (and negative) remarks must be read in the *context* of BPA's financial position at the time the reports are issued. *See id.* at 19. For example, in the 2016 reports, BPA had financial reserves of approximately \$650 million. *Id.* at 19-20. In that context, the credit rating agencies believed BPA had sufficient reserves to support the credit rating BPA received. However, BPA no longer has \$650 million in financial reserves, and in fact, BPA's financial reserves levels have continued to

decline. *See id.*, Attachment 1, January 2017 Quarterly Business Review, at 15 (noting projected financial reserves for agency of \$395 million, of which \$2 million is associated with Power Services); *see also* Power and Transmission Risk Study, BP-18-FS-BPA-05, at 127, 129 (the current expected value for BPA in FY 2017 is \$441 million, with \$28 million attributed to Power Services and \$413 million attributed to Transmission Services). Thus, there is no guarantee that the rating agencies will continue to find that BPA’s liquidity and financial reserves remain robust and able to support a continued positive (or stable) credit outlook. Harris *et al.*, BP-18-E-BPA-33, at 20.

Indeed, the continuing decline in BPA’s reserves resulted in changes in the most recent credit reports. For example, in a section titled “DECLINING CASH RESERVES,” Fitch stated, “cash reserves are at their lowest level since 2007, which is a concern even with the \$750 million federal line of credit that provides additional liquidity.” Motion to Take Official Notice of Credit Rating Agency Reports, BP-18-M-BPA-09, Attachment B, at 2. Such statements confirm that Staff placed the proper emphasis on financial reserves levels when interpreting the 2016 reports.

The credit rating agencies’ descriptions of BPA’s past liquidity and financial reserves levels further support the need for a financial reserves policy. Harris *et al.*, BP-18-E-BPA-33, at 20. BPA’s high credit rating is affirmed in the 2016 Fitch and Moody’s reports, in part, because BPA consistently held a high level of days cash on hand—more than 116 days cash—from 2011 through 2015. *Id.* (citing Attachment 4, Fitch BPA Credit Rating Report (Mar. 23, 2016), at 10; Attachment 5, Moody’s BPA Credit Rating Report (June 14, 2016), at 3). This suggests that BPA’s strong credit rating was being maintained, in part, on the basis that BPA was holding financial reserves in excess of 116 days cash on hand. *Id.*

However, no current BPA policy supports maintaining this amount of financial reserves, and indeed, current projections put BPA’s financial reserves far below 116 days cash. *Id.* at 20-21. As of the first-quarter review, BPA projected end-of-FY 2017 agency financial reserves for risk of \$395 million, approximately 60 days cash on hand. *See id.*, Attachment 1, January 2017 Quarterly Business Review, at 15. Indeed, even this 116 days cash level is low in comparison to similar entities. According to Moody’s, entities similar to BPA hold between 150 and 250 days cash on hand. Harris *et al.*, BP-18-E-BPA-17, at 13; *see also* Harris *et al.*, BP-18-E-BPA-33, at 62-63. As discussed in Issue 6.4.3.2.2 (relevance of credit rating agencies’ factors), BPA’s current TPP standard would permit financial reserves to fall to levels at which a downgrade would be very likely. BPA needs a policy to prevent such a decline.

BPA also notes that Moody’s has indicated downgrades are possible at 60 days cash and upgrades are possible at 250 days cash. Motion to Take Official Notice of Credit Rating Agency Reports, BP-18-M-BPA-09, Attachment A, at 3. If this were viewed as the spectrum for maintaining BPA’s current credit rating, BPA recognizes current reserves levels place it at the bottom end of the spectrum. The FRP represents an important but modest increase to BPA’s current policies within this spectrum.

BPA addresses ICNU’s argument that past financial reserves losses are a “shedding” of excess reserves in Issue 6.4.4.2.2 (shedding excess reserves).

2. Financial Reserves Declines and Staff's Expectations

Second, ICNU contends that the record contains strong evidence that reserves will not “be mired in a continually downward spiral.” ICNU Br., BP-18-B-IN-01, at 47. ICNU argues the record provides “no basis to conclude that an ever-downward-spiraling reserves trend will manifest.” *Id.* at 45. Instead, ICNU points to Staff’s “expected value” calculations to assert that “Staff anticipates agency reserves levels to increase, via naturally occurring dynamics completely independent of the FRP, by well over \$200 million to \$667 million, by 2027.” *Id.* at 45-46. ICNU further claims “Staff has expressly disclaimed reliance upon its own [expected value] projections” *Id.* at 47.

As shown above, ICNU implies that Staff both expects a downward spiral in reserves and, in contradiction, expects a naturally occurring increase. Neither is the case. Although Staff does not expect a downward spiral of reserves, Staff observed a general downward trend *in the past*. With regard to ICNU’s allegations of a naturally occurring increase, ICNU misinterprets the two-word phrase “expected value.” This phrase is a widely recognized term of art, and does not mean “a value that is to be expected.” The expected value is “the sum of all possible values for a random variable, each value multiplied by its probability.” *American Heritage College Dictionary*, 2002, Houghton Mifflin Co.

Thus, the “expected value” is a statistic based on a distribution of possible results. This is how Staff used the term. ICNU cites an attachment to its direct case, Mullins, BP-18-E-IN-AT01, at 91, which includes a table furnished by Staff in response to Data Request PS-BPA-26-12. The table ICNU uses as a basis for asserting that Staff expects reserves to increase is worth examining:

POWER SERVICES										
Proposed Financial Policy without the IRPL provision										
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Minimum Reserves	-\$348m	-\$277m	-\$375m	-\$279m	-\$422m	-\$273m	-\$316m	-\$262m	-\$308m	-\$202m
Expected Value Reserves	\$93m	\$162m	\$201m	\$257m	\$288m	\$329m	\$352m	\$379m	\$394m	\$413m
Maximum Reserves	\$740m	\$911m	\$1,022m	\$1,014m	\$1,023m	\$996m	\$1,049m	\$971m	\$1,081m	\$1,083m
Standard Deviation Reserves	\$198m	\$204m	\$235m	\$223m	\$241m	\$224m	\$239m	\$223m	\$230m	\$216m
Status Quo										
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Minimum Reserves	-\$348m	-\$277m	-\$375m	-\$284m	-\$422m	-\$284m	-\$435m	-\$291m	-\$334m	-\$279m
Expected Value Reserves	\$93m	\$134m	\$165m	\$196m	\$219m	\$243m	\$259m	\$277m	\$290m	\$304m
Maximum Reserves	\$740m	\$1,026m	\$1,096m	\$1,041m	\$1,037m	\$1,142m	\$1,167m	\$1,075m	\$1,210m	\$1,233m
Standard Deviation Reserves	\$198m	\$211m	\$243m	\$245m	\$268m	\$267m	\$285m	\$285m	\$295m	\$295m

First, BPA notes that under the Status Quo, the row “Expected Value Reserves” shows increasing values over time. As explained above, this does not mean Staff expects those values. Indeed, the row “Standard Deviation Reserves” shows how far actual reserves may be from the expected value. The range defined by one standard deviation above and below the expected value will generally contain about two-thirds of the data points, each of which represents a possible future. This implies that roughly one-third of the data points will be more than one standard deviation above or below the expected value. Thus, Staff’s analysis indicates that there

is a one-third chance that the ending reserves for FY 2018 will be either *more than \$198 million above* the expected value or *more than \$198 million below* the expected value. This clearly shows that Staff does not “expect” ending 2018 reserves to be \$93 million. This two-out-of-three range of uncertainty grows over time, such that it is plus or minus \$295 million by FY 2027. It is the recognition of this possibility, not a prediction that it will occur, that is a motivation for the FRP:

[T]here is the real possibility that BPA could operate on a negative cash basis before taking rate action to increase financial reserves. Low to negative financial reserves can result in long-term harm to the financial health of BPA, particularly with respect to BPA’s credit rating.

Harris *et al.*, BP-18-E-BPA-17, at 16. BPA’s current gap in policies continues to allow for reserves to decline without a remedy, and to levels that threaten its credit rating, that is, below 30 days cash on hand. Harris *et al.*, BP-18-E-BPA-33, at 22.

Another point misunderstood by ICNU in referencing this chart is that the expected values are impacted by BPA setting the CRAC threshold at \$0. This feature was modeled in the analysis summarized above. What this means is that every time one of the thousands of scenarios summarized above randomly resulted in reserves below \$0 in one year, the CRAC would generate additional reserves in the next year through a rate increase. In each such scenario, additional reserves were generated by the CRAC, such that when the 3,200 scenarios were averaged, the average was increased by these scenario-specific CRAC actions. This is the explanation for the upward trend in the “expected value” numbers; it is not “naturally occurring dynamics,” ICNU Br., BP-18-B-IN-01, at 45-46, but rather the rate-increasing effect of the status quo CRAC. This does not imply that Staff “expects,” that is, anticipates, that reserves will actually increase under the status quo. It means that if adverse circumstances occur, the CRAC can help reserves build up to \$0.

Therefore, what the table demonstrates is that Staff expects reserves levels to be highly variable, with the possibility to be far above or far below the expected value of the set of scenarios Staff ran. This “expectation,” in the normal sense of belief or anticipation, is compatible with both a (possible) upward trend and a (possible) downward trend, and with many other trajectories of reserves that include large swings in both directions.

ICNU also does not take into account BPA’s analysis that forecast the probability of BPA’s financial reserves falling below 30 days cash on hand on a sustained basis under the status quo, Staff’s Initial Proposal, and the parties’ alternatives. Harris *et al.*, BP-18-E-BPA-33, at 22. Under the “no action” status quo, there is a 20 percent chance of BPA’s financial reserves falling below 30 days cash on a sustained basis. *Id.*

BPA acknowledges that it is impossible to know for certain whether BPA’s financial reserves will fall below 30 days cash on hand. *Id.* at 21. However, it would not be reasonable to ignore BPA’s declining financial reserves and the rating agencies’ warnings about further declines simply because of this lack of certainty. *Id.*; see also Section 6.4.4 (equity and FRP). It is precisely because BPA’s financial reserves levels are *not* certain, and that current gaps in policy

would allow further reserves declines, that BPA needs a policy. Harris *et al.*, BP-18-E-BPA-33, at 22. The FRP provides clear guidance on when action must be taken to mitigate and manage the risk of financial reserves falling to levels that could threaten BPA’s credit rating. *Id.* It is necessary to plan now for these contingencies. *Id.*

ICNU also mischaracterizes Staff’s testimony when ICNU claims that “Staff has expressly disclaimed reliance upon its own projections” ICNU Br., BP-18-B-IN-01, at 47. Staff did not disclaim that the set of projections can be useful. ICNU asserts that “a determination on whether the immediate adoption of an FRP is justified depends on necessarily uncertain assumptions about future reserves levels.” *Id.* ICNU appears to suggest that BPA must predict whether reserves *will* increase or *will* decrease, while BPA believes it is sufficient to have determined that reserves can continue to increase or decrease at a pace that is similar to past history, which is quite significant. BPA is not justifying the FRP on the basis that reserves *will* decrease, but on the basis that (1) financial reserves *have* decreased, see Section 6.4.4 (equity and FRP), (2) reserves *may* decrease in the future, (3) such a decrease would be harmful, and (4) the FRP can significantly reduce the likelihood of that harm.

ICNU also claims Staff’s “expected value” forecast is not a “specific projection or forecast,” since BPA stated it had “not developed . . . a specific projection or forecast of days cash on hand for Power or Transmission over the next ten years.” ICNU Br., BP-18-B-IN-01, at 47. In proper context, however, BPA was asked to provide projections or forecasts as to BPA anticipating changes to the days cash on hand metric. Mullins, BP-18-E-IN-01-AT01, at 97. BPA declined to provide a single projection (essentially a prediction) of how financial reserves will change, knowing that future financial reserves levels are uncertain. Thus, it is more useful to look at a suite of 3,200 possible outcomes to understand the possible future levels of reserves. BPA provided projections of 3,200 possible outcomes for Power, Transmission, and agency reserves over the next 10 years under the status quo, BPA’s Initial Proposal, parties’ proposals and BPA’s Alternative Option to understand the reserves possibilities under each policy framework. *See* Harris *et al.*, BP-18-E-BPA-33, at 108-10.

More fundamentally, even assuming ICNU’s argument is correct that there is strong evidence that financial reserves will increase, such evidence does not negate the need for a financial reserves policy. This is because BPA’s current policies provide almost no guidance on what action BPA should take when financial reserves increase above, or decrease below, levels BPA needs to operate. On the low side, BPA’s current policy would allow total agency financial reserves to fall to \$230 million, which is just 34 days cash. Harris *et al.*, BP-18-E-BPA-17, at 12. As noted above, this amount of financial reserves is precariously close to the level of financial reserves that credit rating agencies have warned would result in additional rating pressure. Harris *et al.*, BP-18-E-BPA-33, Attachment 5, Moody’s BPA Credit Rating Report (June 14, 2016), at 3. Even more concerning is that of this amount, Power Services’ contribution could be as low as \$0. Thus, even assuming BPA’s financial reserves are on the rise, the mere fact that BPA’s existing policies would *permit* BPA’s largest business line to operate with \$0 in financial reserves and allow BPA as an entity to hold no more than 34 days cash strongly supports BPA taking steps *now* to prevent this gap in its policies from harming BPA’s credit rating and financial health. BPA is choosing to act now to fill that policy gap.

3. Analyzing Fluctuations and No Reliable Forecast

Third, ICNU asserts that BPA did not analyze why reserves fluctuate and, therefore, no reliable reserves forecast can be made. ICNU Br., BP-18-B-IN-01, at 47-48. ICNU argues that this counters any weight placed on declining reserves predictions. *Id.* at 47.

ICNU is incorrect that BPA did not explain why its financial reserves fluctuate. BPA explained that the variation in its financial reserves is generally due to market forces outside of BPA's control:

This decline is due primarily to market forces over which BPA has no control, but which underscore the need for a sound financial reserves policy that preserves BPA's ability to remain competitive now and in the future. The energy industry is in the midst of many dramatic changes. Energy prices have remained steady, if not declining, for several years. Loads have also largely remained flat, leaving fewer megawatts (MW) over which to spread rising power and transmission costs. Renewable generation is providing unprecedented amounts of energy to the market. New market entities and structures, such as the Energy Imbalance Market (EIM), stand to change the way power is bought and sold in the region.

Harris *et al.*, BP-18-E-BPA-33, at 3. Elsewhere, BPA also notes the effect of natural gas prices on BPA's net secondary revenues. *Id.* at 104 ("In recent years, revenues have come in less than expenses and thus financial reserves have declined primarily due to a declining natural gas market"). Other parties have similarly identified market forces, and BPA's increasing regulatory costs, as the primary cause of declining revenues for Power Services. As described by WPAG:

Historically and persistently low natural gas prices, the rise of renewable energy, multiplying carbon-free initiatives, and reduced demand have fundamentally changed energy markets throughout the West, significantly lowering both (i) the price BPA can receive for its secondary energy and (ii) the measuring stick by which BPA's rates are compared. Meanwhile, the costs incurred and the revenues forgone by BPA to satisfy its regulatory and legal obligations, and to otherwise provide public benefits, continue to rise.

WPAG Br., BP-18-B-WG-01, at 3-4 (internal footnotes omitted).

These market uncertainties result in a large forecast standard deviation of \$250 million in Power Services' net revenues. Harris *et al.*, BP-18-E-BPA-33, at 115. Thus, there is still a 67 percent chance that BPA's net revenues will be within a range of \$250 million above or below its forecast. Harris *et al.*, BP-18-E-BPA-17, at 16. There is also a one-sixth chance that BPA's net revenues will be higher than the forecast by more than \$250 million, and a one-sixth chance that BPA's net revenues will be lower than the forecast by more than \$250 million. *Id.* In recent years, BPA has seen its net Power receipts fluctuate significantly, with net disbursements (cash flow) in a single rate period being above the expected value by as much as \$213 million and below the expected value by as much as \$337 million. *Id.* at 3.

In light of the significant uncertainty in BPA’s revenues, no “reliable” forecast can be made of BPA’s future financial reserves, such that BPA would be able to forecast that financial reserves will be \$x at time y. However, it is because BPA cannot (and indeed no party can) predict the future with precision that policies seeking to mitigate future risk, such as the FRP, are so valuable. Rather than wait and see how an ever-changing energy market will affect BPA’s credit rating, it is prudent for BPA to take affirmative steps now to adopt sound policies, where they do not already exist, to support BPA’s financial health, including its credit rating, and thus enhance its position to be the supplier of choice come the end of the current long-term customer power sales contracts. Developing the FRP does just that.

4. Staff’s Alleged Misrepresentation of ICNU’s Position

Finally, ICNU argues that Staff misrepresented ICNU’s position. ICNU points to Staff’s rebuttal testimony: “ICNU [believes] that the credit rating agencies have *no concern* with BPA’s financial reserves” ICNU Br., BP-18-B-IN-01, at 75 (quoting Harris *et al.*, BP-18-E-BPA-33, at 18) (original emphasis). ICNU argues this mischaracterizes its direct testimony, which had argued that Staff is focused on a “*minor aspect of BPA’s credit rating.*” *Id.* (quoting Mullins, BP-18-E-IN-01, at 50) (original emphasis). ICNU argues, “Staff resorts to patent misrepresentations of the record on rebuttal, in an apparent attempt to invent a caricature of ICNU as an irrational ‘bête noire,’ who can be lightly dismissed on account [of] making outlandish statements.” *Id.* at 74.

ICNU misunderstands Staff’s rebuttal testimony. The context of Staff’s statement makes clear that Staff was saying that ICNU believes the credit rating agencies have no concern with BPA’s *current levels of financial reserves, i.e.,* that BPA’s financial reserves are healthy. Staff had testified:

ICNU acknowledges Moody’s concern that ‘BPA’s rating could be negatively pressured if BPA’s internal liquidity drops below 30 days cash on hand on a sustained basis[,]’ but then goes on to cite a number of figures from the credit reports that state BPA’s liquidity and financial reserves are healthy. Mullins, BP-18-E-IN-01, at 43–44. ICNU also contends that Staff is focused on a ‘minor aspect of BPA’s credit ratings methodology’ and then goes on to cite a number of other factors that drive BPA’s overall credit rating. Id. at 50.

This leads ICNU to believe that the rating agencies have no concern with BPA’s financial reserves, and that there is no indication that the rating agencies expect BPA’s financial reserves to fall anywhere close to the level that might allow for a “reasonable” assumption of a downward rating action. Id. at 44. Thus, ICNU concludes the credit rating agencies’ reports do not support BPA’s claim that a lower threshold for days cash on hand is necessary to support its credit rating. Id. at 44–45.

Harris *et al.*, BP-18-E-BPA-33, at 18-19 (emphasis added). Staff was not saying that ICNU believes reserves are a factor ignored by credit rating agencies. BPA understands ICNU’s position as presented in ICNU’s direct testimony and has responded to ICNU’s argument “that

Staff displayed an inordinately ‘intense focus’ upon this single factor” ICNU Br., BP-18-B-IN-01, at 75.

Decision

There is sufficient evidence in the record to support a finding that a policy on financial reserves would support BPA’s credit rating.

Issue 6.4.3.2.5

Whether BPA properly considered the FRP’s impact on the credit rating factor of cost-competitiveness.

Parties’ Positions

ICNU argues that BPA did not properly consider the FRP’s impact on the credit rating factor of cost-competitiveness. ICNU Br., BP-18-B-IN-01, at 48-62; ICNU Br. Ex., BP-18-R-IN-01, at 13-16. ICNU argues that “the agency willfully ignores credit rating agencies’ undisputed consideration of impacts on end-use consumers.” ICNU Br. Ex., BP-18-R-IN-01, at 4.

BPA Staff’s Position

Staff properly considered the FRP’s impact on the credit rating factor of cost-competitiveness. Harris *et al.*, BP-18-E-BPA-33, at 63-68.

Evaluation of Positions

ICNU argues that BPA consciously ignored and failed to properly consider certain credit rating factors. ICNU Br., BP-18-B-IN-01, at 48-49. Regarding the rating agencies’ consideration of BPA’s competitiveness, ICNU argues “Staff never so much as attempted to study the potential offsetting consequences of the FRP . . . let alone provide actual evidence to ‘fully explain the consequences’” *Id.* at 50. ICNU describes a trend with BPA rates climbing and market rates declining, and argues that the Initial Proposal’s “guaranteed 3% rate increase through the next ten years” will only make things worse. *Id.* at 52. That is, ICNU argues, the FRP sets financial reserves levels to support BPA’s credit rating, but would result in uncompetitive rates that would actually undermine BPA’s credit rating. *Id.*

In the context of competitiveness as a credit rating factor, recent Moody’s reports listed BPA’s current credit strengths to include “highly competitive rates” and “very competitive power costs.” Harris *et al.*, BP-18-E-BPA-33, Attachment 5, at 2 (Moody’s BPA Credit Rating Report, June 14, 2016); Motion to Take Official Notice of Credit Rating Agency Reports, BP-18-M-BPA-09, Attachment A, at 1-2 (Moody’s BPA Credit Rating Report (Mar. 30, 2017)). Fitch’s 2017 report stated, “the competitive margin between Bonneville’s power rates and market alternatives has compressed due to very low natural gas prices, increased generation from renewables, declining energy demands in the region and increasing costs at Bonneville,” and “Bonneville’s ability to offer competitively priced power supply and extend its contracts beyond

2028 will be a key credit factor.” Motion to Take Official Notice of Credit Rating Agency Reports, BP-18-M-BPA-09, Attachment B, at 2-3 (Fitch BPA Credit Rating Report (Mar. 28, 2017)).

BPA did not ignore these credit rating factors; to the contrary, BPA considered the FRP’s impact on cost-competitiveness in adopting the FRP. As discussed in Issue 6.6.6.3 (FRP and competitiveness), competitiveness is an important priority of BPA. Issue 6.6.6.2 (FRP and sound business principles) also discusses how BPA performed cost-benefit analyses and found that the FRP would have a net benefit to its customers. The record supports that the FRP should position BPA to be more competitive than without a policy by maintaining a high credit rating, which reduces BPA’s borrowing costs and directly supports lower, more competitive, rates through lower interest payments. Harris *et al.*, BP-18-E-BPA-33, at 67. Staff explained in detail the financial value BPA’s credit rating provides to ratepayers in the Initial Proposal and in more detail through the Net Present Value (NPV) cost-benefit analyses. *Id.* (citing Harris *et al.*, BP-18-E-BPA-17, at 1 & Attachment 13, NPV of the FRP; *see also id.* at 55-59). As to any argument that BPA improperly supplemented the record by further considering the FRP’s impact on cost-competitiveness in Staff’s rebuttal testimony, see Issue 6.3.2.1 (procedural issues and FRP).

ICNU argues that Staff, despite acknowledging that the FRP will have long-term rate implications, presented the FRP without any consideration of Focus 2028 strategic concerns. ICNU Br., BP-18-B-IN-01, at 49. In managing a complex business, it is necessary for BPA to focus on multiple strategic initiatives simultaneously. Harris *et al.*, BP-18-E-BPA-33, at 66. Many of these initiatives are connected, at least remotely, to other important agency priorities. *Id.* at 66-67. Evaluation of and response to BPA’s long-term competitiveness is taking place in a number of forums, apart from this proceeding. *Id.* at 65. Because these other processes are ongoing, BPA did not attempt to specifically address BPA’s long-term rate trajectories in the FRP. *Id.* While not specifically designed to address BPA’s competitiveness for the post-2028 period, BPA nevertheless believes for the reasons stated in Issue 6.6.6.3 (FRP and competitiveness), that the FRP should position the agency to be more competitive than it would be without such a policy. *Id.* at 67.

In its Brief on Exceptions, ICNU asserts that the above statement—that the FRP should position the agency to be more competitive—lacks evidentiary support, and argues that “the Draft ROD does not point to even a single legitimate consideration of how the FRP may cause changes to overall demand for BPA power.” ICNU Br. Ex., BP-18-R-IN-01, at 14-15. ICNU argues BPA failed to consider that increasing power costs could cause customers to choose to leave the BPA system, which could cause the agency’s credit rating to fall. *Id.* at 14. In making these arguments, ICNU cites only to Issue 6.4.3.2.5, and not to the above-referenced Issue 6.6.6.3 where the FRP’s impact on competitiveness is discussed or to Issue 6.6.6.2 (FRP and sound business principles), which discusses the analyses showing the FRP will likely result in a net benefit to customers. *See id.*

ICNU incorrectly characterizes the FRP as allowing “no possibility that ‘the average non-Slice rate increase could be less than 3%’ for [each year between now and 2028.]” *Id.* (citing Mullins, BP-18-E-IN-01-AT01, at 87). Of course, Staff’s statements about 3 percent rate increases were

made regarding the Incremental Rate Pressure Limiter (IRPL), a phase-in feature BPA is not adopting. See Section 6.6.4.3 (phase-in). ICNU also argues that “a policy that guarantees major rate increases for the next 10 years is both irresponsible and unsound from a business perspective” ICNU Br. Ex., BP-18-R-IN-01, at 16. BPA disagrees with ICNU’s characterization of the FRP as guaranteeing 10 years of rate increases. As discussed in Section 6.6.4.3 (phase-in), BPA is implementing the FRP’s phase-in by adding \$20 million PNRR in the Power Services revenue requirement. This will cause a one-time incremental rate increase of approximately 1 percent and will be removed as soon as Power’s CRAC threshold has been increased to the Power lower threshold. BPA is deferring a decision on additional phase-in mechanisms and is revisiting how CRAC shortfalls are recovered to allow for further discussion. BPA’s decision to adopt the FRP is a responsible and sound decision. In addition to Issues 6.6.6.2 (FRP and sound business principles) and 6.6.6.3 (FRP and competitiveness), see Issue 6.4.3.2.7, discussing how rate increasing actions can be consistent with sound business principles and finding that customers would be better served by the FRP than by a credit rating downgrade.

The FRP represents an effort by BPA to address the agency’s financial reserves needs in a reasonable, prudent, and systematic way while also persistently and ceaselessly striving for lower costs and greater competitiveness through a variety of other means. *Id.* at 66. BPA views these efforts as complementary, not contradictory. *Id.* For instance, BPA has taken immediate and significant actions in its cost evaluation processes (such as the IPR and CIR, both of which are outside the scope of the rate case) that demonstrate BPA’s commitment to being the provider of choice for both business lines. *Id.* These processes will continue. *Id.* BPA’s commitment to continued competitiveness extends not only to cost-cutting, but also to other strategic efforts to ensure BPA’s long-term ability to bring value to customers on an ongoing basis. *Id.* As important as such efforts are, BPA must pursue multiple priorities simultaneously, both within and outside its financial operations. *Id.* Developing a financial reserves policy addresses one such set of priorities. *Id.* Doing so should not be seen as inherently at odds with others. *Id.*

In its Brief on Exceptions, ICNU argues that BPA ignored the weight given by credit rating agencies to end-use consumer impacts. ICNU Br. Ex., BP-18-R-IN-01, at 4. ICNU cites to a “scenario outlined in credit rating agency reporting” whereby the FRP would incent large customers to leave BPA’s system in response to rate increases, thereby reducing load levels and placing additional upward rate pressure on power rates. *Id.* at 5. This scenario appears, not as a description within a BPA credit rating report, but in Moody’s Rating Methodology for U.S. Public Power Electric Utilities With Generation Ownership Exposure. *Id.* (citing Mullins, BP-18-E-IN-01-AT01, at 49). This scenario is included within a section explaining Moody’s Factor 4: Competitiveness in a subsection titled “Why It Matters.” Mullins, BP-18-E-IN-01-AT01, at 49. In addition to other reasons why cost-competitiveness matters, the subsection discusses the rate pressure on a utility’s remaining customers that could result if retail rates motivate large customers to relocate:

Despite the closed retail market for almost all public power electric utilities, an important advantage of the sector is the price competitiveness for retail and/or wholesale customers, especially relative to investor-owned utilities. We would

expect increased political and regulatory risks if the utility has uncompetitive rates, leading to a potentially more challenging rate setting environment despite the rate autonomy that is prevalent in the sector. High retail rates cause pressure on the governing board (and regulators when applicable) to delay rate increases or perhaps even lower rates, which could affect the utility's ability to recover costs and weaken debt service coverage. In addition, high rates may discourage economic development and contribute to a stagnant or declining revenue base, which could impact debt service coverage in the long-run. Public power electric utilities with large, energy-intensive customers that contribute significantly to their net income could face pressure if high industrial or commercial retail rates motivate those large customers to relocate. The shuttering/relocation of large users can weigh negatively on the local economy and also place additional upward pressure on electric rates for the utility's remaining customers.

Id. Thus, the scenario cited by ICNU is neither a separate factor requiring specific analysis of end-use consumer impacts nor Moody's prediction for BPA. Rather, the relevant credit rating factor is "competitiveness," and Moody's explained why "competitiveness" should be considered. BPA understands why competitiveness should be considered and did analyze the FRP's impact on this factor.

BPA is aware that its cost-competitiveness could impact load levels, which in turn could put upward pressure on power rates. As such, BPA has analyzed the FRP's impact on cost-competitiveness and found a net positive benefit. See above and Section 6.6.6. Having properly considered the FRP's impact on BPA's cost-competitiveness, BPA is not further obligated to perform a separate and distinct analysis of how the FRP will impact each potential subgroup of its customers' end-use consumers. The impact on specific end-use consumers is subsumed within the more general issue of cost-competitiveness. The very "scenario" ICNU cites is subsumed within the credit rating agency's explanation of why competitiveness matters. ICNU has not distinguished the FRP's impact on end-use consumers (who purchase power at the retail level from BPA's customers) from the impact on BPA's customers (who purchase power from BPA at the wholesale level) so as to require BPA to perform such a secondary-level analysis.

BPA recognizes the FRP's impact on a public utility's cost of power, which may be passed through—in whole or in part—to end-use consumers. But the FRP's impact on end-use consumers does not have a separate or distinct impact from BPA's customers. Many of BPA's customers purchase only a portion of their power from BPA and, thus, would have *other* power costs (unrelated to BPA power costs) also in their retail rates. Moreover, BPA's customers include additional costs in their charges to end-use consumers' rates over which BPA has no control, such as overhead expenses. To perform the analysis that ICNU argues BPA must conduct, BPA would have to consider for *each* of its customers (BPA has over 130) how these factors (other power costs and overhead costs) combined with the effects of the FRP on BPA's rates affect that utility's end-use consumers. BPA does not see why this extensive analysis would be necessary or produce results that would be distinct from the analysis that BPA has already performed when evaluating the FRP's effects on BPA's rates in relation to wholesale public utility customers. See Issue 6.6.6.3 (FRP and competitiveness).

BPA understands that its cost-competitiveness vis-à-vis other wholesale suppliers of power will have impacts on the decisions BPA’s customers, and the industries they serve in their retail service area, make in the future. BPA also acknowledges that any BPA rate increase, in combination with the rate increases the utility chooses to pass on to end-use consumers, may make it more difficult for those industries to remain competitive. But BPA need not—and as a practical matter, cannot—determine, for example, at what price point and under what circumstances specific end-use consumers would choose to leave the system of BPA’s customers. Such a decision involves too many factors outside BPA’s control, such as whether an end-user will physically relocate or whether a state will enact a retail consumer choice law. What BPA can do, and has done, is analyze the FRP’s impact on BPA’s cost-competitiveness as to its wholesale power customers. This analysis demonstrates that adopting the FRP would provide a net benefit to BPA’s customers and is consistent with sound business principles. See above and Section 6.6.6. By finding that the FRP will support BPA’s competitiveness, and results in a net benefit to BPA and its customers, BPA has analyzed the customer group it can directly affect with its rates. Further, since any benefit of the FRP would be “passed through” to such end-use consumers by their utilities, *see* ICNU Br. Ex., BP-18-R-IN-01, at 8-9, BPA has also implicitly considered the impact on end-use consumers.

ICNU’s argument as to whether BPA has a statutory mandate to consider impacts on end-use consumers in BPA’s decision-making is discussed in Issue 6.6.6.4.

Decision

BPA properly considered the FRP’s impact on the credit rating factor of cost-competitiveness.

Issue 6.4.3.2.6

Whether BPA properly considered the FRP’s impact on other credit rating factors.

Parties’ Positions

ICNU argues that BPA consciously ignored and failed to properly consider three additional credit rating factors: (1) Cost Recovery Within Service Territory (including “strength of monopoly control” and “relative mix of . . . customers” components), (2) Revenue Stability and Diversity, and (3) Energy Northwest debt. ICNU Br., BP-18-B-IN-01, at 48-61. ICNU argues that “the agency willfully ignores credit rating agencies’ undisputed consideration of impacts on end-use consumers.” ICNU Br. Ex., BP-18-R-IN-01, at 4.

JP07 encourages BPA to consider how the FRP may affect the credit rating factor of cost-competitiveness. JP07 Br., BP-18-B-JP07-01, at 8-10.

BPA Staff’s Position

BPA properly considered all relevant credit rating factors. Harris *et al.*, BP-18-E-BPA-33, at 10-42.

Evaluation of Positions

1. Cost Recovery Within Service Territory

ICNU argues that BPA’s lack of analysis regarding Moody’s “Cost Recovery Framework Within Service Territory” factor demonstrates the FRP has not been sufficiently justified. ICNU Br., BP-18-B-IN-01, at 52-53. ICNU focuses on two components of this factor. *Id.* at 53-58.

One component of this factor is “the strength of monopoly control over a service area.” Harris *et al.*, BP-18-E-BPA-33, Attachment 14, at 11. ICNU argues that, if the FRP’s upward rate pressure causes BPA’s customers not to extend their contracts after 2028, the FRP would negatively impact BPA’s credit rating and result in greater harm than in the absence of the FRP. ICNU Br., BP-18-B-IN-01, at 53-54. However, ICNU’s “monopoly control” argument—that is, BPA must consider that customers will not sign long-term contracts if BPA’s rates are not competitive—is essentially a restatement of its cost-competitiveness argument, as addressed in Issue 6.4.3.2.5 (FRP and cost-competitiveness credit rating factor).

Another component of the Cost Recovery Framework factor is “the relative mix of . . . customers.” Harris *et al.*, BP-18-E-BPA-33, Attachment 14, at 12. ICNU argues BPA also failed to comprehensively consider the FRP’s impact on “the relative mix of residential, commercial and *industrial customers*” *Id.* at 57 (original emphasis). Regarding the “relative mix” component, ICNU interprets Moody’s report to say “‘negative influences on scoring’ could be exerted by a susceptibility to changes in industrial load within a particular customer base.” *Id.* ICNU relies on a BPA comment regarding this factor to depict BPA as abandoning, “as a general policy principle, its traditional concern over broad regional impacts” *Id.*; *see also Id.* at 54-58. ICNU argues in its Brief on Exceptions that BPA’s statements regarding the relevance of this credit-rating factor is an “attempt to abandon [BPA’s] important connection with the region” ICNU Br. Ex., BP-18-R-IN-01, at 8.

Regarding the “relative mix of . . . customers” factor, ICNU mischaracterizes how the FRP might impact this factor. The import of this factor is that a primarily residential customer base is a credit positive relative to a primarily industrial customer base. Moody’s report states:

We look at the relative mix of residential, commercial and industrial customers when assessing the stability of the customer base. Factor scoring for US public power electric utilities that serve a primarily residential customer base (e.g., more than 50% residential sales) would generally be favorably influenced because of benefits from the more stable load and revenue trends that typify the customer class. Alternatively, a customer base dominated by industrial load, particularly if concentrated in one or just a few industrial customers, would exert negative influence on scoring because public utilities with such a characteristic are more susceptible to economic cycles and demand changes that could affect revenue stability.

Harris *et al.*, BP-18-E-BPA-33, Attachment 14, at 12.

Following ICNU’s logic, BPA would be required to specifically analyze whether the FRP might disparately impact end-use customer base sectors so as to determine whether BPA might receive the credit rating benefit of a residential increase in the relative mix. BPA did not, and need not, perform such an analysis. This is especially true since BPA supplies power at wholesale, and does not serve end-use retail consumers. This is an example of a factor that may impact BPA’s credit rating, but is not within the direct control of the agency. See Issue 6.4.3.2.2 (relevance of credit rating agencies’ factors). That is, the relative mix of end-use customers will be driven by larger demographic and economic trends, not by whether BPA adopts a financial reserves policy. Accordingly, in Staff’s rebuttal testimony, BPA responded to ICNU’s “relative mix” argument by stating:

ICNU claims we did not specifically analyze the effect our policy would have on the “relative mix of residential, commercial and industrial customers” of our customers’ retail loads. Mullins, BP-18-E-IN-01, at 54–55. We fail to see how such an analysis, which would have involved analyzing loads BPA has *no* statutory or legal obligation to serve, could have informed our development of the FRP.

Harris *et al.*, BP-18-E-BPA-33, at 29-30 (original emphasis).

BPA maintains its regional focus, consistent with its statutory authorities. ICNU argues that BPA did not properly analyze the FRP’s potential impact in “prompting large end-use consumers to seek more competitive power rates.” ICNU Br., BP-18-B-IN-01, at 57 (internal citations omitted). While BPA is concerned about the retail rates charged by BPA’s utility customers, BPA itself has no privity with end-use retail consumers. Finer detailed analysis is especially unnecessary regarding end-use customers with pass-through contracts. *Id.* at 57-58.

JP07 also cites to components within Moody’s Cost Recovery Framework Within Service Territory factor. JP07 Br., BP-18-B-JP07-01, at 6; *see* Harris *et al.*, BP-18-E-BPA-33, Attachment 14, at 11. JP07 does not argue the FRP would not help maintain BPA’s credit rating, but emphasizes that “BPA must recognize that factors other than the existence of a financial reserves policy or a certain level of financial reserves can also impact its credit rating, such as ‘service area economic strength and customer base stability; willingness and ability to recover costs with sound financial metrics; and rate competitiveness.’” JP07 Br., BP-18-B-JP07-01, at 6. “[T]hese factors underscore the need for BPA to ultimately adopt a financial reserves policy that supports its initiative to become cost-competitive and improve its cost trajectory.” *Id.* at 6-7.

In summary, BPA considered how the FRP’s effect on cost-competitiveness would impact BPA’s credit rating, and specifically addressed the Cost Recovery Framework Within Service Territory factor above. BPA also analyzed the FRP’s effect on cost-competitiveness. See Issue 6.6.6.3 (FRP and competitiveness).

2. Revenue Stability and Diversity

ICNU argues that if the FRP raises rates, particular sectors may leave the system, and remaining customers will bear higher costs to cover BPA’s revenue requirement. ICNU Br., BP-18-B-IN-

01, at 58-59. ICNU claims this could lead to a “notching adjustment” under Moody’s Revenue Stability and Diversity factor. *Id.* at 58.

This factor is concerned with a utility’s “exposure to wholesale power markets and other higher risk businesses, customer concentration and diversity from combined utility operations.” Harris *et al.*, BP-18-E-BPA-33, Attachment 14, at 22. The “notching adjustment” ICNU refers to is concerned with whether a utility has large customer concentration:

Large customer concentration can create credit pressure, especially at smaller utilities, because a single large customer (or group of customers in a particular sector) may leave the system without compensating the utility for any outstanding debt used to construct the generation facilities needed to serve that load and may leave the utility with excess power that can only be sold into the wholesale market. Meaningful customer concentration can typically lead to a downward adjustment

Id. BPA does not need to specifically analyze whether the FRP will impact customer concentration in order to justify adoption of the FRP. Further, ICNU’s argument is premised on competitiveness, which is addressed in Issue 6.4.3.2.5 (FRP and cost-competitiveness credit rating factor). BPA understands the important and material relationship between BPA’s rates and BPA’s load and has taken into account the relationship between the FRP and BPA’s competitiveness positioning as evidenced in particular by BPA’s gradual phase-in of a modest increase in Power reserves to support the agency’s overall financial health and long-term competitiveness. See Section 6.6.4.3 (phase-in).

ICNU also argues that “Staff is figuratively hiding its head in the sand by refusing to conduct system-impact load analysis under the scant refuge of an emphatic and hyper-technical argument that ‘BPA has *no* statutory or legal obligation to serve’ preference customer retail load.” ICNU Br., BP-18-B-IN-01, at 59 (citing Harris *et al.*, BP-18-E-BPA-33, at 30) (original emphasis). ICNU’s criticism is unfounded. First, it is unclear from ICNU’s brief and testimony what a “system-impact load” analysis is or what this analysis would show that Staff has not already considered.

Moreover, Staff’s statement that BPA does not serve preference customers’ retail consumers is not a “hyper-technical argument” but *the law*. See Bonneville Project Act, 16 U.S.C. § 832b (“‘public body’, or ‘public bodies’, means States, public power districts, counties, and municipalities, including agencies or subdivisions of any thereof.”); Northwest Power Act, 16 U.S.C. § 839c(b)(1) (“Whenever requested, the Administrator shall offer to sell to each requesting public body and cooperative entitled to preference and priority under the Bonneville Project Act of 1937”). Staff was correct not to analyze whether there were ways BPA could influence the relative concentration of retail industries in BPA’s customer territories. BPA’s statutory role is to sell power to its preference customers, not to the industries that purchase power from its customers. *Id.*

To that end, BPA’s statutes do not contemplate BPA influencing the industrial mix of its customers. Indeed, provisions of the Northwest Power Act generally discourage large new

industries from concentrating within BPA's preference customers' territory. For instance, the Northwest Power Act defines a "new large single load" as any load that increases the power requirements of a public customer by more than 10 average megawatts in a year. 16 U.S.C. § 839a(13). Large manufacturing and other industrial loads can easily exceed 10 aMW per year. Such loads are *expressly excluded* from the calculation of the loads that are served by BPA's most favorable power rate, and power to serve such loads is sold at a much higher power rate. 16 U.S.C. § 839e(b)(4) ("The term 'general requirements' as used in this section means the public body, cooperative or Federal agency customer's electric power purchased from the Administrator under Section 839c(b) of this title, exclusive of any new large single load."). Thus, Staff was not "figuratively hiding its head in the sand" when it noted that large customer concentration was not a factor in its consideration of the FRP, but simply acknowledging the legal limits of what BPA can influence.

3. Energy Northwest Debt

ICNU argues that Staff ignored the negative ratings implications of third-party debt financing through Energy Northwest identified in Moody's reports. ICNU Br., BP-18-B-IN-01, at 60. ICNU argues, "[e]ven to the extent the FRP would bolster the agency's credit rating, therefore, and allow for continued access to third-party debt, that very practice of continuing to rely on third-party debt will create a corresponding 'credit negative.' Thus, at *best*, the FRP would essentially be a wash" *Id.* at 60-61 (original emphasis).

Undercutting ICNU's argument that the FRP would be a wash, Moody's most recent report recognizes that BPA's Regional Cooperation Debt is a business decision with both positives and negatives:

We see BPA's Regional Cooperation Debt (RCD) program as undermining the benefits of the federal debt's subordination, since the program results in a substantial extension of non-federal debt in exchange for the accelerated repayment of federal appropriations debt. While we recognize the cost savings benefits for this strategy, Energy Northwest's debt funding of interest and O&M expenses to accelerate repayment of federal appropriations debt further undermines the subordination and is credit negative.

Motion to Take Official Notice of Credit Rating Agency Reports, BP-18-M-BPA-09, Attachment A, at 6 (portions in italics not included in ICNU's initial brief).

Moody's report recognizes that the RCD program has costs and benefits, but the fact that a course of action has both costs and benefits does not make it a wash. ICNU's argument implies BPA should rely less on third-party debt rather than adopt the FRP. This would result in either (1) reductions in BPA's capital program, or (2) accelerated depletion of BPA's borrowing authority. Neither of these would be beneficial for BPA's stakeholders, including customers. S&P specifically noted that "debt acceleration that saps [BPA's] liquidity . . . could lower the stand-alone credit profile." *Id.*, Attachment C, at 5. BPA made the business decision to obtain the benefits of the RCD program and to minimize the costs. See Section 2.2 (Revenue Requirement).

ICNU argues in its Brief on Exceptions that BPA has “willful[ly] ignor[ed] express credit rating agency standards of major importance” ICNU Br. Ex., BP-18-R-IN-01, at 4. BPA has considered the FRP’s impact on all relevant credit rating factors and addressed the relevancy of certain credit rating factors cited by ICNU. ICNU’s more general argument—that BPA has failed to consider the FRP’s impact on BPA’s credit rating based on credit rating agencies’ consideration of end-use consumer impacts, *id.* at 4-7—is discussed in Issue 6.4.3.2.5, Whether BPA properly considered the FRP’s impact on the credit rating factor of cost-competitiveness. See also, Issues 6.6.6.2 (FRP and sound business principles), 6.6.6.3 (FRP and competitiveness) and 6.6.6.4 (FRP and statutory mandate).

Decision

BPA properly considered the FRP’s impact on other credit rating factors.

Issue 6.4.3.2.7

Whether BPA’s customers would be better served by a credit rating downgrade than by the FRP.

Parties’ Positions

ICNU argues that customers would be better served by a credit rating downgrade than by the FRP. ICNU Br., BP-18-B-IN-01, at 62.

BPA Staff’s Position

Even under conservative assumptions, the FRP provides a net benefit to BPA’s customers. Harris *et al.*, BP-18-E-BPA-33, at 59.

Evaluation of Positions

ICNU argues “the evidence on record demonstrates that customers would be in a *better* position if the Administrator were to reject the FRP, rather than suffering the negative rate impacts of an FRP proposal which has not been shown to provide benefits exceeding costs.” ICNU Br., BP-18-B-IN-01, at 62 (original emphasis).

As a general matter, it is consistent with sound business principles for a business to take a rate-increasing action to maintain its high credit rating, assuming the business is reliant on third-party financing. Harris *et al.*, BP-18-E-BPA-33, at 53. BPA acknowledges that the timing and impact of the rate action taken, however, must consider costs and benefits, from both quantitative and qualitative perspectives. *Id.* From a purely quantitative perspective, if the costs and benefits are determined to produce net positive benefits, raising rates would undoubtedly be consistent with sound business principles. *Id.*; see also Issue 6.6.6.2 (FRP and sound business principles).

However, even if the FRP produced a net cost, it would still be consistent with sound business principles to maintain a high credit rating so long as the qualitative benefits are material. Harris *et al.*, BP-18-E-BPA-33, at 53. It is generally easier to quantify the costs of increasing rates to

support a high credit rating and the benefits of avoiding a downgrade's added interest expense than it is to quantify the qualitative or intangible benefits of that high rating. *Id.* There are many intangible benefits from having a good credit rating, such as the positive impact BPA's credit rating may have on its customers' credit ratings, and consistent market demand for BPA's debt even under challenging market conditions. *Id.* Other examples include access to alternative forms of financing, such as lease financing lines of credit, as well as the maintenance of favorable credit requirements with BPA's various trading partners. *Id.* Quantifying the long-term consequences of a downgrade on these intangible benefits is very difficult, but nonetheless it is reasonable to assume a downgrade would have a material real-world effect on BPA's long-term financial health and business operations. *Id.*

Even putting aside these important qualitative benefits, the record substantiates that the FRP's benefits would likely exceed its costs. Results of BPA's cost-benefit analyses show that, even under conservative assumptions, the FRP provides a net benefit to customers. *Id.* at 59; see also Issue 6.6.6.2 (FRP and sound business principles).

ICNU makes five arguments regarding specific evidence in the record. ICNU Br., BP-18-B-IN-01, at 63-67.

First, ICNU concludes the “*minimum* rate increase [under the FRP] is still more than the absolute maximum [rate increase] estimate that Staff provides in the event of a downgrade.” *Id.* at 65.

ICNU's conclusion is not a meaningful comparison. The latter number represents rate pressure directly attributable to a credit downgrade, which would be *in addition* to any other rate increase. The former number refers to the IRPL phase-in mechanism, which only adds additional FRP-related rate pressure until the *total* rate increase for a rate period is 3 percent. Regardless, BPA is not adopting the IRPL phase-in mechanism.

Second, in a footnote, ICNU reads a Staff illustration to mean rate increases under the FRP “could actually turn out to be much higher [than 3%]” *Id.* at 65, n.242 (citing Harris *et al.*, BP-18-E-BPA-17, Appendix B, at B-1). ICNU's footnote is true, but irrelevant. Total rate increases may be higher than 3 percent without the FRP, and the FRP does not limit total rate increase. The cited illustration does not show a 4 percent rate increase resulting from the FRP. The illustration demonstrates that the IRPL mechanism would not add FRP-related rate pressure if the total rate-period increase was already at 4 percent.

Third, ICNU discounts Staff's cost-benefit analyses based on Staff's December 2016 statement, “The best source and most comprehensive characterization of the costs and benefits of the proposed policy is BPA's financial reserves policy testimony.” *Id.* at 67 (quoting Mullins, BP-18-E-IN-01-AT01, at 81 (Data Response PP-BPA-26-10)). ICNU argues this means “all ‘expressly stated’ evidence in support of the FRP is limited to the four corners of Staff's initial proposal.” *Id.* at 68. ICNU asserts “parties presented their direct cases in reliance on Staff's own confinement of the ‘best’ and the ‘most comprehensive’ FRP evidence to within the four corners of the initial proposal” and, therefore, BPA should not adopt the FRP on a different evidentiary basis. *Id.*

Staff’s statement cited by ICNU was made prior to parties’ direct cases and rebuttal testimony. BPA makes its decision based on the evidence in the whole record. The parties could and did present evidence in their direct cases to challenge BPA’s Initial Proposal. BPA considered and responded to the evidence presented by the parties before making a decision based on the evidence in the whole record.

Fourth, ICNU asserts that the record shows “Staff has overstated credit downgrade impacts by a *threefold* factor.” *Id.* at 65 (original emphasis). ICNU notes Staff’s downgrade impact calculations assume a three-notch downgrade from AA to A. *Id.* at 66. ICNU argues the record contains precedent of only single-notch downgrades to BPA’s credit rating, and that BPA did not rebut this evidence. *Id.* ICNU disputes the evidentiary foundation of BPA’s assumption as based on “mere allusions to undocumented oral discussions . . .” or “unilateral, unsupported ‘belief’ statement[s] . . .” *Id.* at 63, 66. *See also id.* at 67.

BPA interpreted the rating agency guidance cited in Staff’s testimony regarding financial reserves, the policies governing them, and the risk profile to reach its three-notch downgrade assumption. Harris *et al.*, BP-18-E-BPA-33, at 61. It is reasonable and not overly conservative to assume that BPA’s credit rating would be negatively impacted in this material and significant way if financial reserves levels fell below 30 days cash on hand on a sustained basis, especially if BPA did not take any action, policy or otherwise, to remedy the situation. *Id.* BPA’s current TPP standard allows this to occur and offers no remedy. *Id.*

Staff’s expert testimony is evidence that has been admitted into the record. The panel’s expert opinion is supported by decades of practical experience within BPA’s unique financial context. *See* BP-18-Q-BPA-08; BP-18-Q-BPA-09; BP-18-Q-BPA-15; BP-18-Q-BPA-25. The four members of the panel hold an array of bachelor’s, master’s, and doctoral degrees in fields such as Economics/Management Science, Business Administration, Mathematics, and Systems Science. *Id.* Despite ICNU’s attempt to belittle the weight of the panel’s expert testimony, their three-notch downgrade assumption is the product of careful analysis of the relevant data, including interpreting the credit rating agencies’ reports.

BPA need not wait until BPA experiences a multi-notch downgrade to interpret available evidence and take action. In this case, the most recent credit rating agency reports confirm the validity of Staff’s assumption. For example, where Staff partially based its three-notch downgrade assumption on its interpretation of Moody’s 2016 report, which states that “BPA’s rating could be negatively pressured if BPA’s internal liquidity drops below 30 days cash on hand on a sustained basis . . .,” Harris *et al.*, BP-18-E-BPA-33, Attachment 5, at 3 (Moody’s BPA Credit Rating Report, June 14, 2016), Moody’s now says “BPA’s rating could be lowered . . . if we expect internal liquidity to fall below 60 days . . .” Motion to Take Official Notice of Credit Rating Agency Reports, BP-18-M-BPA-09, Attachment A, at 3. If BPA’s rating could be lowered by reserves below 60 days cash, Staff was correct to assume that reserves below 30 days cash on a sustained basis would lead, not merely to BPA’s rating being lowered, but to a significant multi-notch downgrade.

ICNU takes issue with sentences in testimony that begin with “We believe . . .” *See, e.g.*, ICNU Br., BP-18-B-IN-01, at 56, 66, 73. Although it is unnecessary to state “we believe”—

since everything in testimony is by definition the experts' opinion—doing so does nothing to diminish the evidence. *See, e.g.*, Mullins, BP-18-E-IN-01, at 55 (“I believe that guaranteed rate increases of at least 3% for the next decade will diminish the agency’s ‘essential’ goal of ensuring contract renewals in 2028.”).

BPA acknowledges the effects of a credit rating downgrade are somewhat uncertain and will be a result of several factors. *Id.* BPA took into account this uncertainty in impact and timing of a downgrade through its matrix of 168 cost-benefit analyses. *Id.* at 61-62. Even under very conservative assumptions, BPA’s analysis shows a positive NPV. *Id.* at 62.

Fifth, ICNU argues there is a lack of rigorous evidentiary substantiation for BPA’s concern that a credit downgrade would impact its ability to access third-party credit. ICNU Br., BP-18-B-IN-01, at 63. ICNU noted that BPA provided no written documentation for this impact, but only alluded to oral discussions. *Id.* (citing Mullins, BP-18-E-IN-01-AT01, at 70-71 (Data Response PP-BPA-26-4)).

ICNU again attacks the weight of expert testimony in the record supported by Staff’s analysis of relevant data. In the data response cited by ICNU, BPA describes the basis for its expert testimony that a credit rating downgrade would impact its ability to access third-party debt.

[W]ith lease-purchase lines of credit . . .[,] the third party issuer does not go to market, receiving a market interest rate, but rather conducts a competitive bidding process with banks to determine the interest rate and amount banks will lend. *Each bank has its own internal decision process* that includes reviewing the credit worthiness of the potential borrower . . . BPA analyzed the impacts of a downgrade to the lease-purchase lines of credit by discussing with subject matter experts, with various lending banks and with BPA’s financial advisor. Through these discussions, BPA understands that the third party lines of credit are unique in the marketplace, changing market conditions or changes to BPA’s credit rating or both, may materially impact the cost or amount lent. BPA concluded that it was reasonable to assume the cost of third party lines of credit would increase significantly (estimated 100 bps) and/or the amount of funds offered would be materially reduced or eliminated.

Mullins, BP-18-E-IN-01-AT01, at 71 (emphasis added).

ICNU did not argue that a credit rating downgrade would not impact BPA’s ability to access credit or otherwise rebut the merits of this expert testimony. Instead, ICNU argues that the evidence is not substantiated rigorously enough. BPA does not need to be able to predict which banks would stop offering lines of credit at which credit rating levels in order for BPA to conclude that a lower credit rating would materially affect access to funding or amounts offered. Furthermore, Staff explained the commonsense point that entities with higher credit ratings have better access to markets than entities with lower credit ratings.

It is common knowledge that entities with higher credit ratings have better access to financial markets relative to lower credit rated entities. This is as true in commercial and municipal credit

as it is in consumer credit. We do not believe this basic concept needs additional explanation or quantification. Moreover, ICNU has not presented any information to indicate that a lower credit rating has no effect on an entity's access to capital.

Harris *et al.*, BP-18-E-BPA-33, at 60-61. ICNU has not proven otherwise.

Decision

BPA's customers would be better served by the FRP than by a credit rating downgrade.

Issue 6.4.3.2.8

Whether the FRP is justified even if the FRP will not ensure a credit rating upgrade.

Parties' Positions

ICNU argues the FRP is not justified on the basis that the FRP will result in a credit rating upgrade. ICNU Br., BP-18-B-IN-01, at 71.

BPA Staff's Position

The key purpose of the FRP is protecting BPA's credit rating, making it less likely that BPA would experience a downgrade in the future, but to the extent the rating agencies consider upgrading BPA's credit rating, having a financial reserves policy would be one of the factors that would support an upward adjustment. Harris *et al.*, BP-18-E-BPA-33, at 27.

Evaluation of Positions

ICNU argues that "Staff's proposed FRP cannot be rationally justified on an argument that the policy could positively improve, or lead to an upgrade of, BPA's credit rating." ICNU Br., BP-18-B-IN-01, at 71. ICNU notes "Moody's states that 'if BPA implements policies to ensure strong internal reserves for risk resulting in at least 250 days cash on hand on a sustainable basis,' then 'BPA's rating could improve over the long term.'" *Id.* (quoting Mullins, BP-18-E-IN-01-AT01, at 113). ICNU takes particular issue with BPA's "reversion to . . . arch-vaguery and equivocation," arguing that the Administrator should ensure fairness by not allowing BPA to put heavy weight on certain portions of the reports and dismiss others. *Id.* at 72-73. ICNU argues, given that if the FRP will increase costs but credit rating benefit is uncertain, "the only 'sound' business decision left is to reject any changes at all . . ." *Id.* at 73.

BPA acknowledges that the FRP is unlikely to cause an upgrade to BPA's credit rating in the near term, and has not claimed otherwise. The key purpose of the FRP is protecting BPA's credit rating, making it less likely that BPA would experience a downgrade in the future. Harris *et al.*, BP-18-E-BPA-33, at 27. In that vein, the purpose of the FRP is to move BPA's financial policies in a direction that would make a downgrade less likely under whatever future conditions may prevail rather than to cause an upgrade. *Id.* Given the discussion of financial reserves and

financial reserves volatility in the credit reports, the FRP could reasonably be expected to provide a meaningful safeguard against a credit downgrade. *Id.*

Further, by putting BPA on a firm financial footing, the FRP helps lay a foundation that can be built upon in future years. *Id.* Although it is not possible to predict with certainty the precise effect of any particular future change on an entity's credit rating, the rating agencies have noted that having a robust policy would have a "positive" effect on BPA's credit rating. *Id.* at Attachment 4, Fitch BPA Credit Rating Report (Mar. 23, 2016) & Attachment 5, Moody's BPA Credit Rating Report (June 14, 2016)). What this may mean for BPA's credit rating is not known, but to the extent the rating agencies consider upgrading BPA's credit rating, having a financial reserves policy would be one of the factors that would militate in favor of an upward adjustment. *Id.* at 27.

As to ICNU's issue with Staff's testimony, ICNU misunderstands the testimony. Although a near-term upgrade is not likely, BPA does not foreclose the possibility that steps taken through the FRP to improve BPA's financial health could, in the long-term, play a role in BPA receiving a credit rating upgrade. Precise impacts on credit rating are not the only uncertainty BPA faces. BPA must be allowed to make the best decision possible with the available evidence.

Decision

The FRP is justified, in part, on the basis that it will help to avoid a credit rating downgrade. Although unlikely to unilaterally result in a near-term credit rating upgrade, the FRP can be a factor that will support a long-term credit rating upgrade.

6.4.4 Equity and a Financial Reserves Policy

6.4.4.1 Overview

As part of the development of the FRP in this case, Staff included "equity" between the business lines as one of the reasons for developing a financial reserves policy. Harris *et al.*, BP-18-E-BPA-17, at 21, 24. As described above, BPA relies on and uses its strong credit rating to acquire third-party debt to support the capital projects of both of its business lines. See Section 6.4.3 (credit rating and FRP). BPA's credit rating is determined, in part, on the health of the agency's total financial reserves. Harris *et al.*, BP-18-E-BPA-17, at 21. However, BPA's current policies do not require both business lines to contribute to those financial reserves beyond what is necessary for TPP. *Id.* at 10-12. For Power Services, this amount could be as low as \$0, while Transmission Services could be required to supply at least \$230 million. *Id.* at 12. Nothing in BPA's current policies addresses this imbalance nor prevents it from becoming systemic over time. Harris *et al.*, BP-18-E-BPA-33, at 35-36. To address the potential disparity in business line contributions to agency financial reserves, Staff included equity between the business lines as an additional basis for developing a financial reserves policy. Harris *et al.*, BP-18-E-BPA-17, at 21, 24; Harris *et al.*, BP-18-E-BPA-33, at 35-36. A financial reserves policy can help address equity between the business lines by ensuring that both business lines contribute financial reserves to protect BPA's strong credit rating and overall financial health. Harris *et al.*, BP-18-E-BPA-17, at 35-36.

6.4.4.2 Issues

Issue 6.4.4.2.1

Whether the record demonstrates that there is an equity issue between the business lines that should be addressed through a financial reserves policy.

Parties' Positions

ICNU argues that there is no “equity” issue to be redressed through a financial reserves policy. ICNU Br., BP-18-B-IN-01, at 21-22. ICNU identifies three primary reasons why it believes that the FRP cannot be justified on equity considerations. *Id.* The first of these reasons follows:

[R]eserves attributed to power and transmission have fluctuated historically, with power reserves exceeding transmission reserves for years, then vice versa. Moreover, Staff has testified to recent and forecast improvements in power reserves, merely under status quo dynamics, which further weakens any claim of a pressing future inequity problem so allegedly dire that it can only be remedied via immediate adoption of a binding 10-year policy of increased power rates.

Id.

JP07 similarly argues that there is no inherent inequity in the relative distribution of financial reserves between the Power and Transmission business lines. JP07 Br., BP-18-B-JP07-01, at 12. JP07 notes that reserves have fluctuated over time, and Power has in the past provided more financial reserves than Transmission. *Id.* at 12-13.

JP02, Powerex, and M-S-R all describe the status quo as inequitable. Powerex Br., BP-18-B-PX-01, at 4-6; JP02 Br., BP-18-B-JP03-01, at 4-5; M-S-R Br., BP-18-B-MS-01, at 5. These parties describe the status quo as leaning on Transmission Services' financial reserves to support the agency's financial reserves needs. As described by Powerex:

Transmission contributed approximately three-quarters of BPA's overall financial reserves at the end of FY 2016, and at the end of FY 2017 Transmission will be contributing virtually all of the financial reserves to support BPA's credit rating. The sustained dependence on one business line's financial reserves where both benefit from the strong credit rating is inequitable—and will likely continue to be—unless the Administrator takes action to implement a FRP that meaningfully remedies the sustained over-dependence.

Powerex Br., BP-18-B-PX-01, at 5 (emphasis and footnote omitted).

M-S-R states that “it is inequitable for one business line to provide a disproportionate level of reserves beyond a short term imbalance” and that “relative contributions to the reserves by business lines have been out of balance since at least 2010 which is not short term, and hoping

the balance will self-correct is neither sound policy nor consistent with sound business principles.” M-S-R Br. Ex., BP-18-R-MS-01, at 2.

BPA Staff’s Position

Both business lines rely on BPA’s credit rating, and that credit rating is sustained, in part, by BPA maintaining a healthy level of financial reserves. However, BPA’s current policies do not require both business lines to contribute to agency financial reserves. Harris *et al.*, BP-18-E-BPA-17, at 12. A short-term imbalance between the business lines’ respective contributions to agency financial reserves is acceptable. Harris *et al.*, BP-18-E-BPA-33, at 136. Recent declines in Power Services’ financial reserves have perpetuated the imbalance, and waiting for financial reserves to naturally rebound is not reasonable. *Id.* at 49. A policy is needed to ensure both business lines reasonably contribute to agency financial reserves.

Evaluation of Positions

BPA’s current policies do not require both business lines to contribute to agency financial reserves. Harris *et al.*, BP-18-E-BPA-33, at 35. The TPP standard is not intended to address inter-business line equity issues and, therefore, would allow financial reserves to decline to \$0 for Power and \$230 million for Transmission before any action is taken. Harris *et al.*, BP-18-E-BPA-17, at 12. This policy gap has, in fact, allowed a dramatic decline in Power financial reserves, which has required BPA to rely more heavily on Transmission financial reserves to support the agency’s credit rating. Harris *et al.*, BP-18-E-BPA-33, at 8-9, 49. The present situation, where BPA holds a disproportionately large amount of financial reserves of one business line to support total agency reserves, is not “sustainable.” *Id.* at 3.

Several parties agree. M-S-R notes that “[t]he sustained erosion of Power’s financial reserves highlights the need for an FRP that can be implemented in a real and timely manner, to support BPA’s sound business operations.” M-S-R Br., BP-18-B-MS-01, at 1; *see also* M-S-R Br., BP-18-B-MS-01, at 4 (“M-S-R agrees with BPA that the steep and sustained decline in the Power business line’s reserves demonstrates a need for a change from the status quo.”) M-S-R also generally agrees with the theoretical equity positions set forth by BPA, particularly that reliance on one business line’s reserves to support another business line’s operations for a sustained period is inequitable. *Id.* at 8.

Powerex notes that with this downward trend in Power Services’ reserves, BPA has become increasingly reliant on the financial reserves attributed to Transmission Services. Powerex Br., BP-18-B-PX-01, at 2-3. Powerex also argues that, as the current and projected levels of financial reserves indicate, Transmission contributed approximately three-quarters of BPA’s overall financial reserves at the end of FY 2016, and at the end of FY 2017 Transmission will be contributing virtually all of the financial reserves to support BPA’s credit rating. *Id.* at 5. JP02 similarly argues that Power Services’ financial reserves are susceptible to greater volatility and are in a downward trend. JP02 Br., BP-18-B-JP02-01, at 6. All of these parties note that the current imbalance is inequitable because it shows an overreliance on one business line’s financial reserves to support agency financial reserves. Powerex Br., BP-18-B-PX-01, at 5; JP02 Br., BP-18-B-JP02-01, at 6, 49; M-S-R Br., BP-18-B-MS-01, at 5. These parties generally concur

that BPA should be able to take corrective action to eventually re-balance contributions to agency reserves. Powerex Br., BP-18-B-PX-01, at 5-6.

JP07 disagrees with the testimony of JP02, Powerex, and M-S-R that there is inherent inequity in the relative distribution of financial reserves between the Power and Transmission business lines. JP07 Br., BP-18-B-JP07-01, at 12. JP07 asserts these parties overlook changes over time. *Id.* JP07 acknowledges that, recently, more reserves have been attributed to Transmission than Power, but between 2004 and 2009, “more than half of the agency’s financial reserves were attributed to Power, with a peak of more than 80% . . . in 2006 and 2007.” *Id.* at 12-13 (citing Deen *et al.*, BP-18-E-JP05-02, at 6). JP07 cites Staff’s testimony as supporting “longer-term interaction between business lines [being] the appropriate metric to examine, not short-term snapshots of which business is attributed greater reserves.” *Id.* at 13.

ICNU argues that BPA acknowledges that a “temporary imbalance” between agency financial reserves is acceptable, so long as it is not systematic or long-term. ICNU Br., BP-18-B-IN-01, at 22. ICNU also argues that any alleged inter-business line imbalance must be demonstrated to be “systematic or long-term” before power rate increases could ever be justified as a needed “solution” toward achieving an equity objective between business lines. *Id.* Otherwise, ICNU asserts, any purported imbalance would simply be acceptable under Staff’s own metric and no compelling basis would exist for increasing rates to alter such an “acceptable” condition. *Id.* ICNU then argues that the record in this case shows that BPA’s financial reserves “appear to be cyclical in nature” and not “long-term” in any one direction. *Id.* ICNU suggests that power reserves are “trending upward once more” without any “officious tinkering from Staff’s proposed FRP mechanics.” *Id.* (emphasis omitted).

BPA agrees that short-term imbalances between business line contributions to agency financial reserves are permissible. Harris *et al.*, BP-18-E-BPA-33, at 35-36. BPA also acknowledges that business line contributions to agency financial reserves have, as ICNU and JP07 note, fluctuated over time, with Power Services supplying most of agency’s financial reserves in certain periods, and Transmission Services supplying more in others. *See* Arthur, BP-18-E-MS-12, Exhibit 12, at 18. Staff also stated, “a short-term reliance on one business line on financial reserves attributed to the other is not inequitable as long as there are provisions in place to ensure that such reliance is truly only short-term.” Harris *et al.*, BP-18-E-BPA-33, at 136.

However, recent information does not support a finding that the imbalance in financial reserves contributions between the business lines is *short-term* or *self-correcting* absent a policy. In BPA’s June 15, 2016, workshop, BPA included a chart that described the trend in BPA’s financial reserves by business line since 2004. Arthur, BP-18-E-MS-12, Exhibit 12, at 18. As noted in that chart, BPA’s financial reserves have declined from a high of \$1.286 billion in 2008 to \$627 million in 2016. *Id.* The 2016 numbers have since been updated, and the final values are \$159 million for Power Services and \$444 million for Transmission Services. Harris *et al.*, BP-18-E-BPA-33, at 36. This is a decline of nearly \$700 million. During that time, Power Services’ financial reserves declined from \$852 million in 2008 to \$159 million in 2016 (a \$693 million loss). Arthur, BP-18-E-MS-12, at 10; *see also* Arthur, BP-18-E-MS-12, Exhibit 12, at 18. In only one year since 2010, namely 2015, has Power Services contributed roughly equal

amounts (compared to Transmission Services) to BPA’s financial reserves. Arthur, BP-18-E-MS-12, Exhibit 12, at 18.

More recent information shows the disparity in business line contributions to agency financial reserves is increasing. In a January 2017 presentation, BPA estimated Power Services financial reserves for the end of FY 2017 would decline from an earlier projection of \$53 million to only \$2 million. Harris *et al.*, BP-18-E-BPA-33, at 4; *see also* Harris *et al.*, BP-18-E-BPA-33, Attachment 1, at 15. This is the lowest amount of financial reserves Power Services has had since 2004. Arthur, BP-18-E-MS-12, Exhibit 12, at 18. Transmission Services’ end of year FY 2017 forecast of reserves, in contrast, have slightly improved to \$394 million. Harris *et al.*, BP-18-E-BPA-33, at 4; *see also* Harris *et al.*, BP-18-E-BPA-33, Attachment 1, at 15. In the final studies, these values have been updated to new expected values of \$28 million for Power Services and \$413 million for Transmission Services. *See* Power and Transmission Risk Study, BP-18-FS-BPA-05, at 127, 129. Taken together, the current forecasts project that Transmission Services will supply nearly 94 percent of total financial reserves for the agency in FY 2017. At no point in the past 14 years has BPA experienced such a large disparity in business line contributions to total agency financial reserves. Arthur, BP-18-E-MS-12, Exhibit 12, at 18. The current status quo policy has allowed for Power Services financial reserves to reach these very low levels and, more importantly, would require no rate action to increase them unless they fall below \$0.

The combination of these factors—(1) that financial reserves *have* declined dramatically for Power Services over recent years, (2) that a persistent imbalance in business line contributions to agency financial reserves has occurred over multiple years since 2010, (3) that BPA’s status quo policy requires no increase in financial reserves for Power Services unless they fall below \$0, and (4) that the imbalance is increasing, with almost 94 percent of the financial reserves BPA will hold for FY 2017 being supplied by Transmission Services—shows that the present imbalance is not a “temporary imbalance” that will naturally correct itself. Far from it, these factors show that the imbalance has moved toward “a persistent reliance (*i.e.*, over multiple rate periods with one business line seemingly excused from contributing to the agency’s financial reserves and with no evidence of eventual self-correction),” which can become inequitable if provisions are not put in place to correct such reliance. Harris *et al.*, BP-18-E-BPA-33, at 49, 98. Hoping that the reserves imbalance will self-correct as a result of better financial results is not a sound policy or consistent with sound business principles. 16 U.S.C. § 838g (2015).

ICNU argues that Staff’s proposed IRPL and Good Year Ratchet—features of Staff’s Initial Proposal—do not support the equity objective as neither “drive Staff’s goal to raise power reserves to transmission reserves levels.” ICNU Br., BP-18-B-IN-01, at 24. ICNU’s brief misunderstands these features of the FRP’s implementation, including the fact that the IRPL would not guarantee a 3 percent rate increase, Harris *et al.*, BP-18-E-BPA-33, at 62, and that no element of the FRP requires BPA to “raise power reserves to transmission reserves levels,” *see* Harris *et al.*, BP-18-E-BPA-17, at 22 (describing lower thresholds). However, BPA need not resolve these misunderstandings as neither the IRPL nor the Good Year Ratchet features of Staff’s proposal will be adopted in this Final ROD. *See* Issue 6.6.4.3 (phase-in).

Nonetheless, ICNU uses Staff’s statements regarding the Good Year Ratchet to argue that the evidence in the record, and evidence supplied by Staff, demonstrates “that power reserves levels are expected to organically rebound, without the artificial tinkering of Staff’s proposed FRP mechanics.” ICNU Br., BP-18-B-IN-01, at 25. For instance, ICNU notes that “two-thirds’ of [Power Services’] reserves increase goal would already have been achieved in this manner, simply by capturing power reserves increases that *naturally occurred* in recent years.” *Id.* (emphasis added).

ICNU’s assertion that power financial reserves levels are expected to organically rebound is incorrect. Financial reserves could, of course, increase or decrease over the rate period as BPA’s revenues and costs vary from the rate case forecasts. See Section 6.2.4 (how financial reserves accumulate); Section 6.2.5 (how financial reserves decline). But there is nothing in the record to suggest that financial reserves will “organically” rebound, or that the current imbalance in business line contributions to agency reserves is self-correcting. BPA establishes rates to recover its costs only; thus revenues match expenses and cash flow over the rate period is expected to be \$0. Thus, from a ratemaking perspective, financial reserves are not expected to increase or decrease over the rate period, but rather stay the same. (Indeed, if BPA *knew* its financial reserves would increase as a result of “organic” changes in its costs or revenues, it would *include* that change in its cost and revenue forecasts when setting its power rates.)

Under the status quo policy, BPA only plans to increase financial reserves (through rate actions) if they are insufficient to meet the 95 percent TPP standard, which means they would have to be below \$0 for Power Services. Harris *et al.*, BP-18-E-BPA-17, at 12. The expected value for Power Services’ financial reserves at the end of 2017 is \$28 million, above \$0, and in that case, BPA would take no additional rate action for FY 2018 to increase its financial reserves to meet the TPP standard. See Power and Transmission Risk Study, BP-18-FS-BPA-05, at 72.

(To the extent ICNU relies on Staff’s “expected values” for its assertion that financial reserves *will* naturally rebound, BPA has fully responded to ICNU’s misunderstanding of the term “expected value” in Issue 6.4.3.2.4.)

More generally, ICNU misunderstands Staff’s testimony regarding financial reserves levels as it relates to the Good Year Ratchet. ICNU Br., BP-18-B-IN-01, at 25. Although BPA is not adopting the Good Year Ratchet in this Final ROD, see Issue 6.6.4.3.1 (phase-in), a description of this mechanism is important to understand the context of the statements cited by ICNU. The Good Year Ratchet was designed to capture growth in financial reserves from good years, and hold on to that level of financial reserves during bad years, thereby allowing financial reserves for Power Services to grow over time to Power Services’ lower threshold of \$300 million. *Id.* at 39-40. For example, if BPA ended a fiscal year with \$50 million in financial reserves for Power Services, the Good Year Ratchet would set the CRAC threshold to \$50 million. That threshold could never decrease, but only increase. *Id.* at 40. In a subsequent rate case, if Power Services’ financial reserves *increased* to \$75 million, the Good Year Ratchet would set the new CRAC threshold for Power Services to \$75 million. If financial reserves thereafter *decreased* to \$45 million, Power Services would not lose financial reserves (by the end of the fiscal year) because the CRAC would increase power rates to generate additional financial reserves to return to the CRAC threshold (*e.g.*, \$75 million). Thus, the Good Year Ratchet was a driving force of

Staff's Initial Proposal because it ensured that Power Services' financial reserves could only go higher—never lower—than the prior rate period. *Id.*

ICNU asserts that Staff's support of the Good Year Ratchet shows that "naturally occurring power reserves level increases" will "fully answer customer concerns regarding 'equity' problems between business lines." ICNU Br., BP-18-B-IN-01, at 25. ICNU also asserts that "according to Staff," two thirds of the proposed financial reserves goal would have been achieved simply by capturing power reserves increases that naturally occurred. *Id.* ICNU, however, misunderstands the Good Year Ratchet and the importance of this feature in Staff's testimony. Staff was clear that the Good Year Ratchet addressed the imbalance between the business lines by *capturing* Power Services' financial reserves from a good year's financial performance, and then *holding on* to those financial reserves by not allowing them to be consumed without replenishment. Harris *et al.*, BP-18-E-BPA-33, at 100. It was within that context that Staff emphasized the "replenishing power" of the Good Year Ratchet through Power Services' natural fluctuations in its revenues. *Id.* at 102. Staff explained that the Good Year Ratchet was key:

Moreover, the feasibility of our proposal can also be demonstrated through Power's historical financial reserves performance from FY 2013 through FY 2015. During that time, Power's financial reserves grew by approximately \$200 million. *Had the Good Year Ratchet been in effect during this period, the CRAC threshold would have increased by approximately two-thirds of the financial reserves goal included in our FRP proposal.* This would have been achieved with the Good Year Ratchet alone, without base rate increases, and in only two years.

Id. at 45-46 (emphasis added).

As the above text makes clear, Staff did not agree that the status quo would naturally and organically right-size the business lines' contributions to agency reserves in the absence of a feature like the Good Year Ratchet. Instead, Staff noted that the status quo dynamic, which contains no lower thresholds for financial reserves for either business line, was "not sustainable" because it permitted Power Services' financial reserves to be consumed all the way to \$0 and allowed to remain at \$0. Harris *et al.*, BP-18-E-BPA-17, at 12; Harris *et al.*, BP-18-E-BPA-33, at 3. This is very nearly what happened in January of 2017, when projected Power Service reserves fell to an estimated level of \$2 million before Power Services engaged in extensive cost cutting. Harris *et al.*, BP-18-E-BPA-33, at 4; *see also* Harris *et al.*, BP-18-E-BPA-33, Attachment 1, at 15. Far from "fully answer[ing]" the concerns over inequity, ICNU Br., BP-18-B-IN-01, at 25, Staff rightly found that the status quo practice perpetuates equity problems by requiring BPA to "indefinitely hold[] onto the financial reserves of whichever business line has cash until the revenue situation of the Agency improves." Harris *et al.*, BP-18-E-BPA-33, at 36.

Moreover, even if the downward trend in Power Services' financial reserves were expected to reverse itself, equity considerations would still support developing a financial reserves policy. As explained extensively in the record, BPA's current policies do not set minimum levels of financial reserves for either business line other than for purposes of TPP support. Harris *et al.*,

BP-18-E-BPA-17, at 10-12. Thus, it is entirely possible that BPA could have sufficient financial reserves for TPP standard purposes, but insufficient financial reserves to support other high value agency objectives, like maintaining the agency’s credit rating. *Id.* at 10-16. This is because “[t]he TPP standard is simply not designed to address credit rating risks.” *Id.* at 16. Current policies would allow Power Services’ financial reserves to be reduced to \$0 and no BPA policy or practice would require that any additional action be taken. *Id.* at 12. In this instance, BPA would need to rely solely on Transmission Services’ financial reserves to support the agency’s credit rating. *Id.*

As Staff explained, the lack of a policy on BPA’s financial reserves not only permits the imbalance between the business lines to continue unabated, but compounds it by allowing “one business line [to] use all of its financial reserves, leaving BPA no choice but to ‘lock in’ the other business line’s financial reserves to support the agency’s credit rating.” Harris *et al.*, BP-18-E-BPA-33, at 71. BPA fundamentally does not agree that it is prudent or reasonable to maintain a policy paradigm that permits one business line to contribute minimally to the agency’s financial reserves, while another business line contributes most, if not all of the financial reserves. Both business lines rely on and use BPA’s credit rating to support their respective capital programs and, consequently, both business lines should be required to contribute to the financial reserves of the agency to support BPA’s credit rating. This requirement does not exist under the status quo policies, but would under a financial reserves policy. See Section 6.6.4 (final FRP).

Decision

The record supports a finding that there is an equity issue between the business lines that should be addressed through a financial reserves policy.

Issue 6.4.4.2.2

Whether declines in high levels of agency financial reserves represent a decline in excess financial reserves and, therefore, are not indicative of an imbalance in business line contributions to agency financial reserves.

Parties’ Positions

ICNU argues that there is no “equity” issue to be redressed through a financial reserves policy. ICNU Br., BP-18-B-IN-01, at 21-22. ICNU’s second reason why it believes that the FRP cannot be justified on equity considerations is as follows:

[R]ecent declines in high levels of agency reserves represent a decline in *excess* reserves, which Staff and transmission customers all agree should not be held by the agency. This means that recent declines do not represent a “doomsday” equity problem which must be solved immediately.

Id. at 22.

BPA Staff's Position

The declines in agency financial reserves are not attributable to the “shedding” of excess reserves. The only rate mechanism that permits the distribution of excess reserves is the DDC that applies to Power rates only. Harris *et al.*, BP-18-E-BPA-17, at 11.

Evaluation of Positions

ICNU's second major contention is that recent declines in agency financial reserves levels are properly characterized as the shedding of “excess reserves,” which ICNU claims Staff and transmission customers agree should not be held by the agency. ICNU Br., BP-18-B-IN-01, at 26. ICNU notes that BPA met the agency target of \$600 million in FY 2016, thereby indicating that all declines in reserves prior to FY 2016 were not actually a problem. *Id.* The problem with the 2008-2016 period, ICNU contends, was that BPA held on to excess or unnecessary agency reserves levels, instead of using them for “higher value purposes.” *Id.* ICNU then asserts that the decline in agency reserves is properly attributable to shedding excess reserves levels, and as such, “blame” or “fault” cannot be reasonably attributed to Power Services for not carrying its equitable “share” of those previously excess reserves levels. *Id.* at 27.

ICNU's argument is difficult to understand and subject to several interpretations. ICNU appears to be arguing that BPA should consider declines in financial reserves above Staff's proposed target of \$600 million as not “problematic” because it is simply the “shedding” of “excess reserves.” *Id.* at 26. If this is what ICNU is attempting to argue, its argument makes little sense. BPA did not have agency financial reserves thresholds or policies determining when financial reserves were “excess” in FY 2016 or any prior year. The only metric BPA had in effect in FY 2016 to determine whether reserves were “excess” was Power Services' DDC, which allowed Power Services' reserves in excess of \$750 million to be returned to power customers. Harris *et al.*, BP-18-E-BPA-17, at 11. The DDC has never triggered and, thus, was not the basis for any reductions in financial reserves prior to FY 2016. As such, the loss of financial reserves prior to FY 2016 could not be attributable to the “shedding” of excess reserves pursuant to any policy, but instead the losses were associated with differences between expected revenues and costs and actual revenues and costs.

Alternatively, ICNU may be positing a hypothetical. That is, ICNU may be arguing that since BPA has now established a target level of financial reserves (*e.g.*, \$600 million), prior losses in financial reserves above this amount should be considered distributions of “excess” financial reserves that are not relevant to the current policy development. As a result, ICNU may be contending that had the FRP been in effect prior to FY 2016, Power Services' current financial reserves position would not be improper (*i.e.*, “‘blame’ or ‘fault’ cannot be reasonably attributed . . . to the power business line” ICNU Br., BP-18-B-IN-01, at 27) because the decline in Power Services' financial reserves would have been eligible for repurposing as “excess” financial reserves in any event.

If this is ICNU's claim, the argument remains flawed. BPA agrees that financial reserves in excess of the agency upper threshold are eligible for repurposing for other, higher value

purposes. Harris *et al.*, BP-18-E-BPA-33, at 145; see also Section 6.6.4.5 (upper threshold). However, ICNU’s analysis fails to note that the FRP definition of “excess” financial reserves is a *two-part* test: (1) the business line has financial reserves above *its* upper threshold (*e.g.*, 120 days cash threshold); *and* (2) BPA has total financial reserves exceeding the agency upper threshold (*e.g.*, 90 days cash). *Id.*; see also Section 6.6.4.5 (upper threshold). Power Services’ upper threshold is \$609 million, and the agency’s upper threshold is \$606 million. Power and Transmission Risk Study, BP-18-FS-BPA-05, at 128, Tables 5 and 6. Under these criteria, during the 2008–2016 period, the only financial reserves that would have been eligible for Power Services to repurpose as “excess” would have been the financial reserves attributed to Power Services in 2008, when Power Services had \$852 million. Arthur, BP-18-E-MS-12, Exhibit 12, at 18. All other financial reserves would *not* have been eligible for Power Services to repurpose as “excess” financial reserves.

BPA is also confused by ICNU’s reference to the concept of “shedding excess reserves” in the absence of a financial reserves policy. ICNU Br., BP-18-B-IN-01, at 26-27. The term “excess reserves” presumes that financial reserves are being measured against a standard that establishes a normal level of financial reserves. But, as Staff has argued throughout the record, there is no such standard under the status quo. Harris *et al.*, BP-18-E-BPA-17, at 20 (“the 95 percent TPP implementation does not include a methodology for calculating an upper limit on the amount of financial reserves BPA should hold before taking other actions with the funds.”); Harris *et al.*, BP-18-E-BPA-33, at 44 (“in the absence of a financial reserves policy, BPA lacks policy guidance on what actions to take when one business line holds a level of financial reserves that is in excess of TPP or operational needs but nonetheless necessary to support BPA’s credit rating.”) The only measure for financial reserves between the business lines is the TPP standard, which allows Power Services’ financial reserves to decline to \$0, and Transmission Services’ financial reserves to decline to \$230 million. Harris *et al.*, BP-18-E-BPA-17, at 12. The concept of “excess reserves” does not exist under the TPP standard. *Id.* at 20.

Another interpretation of ICNU’s argument may be that ICNU contends that a decline in agency reserves should be “attributable” to shedding “excess reserves” such that any decline in financial reserves is always an act of “shedding excess reserves levels.” ICNU Br., BP-18-B-IN-01, at 27. As ICNU notes:

The purpose of the foregoing discussion is to demonstrate that *alleged declines in agency reserves are properly attributable to shedding excess reserves levels*, which no party believes should be (or should have been) held anyway. In turn, if *recent declines are attributable to excess reserve holdings*, then “blame” or “fault” cannot be reasonably attributed, by Staff or transmission customers, to the power business line for not carrying its equitable “share” of those previously *excess* reserves levels, such that a form of “recompense” should be implemented now via the FRP.

Id. (emphasis added).

Following the above description, Power Services could lose *all* its financial reserves (as it was essentially projected to do in January 2017), Harris *et al.*, BP-18-E-BPA-33, Attachment 1, at 15

(projected \$2 million associated with Power Services in EOY 2017), and no action would (or should) be taken because this would simply be Power Services “shedding excess reserves.” ICNU Br., BP-18-B-IN-01, at 27. Stated another way, the definition of “excess reserves” appears to mean anything above \$0 for Power Services so long as the agency is above \$600 million. If that is what ICNU intends to convey, then its argument further supports BPA’s determination that there is an equity issue between the business lines that should be addressed through a financial reserves policy. If all of Power Services’ financial reserves in excess of \$0 could be deemed “excess reserves,” then Power Services could avoid contributing to the agency’s financial reserves by simply retaining no financial reserves. This would place the full and unbridled obligation of maintaining financial reserves for credit support on Transmission Services.

In this regard, it is significant that ICNU is not clear whether the same definition of “excess reserves” would apply to Transmission Services. Indeed, such a definition could not apply because, if Transmission Services were to shed its “excess reserves” to the minimum level necessary to meet the 95 percent TPP standard, BPA would hold low financial reserves that would be inadequate to support the agency’s credit rating. Harris *et al.*, BP-18-E-BPA-17, at 16 (“\$230 million is equivalent to 34 days cash on hand, which is close to the level Moody’s has specifically warned against.”) Thus, BPA would have to apply a different definition of “excess reserves” for Transmission Services in order to ensure the agency held sufficient financial reserves to support BPA’s credit rating. In doing so, however, BPA would be perpetuating the very equity concerns that it seeks to address through the FRP: “a persistent reliance and inequitable imbalance . . . with one business line contributing more than its reasonable share of financial reserves to support the Agency’s credit rating.” Harris *et al.*, BP-18-E-BPA-33, at 71.

The foregoing discussion, which works to understand and address ICNU’s after-the-fact definition of “excess reserves,” highlights the value of a financial reserves policy that sets clear *prospective* parameters around when financial reserves are excess and when they are not. A financial reserves policy can provide a consistent, transparent, and financially prudent method for determining upper and lower financial reserves thresholds for Power Services, Transmission Services, and the agency. *Id.* at 4. The policy also guides the actions BPA may take when financial reserves levels either fall below the lower threshold or exceed an upper threshold. *Id.*

Decision

The declines in past levels of agency financial reserves were not the result of “shedding” excess financial reserves and are therefore indicative of an imbalance in business line contributions to agency financial reserves.

6.4.5 Liquidity and a Financial Reserves Policy

Issue 6.4.5.1

Whether a financial reserves policy would support BPA's liquidity.

Parties' Positions

ICNU argues that BPA does not need to develop a financial reserves policy to support the agency's liquidity. ICNU Br., BP-18-B-IN-01, at 17. JP07 agrees, noting that liquidity "will continue to be addressed through the TPP standard even without adoption of a financial reserves policy." JP07 Br., BP-18-B-JP07-01, at 5-6. JP06 similarly argues that the TPP standard already provided BPA with all of the liquidity to run its business. JP06 Br., BP-18-B-JP06-01, at 3. Kalispel supports JP06's arguments and positions. Kalispel Br., BP-18-B-KT-01, at 2-3.

M-S-R and JP02 argue that a financial reserves policy would support BPA's liquidity. JP02 Br., BP-18-B-JP02-01, at 18; M-S-R Br., BP-18-B-MS-01, at 5-6, 9-10, 16.

BPA Staff's Position

BPA's current TPP standard ensures that BPA has sufficient liquidity to meet its Treasury payment obligations. Harris *et al.*, BP-18-E-BPA-33, at 32. Financial reserves are a primary and preferred source of liquidity. Harris *et al.*, BP-18-E-BPA-17, at 18. The FRP would raise the minimum level of financial reserves BPA holds and, therefore, would benefit BPA's liquidity. Harris *et al.*, BP-18-E-BPA-33, at 32.

Evaluation of Positions

As Staff stated in its testimony, financial reserves are a primary source of liquidity for BPA and most other entities. Harris *et al.*, BP-18-E-BPA-17, at 18. Liquidity ensures that bills can be paid on time. *Id.* Liquidity allows BPA to fill financial gaps when expenses are paid before revenues are received or when expenses are simply greater than revenues. *Id.* at 3. In that way, financial reserves provide a financial buffer against timing differences between receipts and disbursements and against short-term and long-term financial uncertainty. *Id.* The more financial reserves an entity has, the more liquidity it has, and thus the greater security an entity has to pay all its bills and the better able it is to withstand unexpected adverse circumstances. *Id.* at 18.

Staff notes that BPA has three primary forms of liquidity: (1) financial reserves; (2) the Short-Term Treasury Borrowing Note (Treasury Facility); and (3) the ability to defer principal and interest payments to the Treasury. *Id.* at 4. The Treasury Facility is a line of credit BPA has with the Treasury. *Id.* The line of credit can be used to fund expenses recognized under the Northwest Power Act and is limited to a maximum amount outstanding of \$750 million or the amount of BPA's remaining borrowing authority, whichever is smaller. *Id.* at 4-5. The maximum borrowing term is two years. *Id.* at 5. BPA pays an interest rate from the applicable U.S. Agency yield curve corresponding to the borrowing term. *Id.*

BPA meets the respective liquidity needs for its two business lines in different ways. Liquidity for Transmission Services is currently provided solely by financial reserves. *Id.* at 9. At the end of Fiscal Year 2016, Transmission Services had \$444 million in financial reserves. Harris *et al.*, BP-18-E-BPA-33, at 97 (citing Arthur, BP-18-E-MS-12, at 23-24). Liquidity for Power Services, in contrast, comes from both financial reserves and the \$750 million Treasury Facility. Harris *et al.*, BP-18-E-BPA-17, at 8-9. If financial reserves for Power Services are exhausted, BPA can institute a rate increase—a CRAC—to begin to replenish financial reserves to \$0. *Id.* at 11. While, for purposes of BPA’s TPP standard, both forms of liquidity are adequate, financial reserves are BPA’s primary and preferred source of liquidity. *Id.* at 18. As noted, borrowing under the Treasury Facility needs to be repaid within two years. *Id.* Deferred portions of a Treasury payment become a payment obligation for the next fiscal year. *Id.* Thus, those two forms of liquidity would produce rate pressure for ratepayers directly and soon. *Id.* Financial reserves, in contrast, “do not have to be paid back,” although BPA will not be able to rely on those financial reserves to meet future liquidity needs until they have been replenished. *Id.* at 18-19. Financial reserves are a subset of, and BPA’s primary source of, liquidity and, therefore an area that would be supported by a financial reserves policy. Harris *et al.*, BP-18-E-BPA-33, at 32.

JP02 agrees that financial reserves support liquidity. JP02 Br., BP-18-B-JP02-01, at 18. JP02 also supports Staff’s position that financial reserves are BPA’s primary and preferred source of liquidity. *Id.* at 19, 20-21. JP02 notes that Power Services’ liquidity today relies on the Treasury Facility, and that “the Treasury facility is also limited to the size agreed upon with the Treasury.” *Id.* at 19. JP02 also states that financial reserves are superior to the Treasury Facility because they do not have to be repaid on a short, fixed schedule, do not depend upon reaching an agreement with the Treasury for such borrowing, and do not reduce the available BPA borrowing authority from the Treasury for capital investment. *Id.* at 41-43.

M-S-R notes that, while financial reserves support BPA’s credit rating, that rating is merely a measure of the strength of the agency’s financial performance. M-S-R Br., BP-18-B-MS-01, at 1. M-S-R argues that the FRP is necessary to ensure that BPA retains sufficient financial reserves to operate consistent with sound business practices and to address uncertainties in operations and financial risks. *Id.* at 5-6, 9-10, 16. Those risks differ by business line, with Power Services experiencing significantly greater volatility. *Id.* at 1.

ICNU argues that the liquidity objective is “superfluous” because BPA’s current policies, in particular the TPP standard, already ensure adequate liquidity through the BP-18 rate period. ICNU Br., BP-18-B-IN-01, at 17. ICNU notes that Staff has admitted that the FRP is not required for BPA’s liquidity. *Id.* Thus, ICNU argues that liquidity is not a reason to develop a financial reserves policy.

Other parties make similar arguments. JP07 cites Staff’s testimony to argue “BPA’s liquidity is adequately addressed through existing mechanisms” and “will continue to be addressed through the TPP standard even without adoption of a financial reserves policy.” JP07 Br., BP-18-B-JP07-01, at 5-6. “BPA addresses liquidity through incorporation of the TPP standard into the financial reserves policy.” *Id.* at 6. JP06 similarly argues that the TPP standard already provides BPA with all of the liquidity needed to run its business. JP06 Br., BP-18-B-JP06-01, at 3.

As ICNU and the public power customers note, a financial reserves policy is not needed solely to support BPA's liquidity as determined under BPA's TPP standard. BPA agrees that the TPP standard is currently BPA's primary way of assessing its need for liquidity for each business line, for ensuring BPA's ability to make required payments, and ensuring the adequacy of BPA's current liquidity. Harris *et al.*, BP-18-E-BPA-33, at 32. BPA also agrees that it is not proposing the FRP to "solve a liquidity problem." *Id.*

At the same time, however, BPA disagrees that the FRP would "do nothing to benefit BPA's ability to ensure adequate liquidity." ICNU Br., BP-18-B-IN-01, at 17. The FRP is intended to establish a method for determining upper and lower action thresholds for each business line and for the agency as a whole. Harris *et al.*, BP-18-E-BPA-17, at 22. The lower and upper thresholds are used to determine when certain rate mechanisms are enacted within a rate period to support the stated policy objectives. *Id.* The FRP would create a paradigm that sets both a minimum amount of reserves (through the lower threshold) as well as a maximum amount of financial reserves (through the upper threshold). Both the lower and upper thresholds have an impact on BPA's financial reserves levels, and as such, it was appropriate for BPA to consider how the FRP would affect BPA's overall liquidity.

The FRP would create a minimum level of financial reserves for both business lines that determines when rate action would be taken to increase financial reserves. *Id.* at 22, 35. This minimum level would be higher than the minimum level under BPA's current practices. *Id.* at 35. A higher minimum level would increase the minimal level of financial reserves for BPA as an agency and, therefore, it would also increase the minimum liquidity. *Id.* That is, the FRP would increase financial reserves, which is BPA's preferred source of liquidity. *Id.* at 18; Harris *et al.*, BP-18-E-BPA-33, at 32 ("The FRP supports BPA's liquidity by raising the level of financial reserves BPA intends to maintain.")

As noted above, BPA has three sources of liquidity: financial reserves, the Treasury Facility, and deferring Treasury payments. Harris *et al.*, BP-18-E-BPA-17, at 4. BPA prefers financial reserves over the other two forms of liquidity for the common sense reason that it does not have to be paid back. *Id.* at 18. Drawing on the Treasury Facility for liquidity, that is, borrowing from the Treasury to pay a present expense, requires that such borrowing be repaid within the next two years. *Id.* at 5. This practice, in effect, burdens future ratepayers for the expenses that BPA has incurred in the present rate period and adds additional interest costs. Thus, to the extent BPA has a choice in sourcing its liquidity, using cash or using debt, using cash (financial reserves) would be the preferred source of that liquidity. *Id.* The FRP would increase BPA's financial reserves, and consequently, increase the available liquidity. Harris *et al.*, BP-18-E-BPA-33, at 32. Thus, having a choice in the source of liquidity is an important benefit of a financial reserves policy.

In addition, the Treasury Facility is limited by both BPA's borrowing authority and negotiations with Treasury. The Treasury Facility is a component of BPA's borrowing authority, and BPA's borrowing authority is capped by legislation. As Staff explained in a data response to ICNU: "The Treasury Facility is not capped by legislation. The Treasury Facility is capped at \$750 million under the terms of the facility BPA has negotiated with the Treasury. BPA's total borrowing authority is capped by legislation." Mullins, BP-18-E-IN-01-AT01, at 26; *see also*

Harris *et al.*, BP-18-E-BPA-17, at 19 (“Use of the Treasury Facility is . . . limited to the amount of remaining borrowing authority.”) Another limitation is the term of the Treasury Facility itself. The Treasury Facility is renegotiated annually with the Treasury and “is limited to the size agreed on with the Treasury . . .” Harris *et al.*, BP-18-E-BPA-17, at 19; *see also* Mullins, BP-18-E-IN-01-AT01, at 37 (“Negotiation of the terms of that agreement and any ‘obligations’ including the Treasury Facility issued thereunder have been and are expected to be an annual process tied to the federal fiscal year.”). Developing a financial reserves policy would help support liquidity by ensuring BPA has a prudent lower level of financial reserves in the event the Treasury Facility’s terms or availability change in the future.

Having additional sources of liquidity also makes good business sense and is consistent with a business-oriented philosophy. As stated earlier, under BPA’s current liquidity paradigm, Power Services’ financial reserves could go to zero. Harris *et al.*, BP-18-E-BPA-17, at 12; Harris *et al.*, BP-18-E-BPA-33, at 54. Very few, if any, businesses can sustainably operate without some sort of positive cash balance. Harris *et al.*, BP-18-E-BPA-33, at 54. This is true for BPA, BPA’s customers, retail customers of BPA’s customers, consultants, law firms, BPA’s customer representative organizations, and BPA’s competitors. *Id.* While BPA may have mechanisms in place to address its ultimate solvency, such as the TPP standard and access to the Treasury Facility, these features only set the bare minimum for financial reserves. *Id.* The TPP standard does not consider other reasons to hold financial reserves (such as to support BPA’s credit rating). A financial reserves policy, in contrast, would benefit BPA’s liquidity because it looks beyond the bare minimum amount of financial reserves needed for liquidity under the TPP standard (currently \$0 for Power Services) to the broader issue of the amount of financial reserves that BPA—as a prudent business and for credit support—should hold. *Id.*

In sum, the FRP would raise the minimum amount of financial reserves BPA will hold, which in turn supports BPA’s liquidity. As noted above, a financial reserves policy is not being developed to “solve a liquidity problem,” but developing such a policy would benefit BPA’s liquidity. Harris *et al.*, BP-18-E-BPA-33, at 32. The more financial reserves an entity has, the more liquidity it has, and thus the greater security the entity has to pay all its bills, and the better able it is to withstand unexpected adverse circumstances. Harris *et al.*, BP-18-E-BPA-17, at 18. With financial reserves, BPA is given a choice as to the source of its liquidity to address uncertainty and unexpected costs. *Id.* It can choose to consume its financial reserves, draw on the Treasury Facility, or some combination of the two. With no financial reserves, BPA has no choice but to draw on the facility and increase future rates. Harris *et al.*, BP-18-E-BPA-33, at 54 (“The use of debt can avoid or limit an immediate rate increase, but only at the expense of future ratepayers.”).

Decision

A financial reserves policy would support BPA’s liquidity.

6.4.6 Rate Stability and a Financial Reserves Policy

Staff explained that financial reserves also provide rate stability for both business lines. Harris *et al.*, BP-18-E-BPA-17, at 19. Financial reserves are accumulated when financial performance

is better than expected and the reserves are not obligated for a future specific purpose. *Id.* Reserves would then provide liquidity when financial results are worse than expected and, unlike the Treasury Facility or deferring a U.S. Treasury payment, would not have to be replenished unless financial policies guided them to be replenished. *Id.* Financial reserves may therefore allow BPA to forgo a rate increase that would otherwise have been necessary. *Id.*

Staff also acknowledged that the benefit of rate stability will generally be when financial reserves are “floating within the deadband of our proposed policy” Harris *et al.*, BP-18-E-BPA-33, at 40. As such, rate stability “would be fully realized when the lower threshold has been phased in.” *Id.* Staff acknowledges that until the phase-in is complete, “rate stability is somewhat impaired during the phase-in period.” *Id.*

The use of more than \$800 million in Power’s financial reserves over the last 10 years has provided significant rate stability in the aftermath of the financial crisis. Replenishing those financial reserves will support BPA’s financial health and provide rate stability in the future.

Parties generally acknowledge that a financial reserves policy, once fully implemented, would provide rate stability. M-S-R acknowledges that rate stability is one of the sound business purposes of financial reserves. M-S-R Br., BP-18-B-MS-01, at 5-6, 16. Powerex notes that financial reserves can be a source of rate stability, as shown by the decline in reserves over recent years. Powerex Br., BP-18-B-PX-01, at 2. JP07 agrees that “the goal[] of . . . rate stability [is] laudable and could be addressed with a sound and equitable financial reserves policy.” JP07 Br., BP-18-B-JP07-01, at 5. JP07’s concerns with the FRP’s impact on rate stability are discussed in Section 6.6.6 (FRP and policy objectives).

6.5 Objectives Used to Measure a Financial Reserves Policy

6.5.1 Overview of Objectives Staff Used to Measure the FRP

As noted in Section 6.4.1 (need for FRP), BPA must answer two questions in this case: (1) whether BPA would benefit from adopting a financial reserves policy; and (2) if so, what objectives should that policy meet?

Having answered the first question in Section 6.4.1 (a financial reserves policy should be developed), the second question BPA must address is what features that policy should include. Staff answered this question by developing a set of six objectives that the FRP should meet. Harris *et al.*, BP-18-E-BPA-17, at 21-36; Harris *et al.*, BP-18-E-BPA-33 at 42-103, 139-146. These are:

1. Maintain sufficient financial reserves levels to support BPA’s credit rating.
2. Ensure adequate liquidity throughout each rate period.
3. Maintain equity between business lines.
4. Establish prudent lower financial reserves thresholds and actions supporting objectives 1 and 2.

5. Establish prudent upper financial reserves thresholds so that financial reserves are efficiently redeployed for other high-value purposes.
6. Be compatible with BPA's existing 95 percent TPP standard.

Harris *et al.*, BP-18-E-BPA-17, at 24. Staff explained that “a policy that achieves these objectives will provide the region a prudent and sustainable framework from which to preserve the Agency’s financial health, while balancing the interest of BPA’s Power and Transmission customers.” Harris *et al.*, BP-18-E-BPA-33, at 43. Staff then explained how the specific FRP proposals in Staff’s initial and rebuttal testimony support meeting each of these objectives. Harris *et al.*, BP-18-E-BPA-17, at 35-36; Harris *et al.*, BP-18-E-BPA-33, at 42-103, 146-52.

ICNU contends that Staff’s objectives do not each “independent[ly]” justify adopting a financial reserves policy. ICNU Br., BP-18-B-IN-01, at 15. ICNU argues the sole purpose of the FRP is to support BPA’s credit rating. *Id.* ICNU also argues all of Staff’s other objectives are “superfluous,” “irrelevant” and “functionally useless.” *Id.* at 16, 20.

BPA responds to ICNU’s concerns below.

Issue 6.5.1.1

Whether each policy objective identified by Staff must independently justify the need for a financial reserves policy.

Parties’ Positions

ICNU notes that Staff offered “six general objectives” in support of its proposed FRP. ICNU Br., BP-18-B-IN-01, at 15. However, ICNU asserts that “the sole purpose of the FRP essentially boils down to a single objective: ‘Maintain sufficient financial reserves levels to support BPA’s credit rating.’” *Id.* (citing Mullins, BP-18-E-IN-01, at 39-40, quoting Harris *et al.*, BP-18-E-BPA-17, at 24; *see also* ICNU Br. Ex., BP-18-R-IN-01, at 11-13). To make the point that BPA’s sole reason for adopting the FRP is the credit rating objective, ICNU argues that adoption of the FRP cannot be “rationally grounded” on any of the other five objectives propounded by Staff, at least on “an independent basis or absent a demonstration that another objective is not first deemed to be necessary before a second, ‘supporting’ or dependent/ derivative objective is later factored.” *Id.* ICNU further argues that the rate pressure from the FRP cannot be supported by “the lowest possible rates to consumers consistent with sound business principles” standard, so long as those “same rate increases are at best shown to be discretionary or gratuitous, and are not demonstrated to provide independent benefits justifying their costs, relative to any stand-alone consideration of these other five ‘objectives.’” *Id.* at 15-16.

ICNU also argues BPA has mischaracterized its arguments. ICNU Br. Ex., BP-18-R-IN-01, at 11-12. ICNU contends that BPA’s car analogy is not supportive of BPA’s position. *Id.* at 12-13.

BPA Staff's Position

Staff's six objectives are appropriate evaluative criteria for determining the FRP. Harris *et al.*, BP-18-E-BPA-17, at 24, 35-36; Harris *et al.*, BP-18-E-BPA-33, at 42-103, 146-52.

Evaluation of Positions

ICNU appears to be arguing that, of the six objectives Staff identified that the FRP should meet, the only salient objective that justifies the need for the FRP is that regarding the credit rating (which ICNU contends is inadequate to support the FRP). *Id.* at 15. ICNU believes the five remaining objectives are derivative of the credit rating objective and, therefore, the decision to adopt the FRP "cannot be rationally grounded" in the remaining objectives. *Id.* Because these other objectives do not "independently justify FRP-based rate increases," ICNU contends Staff's "overall justification for the FRP" is diminished. *Id.* at 16 (emphasis omitted).

As demonstrated by the record in this proceeding, Staff has not justified the FRP solely on the credit rating support objective. *See* Section 6.4 (need for FRP). Nonetheless, this objective by itself would support BPA's decision to develop the FRP. As noted above in Section 6.4.3 (credit rating and FRP), BPA relies heavily on the third-party market for its capital projects and receives favorable interest rates from those markets because of its strong credit rating. Congress intended BPA to take reasonable business steps to fulfill its statutory mission, which includes developing policies, like a financial reserves policy, to ensure BPA's long-term financial health and financial independence. Harris *et al.*, BP-18-E-BPA-33, at 6. Even assuming *arguendo* that no other BPA policy objective were sustained, BPA's decision to develop a financial reserves policy to ensure a minimal level of financial reserves to support BPA's business and maintain its credit rating would support developing such a policy. *Id.* at 7-8.

Turning to ICNU's more general contention that each policy objective must "independently justify" the FRP, ICNU misunderstands and mischaracterizes Staff's objectives. As discussed above, Staff's six objectives were established to create a set of evaluation criteria to measure what the FRP should achieve. Harris *et al.*, BP-18-E-BPA-17, at 24; *see also* Harris *et al.*, BP-18-E-BPA-17, at 35-36 (summarizing how "the Financial Reserves Policy meets [the six] objectives.") ICNU's characterization of Staff's objectives conflates Staff's justification of the need for the policy with the objectives a policy (once determined to be needed) should achieve. Harris *et al.*, BP-18-E-BPA-33, at 48. Stated another way, since the six objectives are designed to address *what* the policy should *do*, they of course would be irrelevant if BPA concluded that developing a policy would not be beneficial. Staff pointed this out in rebuttal testimony:

ICNU generally opposes the need for the FRP to begin with, therefore many of the objectives we identified, such as the objective to set prudent upper and lower thresholds (Objectives 4 and 5) or compatibility with TPP (Objective 6), may appear "superfluous" or "irrelevant" to ICNU.

Id. at 47.

ICNU argues in its Brief on Exceptions that BPA has mischaracterized ICNU's position. ICNU Br. Ex., BP-18-R-IN-01, at 11. ICNU contends it did not argue that each of BPA's six objectives

must independently justify the FRP. *Id.* BPA’s understanding of ICNU’s position is from the following paragraph in ICNU’s initial brief:

In this sense, the importance of considering and then rejecting objectives which do *not* independently justify an immediate adoption of the FRP is a corollary to Staff’s “gainsay” logic. Specifically, Staff has reasoned that, regarding a particular factor relevant to the first of its objectives (which will be discussed in more detail later), “the existence of other important credit rating factors does not *gainsay* the importance of financial reserves.” The flipside to Staff’s “gainsay” rationale is as follows—the significance attached to a single FRP objective (e.g., supporting BPA’s credit rating) also does not “gainsay” or diminish the significance (or lack thereof, in this circumstance) that ought to be attached to multiple FRP objectives. Therefore, evidence establishing that the other five “objectives” are superfluous, irrelevant, or at best “supporting” or derivative objectives that cannot *independently* justify FRP-based rate increases will necessarily diminish the overall justification for the FRP.

ICNU Br., BP-18-B-IN-01, at 16 (emphasis in original) (citation omitted).

BPA’s understanding of ICNU’s point comes from the first sentence and the last sentence of this paragraph. Both sentences express the idea that ICNU’s ability to “reject” objectives that do not “independently justify” the adoption of the FRP will injure BPA’s justification of the FRP. Notably, the final sentence in this paragraph begins with the word “therefore,” which typically signals a conclusion. *Id.* at 16. Thus, in simple terms, ICNU appears to argue that, by showing that the five other objectives do not “independently justify” adopting the FRP and its rate consequences, ICNU will also “diminish” BPA’s basis for adopting the FRP. BPA responds to this assertion in this section.

In its Brief on Exceptions, ICNU explains it was actually arguing the following:

Properly considered, ICNU’s contention is that the record plainly demonstrates that five of Staff’s six objectives flow from the primary or central objective—that is, BPA would not be considering the adoption of such a costly and burdensome FRP unless the agency believed it was necessary to support its credit rating. The other five objectives are essentially add-ons.

ICNU Br. Ex., BP-18-R-IN-01, at 11-12. ICNU’s new characterization of its argument does not demonstrate that BPA mischaracterized ICNU’s original position. Indeed, BPA reads the above paragraph as making essentially the same point ICNU made in its original brief: the only basis for the FRP is to support BPA’s credit rating and the other five objectives identified by Staff are irrelevant. The only difference in ICNU’s Brief on Exceptions argument is that it omits any reference to the idea that rejecting the other objectives diminishes BPA’s overall decision to adopt the FRP. If it is ICNU’s intent in its Brief on Exceptions to waive its prior argument (or clarify that it does not believe that rejecting the other objectives diminishes BPA’s decision to adopt the FRP), then BPA accepts ICNU’s clarification. If this is not ICNU’s point, then BPA’s arguments and characterization of ICNU’s position were proper.

ICNU argues that if the criteria used by the Administrator to evaluate a policy have no apparent connection to the need for that policy in the first place, the evaluative criteria are functionally useless. ICNU Br., BP-18-B-IN-01, at 20. BPA disagrees. Using the analogy of a decision to purchase a new car, Staff’s testimony can be viewed as asking two questions (1) whether to buy a new car; and (2) if so, what objectives (or features) should that car contain. Staff’s testimony established the “reasons to buy a new car” under the heading in its testimony entitled “need for financial reserves policy.” Harris *et al.*, BP-18-E-BPA-17, at 10-21; Harris *et al.*, BP-18-E-BPA-33, at 8-42. The testimony is not addressing specific features of the policy just yet; it is simply asking the foundational question of whether a car should be purchased. In this instance, Staff would be identifying whether a new car was needed (*i.e.*, will existing modes of transportation suffice) and what needs would be fulfilled with a new car (*e.g.*, could carry more people, better fuel efficiency, newer technology).

If the decision to buy a car is made, Staff’s six objectives can be viewed as providing a set of criteria that should be considered when making the purchase. Harris *et al.*, BP-18-E-BPA-17, at 24. These objectives help to determine what type of car to buy and what features that car should have. Thus, the policy objectives would set guidelines for the new car, such as whether it should get greater than 30 miles per gallon, be large enough for a family of six, fit in the existing garage, or have satellite radio. Certainly, some of these objectives have a connection to the original decision to buy the car (such as fuel efficiency and miles per gallon), but since the decision to proceed has been made, *other* factors relevant only to a new car would be considered (would it fit in the existing garage).

ICNU’s response is that five of the six evaluative criteria Staff identified in its objectives are irrelevant because those factors do not “independently justify” the need for a financial reserves policy. ICNU Br., BP-18-B-IN-01, at 15-16. This is like arguing that a new car should not be purchased because the features being considered for that new car (like satellite radio) do not “independently justify” the purchase.

ICNU criticizes the above analogy, calling it “ironic[]” and objecting that this illustrative family seems to be treating primary and secondary motives as co-equal. ICNU Br. Ex., BP-18-R-IN-01, at 12. ICNU asserts that no rational real-world family would weigh all of these criteria equally. *Id.* ICNU’s criticism misunderstands the analogy and does not reference the two questions the family considered. *See id.* ICNU claims that the primary objective is to have a vehicle that moves and if the car “has no engine,” no secondary objectives would entice the family to make the purchase. *Id.*

The point of the analogy, which ICNU’s brief ignores, is that there are threshold questions that ask *whether* to take an action, and post-threshold questions that guide the type of action to take. The question asked in this case is *whether* to develop a financial reserves policy, and if so, *what* features that policy should contain. ICNU has consistently conflated the reasoning for the second question with the first question. They are related, but not the same, as demonstrated by the above car-purchase analogy.

For the above reasons, ICNU’s contention that the evaluative objectives must “independently justify” the FRP is misplaced. BPA agrees with ICNU that if there is no basis for a financial

reserves policy, then the six objectives Staff identified in its testimony (to guide the policy's development) would be "superfluous," "irrelevant" and "functionally useless." *Id.* at 16, 20. Thus, for example, if BPA had concluded that a financial reserves policy would not benefit the agency's credit rating, liquidity, equity, or rate stability, then it would have been nonsensical for BPA to nevertheless adopt a financial reserves policy solely for the purpose of developing a "prudent lower threshold" (Objective 4). *See Harris et al.*, BP-18-E-BPA-17, at 24.

In that same way, however, the converse of this point would also be true. That is, if there *is* a basis for developing a financial reserves policy, then the six objectives Staff identified would be relevant and necessary in determining the provisions of that policy. In that instance, ICNU's argument that the six objectives should "independently justify" the FRP would be nonsensical because the underlying basis for the policy (and Staff's six objectives) would have been established. ICNU Br., BP-18-B-IN-01, at 15-16. The question would then turn from *whether* the policy should be developed to *what* it should include. In that context, Staff's six objectives are relevant and useful.

Staff's description of the latter three of its six objectives makes apparent the evaluative nature of those objectives. ICNU spends seven pages of its Initial Brief arguing that Staff has not established that Objective 4 ("establish prudent lower financial reserves thresholds and actions supporting objectives 1 and 2"), Objective 5 ("establish prudent upper financial reserves thresholds so that financial reserves are efficiently redeployed for other high-value purposes"), and Objective 6 ("compatibility with BPA's existing 95 percent TPP standard") independently "justify" the FRP. *Id.* at 33-39. As the verb at the beginning of each objective makes clear, the objectives were intended to *be evaluative of a* financial reserves policy, not an *independent justification for* a financial reserves policy. *Harris et al.*, BP-18-E-BPA-17, at 24. As ICNU points out, these objectives are dependent on BPA first concluding that a financial reserves policy is even needed. *See, e.g.*, ICNU Br., BP-18-B-IN-01, at 39 ("Consideration must start, then, with the question of whether 'additional' reserves are justified at all, before a TPP compatibility 'objective' becomes relevant . . .").

ICNU's challenge to the first three objectives makes more sense in that there is overlap between the factors that Staff identified as supporting the need for a financial reserves policy and the objectives Staff believed should be met through the policy. *See id.* at 17-33. Thus, for example, Objective 1 (maintain sufficient financial reserves levels to support BPA's credit rating), Objective 2 (ensure adequate liquidity throughout each rate period), and Objective 3 (maintain equity between business lines) are the outgrowth of the factors that would benefit from a financial reserves policy (credit rating support, liquidity support, rate stability, and equity). *Compare Harris et al.*, BP-18-E-BPA-17, at 24 (identifying objectives) *with Harris et al.*, BP-18-E-BPA-17, at 13-21, (noting primary reasons for holding financial reserves). BPA addresses ICNU's challenges to these objectives in the relevant sections.

ICNU argues that "Staff plainly demonstrates the importance of connecting alleged need and evaluative criteria in [its] own analysis . . ." by explaining the perceived "need" for the FRP, based on what "rating agencies consider," before concluding: "The fact that BPA has a policy . . . will be an additional factor in support of BPA's favorable credit rating." ICNU Br., BP-18-B-IN-01, at 20 (citing *Harris et al.*, BP-18-E-BPA-17, at 35). ICNU also notes that Staff

“alleges that reliance on ‘third-party debt’ is ‘driving the *need* for BPA to create a financial reserves policy,’ while further elaborating that ‘[t]he interest rates that BPA pays for third-party debt are strongly influenced by BPA’s credit rating, which is in turn heavily influenced by BPA’s financial reserves levels and policies.’” *Id.* (citing Harris *et al.*, BP-18-E-BPA-17, at 2-3). Thus, ICNU concludes, BPA has connected the perceived need for securing favorable third-party debt interest rates to a financial reserves policy in support of the agency’s credit rating. *Id.*

BPA agrees that the cited sections of Staff’s testimony support the need for a financial reserves policy. BPA also agrees that these same cited sections support the evaluation criterion that Staff identified in Objective 1 – Maintain sufficient financial reserves levels to support BPA’s credit rating. Harris *et al.*, BP-18-E-BPA-17, at 24. However, BPA does not see why *each* evaluative criterion must *independently justify* the FRP.

ICNU argues at length that Staff has not justified the six policy objectives with factual statements, but only with belief statements. ICNU Br., BP-18-B-IN-01, at 34. ICNU criticizes Staff’s objectives as an “‘amorphous cloud’ of evaluative criteria not reducible or susceptible to forensic analysis.” *Id.* at 37.

But again, ICNU takes Staff’s testimony out of context, and ignores that Staff had already established the need for the policy. Harris *et al.*, BP-18-E-BPA-17, at 10-21; Harris *et al.*, BP-18-E-BPA-33, at 8-42. Thus, it was unnecessary for Staff to re-establish at a separate point in its testimony the *need* for the policy through the six objectives (which were focused on what the policy should achieve). In this way, Staff properly identified these policy objectives with “belief” statements because they were proposing a set of criteria that they believed (as expert policy witnesses) should inform the development of the FRP. Harris *et al.*, BP-18-E-BPA-33, at 47. Since this aspect of Staff’s testimony was focused on policy development, Staff properly laid out its view of the appropriate considerations for that policy. *Id.* at 42-50.

Other parties did the same. For example, Powerex asked Staff to reconsider its definition of equity between the business lines. Opatrny, BP-18-E-PX-01, at 13–14. JP05 asked Staff to consider cost-competitiveness. Deen *et al.*, BP-18-E-JP05-01, at 11. M-S-R asked Staff to modify its criteria and identified additional factors for the Administrator to consider. Arthur, BP-18-E-MS-12, at 30–31. WPAG similarly identified its own factor to be considered in developing a financial reserves policy. Saleba *et al.*, BP-18-E-WG-01, at 7. Following ICNU’s logic, BPA should have required “forensic analysis” from each of these parties to support their proposed policy objectives. ICNU Br., BP-18-B-IN-01, at 37. As these objectives were intended to develop evaluative criteria of a policy, it was neither reasonable nor necessary for the objectives of Staff (or parties) to be supported by statistical analysis explaining *why* the particular policy objectives were necessary.

Furthermore, BPA need show only that it considered the relevant factors in developing the FRP. *Pac. Coast Fed'n of Fishermen's Ass'ns v. Nat'l Marine Fisheries Serv.*, 265 F.3d 1028, 1033-34 (9th Cir. 2001) (assessing “whether the agency considered the relevant factors and articulated a rational connection between the facts found and the choice made.”). The six factors Staff considered for evaluating the FRP are relevant in that they touch on the factors that support

developing the policy (credit rating, liquidity, rate stability, and equity), Harris *et al.*, BP-18-E-BPA-17, at 10-21, Harris *et al.*, BP-18-E-BPA-33, at 8-42, the major components of the policy (upper and lower thresholds), Harris *et al.*, BP-18-E-BPA-17, at 22-23, 36, and compatibility with BPA's existing policies (compatibility with TPP), Harris *et al.*, BP-18-E-BPA-17, at 36.

Moreover, even though the *objectives* were not created as a result of “forensic analysis,” what the objectives *measured* was subject to analysis. For instance, BPA included an analysis that evaluated the lower and upper thresholds proposed by Staff and the parties. Harris *et al.*, BP-18-E-BPA-33, Attachment 7. In this analysis, Staff calculated the relative probability of an increase to power rates, a decrease to transmission rates, and the likelihood of a reduction in cash below 30 days cash on hand, which would likely threaten BPA's credit rating. *Id.*; *see also id.* at 108. This provided valuable statistical analysis into how well Staff's and the parties' proposals met the objective to set “prudent” lower and upper thresholds, supported BPA's credit rating, and maintained equity between the business lines. *Id.* at 105-13, Attachment 7.

ICNU also argues that Staff's testimony was not “self-explanatory” or clear that the six objectives were *evaluative* criteria, rather than “independent justifications” for the policy. ICNU Br., BP-18-B-IN-01, at 21. BPA disagrees. Staff differentiated between the factors supporting the *need* for the policy and the objectives that the policy should achieve. Harris *et al.*, BP-18-E-BPA-17, at 10 (“Need for a Financial Reserves Policy”), 24 (describing six objectives the policy should meet), 35-36 (explaining how the FRP would meet Staff's six objectives). Staff also explained this distinction in its rebuttal testimony. Harris *et al.*, BP-18-E-BPA-33, at 8-9 (entitled “Need for a Financial Reserves Policy,” followed by testimony “In the Initial Proposal, we identified four reasons why we believed a financial reserves policy would be appropriate: credit support, liquidity, equity between business lines, and rate stability”), 42 (entitled “Objectives BPA Proposed to Measure Financial Reserves Policy” followed by discussion of six objectives.). BPA also explained how the FRP (Staff's proposal) met the six policy objectives. Harris *et al.*, BP-18-E-BPA-17, at 35-36; Harris *et al.*, BP-18-E-BPA-33, at 92-103.

Moreover, all parties to this proceeding presented their responses to Staff's analysis consistent with Staff's testimony. Wrigley *et al.*, BP-18-E-JP02-01, at 6-8 (acknowledging Staff's equity concerns and then discussing the equity objective); Deen *et al.*, BP-18-E-JP05-01, at 3-13 (includes title “Need for a Financial Reserve Policy,” followed by discussion of Staff's reasons for policy; also includes the title “BPA Staff's Proposed Policy Fails To Meet Objectives,” explaining how JP05 believes the proposed FRP would not meet Staff's objectives); Arthur, BP-18-E-MS-12, at 18-28 (explaining why M-S-R believes the proposed FRP would not meet the six objectives); Opatrny, BP-18-E-PX-01, at 12-13 (supporting Staff's six evaluative objective criteria, but also noting that Powerex believes the proposed FRP does not meet the equity objective); Saleba *et al.*, BP-18-E-WG-01, at 6-7 (noting “BPA Staff evaluated *their* reserve proposal using the following six policy objectives,” and adding another objective).

ICNU also argues that Staff's evaluative six objectives must be an all-or-nothing proposition; that is, ICNU contends that Staff's objectives must each *independently* justify the FRP, and to the extent they do not, they further “diminish” the justification for the policy. ICNU Br., BP-18-B-IN-01, at 15-16, 33-35. This standard, which ICNU creates in its brief, is unreasonable.

Agency policy decisions are rarely the product of one single, overarching objective. They often must balance multiple objectives, many of which are often built off of and related to each other. Staff identified four factors supporting the development of a financial reserves policy. Harris *et al.*, BP-18-E-BPA-17, at 10-21; Harris *et al.*, BP-18-E-BPA-33, at 8-42. As explained in Section 6.4 (need for FRP), the record supports Staff’s assessment that BPA should develop a financial reserves policy. Staff did not present any one factor as the *only* basis for the policy, and consequently, BPA does not believe it must now evaluate the FRP under that standard. A financial reserves policy would support each of the factors identified by Staff, and, thus, it is appropriate to consider these factors together and holistically, in determining whether a financial reserves policy should be developed.

ICNU concludes that “little to no weight should be attached to these five ‘objectives’ proposed by Staff.” ICNU Br., BP-18-B-IN-01, at 16. ICNU also argues that all of the other objectives BPA has identified are “essentially irrelevant to the overall decision to implement an FRP” because they are not relevant to BPA’s credit rating. ICNU Br. Ex, BP-18-R-IN-01, at 13 (emphasis omitted). ICNU contends that “without a potential benefit to the agency’s credit rating, the FRP would not even be on the table.” *Id.* BPA disagrees for the reasons stated above. The merits of ICNU’s challenge to Objective 1 (Maintain sufficient financial reserves levels to support BPA’s credit rating) were addressed in Section 6.4.3 (credit rating and FRP). BPA has also responded to ICNU’s objections to equity as a basis for the policy in Section 6.4.4 (equity and FRP). BPA will respond to ICNU’s specific concerns with Objective 2 (Ensure adequate liquidity throughout each rate period), and Objective 3 (Maintain equity between business lines) in the sections following this issue. ICNU’s argument regarding Objectives 4, 5, and 6 are derivative of its argument that BPA need not develop a financial reserves policy, and have been addressed fully here.

Decision

Each policy objective identified by Staff need not solely and independently justify the need for the FRP.

6.5.2 Staff’s Liquidity Objective

Issue 6.5.2.1

Whether the liquidity objective (Objective 2) is irrelevant.

Parties’ Positions

ICNU argues that the liquidity objective is “superfluous” because BPA’s existing policies, in particular the TPP standard, already address BPA’s liquidity needs. ICNU Br., BP-18-B-IN-01, at 17.

BPA Staff's Position

The objective to ensure adequate liquidity throughout each rate period is an appropriate consideration for the FRP. Harris *et al.*, BP-18-E-BPA-17, at 24, Harris *et al.*, BP-18-E-BPA-33, at 32.

Evaluation of Positions

The policy objective to “[e]nsure adequate liquidity throughout each rate period” was included as an objective of the policy in order to evaluate whether the policy would enhance or degrade BPA’s liquidity. Harris *et al.*, BP-18-E-BPA-33, at 32, 42. It was not included to “solve a liquidity problem.” *Id.* at 32.

ICNU argues that the liquidity objective is “superfluous” because BPA’s current policies, in particular the TPP standard, already ensure adequate liquidity through the BP-18 rate period. ICNU Br., BP-18-B-IN-01, at 17. ICNU claims that Staff admitted that the FRP is not required for BPA’s liquidity. *Id.* Thus, ICNU argues that liquidity is neither a reason to develop a financial reserves policy nor is it relevant to include liquidity as part of the evaluative criteria for the policy.

As noted previously in Section 6.4.5 (liquidity and a financial reserves policy), a financial reserves policy is not needed solely to support liquidity because BPA’s liquidity needs are adequately addressed under the TPP standard. BPA agrees that the TPP standard is currently BPA’s primary way of assessing its need for liquidity for each business line, for ensuring required payments, and ensuring the adequacy of current liquidity. Harris *et al.*, BP-18-E-BPA-33, at 32.

Nonetheless, Staff correctly included liquidity as an objective of the FRP in order to consider how liquidity could be affected by the policy. For example, the implementation of a financial reserves policy could *reduce* financial reserves. As noted above, the FRP would also create a new upper threshold on the amount of financial reserves for each business line and the agency. Harris *et al.*, BP-18-E-BPA-17, at 32. This new mechanism would allow above-threshold financial reserves to be repurposed for other high value uses, including distribution to customers through a dividend mechanism. *Id.* at 34. Because the FRP includes new ways of *reducing* financial reserves, it was prudent for BPA to consider how these features could be designed without “jeopardizing liquidity, BPA’s credit rating, or rate stability.” *Id.* at 32. Thus, BPA included the policy objective to “[e]nsure adequate liquidity throughout each rate period” in order to ensure that liquidity was not harmed through establishing an upper threshold for financial reserves. As Staff explained:

BPA’s financial policies are interdependent. Changes in one area of policy often have impacts in other areas and on other policies. It is within this context of interdependence we included the objective of maintaining adequate liquidity. By helping the Agency ensure it maintains adequate liquidity throughout the rate period, the FRP ensures that these interdependencies are considered and addressed.

Harris *et al.*, BP-18-E-BPA-33, at 48. Thus, including liquidity as part of the evaluative criteria for the policy was not an “irrelevant” or “superfluous” activity. See ICNU Br., BP-18-B-IN-01, at 17. Instead, including the second objective provided a prudent check on the development of a complex policy like the FRP. Harris *et al.*, BP-18-E-BPA-33, at 47.

Decision

The liquidity objective, objective 2, is a relevant objective of the FRP.

6.5.3 Staff’s Equity Objective

6.5.3.1 Overview

The third policy objective of the FRP is to “maintain equity between business lines.” Harris *et al.*, BP-18-E-BPA-17, at 24. This objective was included in response to concerns that BPA’s existing TPP policy “does not provide a basis for assessing inter-business line equity issues.” *Id.* at 21. In determining how a financial reserves policy would support equity between BPA’s business lines, Staff considered three areas: (1) equity in terms of symmetry between the methodologies for determining, collecting, and redistributing financial reserves; (2) equity in terms of each business line’s participation in supporting financial reserves; and (3) equity in terms of the amount of each business line’s contribution to financial reserves. *Id.*; Harris *et al.*, BP-18-E-BPA-33, at 35-36. Staff found that a financial reserves policy would support equity between the business lines in each of these areas.

First, a financial reserves policy would help establish symmetrical methodologies and mechanisms between the business lines. Harris *et al.*, BP-18-E-BPA-33, at 35. Currently, no symmetry exists. *Id.* Power customers have a means of receiving excess financial reserves from BPA (through the Distribution Dividend Clause (DDC)); Transmission customers do not. Power customers are subject to a CRAC if reserves fall below levels acceptable under the TPP standard; Transmission customers are not subject to such a mechanism. *Id.* Inter-business line equity is furthered by putting parallel CRAC and Reserve Distribution Clause (RDC) mechanisms into BPA’s Power and Transmission rates, based on a common methodology, in order to define ranges of financial reserves below which action will be taken to increase financial reserves and above which actions may be taken to repurpose financial reserves. *Id.*

Second, a financial reserves policy would establish a metric by which BPA could ensure that both business lines were making a contribution to the agency’s financial reserves. *Id.* As noted throughout the record, both business lines derive a benefit from BPA’s credit rating. *Id.* That credit rating is based, in part, on BPA maintaining a healthy level of financial reserves. *Id.* However, BPA has no current policy that requires both business lines to contribute to financial reserves. *Id.* Thus, a financial reserves policy can promote equity by ensuring that both business lines contribute to the agency’s financial reserves. *Id.*

Third, a financial reserves policy would help ensure equity in the *amount* of the contribution each business line is expected to make to the agency’s financial reserves. *Id.* at 36. Currently, there are no financial reserves targets or thresholds for the agency or either business line that

would guide BPA’s actions in the event financial reserves fell to levels that would put pressure on BPA’s credit rating. *Id.* This creates uncertainty in the actions BPA would take when a business line’s financial reserves significantly exceeded a business line’s needs, or a business line’s financial reserves precipitously declined to very low levels (but were still sufficient to meet TPP). *Id.* The default is where BPA is today: BPA indefinitely holds onto the financial reserves of whichever business line has cash until the reserves situation of the agency improves. *Id.* A financial reserves policy would help establish clear guidelines on how much each business line was expected to contribute to the agency’s financial reserves, thereby ensuring that both business lines were contributing fairly and equitably to the agency’s financial reserves. *Id.*

6.5.3.2 Issues

Issue 6.5.3.2.1

Whether equity between business lines (Objective 3) is a valid objective for the FRP.

Parties’ Positions

JP02, Powerex, and M-S-R support Staff’s proposal that “maintain[ing] equity between the business lines” is an appropriate policy objective for the FRP. JP02 Br., BP-18-B-JP02-01, at 6-7, 48; Powerex Br., BP-18-B-PX-01, at 8; M-S-R Br., BP-18-B-MS-01, at 7. JP07 also agrees that equity between business lines is an important consideration in adopting the FRP. JP07 Br., BP-18-B-JP07-01, at 8. JP07 argues that the current relative distribution of financial reserves between Power and Transmission is not inherently inequitable because the imbalance has not been long-term. *Id.* at 12-13. WPAG acknowledges that the three factors Staff identifies (symmetry, contribution, and amount) would satisfy the equity objective. WPAG Br., BP-18-B-WG-01, at 12.

ICNU argues that the equity objective is not a valid criterion for evaluating the FRP. ICNU Br., BP-18-B-IN-01, at 19. ICNU contends that because BPA’s credit rating is measured at the agency level, considerations of equity between business lines are “irrelevant to BPA’s actual credit rating.” *Id.*

BPA Staff’s Position

Maintaining equity between the business lines is a valid policy objective of the FRP. Harris *et al.*, BP-18-E-BPA-33, at 48-49.

Evaluation of Positions

Several parties agree that maintaining equity between the business lines is an appropriate objective of the FRP. JP02 Br., BP-18-B-JP02-01, at 6; M-S-R Br., BP-18-B-MS-01, at 8; Powerex Br., BP-18-B-PX-01, at 8. ICNU disagrees. ICNU Br., BP-18-B-IN-01, at 19. In response to ICNU, JP02 states that ICNU “misses the point.” JP02 Br., BP-18-B-JP02-01, at 48. JP02 notes that the point is not that equity is necessary to achieve BPA’s preferred credit rating;

rather, the point is that one business line's ability to maintain low financial reserves *because* the other business line has excessively high financial reserves is *inequitable*. *Id.* at 49. That is, the disproportionate reliance on one business line's financial reserves as justification for maintaining a low level of financial reserves for the other business line is inequitable. *Id.*

JP07 “agrees that a financial reserves policy that is transparent and equitable between business lines . . . may aid the agency’s long-term financial health” JP07 Br., BP-18-B-JP07-01, at 8. JP07 also notes that it “could support the adoption of a financial reserves policy that [in addition to meeting other criteria] . . . is equitable between [the] Power and Transmission business lines.” *Id.*

WPAG agrees that the three factors identified by Staff (symmetry, contribution, and amount) are appropriate factors to measure whether the FRP satisfies the equity objective. WPAG Br., BP-18-B-WG-01, at 12. WPAG also notes that Staff’s Alternative Option meets the equity objective. *Id.* M-S-R agrees that equity between the business lines should encompass symmetrical provisions and ensure that financial reserves are accumulated and maintained in amounts necessary to support sound business practices by the agency, taking into account each business line’s cash flow needs, financial variability, and risks. M-S-R Br., BP-18-B-MS-01, at 7-8.

ICNU argues that equity between the business lines is not a valid consideration for a financial reserves policy because “BPA’s credit rating is assessed on a single-entity agency level, and not a business line level.” ICNU Br., BP-18-B-IN-01, at 19. ICNU contends there is a critical distinction between Staff’s objective to “[m]aintain equity between business lines” and the separate objective to “[m]aintain sufficient reserves levels to support BPA’s credit rating.” *Id.* (citing Harris *et al.*, BP-18-E-BPA-17, at 24). ICNU maintains that considerations of equity between business lines are “irrelevant to BPA’s actual credit rating.” *Id.* ICNU claims that to contend otherwise would make little sense given Staff’s admission that “BPA’s credit rating thus rises and falls on the prospects of both its business lines *viewed as a single entity.*” *Id.* at 19-20 (citing Harris *et al.*, BP-18-E-BPA-17, at 21).

BPA agrees that inter-business line equity is not a key consideration for the agencies rating BPA’s credit. Harris *et al.*, BP-18-E-BPA-33, at 48. As ICNU notes, the credit rating agencies evaluate BPA as a single entity. ICNU Br., BP-18-B-IN-01, at 19-20 (citing Harris *et al.*, BP-18-E-BPA-17, at 21). However, BPA disagrees with ICNU’s view that because equity does not factor into BPA’s overall credit rating, it would be unlawful or erroneous for BPA to consider equity in developing the FRP. Harris *et al.*, BP-18-E-BPA-33, at 48.

First, BPA is not gratuitously including “equity” as a basis for developing a financial reserves policy. BPA previously received feedback and comments from transmission customers expressing concern with the equity of the status quo, and the imbalance between the business lines’ respective contributions to BPA’s financial reserves. BP-16 Final Record of Decision, BP-16-A-02, at 99-100. This equity concern, as explained extensively in Section 6.4.4 (equity and FRP), is that even though both business lines rely on BPA’s high credit rating, BPA’s current policies allow the financial reserves generated from one business line to become the primary source of the financial reserves that support the agency’s credit rating. Harris *et al.*,

BP-18-E-BPA-17, at 21, *Harris et al.*, BP-18-E-BPA-33, at 34. This concern was raised in the BP-16 rate case and has been reiterated in this case. BP-16 Final Record of Decision, BP-16-A-02, at 99-100; *see also* JP02 Br., BP-18-B-JP02-01, at 4-6; Powerex Br., BP-18-B-PX-01, at 5-6; M-S-R Br., BP-18-B-MS-01, at 5-6; Opatrny, BP-18-E-PX-01, at 13; *Wrigley et al.*, BP-18-E-JP02-01, at 7; Arthur, BP-18-E-MS-12, at 25 (“It is not equitable for one business line to be forced to carry greater reserves than necessary to meet its liquidity, while the other is permitted to carry far less than necessary for an extended period of time.”) By including equity as a factor in the FRP’s development, and as a policy objective, BPA is simply responding to a concern that it has heard from its customers—a concern that BPA agrees is not resolved under current policies and should be addressed. *Harris et al.*, BP-18-E-BPA-17, at 21.

Second, BPA does not agree with ICNU that in developing the FRP, BPA must limit its policy development to the single objective of credit support. Staff explained why equity, while not important to the credit rating agencies, is an important factor for BPA:

Objectives such as equity, which seek to ensure the policy reasonably impacts BPA’s divergent customer base, are critical to developing a well-balanced policy. Without this objective, the record would not mention any of the inter-business line concerns with the present state of BPA’s financial reserves. While these inter-business line issues may be of no interest to the rating agencies, they have material impacts on BPA’s customers.

Harris et al., BP-18-E-BPA-33, at 48-49. Staff’s assessment is sound because policy development can rarely be whittled down to achieving a single objective. This is particularly true in the development of the FRP, which is distinctive among BPA policies in that it will apply to *both* of BPA’s business lines. *Harris et al.*, BP-18-E-BPA-17, at 22. While most of BPA’s power customers are also transmission customers, BPA’s transmission customers often have interests distinct from BPA’s power customers (and vice versa). As the record in this case demonstrates, those interests are not always aligned. (*Cf.* ICNU Br., BP-18-B-IN-01, at 80-85, recommending BPA expand use of the Treasury Facility, *with* JP02 Br., BP-18-B-JP02-01, at 7-9, suggesting BPA should limit use of the Treasury Facility). As such, in developing a policy that affects both business lines, it is appropriate to consider how the benefits (and burdens) of that policy should be shared between the different customer classes served by the business lines.

Third, BPA is unaware of any legal standard or requirement that prohibits it from considering relevant factors when developing its policies, particularly when those factors have been brought to the agency’s attention. Indeed, the legal standard for evaluating BPA’s decision would require it. *See California Dep’t of Water Res. v. FERC*, 341 F.3d 906, 910 (9th Cir. 2003) (noting agency decision will be upheld so long as the “record reflects that the decision was ‘based on a consideration of relevant factors and there was no clear error of judgment’”) Transmission customers have previously raised concerns regarding equity between the business lines as a reason that the status quo is faulty, and have raised those concerns again in this case. BPA agrees that those concerns should be addressed. In this way, it was “entirely reasonable, and indeed necessary, for the Administrator to consider BPA-centric issues, such as equity between

business lines, when developing a[n] FRP that will affect both business lines.” Harris *et al.*, BP-18-E-BPA-33, at 49.

Decision

Equity between business lines (Objective 3) is a valid objective for the FRP.

Issue 6.5.3.2.2

Whether Staff’s consideration of an alternative means of satisfying the equity objective renders the equity objective useless.

Parties’ Positions

ICNU argues that there is no “equity” issue to be redressed through a financial reserves policy. ICNU Br., BP-18-B-IN-01, at 21-22. ICNU contends that Staff has effectively conceded to a wholesale reversal of how FRP benefits should be measured. *Id.* ICNU claims that Staff’s reversal undercuts the fundamental evaluation of how equity between business lines was considered in the Initial Proposal, leaving no rationally consistent foundation on which to assess an equity objective. *Id.*

BPA Staff’s Position

As decided previously, the equity objective is a valid consideration for the FRP. Staff’s acknowledgment of an alternative means of satisfying the objective was supported by facts and arguments presented by the parties. Harris *et al.*, BP-18-E-BPA-33, at 116-17, 122.

Evaluation of Positions

ICNU argues that the equity objective has been “transformed beyond rational usefulness by Staff’s . . . acknowledgment of the merit in a ‘relative benefit’ argument.” ICNU Br., BP-18-B-IN-01, at 29. ICNU claims that Staff has made equity an “entirely subjective issue, from an evidentiary standpoint” and as a consequence, undermines any rational prospective use of equity to support objective justifications for power rate increases. *Id.* ICNU then summarizes Staff’s rationale on the Alternative Option, in which Staff considered whether the objective to “maintain equity between the business lines” could also be satisfied under a benefit allocation of the agency’s lower threshold. *Id.* at 29-30. ICNU suggests that Staff’s basis for justifying the FRP on an equity objective fails because Staff has either accepted a “relative benefits” approach to the equity objective or has equivocated from its original position. *Id.* at 30. ICNU describes the import of such equivocation as follows:

On the other hand, interpreting Staff’s rebuttal testimony as equivocation renders any further attempt to satisfy the “equity” objective as “mere ethereal guesswork,” since the fungibility in how the objective may be justified, in order to fit any infinite variation of an FRP proposal, correspondingly devalues the “equity”

objective's usefulness for purposes of being a defensible (and even comprehensible) evidentiary criterion.

Id.

At the risk of mischaracterizing ICNU's argument, BPA will summarize its understanding of ICNU's concerns. Staff originally argued that to "maintain equity between the business lines," the allocation of the lower threshold of the FRP should be allocated based on days cash on hand. Harris *et al.*, BP-18-E-BPA-17, at 35-36. Parties then filed direct cases suggesting an alternative method of meeting the "equity" objective, specifically, a benefits-based approach using projected capital expenditures. See Saleba *et al.*, BP-18-E-WG-01, at 10, 21-27; Deen *et al.*, BP-18-E-JP05-01, at 17-21, 23-24. Staff, in rebuttal testimony, acknowledged that the benefits-based allocation could be another way of meeting the equity objective. Harris *et al.*, BP-18-E-BPA-33, at 140, 149. ICNU then argues that by acknowledging that the equity objective could be met in another way, Staff effectively undermined any rational method for determining whether the equity objective could be met. ICNU's central claim is that the equity objective is essentially a subjective standard that is not capable of being evaluated under an evidentiary-based criterion. ICNU Br., BP-18-B-IN-01, at 30.

Assuming the foregoing is accurate, BPA disagrees that the equity objective is incapable of being used as a valid objective because Staff acknowledged an alternative way of meeting the objective. The fact that an objective can be met in multiple ways does not undermine the validity of the objective. This is true of Staff's objectives for the FRP as well as any other metric that may be employed to gauge the merits of the policy. For example, ICNU argues that BPA should demonstrate a net customer benefit to support the FRP. Mullins, BP-18-E-IN-01, at 39-40. There are multiple ways, however, to perform a cost-benefit analysis. Power customers and ICNU suggested one method. See Saleba *et al.*, BP-18-E-WG-01, at 20-21; Deen *et al.*, BP-18-E-JP05-01, at 12-14, 21-22; Mullins, BP-18-E-IN-01, at 39-40, 62. Staff performed a different method. Harris *et al.*, BP-18-E-BPA-33, at 56 ("In performing this analysis, we have applied a methodology different from the one the parties used."). Following ICNU's argument, because there are multiple ways of performing a cost-benefit analysis, BPA should jettison any attempt at such analysis as "mere ethereal guesswork." See ICNU Br., BP-18-B-IN-01, at 30. This makes little sense. Whether one analysis should prevail over another depends on the merits of the proposals, which turn on the evidence, arguments, and rationales used to support the proposals.

In the same way, the validity of the equity objective will turn on the *arguments* and *evidence* that the litigants put on the record to support their view that one method of allocation is more (or less) equitable to the business lines. Here, Staff explained that the equity objective could be met by ensuring symmetry between the methodologies, that each business line contribute to the financial reserves of the agency, and that each business line contribute a reasonable amount to such financial reserves. Harris *et al.*, BP-18-E-BPA-17, at 21, 35-36; Harris *et al.*, BP-18-E-BPA-33, at 35-36. Staff explained how the FRP met the stated objectives, including how it "maintain[ed] equity between the business lines." *Id.*

Parties had other ideas as to how the FRP could meet the objective to "maintain equity between business lines." Powerex argued that equity required a greater contribution from Power Services

(and a lower contribution from Transmission Services) to agency reserves. Opatrny, BP-18-E-PX-01, at 13-14. JP05 and WPAG argued that equity would require that the contribution of financial reserves by business line be determined by the relative benefit that each business line received through BPA’s credit rating. *See* Saleba *et al.*, BP-18-E-WG-01, at 10, 21-27; Deen *et al.*, BP-18-E-JP05-01, at 17-21, 23-24. Indeed, ICNU argued that the equity objective would not be met under Staff’s proposal, as it would require Power Services to implement a \$309 million increase to reserves, a magnitude that creates a “perception of inequity.” Mullins, BP-18-E-IN-01, at 61. The key point here is that each party that argued either for or against Staff’s proposal had a *rationale* for explaining why the equity objective would or would not be met; they each offered their view on what it means for each business line to contribute a *reasonable amount* to such financial reserves.

Staff then evaluated the parties’ alternatives. Staff first found that various components of the parties’ alternatives *would not meet* the equity objective. Specifically, Staff explained that the proposals offered by WPAG and JP05 would not satisfy the equity objective because they failed to ensure that *both* business lines contributed to the agency’s financial reserves. As explained by Staff:

Under WPAG’s proposal, Power’s financial reserves could go to \$0, and Transmission’s financial reserves could go to \$297 million, and no action would be taken to increase Power financial reserves to its lower threshold. While Transmission would be carrying the full brunt of contributing to Agency financial reserves to support BPA’s credit rating, Power would be making no contribution. Nevertheless, Power would continue to receive the benefits of BPA’s credit rating through interest savings on debt issued to support Power capital projects. We do not see this outcome as either sustainable or equitable.

Harris *et al.*, BP-18-E-BPA-33, at 122. Staff made a similar comment regarding JP05’s proposal:

With regard to our [equity] objective, JP05’s proposal allocates BPA’s financial reserves requirement by business line, but makes no attempt to align or balance actual financial reserves contributions with that allocation when BPA, as an Agency, has sufficient financial reserves. Under JP05’s proposal, one business line could indefinitely carry 100 percent of BPA’s financial reserves requirement We believe that support of our third objective of equity requires some form of corrective ratemaking adjustments to ensure that both business lines are reasonably contributing to the pool of financial reserves that support BPA’s credit rating; that is, to ensure that any temporary imbalances in business line contributions are just that—temporary. JP05’s proposal lacks such a mechanism, and perpetuates the equity concerns between the business lines indefinitely.

Id. at 116-17.

At the same time, Staff recognized that the parties had identified a plausible alternative method of maintaining the equity between the business lines through a benefits-based allocation

methodology. *Id.* at 115, 140, 149. Thus, Staff indicated that “allocating the lower threshold financial reserve amounts based on benefits . . . is another *plausible* way of allocating the financial reserves responsibility between the business lines.” *Id.* at 115 (emphasis added). Staff explained its rationale and identified the *facts* and *arguments* the parties made that supported the alternative allocation:

Parties, however, particularly JP05 and WPAG, have made a fair case that other bases for this allocation could be chosen. Deen *et al.*, BP-18-E-JP05-01, at 18-19, 22, 25; Saleba *et al.*, BP-18-E-WG-01 at 10, 25. They make the point that it may not be equitable to hold Power customers to providing 75 percent of the cash needed to support Agency financial reserves for the lower threshold when the benefit derived from holding this cash (in terms of credit benefits) accrues differently to the business lines. As JP05 and WPAG note, current projections show Transmission needing more capital expenditures than Power, so it could appear inequitable that Power shoulders a greater share of the reserves obligation. Deen *et al.*, BP-18-E-JP05-01, at 21-24; Saleba *et al.*, BP-18-E-WG-01 at 12, 25-26.

Harris *et al.*, BP-18-E-BPA-33, at 148-49. Thus, Staff acknowledged that this methodology, though “not our preferred method, . . . could also be a means of achieving our equity objective” and, therefore, left it to the Administrator to decide. *Id.* at 140, 149. Section 6.6.4.2 (lower threshold) discusses the Administrator’s decision regarding the method for determining the lower threshold.

As the foregoing discussion makes clear, Staff explained why some features of the alternative proposals failed to meet the equity objective, and why other features were “plausible” alternatives. *Id.* at 115-17, 122, 140, 149. In both instances, Staff explained its reasoning and referenced the record. ICNU’s argument that Staff’s consideration of these alternatives (rejecting some and accepting others) in any way undermines either Staff’s credibility or the validity of the equity objective is baseless.

Nonetheless, ICNU contends that “Staff’s willingness to shift positions is . . . *inappropriate for a formal rate proceeding* based on strict evidentiary rules requiring ‘clarity of evidence,’ including ‘expressly stated’ and ‘self-explanatory’ testimony.” ICNU Br., BP-18-B-IN-01, at 30 (emphasis added). This is a puzzling statement. ICNU is either arguing that the parties’ alternative was completely unfounded (and hence Staff was irrational in considering it) or that Staff must enter the rate case with an irreversibly closed mind that cannot be changed by the parties’ arguments. BPA finds that both arguments lack merit.

ICNU continues its challenge to Staff’s consideration of an alternative, arguing that “the fluidity and imprecision which characterize Staff’s thinking on inter-business line equity issues, when factoring the entire course of this proceeding, demonstrate the impropriety of attempting to establish a viable FRP in an adjudicatory rate proceeding governed by ‘quite explicit’ evidentiary rules.” *Id.* BPA has already addressed ICNU’s arguments on the alleged procedural defects of Staff’s testimony in Section 6.3 (procedural issues and FRP).

ICNU also appears to be operating under a misunderstanding of the nature of BPA’s rate proceedings. Staff’s Initial Proposal is just that—an *initial proposal*. During the hearing phase of the case, Staff presents arguments and evidence to support the positions that Staff believe should be adopted by the Administrator. Other parties do the same. It is entirely possible, and indeed common, for Staff to adopt new positions as a result of the parties’ arguments. See Weekley *et al.*, BP-18-E-BPA-28, at 12 (proposing alternative to “accommodate NRU’s argument”). But even here, Staff’s adoption of a separate position *does not dictate* the outcome of the final decision. Whether Staff’s changed position, or some other position proposed by the parties, is accepted depends entirely on the *Administrator*. In some cases, such as this, there are multiple possible answers to an issue. Staff, when appropriate, may present *multiple* options to the Administrator so that he will be aware of different possible solutions to a problem. That is what happened here. Staff specifically noted that it included the Alternative Option to make the Administrator aware of additional approaches for achieving equity:

The proposed FRP is our preferred option. Nonetheless, the alternative option we describe below is also a strong alternative that the Administrator should consider.

...

While not our preferred method, in providing the Administrator other options derived from the parties’ cases, we believe the allocation method in the alternative option (which uses a different perspective on equity) could also be a means of achieving our equity objective.

Harris *et al.*, BP-18-E-BPA-33, at 140, 149 (internal citation omitted). In summary, Staff’s recognition that there may be more than one manner in which an issue might be resolved is not only legitimate, but commendable.

ICNU makes the unfounded accusation that Staff’s decision to consider alternatives was motivated not by the facts of the parties’ arguments, but by “business partner” or “relationship” considerations. ICNU Br., BP-18-B-IN-01, at 32. ICNU argues that these were the real grounds for Staff’s change of position—rather than what Staff said in its testimony—and basing a decision on Staff’s testimony would be both “risky and improper” and would leave BPA’s decision vulnerable to reversal. *Id.* ICNU also notes that it has been cast as a “bête noire,” in reprisal for not offering its own counterproposal. *Id.* BPA responds in Section 6.6.5 (parties’ alternative proposals) to ICNU’s assertion that Staff developed the Alternative Option based on “business partner” or “relationship” grounds. For the reasons described above, Staff had extensive evidence in the record upon which it could rely when considering alternative allocation methodologies.

Decision

Staff’s consideration of an alternative means of satisfying the equity objective was appropriate and does not render the equity objective useless.

6.6 Financial Reserves Policy

6.6.1 Overview of Staff’s Initial Proposal Financial Reserves Policy

In the Initial Proposal, Staff presented a draft financial reserves policy with a methodology to establish target financial reserves levels, lower and upper financial reserves thresholds, the actions to be taken when financial reserves are below or above the thresholds, and how to determine the target and thresholds between Power Services and Transmission Services. Harris *et al.*, BP-18-E-BPA-17, at 22. The primary features of Staff’s draft FRP were as follows:

Financial reserves targets for each business line are calculated independently for each rate period based on the higher of the amount necessary to meet the 95 percent TPP standard or 90 days cash on hand (a common industry liquidity metric). *Id.*, Appendix A, Policy §§ 3.1, 3.2, 3.5.

- Lower financial reserves thresholds are calculated for Power and Transmission for each rate period based on 30 days cash on hand below the financial reserves target. For each business line, if financial reserves fall below the lower threshold, a rate increase (a CRAC) will trigger to replenish reserves in the following fiscal year. *Id.*, Appendix A, Policy §§ 3.3, 3.5.
- Upper financial reserves thresholds are calculated for Power and Transmission for each rate period based on 30 days cash on hand above the financial reserves target. The agency upper threshold is the sum of the business line upper thresholds. If (1) reserves for a business line are above the upper threshold for that business line, and (2) BPA’s financial reserves are above the BPA upper threshold, an RDC will trigger, and the above-threshold financial reserves will be considered for investment in other high-value purposes such as debt retirement, incremental capital investment, or rate reduction. *Id.*, Appendix A, Policy §§ 3.4–3.5.
- The Policy includes a “phase-in” of the lower financial reserves threshold for Power Services. *Id.* at 36-41.

6.6.2 Overview of Parties’ Positions and Alternatives

Five parties proposed alternative policies, or components of policies, for BPA’s consideration. Harris *et al.*, BP-18-E-BPA-33, at 105. The parties presented a diverse set of ideas on how to improve Staff’s proposal. *Id.* at 106. The parties explained how they believed their proposals met Staff’s six objectives at least as well as Staff’s proposal. *Id.* The parties’ proposals agreed in many parts with Staff’s objectives, but tended to emphasize one objective over others. *Id.*

ICNU, while not proposing a separate alternative, suggested BPA expand its existing financial tools to support BPA’s credit rating. Mullins, BP-18-E-IN-01, at 56-59. ICNU reiterates that proposal in its brief. ICNU Br., BP-18-B-IN-01, at 80-85. BPA evaluates that issue in Section 6.6.5 (parties’ alternative proposals).

The main components of the parties' proposals were as follows:

JP05

JP05's proposal included upper and lower thresholds for financial reserves for BPA as a whole, as well as an allocation of those amounts between Power and Transmission. Deen *et al.*, BP-18-E-JP05-01, at 18. Specifically, in addition to the status quo CRAC provisions, JP05 proposed to add 1 percent of PNRR to the rates of the business line that is below its target. *Id.* at 19–20. However, application was conditional on the agency's financial reserves. The 1 percent of PNRR proposed by JP05 would occur only if agency financial reserves were below the agency lower threshold. *Id.* at 19.

(PNRR is an expense line item in the revenue requirement without a corresponding planned cash disbursement. Harris *et al.*, BP-18-E-BPA-17, at 8. It has the effect of raising rates above the level necessary to recover all costs, resulting in a planned increase in financial reserves throughout the rate period. *Id.*)

JP05 proposed a lower threshold of 35 days cash and an upper threshold of 95 days cash. Deen *et al.*, BP-18-E-JP05-01, at 18. JP05 proposed to allocate responsibility for the agency's lower threshold to the business lines by the proportion of each business line's forecast contribution to BPA's overall planned capital expenditures on a rolling 10-year basis. *Id.* For the current rate proceeding, that allocation would be 46 percent Power and 54 percent Transmission. *Id.* at 19. These values would be updated in the Final Proposal. *Id.*

WPAG

WPAG's proposal included two CRAC mechanisms: one that supports BPA's TPP (the TPP-CRAC) and another that supports BPA's credit rating (the CRS-CRAC). WPAG's two CRACs are independent calculations, mutually exclusive, and not additive. Thus, if both the TPP-CRAC and the CRS-CRAC trigger, only the higher of the two is implemented. Saleba *et al.*, BP-18-E-WG-01, at 9-11.

The CRS-CRAC included upper and lower thresholds for the agency as well as upper and lower thresholds for each business line. *Id.* The agency's upper and lower thresholds would be used to establish each business line's threshold. WPAG proposed a lower threshold of 45 days cash on hand and an upper threshold of 105 days cash on hand. *Id.* at 10.

WPAG proposed to allocate the agency's thresholds, both lower and upper, to each business line based on its forecast *pro rata* share of BPA's capital program over the next 10 years. This is equal to 45 percent to Power and 55 percent to Transmission. These values would be updated based on BPA's biennial CIR process. *Id.* at 10-12.

WPAG's proposal would trigger the RDC only when the agency is above its upper threshold (and business line financial reserves are above their upper threshold) and trigger the CRS-CRAC only when agency financial reserves are below their lower threshold. *Id.*

JP02

JP02 proposed five changes to the FRP methodology. These changes would (1) exclude the Treasury Facility from the TPP calculation when establishing the financial reserves target for each business line; (2) shorten the 10-year phase-in for the Power lower threshold; (3) modify the language of the FRP to make the CRAC and RDC mandatory; (4) narrow the RDC mechanism to rate reduction only (eliminating the possibility of other uses of reserves, such as debt retirement); and (5) adopt a modified agency upper threshold for the RDC mechanism. Wrigley *et al.*, BP-18-E-JP02-01, at 2.

Powerex

Powerex broadly supported the structure and function of the FRP as proposed, but suggests three incremental changes. Opatrny, BP-18-E-PX-01, at 17-19. First, Powerex proposes a cap on Transmission's financial reserves during the phase-in period for the FRP. *Id.* at 17-18. Second, Powerex proposes that certain high current Transmission financial reserves be immediately redeployed for other purposes. *Id.* at 18-19. Finally, Powerex requests an opportunity for customers to provide input on how excess financial reserves should be used. *Id.* at 19.

M-S-R

M-S-R proposed three kinds of changes: (1) revisions to the targets and upper and lower thresholds; (2) modifications to the RDC two-factor test; and (3) compensation between business lines when the financial reserves of one are deemed necessary to offset deficiencies of the other to preserve the agency's credit rating. Arthur, BP-18-E-MS-12, at 31.

6.6.3 BPA Staff's Alternative Option

Staff evaluated each of the parties' proposals, identifying features they supported and features they believed would undermine one or more of the six policy objectives. Harris *et al.*, BP-18-E-BPA-33, at 105-39. Staff also analyzed the parties' alternatives (as well as re-analyzed Staff's Initial Proposal), focusing on four aspects of the proposals.

- The probability of BPA's financial reserves falling below 30 days cash under the parties' proposals for a sustained period. *Id.* at 106-07.
- The expected value of RDC distributions to Power and Transmission rates as a result of the various proposals. *Id.* at 107.
- The likelihood that Transmission rates would receive some benefit through the application of an RDC. *Id.*
- The likelihood that the Power CRAC threshold would be fully phased in, equal to the FRP lower threshold, after 10 years. *Id.*

Staff provided a summary of its analysis with its rebuttal testimony. *See id.*, Attachment 7.

After considering the parties' alternatives, Staff noted that no one proposal met all of Staff's six policy objectives. *Id.* at 139. Staff noted, however, that an Alternative Option could be constructed from the Initial Proposal and specific features proposed by parties. *Id.* at 140.

Staff's Alternative Option was as follows:

- **Business Line Lower Thresholds and Allocation.** Each business line would have a CRAC that would function as described in BPA's Initial Proposal. Each business line's lower threshold would be based on its fraction of a 10-year projection of BPA capital spending multiplied by the agency's 60 days cash level. Roughly speaking, for the BP-18 rate period, this would mean a lower threshold for Power of \$180 million and for Transmission of \$220 million. The Transmission CRAC threshold would be set to the Transmission lower threshold. The Power CRAC threshold would be increased from the current level of \$0 to the Power lower threshold level, however, only when the phase-in (described below) is completed.
- **Upper Thresholds and RDC.** Each business line would have an RDC as outlined in BPA's Initial Proposal. The RDC thresholds would be set to the FRP upper thresholds. The upper threshold would be 60 days cash (for that business line) above the business line's lower threshold. For the BP-18 rate period, the Power RDC threshold would be about \$480 million and the Transmission RDC threshold would be about \$320 million. The test for an RDC would continue to be a two-part test: (1) the financial reserves attributed to a business line must be above its RDC threshold; and (2) agency financial reserves must be above the agency target of *90 days cash* (currently about \$600 million). Distributions under the RDC would continue to be subject to the Administrator's discretion.
- **Power Phase-In.** We would continue to propose a phase-in for Power based on the following: Power rates would include \$20 million of PNRR per year in Power's revenue requirement in each rate case until forecast Power financial reserves exceed the Power lower threshold (about \$180 million for the BP-18 rate period). If the end-of-year projection of Power financial reserves is above the Power lower threshold, the Power CRAC threshold for the subsequent year and all future years would be raised to the Power lower threshold level. This creates a one-time ratchet in the Power CRAC threshold. Until this ratchet takes effect, the Power CRAC threshold would continue to be set pursuant to BPA's TPP standard. PNRR would continue to be included in the revenue requirement in Power rate proceedings until the Power CRAC threshold has been increased to the Power lower threshold. Because rates, and therefore PNRR, are established and fixed for whole rate periods, there would be a timing lag, and there would be one or two years in which PNRR is still included in Power rates after the Power CRAC threshold has been increased to the Power lower threshold. This would reduce the likelihood that the Power CRAC would trigger immediately following the increase in the Power CRAC threshold to the Power lower threshold.

Id. at 144-46.

In providing this alternative, Staff was clear that “the proposed FRP is our preferred option” and Staff was presenting the Alternative Option as “a strong alternative that the Administrator should consider.” *Id.* at 140. Staff then explained how the Alternative Option could meet Staff’s six objectives. *Id.* at 146-52.

6.6.4 Final Financial Reserves Policy

6.6.4.1 Overview

BPA appreciates the robust debate that has occurred in the record regarding whether to adopt a financial reserves policy and the terms of that policy. The parties’ arguments and counter-proposals were very helpful as BPA considered the specific features to adopt in the final FRP. As described in the following sections, the FRP that BPA is adopting reflects features from Staff’s Initial Proposal and the parties’ proposals. At the same time, BPA agrees in part with some parties that additional review of certain features of the FRP is necessary and BPA will defer the development of one component of the FRP’s implementation to a separate process.

The main features of the final FRP are as follows:

- **Lower Reserves Thresholds.** Lower financial reserves thresholds shall be calculated independently for Power and Transmission on a rate-period basis, based on the higher of what is necessary to meet the 95 percent TPP standard or 60 days cash on hand. For each business line, if financial reserves fall below the lower threshold, a rate action shall trigger the following fiscal year to recover, in part or in whole, the shortfall.
- **Upper Reserves Thresholds.** Upper financial reserves thresholds shall be calculated independently for Power and Transmission on a rate-period basis, based on the financial reserves equivalent of 60 days cash on hand above the business line’s lower threshold. The agency upper threshold is the sum of Power and Transmission’s lower thresholds plus 30 days cash (agency cash). Thus, the agency upper threshold will be 90 days cash or greater.
- **Reserves Distributions.** If business line financial reserves and agency financial reserves are above their respective upper thresholds, the Administrator shall consider the above-threshold financial reserves for investment in other high-value business line-specific purposes including, but not limited to, debt retirement, incremental capital investment, or rate reduction. Application of any above-threshold reserves shall be via the RDC rate mechanism.
- **Phase-In.** The Power CRAC threshold will be \$0 for the BP-18 period, and thereafter no less than \$0. Power rates will include \$20 million of PNRR per year in the Power revenue requirement in each rate case until the Power CRAC threshold is raised to the Power lower threshold. The timing and mechanism used to increase the Power CRAC threshold to the lower threshold will be developed in

a separate process. The specifics of how CRAC shortfalls are recovered may be revisited in separate processes. The phase-in will not modify any upper or lower thresholds.

The final FRP is attached to this Final ROD as Appendix A. The rationale and support for the policy is described in the following sections.

6.6.4.2 Lower Threshold

6.6.4.2.1 *Overview*

As described in Section 6.4.3 (credit rating and FRP), the credit rating agencies have warned that negative credit rating action could occur if BPA's financial reserves fall below certain levels, measured in days cash on hand. *See, e.g.*, Motion for Official Notice of Credit Rating Agency Reports, BP-18-M-BPA-09, Attachment A, at 3. The FRP, therefore, sets agency and business line thresholds to guide BPA's actions in maintaining an appropriate amount of financial reserves based on days cash on hand. *See* Section 6.6.4 (Final FRP). The days cash on hand metric measures the relationship between an entity's financial reserves and daily average operating expenses (*e.g.*, staffing and O&M costs). Harris *et al.*, BP-18-E-BPA-17, at 28. Days cash on hand is a common industry measure of liquidity and is useful because it is a ratio that scales to businesses of different sizes, allowing businesses with any amount of annual operating expenses to be compared under the same metric. *Id.*

In Staff's initial FRP proposal, Staff proposed to set each business line's lower threshold based on the greater of 60 days cash or the CRAC threshold necessary to meet that business line's TPP standard. *Id.*, Appendix A, at A-2 (Policy § 3.3). Setting a days cash lower threshold for each business line implicitly allocated responsibility for the agency's financial reserves to each business line based on the size of each business line. Harris *et al.*, BP-18-E-BPA-33, at 141. Power Services' revenue requirement is approximately \$2.9 billion. Power and Transmission Risk Study, BP-18-E-BPA-05, at 114, Table 11. Transmission Services' revenue requirement is approximately \$1 billion. *Id.* at 115, Table 12. Dividing the business lines' respective operating expenses by 365 days results in a per-day cash calculation of \$5 million for Power Services and \$1.6 million for Transmission Services. *Id.* at 114-15, Tables 11 & 12; *see also* Harris *et al.*, BP-18-E-BPA-17, at 28-29. For this rate period, 60 days cash is approximately \$300 million for Power Services and approximately \$100 million for Transmission Services. Harris *et al.*, BP-18-E-BPA-33, at 141 (citing Power and Transmission Risk Study, BP-18-E-BPA-05, Tables 11 & 12). Power's lower threshold is roughly three times larger than Transmission Services' because Power Services' revenue requirement is roughly three times larger than Transmission Services. *Id.*

JP05 and WPAG, in their direct cases, opposed Staff's proposal for determining the lower thresholds based on days cash, and proposed BPA allocate responsibility "based on the percentage of total capital expenditures attributable to each business line over the next 10 years." JP07 Br., BP-18-B-JP07-01, at 19. They contended their proposals are more equitable because they determine the lower threshold based on the relative benefit each business

line receives from BPA's high credit rating. Harris *et al.*, BP-18-E-BPA-33, at 141 (citing Deen *et al.*, BP-18-E-JP05-01, at 18-19, 22, 25; Saleba *et al.*, BP-18-E-WG-01, at 10, 25). Allocating the lower threshold responsibility based on capital expenditures ("capex" or benefits allocation) results in roughly 45 percent of the responsibility for agency financial reserves to Power Services and 55 percent to Transmission Services, or roughly \$180 million to Power and \$220 million to Transmission. *Id.*

In rebuttal testimony, Staff acknowledged that JP05's and WPAG's proposals could be a valid allocation methodology and included it within Staff's Alternative Option. *Id.* at 140-52. Staff modified JP05's and WPAG's proposal to create more appropriate deadbands for the business lines. *Id.* at 141-42. Nonetheless, Staff's support for the capex allocation was tepid. Staff made clear that its support for the Alternative Option was provided in the spirit of providing the Administrator with additional options on the record, but that its initial FRP proposal remained its recommendation:

Q. Are you are supporting this new alternative option as a replacement for your Initial Proposal?

A. No. The proposed FRP is our preferred option. Harris et al., BP-18-E-BPA-17, Appendix A. Nonetheless, the alternative option we describe below is also a strong alternative that the Administrator should consider.

Id. at 140; *see also id.* at 149 ("While not our preferred method, in providing the Administrator other options derived from the parties' cases, we believe the allocation method in the alternative option (which uses a different perspective on equity) could also be a means of achieving our equity objective.").

In the following section, BPA discusses its decision regarding the appropriate methodology and allocation for the lower threshold in the final FRP. BPA also addresses parties' technical arguments regarding the calculation of the lower threshold.

6.6.4.2.2 Issues

Issue 6.6.4.2.2.1

Whether the lower thresholds for the business lines should be determined based on days cash or projected capital expenditures (capex).

Parties' Positions

Powerex, JP02, and M-S-R contend that BPA should determine the lower thresholds for the business lines based on the days cash on hand metric, which reflects the relative *need* for holding financial reserves. That need, according to these parties, is shaped by the business lines' size and volatility. JP02 and Powerex argue the capex allocation ignores the business lines' relative size and volatility and, therefore, does not link the cost of holding reserves with the need for reserves. JP02 Br., BP-18-B-JP02-01, at 27, 31; Powerex Br., BP-18-B-PX-01, at 18. In contrast, as noted

by Powerex, “[t]he days’ cash metric accounts for the magnitudes of the annual revenue requirements of each business line . . . [and] provides an adequate buffer for the revenue variability of each business line because it reflects the cash needed to cover operating expenses.” Powerex Br., BP-18-B-PX-01, at 18-19. M-S-R agrees: “[the days cash] metric considers the business line’s relative cash needs” M-S-R Br., BP-18-B-MS-01, at 18.

M-S-R, Powerex, and JP02 also argue the capex allocation is inconsistent with cost-causation principles, and instead advocate for BPA to adopt the days cash allocation as more consistent with cost-causation principles. M-S-R Br., BP-18-B-MS-01, at 15; Powerex Br., BP-18-B-PX-01, at 12, 16; JP02 Br., BP-18-B-JP02-01, at 31. These parties describe cost-causation principles as prescribing that costs should follow need. Powerex states, “[a]t a high level, the principle of cost causation is a fundamental [tenet] of BPA’s ratemaking and is generally stated as the costs should follow those who caused the costs.” Powerex Br., BP-18-B-PX-01, at 16. M-S-R states, “[w]hile not perfect, the [days cash allocation] at least has some relationship to cost causation, as the cash reserves thresholds would be measured by the cash needs of each business line.” M-S-R Br., BP-18-B-MS-01, at 21. JP02 states, “[c]ost causation principles call for financial reserves to be determined based upon the need for financial reserves” JP02 Br., BP-18-B-JP02-01, at 31.

In its Brief on Exceptions, M-S-R states its support for BPA’s draft decision to allocate the lower threshold based on days cash as being “equitable and more consistent with cost causation than allocating reserves requirements based on projected capital spending.” M-S-R Br. Ex., BP-18-R-MS-01, at 2.

WPAG asserts the capex allocation is consistent with cost-causation principles. WPAG Br., BP-18-B-WG-01, at 12-13. Instead of viewing the allocation methods through the cost-causation lens that costs should follow *need*, WPAG argues the capex allocation is consistent with the cost-causation principle that costs should follow *benefits*. *Id.* at 13. WPAG characterizes the days cash allocation as, “essentially, using ‘but for’ causation to allocate financial reserves responsibility between the business lines—*i.e.*, but for Power’s larger days cash needs, the Agency as a whole would have a lower reserve requirement, so Power is allocated the greater share of the reserve responsibility.” *Id.* WPAG asserts “[i]t is well established . . . that ‘but for’ causation is not necessarily dispositive. Rather . . . costs are often assigned to the beneficiaries of those costs even where such beneficiaries are not the ones who caused the costs in the first instance.” *Id.* As an example, WPAG cites FERC’s transmission pricing model. *Id.* at n.45. WPAG argues the FRP “is particularly well suited for use of this principle” because it argues there would be little justification for the FRP without borrower-based benefits associated with BPA’s credit rating. *Id.* at 13-14.

In its Brief on Exceptions, WPAG challenges BPA’s rationale for adopting the days cash method. WPAG Br. Ex., BP-18-R-WG-01, at 5-13. WPAG argues that BPA’s cost causation rationale does not account for credit-support benefits, *id.* at 6-7; that BPA unfairly weighed the methods’ relative “imprecision,” *id.* at 8-9; that liquidity benefits are immaterial in selecting an allocation method, *id.* at 10-12; that the 60-day threshold was based on credit rating support as opposed to other business purposes, *id.* at 12-13; and that capex could be understood by rating agencies, *id.* at 13.

JP07 and JP06 also support the capex allocation as an allocation by relative *benefits*. JP06 argues the FRP should “align[] between Power and Transmission the costs and benefits of supporting BPA’s credit ratings by allocating the responsibility of supplying cash reserves based on projected interest cost saving on projected borrowing needs of Power and Transmission” JP06 Br., BP-18-B-JP06-01, at 4-5. JP06 has previously argued that “responsibility for any cash collected or retained primarily to preserve BPA’s credit ratings should be allocated between the two business lines based on the borrowing needs of the business lines because the benefit of higher credit ratings is to lower the cost of new borrowings.” *Id.* at 3-4. JP06 supports the Alternative Option as a “creative response to the dual purposes for cash reserves: to provide liquidity and to support credit ratings” by allocating lower thresholds by capex and adding a days cash deadband. *Id.* at 6. Kalispel supports JP06’s arguments and positions. Kalispel Br., BP-18-B-KT-01, at 2-3.

In its Brief on Exceptions, JP06 agrees with BPA that both the capex and days cash methods “are legally and logically valid methods for calculating the lower threshold for each business line.” JP06 Br. Ex., BP-18-R-JP06-01, at 4. But JP06 disagrees that the days cash method is superior. *Id.* JP06 presents a number of equity arguments to make its case that the FRP unfairly advantages Transmission customers at the expense of Power customers. JP06 Br. Ex., BP-18-R-JP06-01, at 1-3.

JP06 filed its Brief on Exceptions after the deadline set in the Hearing Officer’s Order Amending Schedule, BP-18-HOO-30, at 3-4. Notwithstanding this procedural defect, and without waiving BPA’s right to deny other late filings, BPA has considered JP06’s arguments.

JP07 characterizes the days cash allocation as inequitable because it “came with no commensurate benefits to its customers” JP07 Br., BP-18-B-JP07-01, at 18. JP07 states, “[t]ransmission customers clearly have more to gain from the proposed BPA financial reserves policy, and any sound financial reserves policy should reflect that.” *Id.* at 14. In contrast, JP07 appreciates the capex allocation because it “takes a long-term and balanced view of aligning costs and benefits and acknowledges that both business lines benefit from BPA managing its debt portfolio on an integrated basis.” *Id.* at 19.

In its Brief on Exceptions, JP07 argues that the days cash method fails to equitably align costs with benefits between business lines, given that the primary objective of the FRP is to maintain BPA’s credit rating. JP07 Br. Ex., BP-18-R-JP07-01, at 3-6.

ICNU argues that the two perspectives on allocation described above cannot both be valid. ICNU Br., BP-18-B-IN-01, at 70-71. ICNU argues Staff’s testimony acknowledging the capex proposal’s merit undermines the evidentiary basis for either allocation method to satisfy the equity objective. *Id.* at 29-30.

BPA Staff’s Position

Staff’s preferred method is to determine the FRP’s lower thresholds for each business line based on days cash on hand. Harris *et al.*, BP-18-E-BPA-33, at 10-11, 140. Staff, however, concluded that an allocation based on a rolling 10-year projection of BPA capital spending, as proposed by

JP05 and WPAG, has enough merit to also be a means of achieving an equitable allocation. *Id.* at 140, 149.

Evaluation of Positions

BPA acknowledges that determining the lower thresholds for each business line in the FRP was one of the most difficult issues in this case. Both methods are founded on compelling principles, and the parties have presented well-reasoned arguments regarding their respective positions.

Legal Considerations

As BPA evaluated which of the two methodologies to adopt, if any, BPA first considered whether the law required one method over the other. Powerex cites BPA's statutory obligations, and concludes that "by proposing to evaluate each business line independently, BPA Staff's proposal recognizes and comports with BPA's statutory obligation to . . . separately account[] the costs and revenues of each business line to ensure that one is not subsidizing or benefitting from the other." Powerex Br., BP-18-B-PX-01, at 8-9 (citing NWPA § 7(a)(2); *Bonneville Power Admin.*, 25 FERC ¶ 61,140, at 61,376, n.9 (1983) (remanding BPA's proposed rates due to a lack of separate accounting)).

BPA agrees the days cash method would be one way of meeting the cited statutory obligation, but BPA does not view this language as prescribing one method over the other. Both the days cash and the capex methods would include an independent analysis of the business lines' costs to ensure costs were equitably allocated. Neither method assigns responsibility for holding reserves to a business line without justification.

BPA also considered ICNU's position that the two perspectives on calculating the lower threshold described above cannot both be valid. ICNU Br., BP-18-B-IN-01, at 70-71. ICNU argues that Staff's reasoning loses all meaningful value if it would support both calculation methods. *Id.* ICNU also argues that Staff's testimony acknowledging the capex proposal's merit undermines the evidentiary basis for either method to satisfy the equity objective. *Id.* at 29-30.

BPA does not agree that the existence of two potential answers to the same problem invalidates those answers. Both methods are arguably consistent with equity and cost causation principles. The method must have a rationale, so two defensible methods in no way open the door to limitless options. Instead, whether one valid method prevails over another depends on the facts and circumstances at issue.

Thus, BPA finds that neither the law nor alleged evidentiary or reasoning deficiencies prohibit BPA from considering both methods for determining the lower thresholds. To that end, BPA recognizes that both days cash and capex could be viewed as valid methods for calculating the lower thresholds for the business lines. Harris *et al.*, BP-18-E-BPA-33, at 140, 149. However, BPA is persuaded that the most appropriate method for determining the lower thresholds is a days cash calculation for each business line. BPA's rationale is described further below.

Policy, Equity and Practicality Considerations

Proponents of both methods describe the outcome of their preferred method as being more equitable. For example, WPAG describes the capex allocation resulting in Transmission being allocated 55 percent of the responsibility for reserves and states, “[t]his is, by far, a more equitable outcome than the one under BPA’s initial proposal, which would allocate 75 percent of the reserve responsibility to Power even though Power would only receive 45 percent of the benefit from the new policy.” WPAG Br., BP-18-B-WG-01, at 14-15.

Likewise, but from the opposing perspective, JP02 argues the capex allocation would not result in an equitable outcome because it would cause Transmission to bear an inequitable burden for providing financial reserves. JP02 Br., BP-18-B-JP02-01, at 16, 41. The capex allocation would result in “about 35 days cash on hand for Power and 134 days cash on hand for Transmission.” *Id.* at 47.

M-S-R states the capex allocation “would be worse than the status quo, as it would institutionalize Transmission carrying reserves to meet Power’s requirements.” M-S-R Br., BP-18-B-MS-01, at 19. M-S-R includes tables “demonstrat[ing] the current imbalance in reserves and the inequitable results of the [capex allocation.]” *Id.* at 20.

ICNU argues the outcome of the days cash method creates a “perception of inequity” because of “the magnitude and length of Power rate increases required under the FRP” ICNU Br., BP-18-B-IN-01, at 27-28. ICNU claims that Staff estimates transmission customers stand to benefit at a 3:2 ratio in comparison to Power customers, calculated as the avoidance of “\$33 million attributed to Transmission Services and \$22 million to Power Services.” *Id.* at 28. Yet, Staff’s proposal seeks to increase financial reserves by \$309 million, effectively from Power customers. *Id.*

As BPA has considered the parties’ arguments, the record, and general equity and practicality considerations, BPA is persuaded that the days cash method for determining the business lines lower thresholds is the preferable approach because of the following: (1) the days cash method properly treats financial reserves as an asset held by healthy utilities; (2) the days cash method is more consistent with cost causation and equity principles; (3) days cash calculations are the standard metric for assessing financial health; (4) the capex allocation does not account for all the benefits derived from holding financial reserves; and (5) the days cash method is simpler to implement. These reasons are examined more thoroughly below.

1. Financial reserves are a necessary asset measured by days cash.

Fundamentally, BPA is adopting a long-term policy to guide BPA in defining and maintaining prudent levels of financial reserves for BPA and for each business line. Harris *et al.*, BP-18-E-BPA-33, at 8. In developing this policy, BPA has been clear that allowing the current paradigm to continue—where one business line holds little to no financial reserves—would not be acceptable. It is thus imperative that the allocation of the financial reserve obligation between the business lines recognize that financial reserves are an asset to each business line and that each should hold financial reserves to support its business and BPA’s overall financial health. The capex perspective finds that financial reserves are an asset to a business line only to the

extent there are proportional credit-support benefits to the customers of that business line. BPA, then, should hold only that amount of financial reserves at the agency level to placate the credit rating agencies. That is, if a business line is required to hold more in financial reserves than it receives in credit-related benefits, then that business line's allocation would be inconsistent with cost causation and equity principles. *See* WPAG Br. Ex., BPA-18-R-WG-01, at 6-7; JP07 Br. Ex., BP-18-R-JP07-01, at 3-6. Foundationally, then, the capex method finds there is no *intrinsic value* to holding financial reserves beyond that provided through BPA's credit rating. This perspective essentially treats the credit rating agencies' statements about prudent levels of financial reserves as an otherwise arbitrary price for a certain credit rating, and thereby ignores the fact that prudent levels of financial reserves are a metric for evaluating financial health because of the value of those financial reserves. Thus, if a business line does not rely on BPA's credit rating, it equally would have no need to hold *any* financial reserves. In this way, the capex methodology finds that financial reserves have no intrinsic value to BPA or its customers beyond that needed to appease the credit rating agencies.

In contrast, the days cash perspective recognizes that holding financial reserves has intrinsic value to both BPA and the business lines. The days cash method ensures that both business lines hold financial reserves, and does not perpetuate the current paradigm where one business line could go without holding any financial reserves (consistent with TPP) because of the lack of a "credit benefit." The days cash perspective also recognizes that holding financial reserves provides other benefits beyond those associated with BPA's credit rating, including liquidity benefits and the ability to absorb losses without passing on immediate rate increases to customers. These other benefits, which are discussed in more detail below, are inherent in the days cash method, but not in the capex method.

WPAG argues that the capex methodology would also provide these "indirect" benefits of financial reserves. WPAG Br. Ex., BP-18-R-WG-01, at 13. WPAG argues that there is no evidence to show that such other purposes would not also be satisfied by the \$180 million in financial reserves "requirement" for Power under the capex proposal. *Id.* Similar to the "tag-along" liquidity benefits discussed below, WPAG argues the capex proposal will also indirectly advance BPA's other business purposes compared to the status quo simply by increasing Power Services' reserve levels. *Id.* JP07 makes similar arguments. *See* JP07 Br. Ex., BP-18-R-JP07-01, at 7-9.

Although the capex method would make it less likely that a business line's financial reserves would be \$0, this scenario would still remain a possibility under the capex methodology. This is because nothing in the capex methodology *requires* both business lines to hold financial reserves. It follows from the capex method's rationale that a business line's obligation to hold financial reserves should only exist to the extent that the business line intends to spend money in the future for capital programs. If a business line chooses to no longer support future capital investment programs the business line could hold *no* financial reserves. Under this extreme scenario, the capex perspective would contend that requiring a business line to hold even \$1 of financial reserves (unless needed for TPP support) would be inconsistent with the benefits allocation and inequitable.

BPA notes this extreme scenario not to suggest that it will definitively occur, but to highlight a foundational difference between the two methodologies it is considering. One methodology, the capex, finds that financial reserves have no intrinsic value beyond that which can be attached to BPA's credit rating, and would permit reserves to go to \$0 under certain circumstances. The capex methodology, then, would permit the gap in BPA's financial policies to continue by allowing one business line's financial reserves to be \$0 while the other business line's financial reserves would be much higher.

The days cash method, in contrast, recognizes the intrinsic value of holding reserves and calculates a business line's financial reserves based on the business line's need for cash, which will always render a value above \$0, thereby addressing the current gap in BPA's policies. BPA's intent in developing the FRP is to create a long-term policy that will, among other purposes, ensure BPA and its business lines retain reasonable and prudent levels of financial reserves to support BPA's financial health. As an agency tasked with maintaining the federal power and transmission systems, and with a direction to operate like a business, *see APAC v. BPA*, 126 F.3d 1158, 1170 (9th Cir. 1997), BPA finds that it would be imprudent to assume it could operate one of its business lines for a long period of time with \$0 cash or negative cash. *Harris et al.*, BP-18-E-BPA-17, at 16. BPA's current methodologies allow this situation to occur on a short-term, rate-period basis. *Id.* The FRP, with the days cash methodology, corrects this gap in BPA's policies by ensuring that, over time, this gap is corrected, and both business lines retain healthy levels of financial reserves.

2. Consistency with Cost Causation and Equity

As noted above, holding financial reserves is an asset for BPA and each of the business lines, which provides independent benefits to BPA and the business lines above and apart from the credit-rating benefits. Nonetheless, even if holding financial reserves were a "cost" and the benefits of holding financial reserves were limited to the credit-related benefit, determining the business lines' lower thresholds based on days cash would still be appropriate. This is because the days cash methodology is more consistent with cost-causation principles than the capex allocation.

BPA's financial reserves needs, as indicated by the credit rating agencies' metrics, are the sum of the business lines' needs. As established in the FRP, the lower threshold for ensuring those needs are met is 60 days cash for the agency, which is approximately \$400 million. Sixty days cash for Power Services is approximately \$300 million, and 60 days cash for Transmission Services is approximately \$100 million. Power and Transmission Risk Study, BP-18-E-BPA-05, at 114-15, Tables 11 & 12. The agency's lower threshold is the sum of these two values. *Id.* The rationale for determining business line lower thresholds by individual business line days cash is simple: since Power Services is larger, and the amount of financial reserves it needs is greater, it is consistent with cost causation to assign it a proportional share of the financial reserves obligation to meet the lower threshold (*i.e.*, \$300 million). To use traditional cost-causation terminology, the incurrence of the costs in this instance (\$400 million in agency financial reserves) is caused, in part, by Power Services' days cash need (\$300 million), which is substantially more than the need imposed by Transmission Services (*i.e.*, around \$100 million). Thus, determining the lower thresholds based on days cash (which assigns the business lines

their proportional share of the financial reserves attributable to the agency) is consistent with cost causation.

Several parties agree that the days cash method is more consistent with cost causation. Powerex states, “[a]t a high level, the principle of cost causation is a fundamental [tenet] of BPA’s ratemaking and is generally stated as the costs should follow those who caused the costs.” Powerex Br., BP-18-B-PX-01, at 16. M-S-R states, “[w]hile not perfect, the [days cash allocation] at least has some relationship to cost causation, as the cash reserves thresholds would be measured by the cash needs of each business line.” M-S-R Br., BP-18-B-MS-01, at 21. JP02 states, “[c]ost causation principles call for financial reserves to be determined based upon the need for financial reserves” JP02 Br., BP-18-B-JP02-01, at 31.

WPAG, however, argues that “‘but for’ causation is not necessarily dispositive” for cost causation, and advocates for a methodology based on relative benefits. WPAG Br., BP-18-B-WG-01, at 13. As an example, WPAG cites FERC’s transmission pricing model. *Id.* at n.45. WPAG argues the FRP “is particularly well suited for use of this principle” because there would be little justification for the FRP without borrower-based benefits associated with BPA’s credit rating. *Id.* at 13-14. JP07 and JP06 similarly contend that a proper allocation should align the “benefit” with the accompanying burden. JP07 Br., BP-18-B-JP07-01, at 19; JP06 Br., BP-18-B-JP06-01, at 5-6. ICNU argues Staff’s explanation for finding the days cash allocation is more consistent with cost-causation principles than a benefits allocation does not meet evidentiary standards. ICNU Br., BP-18-B-IN-01, at 69-70.

BPA agrees that “[i]n many other situations, allocating costs based on relative benefit could be more consistent with cost causation principles.” Mullins, BP-18-E-IN-01-AT01, at 83 (Data Response PP-BPA-26-13). But cost causation requires “comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party.” *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004). In this instance, the burden imposed to support BPA’s credit rating for the FY 2018 rate period is \$400 million, which is the equivalent of 60 days cash. The requirement to hold \$400 million at the agency level is, as noted above, a direct result of the size of the business lines’ operating expenses. The incurrence of the cost to Power Services (\$300 million) is directly related to the burden imposed on BPA. Thus, the days cash method aligns the costs to the business lines in direct proportion to the financial reserves need that the business lines place on BPA, consistent with cost causation.

In its Brief on Exceptions, WPAG disagrees with BPA’s cost causation rationale, arguing that “BPA’s determination to adopt the days cash method . . . draws a direct line from the supposed ‘burden imposed’ by Power Services to support BPA’s credit rating to the cost ultimately allocated to the service for such purpose without any consideration of the relative benefits drawn by Power Services or Transmission Services from supporting BPA’s credit rating.” WPAG Br. Ex., BP-18-R-WG-01, at 7. WPAG describes a situation under the days cash method wherein “Power Services could stop borrowing altogether, and thereby cease receiving any benefit from supporting BPA’s credit rating, and still be allocated three quarters of the cost of supporting BPA’s credit rating.” *Id.* While describing this scenario as extreme, WPAG argues it illustrates an inequity left unaddressed by the days cash method. *Id.*

WPAG’s argument, however, is flawed since it presumes that under the capex methodology this same alleged inequity would not occur (*i.e.*, if Power Services ceased “borrowing” under the capex methodology, there would be no inequity because Power Services would not be required to hold any additional financial reserves). That is incorrect because the capex methodology does *not* allocate the financial reserves obligations between the business lines based on projected capital *borrowing*, but on *projected capital spending*. See Saleba *et al.*, BP-18-E-WG-01, at 10; Dean *et al.*, BP-18-E-JP05-01, at 18. Thus, under the capex methodology, it does not matter whether a business line borrows (or does not borrow) money to finance a future capital project. All that matters for that business line to be allocated a portion (or all) of the financial reserves obligation is that the business line intends to *spend money* in the future on a capital project. Returning to WPAG’s example, under the capex methodology if Power Services’ chose *not* to “borrow” any more money for its future capital programs, *it still* would be required to hold 45 percent of the financial burden to support BPA’s credit rating *because* Power Service’s capital projects make up 45 percent of the future capital spending. Thus, the very “inequity” WPAG claims the days cash methodology has left unaddressed is equally “unaddressed” by the capex methodology.

Moreover, by divorcing the costs of the business lines from the need of each business line to hold financial reserves, the capex methodology *creates* additional inequities. For instance, assume Power Services’ operating expenses doubled so that now 60 days cash for Power increased from \$300 million to \$600 million. Assume also, Transmission Services’ operating expenses remained the same. The agency lower threshold would now be \$700 million (\$600 million for Power and \$100 million for Transmission), but the allocation of this amount would be divided by the projected capital spending dictated by the capex methodology (55 percent to Transmission and 45 percent to Power). Transmission’s financial reserves obligation would have to *increase* by 75 percent (from \$220 million under current numbers to \$385 million) to receive the *same* 55 percent of the credit rating benefits. What is more, this increase to Transmission customers’ financial reserves obligation would occur for no other reason than the increase caused by *Power’s* increase in operating expenses. The following pattern would hold true even in a scenario in which Transmission’s need for financial reserves were to *decrease*. That is, if Transmission’s operating expenses fell to \$50 million (thereby *reducing* BPA’s overall need for financial reserves to support BPA’s credit rating), under the capex methodology, Transmission customers would nonetheless continue to bear a greater responsibility of holding *more* financial reserves because of *Power’s* higher operating expenses. Far from being a more equitable allocation methodology, as this extreme scenario illustrates, the capex methodology can fundamentally disconnect costs and benefits.

In JP06’s Brief on Exceptions, JP06 presents a number of equity arguments to make its case that the FRP unfairly advantages Transmission customers at the expense of Power customers. JP06 Br. Ex., BP-18-R-JP06-01, at 1-3. JP06 contends that one element of BPA’s equity objective for the FRP is that one business line should not be required to maintain excess reserves so that the other business line might be relieved of the need to put up or maintain its own share of reserves. *Id.* at 2. JP06 argues that, as a practical matter, given the business lines’ relative cash reserves when BPA started considering a financial reserves policy, one virtually certain result of BPA adopting the new FRP is that Power customers would be called upon to pay more for power than

their annual revenue requirement to BPA to increase BPA's cash reserves, and that some of the amount of such above-cost payments would in all probability someday be refunded to, or be otherwise used for, the benefit of Transmission customers. *Id.*

These arguments are without support and fundamentally misrepresent the FRP. Power customers will not be required to pay "more for power than their annual revenue requirement" to increase cash reserves. The FRP requires BPA to include PNRR in rates, which means PNRR becomes a component of the revenue requirement, not independent from it. Further, JP06's concern that it must now pay "more" to rebuild Power's financial reserves is unpersuasive when considering that JP06 has for the past 10 years paid "less" for BPA's power, as BPA absorbed \$700 million in less-than-projected revenues (or increased costs) through its financial reserves. *See* Section 6.2.5 (how financial reserves decline). That is, BPA addressed uncertainty in past years by allowing Power financial reserves to decline without replenishment, with the consequence that Power rates were allowed to remain lower than would otherwise have been the case. Now that Power financial reserves are at or near zero, BPA must take steps to rebuild its financial reserves. Contending that it is inequitable for power customers to now pay "more" for power ignores the series of years in which BPA deferred building or maintaining financial reserves to prevent power rates from increasing higher. Finally, JP06's claim that "some amount of [Power financial reserves] . . . would in all probability someday be refunded to, or be otherwise used for, the benefit of Transmission customers" is without merit. JP06 Br. Ex., BP-18-R-JP06-01, at 2. No provision of the FRP permits one business line to consume the other business line's financial reserves.

JP06 also contends that, given current levels of BPA's financial reserves, Power customers will be required to put up all the "new money" to support BPA's credit rating, from which Transmission is likely for the foreseeable future to benefit more than Power will, and "with any luck for them" Transmission customers could also "receive future rate relief to boot." *Id.* at 3. JP06, once again, mischaracterizes the FRP. Nothing in the FRP relieves Transmission customers from their responsibility to support BPA's financial reserves. Indeed, BPA expressly rejected proposals that would have "capped" financial reserves contributions from Transmission. *See* Issue 6.6.4.5.3 (transmission financial reserves cap). Thus, "new money" may continue to come from both Transmission rate payers and Power rate payers. The only difference imposed by the FRP is that Power rate payers will be *required* to support financial reserves through specific rate action, such as including PNRR in BPA's revenue requirement. As noted throughout this Record of Decision, that requirement does not exist today, with the consequence that Power could deplete *all* of its financial reserves without replenishing them.

Moreover, requiring Power customers to support agency financial reserves is not inequitable because Power financial reserves are at all-time lows, and indeed, is a key factor in BPA's decision to develop the FRP. Power financial reserves' precipitous decline is one of the reasons BPA has found that its current policies contain a gap that must be filled with the FRP. *See* Section 6.1 (introduction); Section 6.2.3 (existing policies on financial reserves); Section 6.4.1 (need for FRP); and Issue 6.4.4.2.1 (equity issue between business lines). Requiring Power to begin rebuilding these financial reserves is sensible and equitable.

JP06 also contends that the Transmission customers are likely to “benefit more” from Power Services holding financial reserves because this new money will be used to support BPA’s credit rating, which JP06 contends benefits Transmission more than Power. JP06 Br. Ex., BP-18-R-JP06-01, at 3. This argument, however, presumes that holding financial reserves provides no value to Power other than that provided by credit support. As discussed below, this is not the case. Holding financial reserves has intrinsic value apart from BPA’s credit support. Thus, requiring Power Services to hold financial reserves is not only good for BPA’s overall credit rating, it is good for Power Services and its customers as well.

Furthermore, while requiring Power Services to hold financial reserves will increase the likelihood that Transmission financial reserves may be repurposed for Transmission customers, this tertiary benefit does not negate the importance or need for Power to hold financial reserves. Indeed, any policy which increases Power’s financial reserves will necessarily raise overall agency financial reserves, making redistribution of Transmission reserves more likely. The key policy question is whether there are sound reasons to require Power Services to hold financial reserves in the amounts identified in the FRP. BPA is convinced, for the reasons described herein, that the answer is yes.

JP07 argues in its Brief on Exceptions that, since Power would bear 75 percent of the agency’s lower reserve threshold and only receive 42 percent of the potential benefits of avoiding a credit downgrade, that the FRP “fails to align costs with benefits, and thus JP07 takes exception to the Draft ROD’s conclusion that the days’ cash on hand method ‘equitably aligns costs and benefits between Power and Transmission.’” JP07 Br. Ex., BP-18-R-JP07-01, at 4 (quoting Administrator’s Draft Record of Decision at 228).

The FRP, including the days cash method for determining the business line lower thresholds, is equitable. The days cash and capex methods use different perspectives on equity. Harris *et al.*, BP-18-E-BPA-33, at 149. Equity can be measured through several different lenses. *Id.* at 147. Here, the FRP applies symmetrical methodologies and mechanisms between the business lines, while allowing an exception to phase-in Power’s lower threshold, and also ensures that both business lines are contributing to the agency’s financial reserves. *Id.* A third component of equity is the concept of equity between the business lines in the amount of the contribution to the agency’s financial reserves. *Id.* at 148. The days cash method allocates responsibility for holding an amount of financial reserves based on business-line days cash, not based on credit-rating benefits. *Id.*

BPA is convinced that the days cash method’s perspective on equity is more appropriate. It properly values financial reserves as an asset and is consistent with the cost causation principle of costs following burden imposed. Since the resulting amounts are consistent with this perspective on equity, the resulting allocation is equitable. Therefore, it cannot be said that the FRP “*unduly* burdens one business line *over* the other.” JP07 Br. Ex., BP-18-R-JP07-01, at 3 (emphasis added). When JP07 argues that the method “should present at least an equivalent business case for each of the agency’s two business lines,” it essentially restates their perspective that a benefits-based allocation, focused solely on credit-rating benefits, is more appropriate. The days cash method equitably aligns the responsibility for financial reserves with the business lines’ relative contribution to the agency’s need for financial reserves.

JP07's concerns with the level of benefits received from the FRP are addressed in Issue 6.6.6.2 (FRP and sound business principles) and Issue 6.6.6.3 (FRP and competitiveness).

In sum, as BPA has considered both of these methodologies—days cash and capex—and considered which of these was more consistent with cost causation and equity, BPA cannot escape the basic tenet that costs should follow their cause. Fundamentally, the FRP is BPA's policy for ensuring it holds an appropriate level of financial reserves. In this case, the *need* to hold financial reserves, even if only from the perspective of supporting BPA's credit rating, is directly related to the amount of cash each business line requires to operate its business. Requiring each business line to hold financial reserves equivalent to 60 days operating cash tracks directly with the causal relationship between BPA's credit rating and its need to hold financial reserves. In contrast, requiring Transmission to hold financial reserves well above its operating needs because of the size of Power's business fails this basic tenet of cost causation.

3. *Days cash is an industry metric for financial health; capex is not.*

The days cash metric itself is recognized as the industry standard unit of measurement for assessing the sufficiency of a utility's financial reserves levels. Financial reserves are an indicator of financial health. See Harris *et al.*, BP-18-E-BPA-17, at 13-15; Harris *et al.*, BP-18-E-BPA-33, at 17. Credit rating agencies assess an entity's financial health in determining creditworthiness, and when they assess the sufficiency of the entity's financial reserves, they do so in terms of days cash on hand. *Id.* Under this metric, a business's financial reserves needs are a factor of that business's operating expenses. As noted below in Issue 6.6.4.2.2.3, BPA determined that it should hold at least 60 days cash as an agency. If BPA's financial health as an entity is evaluated from the agency's days cash position, it makes little sense that BPA would apply a different metric when assessing the relative contributions of its business lines. The FRP reflects the role financial reserves play in determining BPA's creditworthiness by determining the responsibility for holding financial reserves based on the same industry standard days cash metric used by the credit rating agencies to assess financial health. In contrast to the days cash method, the capex allocation has no corollary in the industry that BPA knows of.

Moreover, the capex method creates a significant internal tension within the FRP because levels of financial reserves are considered "healthy" when they are above 60 days cash for BPA, but then Transmission Services is required to hold—under current capex projections—more than twice that amount (134 days) and Power Services is allowed to hold nearly half that "healthy" amount (36 days).

As a policy matter, BPA is concerned with adopting a methodology that would produce a low level of financial reserves (by industry standards) for one business line, and a much higher level of financial reserves for the other. The days cash metric on the other hand, computed individually for each business line, uses a recognized and accepted method for calculating a business' need for financial reserves that is right-sized to the business' operating expenses.

WPAG argues in its Brief on Exceptions that BPA developed a non-standard metric, TPP, and "the rating agencies understand and accept it." WPAG Br. Ex., BP-18-R-WG-01, at 13. Therefore, it argues, BPA should be able to similarly explain other non-standard metrics, such as the capex method. *Id.* BPA does not dispute that it is capable of explaining non-standard

methodologies, such as the TPP, to external parties like the credit rating agencies. How these non-standard metrics are received and what weight they are given by external parties, however, are beyond BPA's control. The credit rating agencies have indicated that having a financial reserves policy would be a positive factor for BPA's credit rating. Harris *et al.*, BP-18-E-BPA-33, at 12. BPA is concerned that including within the FRP non-standard metrics would place the FRP at risk of being misunderstood by the credit rating agencies or having it deemed less valuable due to its non-standard terms. While not a dispositive factor in BPA's determination of the appropriate allocation methodology, BPA finds the more prudent course is to adopt an allocation metric that uses an existing industry standard (*i.e.*, days cash), which is readily understood by the credit rating agencies and its analysts. This approach will help ensure that the financial reserves policy provides both clear and understandable internal and external policy guidance that is simple to explain and easy to calculate.

4. Capex allocation does not account for all benefits.

Even if BPA were to agree that financial reserves for the business lines should not be measured through an industry standard calculation (*i.e.*, days cash), but allocated by a BPA-specific benefits-based methodology (*i.e.*, capex), the capex allocation is an incomplete assessment of the other benefits of holding financial reserves.

4(a) Credit support benefit

First, the capex allocation inadequately accounts even for the *credit support* benefits of holding financial reserves. Powerex and JP02 argue that the capex allocation did not consider all the relevant benefits related to BPA's credit rating. Powerex Br., BP-18-B-PX-01, at 16, 20; JP02 Br., BP-18-B-JP02-01, at 45. These parties note that an additional benefit of BPA's credit rating is related to refinancing, which is not included in the capex allocation. *Id.* That is because BPA's decision to refinance its existing debt is not included in its projections of future spending for capital projects, and thus, would be excluded from the capex methodology. BPA agrees that this omission is important and would change the relative benefits associated with BPA's credit rating. JP07 and WPAG recognized this omission at oral argument and acknowledged that their proposal would need to include some recognition of refinancing. *See* Oral Argument Tr. at 10-13, 120-21.

In its Brief on Exceptions, WPAG stated it "would be open to discussing the inclusion of the refinancings in the capex method in the process to follow the rate case." WPAG Br. Ex., BP-18-R-WG-01, at 8. In contrast, JP07 argued that including refinancings would be difficult and, as a practical matter, would result in "a more favorable allocation to power." JP07 Br. Ex., BP-18-R-JP07-01, at 7-8. JP07 therefore justifies leaving out refinancing benefits "in the spirit of constructive engagement." *Id.* at 8.

As both WPAG and JP07 concede, the business lines receive a benefit from BPA's credit rating in refinancings, the capex method ignores the benefits of refinancings when purporting to allocate by benefits, and the allocation of the lower threshold would be different if refinancing benefits were included. JP07 contends that omitting refinancings is allowable because including refinancings would result in a more "favorable allocation to power." Regardless of which business line benefits during this rate period, though, circumstances will change and these

changes will not be accounted for in the proposed capex method. In this way, the capex method is an incomplete accounting of the benefits of BPA's credit rating in that it accounts for only a specific subset of those benefits.

JP07 contends that including refinancings would result in business line allocations being less stable through time and could lead to potential unintended consequences of financial management decisions being influenced by their impact on the allocation. *See* JP07 Br. Ex., BP-18-R-JP07-01, at 8. BPA agrees. BPA does not forecast planned refinancings in the way it does capital expenditures. BPA's refinancing is done in partnership with Energy Northwest and requires approval by the Energy Northwest board. BPA typically brings only near-term refinancing possibilities to the Energy Northwest board for approval, and generally does not forecast a refinancing until it has been approved. Decisions to refinance are more opportunistic in nature than capital expenditure decisions, based on taking action when economic circumstances are most favorable. Since the interest rates available in the market can change significantly over a short timeframe, incorporating refinancings within the proposed capex method could result in sudden shifts to the allocation (as the amount BPA decides to refinance responds to interest rates becoming more or less economically advantageous). This would likely result in the "unintended consequences" mentioned by JP07 and in conflict between interested parties. At the same time, though, BPA can find no logical basis to *exclude* refinancings from an allocation methodology that purports to assess the financial reserves obligations between the business lines based on relative benefits. Refinancings must either be included (thereby compounding the complexity and difficulty of calculating the capex allocation) or excluded (thereby creating an incomplete allocation). In either case, the capex method becomes a poor proxy for allocating responsibility for holding financial reserves by credit rating benefits, and there is not a clear path forward on how this defect could be remedied.

As noted by JP07 and WPAG, the Draft ROD incorrectly stated that the capex method allocated the financial reserve obligation for the lower threshold based only on non-Federal borrowing. *See* JP07 Br. Ex., BP-18-R-JP07-01, at 9; WPAG Br. Ex., BP-18-R-WG-01, at 8-9. BPA agrees that the proposed capex method would not allocate the lower threshold based on *any* borrowing, whether federal or non-federal. Rather, the capex methodology allocates the lower threshold on projected future capital *spending*. The capex allocation would not be affected by BPA's decision to use Federal or non-Federal debt.

4(b) Liquidity and rate-stability benefits

Another concern BPA has with the capex allocation is that it is indifferent to any of the benefits of holding financial reserves beyond credit rating support.

In the Draft Record of Decision, BPA argued that, because the capex method does not account for these other benefits when calculating the business lines' relative benefit, the capex method fails to accurately allocate by benefit. In its Brief on Exceptions, WPAG argues that, unlike credit rating support, where both business lines benefit from the reserves held by the other business line, each business line will receive the liquidity benefits only of the reserves they hold. WPAG Br. Ex., BP-18-R-WG-01, at 11. WPAG does not dispute that financial reserves provide

these other benefits, only that these benefits are not a basis for allocating the agency's lower threshold between business lines. *Id.* at 11-12.

BPA agrees that a business line will only receive the liquidity and rate-stability benefits from the financial reserves that it holds. BPA further acknowledges that the other benefits associated with holding financial reserves (rate stability and liquidity) will occur inherently whenever a business line holds financial reserves. Thus, to the extent that both the capex and days cash methods *require* the business lines to hold financial reserves, the liquidity and rate-stability benefits of financial reserves will also be present. Nonetheless, BPA is concerned that the capex methodology is indifferent to these other benefits of financial reserves. This is because the capex method only *directly* supports holding financial reserves for a specific purpose—credit rating benefit. If a business line no longer needs to rely on BPA's credit rating, the capex perspective says a business line has no other reason to hold financial reserves, and therefore, would *permit* a business line's financial reserves to go to zero, thereby eliminating the benefits of liquidity and rate-stability that financial reserves normally provide. These other benefits of financial reserves are foundational, *see Harris et al.*, BP-18-E-BPA-17, at 13, and yet would be entirely conditional and dependent on the unrelated variable of BPA's planned capital spending under the capex methodology. The days cash method, in contrast, directly supports each business line holding financial reserves to receive credit-support, liquidity, and rate-stability benefits, and right-sizes the amount of liquidity with the overall financial needs of each business line.

WPAG further argues that the days cash method does not separately account for liquidity benefits, rendering such benefits “tag-along benefits” in the same manner as under the capex method. WPAG Br. Ex., BP-18-R-WG-01, at 11. WPAG also argues that BPA did not settle on the 60 days cash lower threshold for BPA as an agency and each business line because it serves other business purposes. WPAG Br. Ex., BP-18-R-WG-01, at 12. Rather, WPAG claims BPA determined to use 60 days cash on hand as the lower threshold solely because it would support BPA's credit rating. *Id.* at 12-13. WPAG claims there is no evidence to indicate that 60 days (or any number of days) cash is necessary to meet other business purposes. *Id.* at 13.

BPA disagrees that it must independently justify establishing the lower threshold for each business line based on the “other purposes” for financial reserves. Having established that (1) financial reserves are intrinsically valuable and support BPA's credit rating, BPA may naturally turn to the next question, which is (2) *how much* financial reserves should BPA retain for the agency and each business line. To answer (2), it was appropriate for BPA to consider whether one of the policy objectives provided more guidance on setting the *amount* of financial reserves to hold than the other objectives. Here, the credit objective provided that guidance, and thus, served as a basis for BPA finding that it should hold at least 60 days cash to support the agency's credit rating. *See* Issue 6.6.4.2.2.3. The fact that the credit rating objective was the key for the FRP's thresholds does not negate that financial reserves also support the other needs BPA has for financial reserves. The credit rating objective, which relied on the days cash assessments from the credit rating agencies, provided the most ready basis from which to calculate the financial reserves lower thresholds.

Additionally, as noted in Issue 6.6.4.2.2.3, BPA adopted the 60 days cash threshold because, among other reasons, it permitted BPA's financial reserves to absorb one standard deviation

from its rate case projections (e.g., \$250 million for Power). Although not phrased in terms of “liquidity or rate-stability benefit,” but credit rating benefit, the analysis BPA provided nonetheless demonstrates how setting the lower threshold to 60 days cash (and creating a significant “buffer”) ensures each business line meaningfully receives the three benefits of financial reserves: rate stability (by giving Power Services the ability to absorb up to \$250 million in losses), liquidity (by giving Power Service the ability to use its preferred source of liquidity—financial reserves—rather than drawing on the Treasury Facility), and support for its credit rating (by giving BPA sufficient financial reserves to prevent them from dropping below 30 days cash). In these ways, the days cash method can support BPA’s credit rating and provide a business line liquidity and rate stability in a way that the capex methodology (under current projections) would not.

Moreover, and contrary to WPAG’s argument, credit rating support is *not* the only determiner for the business lines’ lower thresholds under the FRP. The FRP establishes the lower threshold as the *greater of* 60 days cash *or* what is necessary to meet BPA’s TPP standard. *See* Section 6.6.4.1. Thus, the lower threshold may be set by *either* 60 days cash *or* what is necessary to support BPA’s liquidity needs under the TPP standard. If BPA had intended the FRP to support *only* the need for credit support, as alleged by WPAG, BPA would not have included the “greater of” provision of the FRP.

Finally, the fact that BPA is relying, in part, on the credit rating agencies’ assessment for financial reserves in no way undermines the basis for BPA finding that holding 60 days cash is an appropriate amount for BPA (and each business line) to hold. The credit rating agencies assess an entity’s financial health by referencing other entities within the same industry. BPA has very low financial reserves by industry standards. The credit rating agencies already give BPA certain benefits for the unique position it holds in relation to the Treasury. If the independent credit rating agencies are expressing concerns with BPA’s finances, even with BPA’s unique position, it would be imprudent for BPA to ignore these warnings and assume that its financial reserves (and financial policies) are fine. The capex methodology provides no certainty that the current capital expenditures will continue indefinitely, thereby allowing either business lines’ financial reserves to drop to \$0. The days cash method would not, and therefore, is the better choice.

Capex allocation proponents also argue “BPA’s liquidity is adequately addressed through existing mechanisms” and “will continue to be addressed . . . even without adoption of a financial reserves policy.” JP07 Br., BP-18-B-JP07-01, at 5, 6; *see also* JP06 Br., BP-18-B-JP06-01, at 5. In its Brief on Exceptions, WPAG further argues that the FRP is not being proposed to solve a “liquidity problem” and, therefore, it is immaterial whether the capex method takes into account the liquidity benefits of holding financial reserves. WPAG Br. Ex., BP-18-R-WG-01, at 10-11. Further, WPAG argues that the capex method would not frustrate BPA’s objective to ensure adequate liquidity because it would increase financial reserves above the status quo. *Id.* at 10. JP07 similarly argues that liquidity benefits are “gratuitous” to deciding which allocation method to adopt. JP07 Br. Ex., JP07-18-R-JP07-01, at 7.

Although BPA has adequate liquidity to ensure minimum solvency over a two-year rate period, having additional liquidity is beneficial to the business lines. *See* Section 6.4.5 (liquidity and a

financial reserves policy), Section 6.5.2 (staff's liquidity objective). Financial reserves are a keystone of BPA's long-term financial health. Harris *et al.*, BP-18-E-BPA-33, at 8. The credit rating agencies, in evaluating BPA's overall long-term creditworthiness, are aware of BPA's Treasury Facility *and* concerned with BPA's liquidity in the form of financial reserves measured in days cash. *See* Motion for Official Notice of Credit Rating Agency Reports, BP-18-M-BPA-09, Attachment A, at 6. As JP02 correctly points out, financial reserves are an asset to the business unit and that asset is BPA's preferred source of liquidity and would be available to pay for an unexpected net revenue shortfall if and when incurred. JP02 Br., BP-18-B-JP02-01, at 25. The fact that BPA is solvent does not imply that any impacts of the FRP on liquidity should be ignored. BPA has chosen to adopt the days cash method, which directly supports each business line holding sufficient reserves to realize these benefits, whereas the capex method does not.

Further, while Power Services' liquidity needs have been primarily met through the Treasury Facility, BPA's access to the Treasury Facility is dependent upon BPA's borrowing authority and Treasury's willingness to provide BPA with the Treasury Facility. *See* Issue 6.4.5.1 (liquidity and a financial reserves policy). Having financial reserves provides a business line with additional ways for meeting its liquidity needs in the event BPA's existing liquidity tools become unavailable or less robust.

BPA also sees value in ensuring that each business line will have sufficient financial reserves to allow BPA flexibility in stabilizing rates while managing uncertainty. Over the last 10 years, Power's financial reserves have declined by over \$700 million. *See* Section 6.2.5. Because power rates are set to recover only its costs, a \$700 million decline in financial reserves means \$700 million in losses were absorbed by financial reserves, thereby avoiding \$700 million in rate increases to power customers. With Power's financial reserves all but exhausted, the current CRAC framework now provides little to no rate stability. Harris *et al.*, BP-18-E-BPA-17, at 12. With no financial reserves, BPA has no financial reserves flexibility to stabilize power rates and still manage uncertainty. When Power's financial reserves fall below the lower threshold by more than \$5 million, the present CRAC paradigm will collect that financial reserves shortfall dollar for dollar (up to \$100 million per year). *See* 2018 Power Rate Schedules and GRSPs, BP-18-A-04-AP03, § II.O.1.b. JP07 and WPAG rightly identify that, under this paradigm, when financial reserves fall below a business line's lower threshold, they provide little to no rate stability. JP07 Br., BP-18-B-JP07-01, at 7; WPAG Br., BP-18-B-WG-01, at 17. But the FRP changes this paradigm.

The FRP identifies each business line's lower threshold and specifies that rate action will result when a business line has financial reserves below its threshold. *See* Section 6.6.4.1 (final FRP overview). The specifics associated with that rate action, *e.g.*, the magnitude and timing of a CRAC, will be discussed in a subsequent process. *Id.*; *see also* Section 6.6.4.3 (phase-in). This implementation detail, however, does not undermine the value of having financial reserves to support rate stability. With the adoption of this policy and its phase-in for Power, both business lines will have a financial reserves asset that is greater than zero. This provides financial flexibility not available when the lower threshold is set at zero. This financial flexibility benefit could take many forms in the future, but one of the more obvious would be in the form of added rate stability. *See* Section 6.4.6 (rate stability and a financial reserves policy). It is BPA's intent

to leverage this asset in a way that provides the most benefit to customers. Therefore, BPA and its customers will be able to further explore how future rate actions can be designed to support BPA's credit rating and provide rate-stability benefits. In contrast, the capex allocation, by linking minimum financial reserves levels solely to credit support benefits, would not ensure that a business line hold the financial reserves that would allow it to meaningfully realize these benefits.

JP07 argues the record does not support a net benefit to Power under the individual business line days cash method. JP07 states, "[t]his inequitable [days cash] allocation of responsibility to Power Services [comes] with no commensurate benefits to its customers, given that the benefit to power customers of avoiding a downgrade [is] \$16 million per year on average, roughly half of the power customers' projected cost." JP07 Br., BP-18-B-JP07-01, at 18-19. JP07 also alleges "BPA Staff does not offer compelling analysis of how shouldering Power Services with 75 percent or roughly \$300 million of responsibility for agency reserves would produce commensurate benefits for Power Services either in terms of lower interest expense or other expense reduction." *Id.* at 11. Similarly, JP06's support for a financial reserves policy is conditional on, among other things, the FRP "align[ing] between Power and Transmission the costs and benefits of supporting BPA's credit ratings by allocating the responsibility of supplying cash reserves based on projected interest cost saving on projected borrowing needs of Power and Transmission" JP06 Br., BP-18-B-JP06-01, at 4-5.

As described in Section 6.6.6 (FRP and policy objectives), BPA expects the FRP to result in a net benefit to BPA overall and to complement BPA's competitiveness efforts. In addition, as discussed above, the individual business line days cash method equitably aligns costs and benefits between Power and Transmission.

5. Simpler to implement

The days cash method is simple to implement. Many parties argue the days cash method is too simplistic. As noted above, WPAG, JP07, and JP06 advocate for a capex allocation because it limits the costs of the FRP to Power rates to the projected capital spending of Power, which approximates a rough measure of credit rating benefits of holding financial reserves. WPAG Br., BP-18-B-WG-01, at 14-15; JP07 Br., BP-18-B-JP07-01, at 11, 19; JP06 Br., BP-18-B-JP06-01, at 4-5. That is, to the extent the days cash method requires Power to hold more financial reserves than under the capex method, the days cash method *allocates too much* of the financial reserves responsibility to power rates. JP02 and M-S-R, however, argue that the days cash method *does not allocate enough* of the financial reserves responsibility to Power rates because it fails to take into account other variables that affect an entity's need to hold cash, such as financial variability and business risk. JP02 Br., BP-18-B-JP02-01, at 34; M-S-R Br., BP-18-B-MS-01, at 18.

The benefit of the days cash method's ease of use outweighs these charges of imprecision. The same cannot be said of the capex allocation, which is not only imprecise (as discussed above), but would inject unnecessary uncertainty, complexity, and controversy into the FRP's implementation.

First, the capex allocation would create additional uncertainty in calculating the lower threshold for each business line. The capex approach uses BPA's projected 10-year capital expenditure as

the basis for allocating the lower threshold between Power Services and Transmission Services. Harris *et al.*, BP-18-E-BPA-33, at 114; Deen *et al.*, BP-18-E-JP05-01, at 18-19. Using this projection of BPA’s capital expenditures, the allocation would be 45 percent to Power Services and 55 percent to Transmission Services. *Id.* This allocation is not fixed and will change over time as BPA’s projection of capital expenditures changes. Significantly, fluctuations in the lower threshold are not unlikely and, as noted by Powerex, could create “disproportionate potential outcomes” and “increase uncertainty about the proportionate levels of financial reserves that might be needed in an upcoming rate period” more than the days cash method. Powerex Br., BP-18-B-PX-01, at 19-20. This is because the relative size of the business lines’ revenue requirements could change over time, but most likely to a lesser degree than an allocation based on the 10-year projections of capex.

The relative benefits approach would also likely create additional complexity in implementing the FRP. As noted above, JP02, M-S-R, and Powerex point out that focusing only on BPA’s future projected capital spending is too narrow for determining the appropriate “relative benefit” that the business lines derive from BPA’s credit rating. *See* Powerex Br., BP-18-B-PX-01, at 16, 20; JP02 Br., BP-18-B-JP02-01, at 45-46; M-S-R Br., BP-18-B-MS-01, at 17-18. The capex allocation, then, would not simply be based on a rolling 10-year projection of BPA’s planned capital spending. It would need to consider a host of other annual financing actions, such as refinancing, to properly account for all of the credit-related benefits. Powerex Br., BP-18-B-PX-01, at 16, 20; JP02 Br., BP-18-B-JP02-01, at 45. The capex allocation would compound the administrative burden of calculating the business lines’ financial reserves thresholds, adding additional tracking and complexity to the FRP’s implementation.

The relative benefits approach also has the potential to introduce unnecessary controversy into BPA’s capital forecasting. As Powerex noted, “[b]asing the financial reserves contributions on forecasted capital spending . . . could result in disputes regarding whether a project was sufficiently ripe to be included in the capital spending forecast” and other arguments about the capex forecast’s accuracy. Powerex Br., BP-18-B-PX-01, at 20. Moreover, Powerex reasons that the capex allocation could disincentivize capital spending. *Id.* at 21. While BPA does not agree that these outcomes would likely influence a decision to proceed with a capital project, BPA appreciates that these functional issues are not present in the individual business line days cash method.

More generally, BPA is concerned that, under the capex allocation, the agency’s ability to maintain equity between the business lines would become more difficult as each financial decision made would be a source of potential conflict between the customers of the business lines. That is, if BPA were to adopt a more holistic benefits-based allocation—modifying the capex allocation to reflect all other potential financial activities that benefit from BPA’s credit rating—then BPA’s financing decisions would take on an additional element of complexity. Questions about whether BPA should use its Federal borrowing, third-party debt, lease-financing, or revenue financing, would need to be informed not only by what is in the best interest of BPA, but also in view of maintaining a level of equity between the business lines and their relative contribution to BPA’s financial reserves. Accusations that BPA is “favoring” one business line over the other in its financing decisions are not unlikely (and indeed have already

been made). *Id.* at 20. This extra level of contention and complexity does not exist today and would not exist under a days cash method.

In light of the potential uncertainty, complexity, and controversy introduced by the “relative benefits” approach, the days cash method is appealingly straightforward. To determine the lower thresholds for Power Services and Transmission Services, BPA need only perform two calculations: each business line’s operating expenses divided by 365 days and then multiplied by 60 days. This methodology will be consistent over time, scaled to the size of the business lines, and simple to implement. Further, the days cash method will be simple and straightforward to communicate externally. The business lines’ capital expenditures and financial variability may shift in the future, but the relative contributions from the business lines based on the days cash method will largely remain stable. Finally, the days cash method is consistent with cost causation and uses the common industry metric used in evaluating an entity’s financial health. For these reasons, BPA is persuaded that the days cash method is the appropriate method for determining the business lines’ lower thresholds in the FRP.

In its Brief on Exceptions, WPAG takes issue with BPA’s acknowledgment of the days cash method’s imprecision. WPAG Br. Ex., BP-18-R-WG-01, at 8-9. WPAG argues that “BPA is on unstable legal ground” due to “discrepancies in how BPA is evaluating the days cash and capex proposals,” namely that “whereas BPA is willing to brush aside the ‘imprecision’ of the days cash method in the name of simplicity, it gives no such quarter in its evaluation of the capex proposal.” *Id.* WPAG frames the issue as “\$120 million is a weighty price to pay for simplicity.” WPAG Br. Ex., BP-18-R-WG-01, at 8.

BPA’s reference to “imprecision” in the days cash method was provided in response to parties’ arguments that BPA should adopt a more complex methodology in order to allocate the financial reserves obligation between the two business lines. BPA’s response was that any alleged imprecision in the days cash methodology would be outweighed by the benefits of its simplicity and ease of administration. WPAG has taken BPA’s reference to “imprecision” to contend that BPA’s *substantive* concerns with the capex methodology should similarly be viewed as only “imprecisions” that should be granted the same leniency that BPA employs on the days cash method.

BPA disagrees. BPA’s concerns with the capex methodology go far beyond simple “imprecisions.” As described extensively above, BPA has identified a number of concerns with the capex methodology that are not present in the days cash method. BPA adopts the days cash method because BPA is convinced that financial reserves are a necessary asset for healthy businesses, that the cost-causation and equity principles behind the days cash method are more appropriate, and that the days cash metric is an industry standard. Flaws in the capex method in not accounting for the benefits of holding financial reserves also dissuaded BPA from adopting the capex method. The difference between a business line’s lower threshold under the capex versus under the days cash method (\$120 million) is not being adopted because of “simplicity,” but because the days cash method is the more appropriate method from which to set the lower threshold. The fact that it is also easier to implement (and will introduce less uncertainty, complexity, and controversy) are added benefits of the days cash method, but not the exclusive reason BPA chose it for the final FRP.

Decision

BPA will determine the business lines' lower thresholds based on individual business line days cash on hand.

Issue 6.6.4.2.2.2

Whether use of the Treasury Facility in Power Services' TPP calculation should be eliminated because it renders the FRP's lower thresholds asymmetrical and therefore inequitable.

Parties' Positions

JP02 opposes the use of the Treasury Facility in calculating the 90 day cash target included in Staff's initial FRP proposal, which sets the agency financial reserves target as the greater of the CRAC threshold required by the TPP standard and 90 days cash. JP02 Br., BP-18-B-JP02-01, at 7-9.⁴ (As explained in the footnote, BPA treats this objection as applying equally to the final FRP proposal of establishing the lower financial reserves threshold as the greater of the TPP standard and 60 days cash.)

M-S-R argues that “[w]ith the use of the Treasury Facility, Power’s reserves are not subject to the same controls as Transmission. Accordingly, the TPP underpinnings to the FRP are not symmetrical from the outset.” M-S-R Br., BP-18-B-MS-01, at 9.

JP07 supports BPA’s continued use of the Treasury Facility in calculating Power Services’ TPP. JP07 Br., BP-18-B-JP07-01, at 14-15.

BPA Staff's Position

The TPP is a long-standing metric BPA has used to test whether its available liquidity is sufficient to ensure a high probability of meeting its financial obligations. Harris *et al.*, BP-18-E-BPA-33, at 94. BPA’s TPP methodology permits use of all available liquidity, including the Treasury Facility. Harris *et al.*, BP-18-E-BPA-17, at 4, 7. The FRP’s “higher of” calculation for the FRP’s lower threshold is intended to ensure that the TPP standard and the FRP are compatible. Harris *et al.*, BP-18-E-BPA-33, at 126.

⁴ Staff’s testimony refers to this comparison as between the 90 days cash on hand target and the TPP standard. As discussed in Section 6.6.4.4, the 90 days cash target was a midpoint for calculating the upper and lower financial reserves thresholds. That is, from the target of 90 days cash, BPA added 30 days cash to calculate the upper threshold for each business line, and subtracted 30 days cash to calculate the lower threshold. The FRP did not require or include any mechanism for achieving the 90 days cash target, and the appropriate comparison was always between the TPP-oriented CRAC and the business line’s lower threshold (*e.g.*, 60 days cash). See Harris *et al.*, BP-18-E-BPA-33, at 96. The fact that the 90 days cash target had no other use than being the middle between the upper and lower thresholds became apparent to BPA as it reviewed the record. To simplify the FRP, BPA has removed references to the 90 days cash target, and now refers to the upper and lower thresholds by referencing their respective days cash. This change has no effect on the substantive arguments of either Staff or the parties.

Evaluation of Positions

The context of the TPP standard, and the Treasury Facility's role in that standard, is essential to understanding the issues raised by the parties' briefs. BPA therefore provides the following overview of TPP and the Treasury Facility.

For over 20 years, BPA has used the TPP standard and methodology to ensure the agency has sufficient liquidity to meet its payment obligations, including its payments to the Treasury. Harris *et al.*, BP-18-E-BPA-17, at 6. The TPP standard from the 1993 10-year Financial Plan requires BPA set rates to achieve at least a 95 percent probability of making both Treasury payments in a two-year rate period. BPA's implementation of the TPP standard, the TPP methodology, is essential to ensuring BPA's solvency. Harris *et al.*, BP-18-E-BPA-33, at 54. The TPP methodology does this by evaluating each business line's ability to meet its obligations to the Treasury over the rate period in light of each business line's liquidity and prospective cash flow (both the "average" cash flow and its variability). Harris *et al.*, BP-18-E-BPA-17, at 11. "Liquidity" under the TPP methodology encompasses the business line's financial reserves and its access to any other forms of liquidity (such as short-term debt). *Id.* at 4, 7. If the combination of financial reserves and other sources of liquidity result in a 95 percent or greater probability of meeting each payment to the Treasury over the rate period, then the TPP standard has been met by that business line and no further rate action is taken. Conversely, if the combination of existing financial reserves and other sources of liquidity are insufficient to meet a 95 percent chance of paying Treasury, then the business line's rates are increased (either deterministically through PNR or contingently by raising the CRAC threshold) to generate additional financial reserves until the 95 percent standard is met. *Id.* at 7-8.

One such "other source" of liquidity is the Treasury Facility. The Treasury Facility is a \$750 million line of credit that BPA has with the Treasury that can be used to fund expenses recognized under the Northwest Power Act. *Id.* at 4-5. It is limited by BPA's borrowing authority and must be paid back within two years. *Id.* The TPP methodology includes the Treasury Facility as a source of liquidity available to meet the TPP standard. *Id.* at 8-9.

The TPP standard has been remarkably successful in fulfilling its intended objective of ensuring BPA's ability to pay the Treasury. With the support of the TPP standard, BPA has made 34 consecutive payments, in full and on time, to the Treasury. *Id.* at 6. In recent years, though, BPA has seen the limitations of the TPP standard. While the TPP standard ensures BPA's solvency, it does not establish upper or lower thresholds for financial reserves for either business line or the agency. *Id.* at 11. As such, financial reserves can vary (and have varied) significantly over the years, with the consequence that recent declines in BPA's financial reserves have caught the attention of credit rating agencies. *See* Section 6.4.4 (equity and FRP); *see also* Section 6.4.3 (credit rating and FRP). The TPP standard—which is focused on ensuring BPA's ability to pay its obligations from whatever sources of liquidity BPA has available (cash and short-term debt)—is not designed to actively manage the levels of BPA's financial reserves for other purposes, such as credit rating support. Harris *et al.*, BP-18-E-BPA-17, at 11. As discussed extensively in Section 6.1 (introduction) and Section 6.2 (background), and throughout this Final ROD, this gap in BPA's current policy is the key driver for the FRP, which will establish lower and upper thresholds for the agency's and the business lines' financial reserves.

In designing the FRP, Staff explained that it was not its intent to *replace* the TPP standard with the FRP, but to “supplement[] the 95 percent TPP standard” *Id.* at 24. To that end, the FRP was designed to be compatible with the TPP standard. *Id.* at 24-26. One area that required direct coordination between the TPP standard and the FRP was in setting the lower threshold for financial reserves for both business lines. As noted above, the TPP standard may require a business line to increase its financial reserves in order to meet the 95 percent TPP test. The FRP similarly provides instructions to the business lines to retain financial reserves of at least 60 days cash. *See Id.* at 22. To ensure that the objectives of both the TPP standard and the FRP could be met, Staff included in the FRP a “greater of” test for determining the business line’s financial reserves lower threshold: “the FRP sets the lower financial reserves thresholds for each business line to the greater of (1) the financial reserves needed to meet TPP . . . and (2) 60 days cash” Harris *et al.*, BP-18-E-BPA-33, at 96. Staff explained that by including this “greater of” requirement, Staff could ensure that the FRP did not set a financial reserves requirement that was *below* the amount required by the TPP standard. Harris *et al.*, BP-18-E-BPA-17, at 30; Harris *et al.*, BP-18-E-BPA-33, at 126. This could happen if the TPP standard required a business line to increase financial reserves above an amount equal to 60 days cash. The “greater of” requirement ensured the FRP was compatible with the TPP standard, thereby allowing both policies to achieve their separate objectives.

Turning now to the parties’ arguments, JP02 does not dispute that the FRP should set the lower threshold for financial reserves based on the “greater of” the TPP standard or 60 days cash. JP02 Br., BP-18-B-JP02-01, at 7-9. Instead, it argues that BPA should not include the Treasury Facility as a source of liquidity when calculating the financial reserves needed for the TPP standard as used in the FRP’s “greater of” test. *Id.* JP02 then raises a number of concerns with the Treasury Facility and how it is used in the TPP standard. For instance, JP02 objects to the use of the Treasury Facility in the TPP standard: “To the extent that some or all of the Treasury facility is assumed to be available in calculating TPP for a business line, the TPP test for such business line does not provide a meaningful standard for purposes of determining the target level of financial reserves.” JP02 Br., BP-18-B-JP02-01, at 7.

JP02’s concerns with how BPA implements the TPP standard, and the use of the Treasury Facility in that standard, are outside of the scope of the FRP. The FRP is completely neutral as to how the TPP standard works, what sources of liquidity are included or excluded from TPP, and how the Treasury Facility is allocated for purposes of TPP. These aspects of the TPP methodology are simply taken as a “given” from the perspective of the FRP because the FRP is designed to *supplement* the TPP standard, not supplant it. Harris *et al.*, BP-18-E-BPA-17, at 24. The FRP does not mention the Treasury Facility and, indeed, cash generated from the Treasury Facility is *excluded* from the financial reserves calculation. Harris *et al.*, BP-18-E-BPA-33, at 68-69 & Attachment 8, Data Response IN-BPA-26-29. All that is needed for the FRP to calculate the lower threshold is whether the TPP methodology requires more financial reserves than 60 days cash. *Id.* at 96. If it does not, then there is no conflict between the TPP standard and the FRP, and the FRP sets the lower threshold. If TPP requires more than 60 days cash, then there *is* a conflict, and to resolve that conflict, the FRP’s 60 days cash limitation steps aside and allows the TPP methodology to set the lower threshold. This feature of the FRP was included to

ensure the TPP standard and the FRP work together so that they each may achieve their respective policy objectives. *Id.* at 26.

How BPA calculates TPP for its business lines, and how BPA chooses to use the Treasury Facility in that calculation, are squarely within the ambit of BPA’s implementation of the TPP standard. BPA’s decision to include the Treasury Facility as a component of Power Services’ liquidity was not made *as a result* of the FRP, but was made in the context of implementing the TPP standard for Power Services. *See* Power and Transmission Risk Study, BP-18-E-BPA-05, at 5 (“The full \$750 million in the Treasury Facility is considered to be available for the liquidity needs associated with [Power Services].”), 51 (“For the BP-18 rate period, Power Services has two sources of liquidity: (1) Financial Reserves Available for Risk Attributed to PS (PS Reserves) and (2) the Treasury Facility.”). BPA’s decision to allocate the full value of the Treasury Facility to Power Services is not a recent decision, as it was first made in 2010. *Harris et al.*, BP-18-E-BPA-17, at 8-9. If JP02 believes that BPA should revise its implementation of TPP by excluding the Treasury Facility from the available sources of liquidity for Power Services, then it should bring such arguments directly against BPA’s implementation of the TPP standard. It has not, and as such, its attempts to challenge BPA’s implementation of the TPP standard through the development of the FRP are misplaced.

M-S-R argues that, because the Treasury Facility is used to satisfy Power Services’ TPP test, the “greater of” requirement will not provide the “same controls” between the business lines, and the “TPP underpinnings to the FRP” will “not [be] symmetrical from the outset.” M-S-R Br., BP-18-B-MS-01, at 9. M-S-R’s arguments are mistaken. First, TPP is not an “underpinning” of the FRP; it is a separate policy that serves a separate purpose, which is to ensure BPA’s solvency. *Harris et al.*, BP-18-E-BPA-33, at 54. Second, to the extent there is no symmetry between *how* each business line satisfies its TPP standard, that is a function of the TPP methodology, not the FRP. The FRP is concerned with setting a lower financial reserves threshold based on the greater of two requirements: TPP or 60 days cash. If the FRP value of 60 days cash is higher than the TPP value, then “the TPP calculation effectively becomes irrelevant for purposes of establishing the financial reserves thresholds.” *Id.* at 97. Third, in calculating the lower threshold under the FRP, there *is* symmetry between the business lines as it relates to the use of the TPP standard. The FRP asks each business line whether it needs more financial reserves for the FRP or for TPP, and sets each business line’s lower threshold based on the higher of the two. *Id.* at 96.

JP02 claims that the use of the Treasury Facility in the TPP test does not provide a “meaningful standard for purposes of determining the [business line] target level of financial reserves.” JP02 Br., BP-18-B-JP02-01, at 7. BPA agrees that the TPP methodology *by itself* does not provide a meaningful standard for determining prudent reserves levels—though not because the TPP methodology incorporates the Treasury Facility—and that is why BPA is not solely relying on the TPP standard to determine the lower threshold for the FRP. In fact, recognition of the need to provide a broader, more meaningful foundation for determining prudent reserves levels was a prime motivation for developing the FRP. *Harris, et al.*, BP-18-E-BPA-17, at 10-11. The FRP establishes a lower threshold of financial reserves considering the greater of what is necessary to meet BPA’s TPP standard and BPA’s FRP objectives. If JP02 believes the TPP

standard is being improperly implemented, then its charge is against the TPP methodology—not the FRP, which simply ensures that financial reserves thresholds are not set *below* that which is required by TPP.

JP02 next presents arguments regarding why, from the perspective of the FRP, BPA should remove the Treasury Facility from the TPP calculation. First, JP02 argues that the Treasury Facility is not given the same weight or value as financial reserves by credit rating agencies. JP02 Br., BP-18-B-JP02-01, at 8. BPA agrees that, for purposes of supporting its credit rating, the Treasury Facility is not equivalent to financial reserves. Harris *et al.*, BP-18-E-BPA-33, at 86. For that reason, the Treasury Facility plays no direct role in determining the upper or lower thresholds for financial reserves established by the FRP. The lower threshold for financial reserves is set at the *higher of* what is needed for TPP and 60 days cash. *Id.* at 96. Sixty days cash is a sufficient amount of financial reserves to support BPA’s credit rating. *See Id.* at 70. Thus, under the FRP, the TPP standard can never harm BPA’s credit support, but only *improve* it. In addition, BPA cannot artificially increase its financial reserves through the Treasury Facility because any financial reserves generated from the Treasury Facility are also removed from the calculation of available financial reserves. *Id.* at 68-69 & Attachment 8, Data Response IN-BPA-26-29.

JP02 also argues that financial reserves are BPA’s preferred source of liquidity. JP02 Br., BP-18-B-JP02-01, at 19. While that is true, that does not negate that the Treasury Facility is a ready source of liquidity under the TPP methodology. Harris *et al.*, BP-18-E-BPA-17, at 4, 18. As BPA discussed in Section 6.4.5 (liquidity and a financial reserves policy), a benefit of the FRP will be an increase in BPA’s liquidity. However, this benefit of the FRP does not mean that BPA’s *existing tools* for liquidity somehow are no longer valuable or relevant. Before BPA could even consider removing the Treasury Facility from the TPP methodology, as suggested by JP02, BPA must first find that the Treasury Facility is not an available source of liquidity. Staff made clear that the Treasury Facility *is* (and has been since 2010) a source of liquidity. Harris *et al.*, BP-18-E-BPA-17, at 4, 8-9. No party to this case has argued that the Treasury Facility is *not* a source of liquidity. BPA “assume[s] all liquidity tools are available when calculating the amount of financial reserves needed to support TPP.” Harris *et al.*, BP-18-E-BPA-33, at 86. So long as the Treasury Facility is an eligible liquidity tool, BPA can find no basis for excluding it.

JP02 argues that the Treasury Facility has only allowed one business line’s financial reserves to drop because the “other business line carries more actual financial reserves than it would otherwise carry.” JP02 Br., BP-18-B-JP02-01, at 8. This imbalance of financial reserves under the TPP standard with the Treasury Facility has “proven inadequate in ensuring an equitable allocation of the burden for carrying financial reserves between the business lines.” *Id.* at 22.

JP02’s arguments underscore that the TPP standard *alone* cannot resolve the current imbalance in business line contributions to agency financial reserves. BPA agrees with JP02’s concerns as to the limitations of the current TPP standard and that is why BPA is adopting a new policy—the FRP—to address these concerns. The TPP standard, which is not designed to manage financial reserves for other purposes, still plays an extremely important role in ensuring BPA’s liquidity and overall solvency. Harris *et al.*, BP-18-E-BPA-33, at 94, 126. BPA does not intend to replace the TPP standard with the FRP, but to have the two policies be “complementary financial

management tools. . . [that] are intended to work together to address the effects of variability in market prices and hydrological system output to assure both a high probability of making BPA’s Treasury payments and a strong credit rating.” *Id.* at 26.

Finally, excluding the Treasury Facility when considering Power Services’ TPP would be unreasonable because it would materially increase power rates for Power customers for no apparent business reason. *Id.* at 86; Harris *et al.*, BP-18-E-BPA-17, at 8-9; *see also* JP07 Br., BP-18-B-JP07-01, at 15. Removing all or a part of the Treasury Facility from Power’s TPP calculation would do nothing for Transmission Services’ TPP because Transmission Services’ liquidity needs are already fully met through existing financial reserves. Harris *et al.*, BP-18-E-BPA-33, at 86. It would be neither equitable nor reasonable for BPA to remove the availability of the Treasury Facility from Power Services—thereby decreasing Power’s liquidity, which requires increasing Power rates—simply to free up the Treasury Facility for no purpose. *Id.* As JP07 notes, this outcome would occur not out of necessity, but because BPA chose not to take into account all the liquidity tools it had available. JP07 Br., BP-18-B-JP07-01, at 15. As Staff explained, “We . . . disagree that some of the benefits of the Treasury Facility should go unused simply because of one business line’s claim to something that it does not need and would not use.” Harris *et al.*, BP-18-E-BPA-33, at 86.

Decision

Use of the Treasury Facility in Power Services’ TPP calculation is appropriate and does not render the FRP’s lower thresholds asymmetrical or inequitable.

Issue 6.6.4.2.2.3

Whether the record supports establishing the lower threshold above 30 days cash on hand.

Parties’ Positions

JP02 argues BPA has not justified setting the lower threshold at a level above 30 days cash, which JP02 contends is a “suitable financial reserve level to meet the agency’s financial reserve goals.” JP02 Br., BP-18-B-JP02-01, at 13.

BPA Staff’s Position

A 30 days cash threshold is a minimum level at which point credit rating agencies have warned that a downgrade to BPA’s credit rating may occur. Harris *et al.*, BP-18-E-BPA-33, at 87. Setting the lower threshold to 30 days would significantly increase the likelihood that BPA would operate with less than 30 days cash on hand, which would jeopardize BPA’s credit rating. *Id.* at 87, 115.

Evaluation of Positions

JP02 argues BPA has not justified setting the lower threshold above 30 days cash, which JP02 contends is a “suitable financial reserve level to meet the agency’s financial reserves goals.” JP02 Br., BP-18-B-JP02-01, at 13. BPA disagrees.

First, as discussed in Section 6.4.3 (credit rating and FRP), the credit rating agencies’ reference to 30 days cash established the bare minimum amount of financial reserves BPA could have before significant negative rating pressure would ensue. Specifically, Moody’s noted “BPA’s rating could be negatively pressured if BPA’s internal liquidity drops below 30 days cash on hand on a sustained basis” Harris *et al.*, BP-18-E-BPA-33, Attachment 5, Moody’s BPA Credit Rating Report (June 14, 2016), at 3. Staff explained 60 days cash was an appropriate lower threshold because it created a “buffer” to mitigate the likelihood that BPA’s financial reserves would fall below 30 days cash on hand on a sustained basis. *Id.* at 70. The critical element for sustaining BPA’s credit rating is to prevent agency reserves from falling below 30 days cash on hand on a sustained basis. A lower threshold of 60 days cash on hand significantly mitigates the risk of this occurring. BPA analyzed this risk and found that under Staff’s initial FRP proposal and Alternative Option (both of which assumed a lower threshold of 60 days cash) this risk was reduced by almost half compared to the status quo (20 percent likelihood of occurrence in the status quo versus 13 percent in Staff’s initial proposal and 12 percent in Staff’s Alternative Option). *Id.* at 138-39, 151-52 & Attachment 7.

Having a buffer between critically low financial reserves and healthy financial reserves is appropriate because BPA’s financial reserves can fluctuate significantly during a rate period. Sixty days cash is roughly \$400 million for BPA as an agency. Power and Transmission Risk Study, BP-18-E-BPA-05, at 114-15, Tables 11 & 12; Power and Transmission Risk Study Erratum, BP-18-E-BPA-05-E01. Thirty days cash is roughly \$200 million. Power and Transmission Risk Study, BP-18-E-BPA-05, at 115, Table 12. Both Power Services’ and Transmission Services’ financial reserves can increase and decrease as against expected values. The standard deviation for Power Services’ net revenue is \$250 million, while Transmission Services’ standard deviation is approximately \$49 million in FY 2018. Harris *et al.*, BP-18-E-BPA-17, at 16; Mullins, BP-18-E-IN-01-AT01, at 93. This means that there is roughly a one-in-three chance that Power Services’ net revenue will be *more* than \$250 million above or below rate case expected values, and a one-in-three chance that Transmission Services’ net revenue will be more than \$49 million above or below rate case expected values.

Setting the lower threshold at 60 days cash (\$400 million) creates a buffer that allows BPA to absorb more fluctuations in financial reserves without risking a substantial downgrade to BPA’s credit rating. A threshold set at 30 days cash (\$200 million), in contrast, would provide BPA with *no* ability to weather uncertainty with its financial reserves, thereby creating pressure on BPA’s credit rating whenever actual financial reserves declined below expected values. If the lower threshold were set at 30 days cash, a CRAC triggered to recover some or all of a shortfall throughout the next fiscal year would take 12 months for such recovery, and bad luck during that year could result in even lower financial reserves.

Finally, BPA modeled a party's proposal that set the lower threshold at 30 days cash. BPA found that this proposal (offered by M-S-R) put significantly *more* strain on BPA's credit rating than even the status quo. The risk of agency financial reserves going below 30 days cash on hand more than doubled, from 20 percent in the status quo to 49 percent under the 30 days cash proposal. Harris *et al.*, BP-18-E-BPA-33, at 137 & Attachment 7; *see also* Issue 6.6.5.2 (M-S-R's proposal). The reasons BPA provided in Issue 6.6.5.2 for not adopting M-S-R's proposal applies also to JP02's argument.

Decision

The record supports establishing the lower threshold above 30 days cash as stated in the FRP.

6.6.4.3 Phase-in of Power Services' CRAC Threshold

Issue 6.6.4.3.1

Whether BPA should adopt the phase-in of the Power CRAC threshold as described in Staff's initial FRP proposal.

Parties' Positions

JP07, WPAG, and ICNU oppose the proposed phase-in of the Power CRAC threshold as described in Staff's initial FRP proposal. JP07 Br., BP-18-B-JP07-01, at 8-9; WPAG Br., BP-18-B-WG-01, at 16-18; ICNU Br., BP-18-B-IN-01, at 1, 24, 28, 52, 65. JP07 supports phasing in the Power CRAC threshold by adding \$20 million PNRN per year and phasing in the CRAC threshold in two steps. JP07 Br., BP-18-B-JP07-01, at 23. WPAG contends that if a financial reserves policy is adopted, it should follow Staff's Alternative Option for phasing in the CRAC threshold, with some additional adjustments. WPAG Br., BP-18-B-WG-01, at 17-19.

JP07 agrees BPA should not limit the phase-in to less than 10 years. *Id.* at 15-16. JP06 similarly supports including \$20 million of PNRN in rates as a component of a phase-in for the Power CRAC threshold. JP06 Br., BP-18-B-JP06-01, at 7. JP06 also suggests modifications to Staff's one-time ratchet. *Id.* Kalispel supports JP06's arguments and positions. Kalispel Br., BP-18-B-KT-01, at 2-3.

Powerex generally supports the phase-in described in Staff's initial FRP proposal. Powerex Br., BP-18-B-PX-01, at 21.

M-S-R argues that Staff's initial proposed phase-in of the Power CRAC threshold over 10 years is too long, and there is little certainty that the phase-in will reach the Power lower threshold. M-S-R Br., BP-18-B-MS-01, at 12-13. JP02 raises a similar concern. JP02 Br., BP-18-B-JP02-01, at 9-10. M-S-R and JP02 contend that the delay in implementing the Power CRAC threshold would continue the status quo inequity of disproportionately relying on Transmission financial reserves for the agency's credit rating and financial health support. M-S-R Br., BP-18-B-MS-01, at 12-13; JP02 Br., BP-18-B-JP02-01, at 9-10.

In its Brief on Exceptions, M-S-R requests BPA clarify certain aspects of the phase-in and follow-on process. M-S-R Br. Ex., BP-18-R-MS-01, at 2-3.

In its Brief on Exceptions, JP06 “appreciate[s] that BPA is open to fixing the timing and mechanism to raise the Power CRAC to the Power lower threshold in a separate process.” JP06 Br. Ex., BP-18-R-JP06-01, at 2.

In its Brief on Exceptions, WPAG listed BPA positions in the Draft ROD that WPAG believes are positive steps, including “[r]eserving decisions on how to phase-in the lower reserve threshold for Power Services under the [FRP] . . .” and “[r]ecognizing that the current [CRAC] framework will need to be refined in light of the new FRP and allowing more time following the rate case for BPA and parties to address this important issue.” WPAG Br. Ex., BP-18-R-WG-01, at 1-2.

BPA Staff’s Position

Staff proposes to phase in the implementation of the Power CRAC threshold. Harris *et al.*, BP-18-E-BPA-17, at 36-37. Staff proposes to do this through two mechanisms: (1) the Good Year Ratchet and (2) the IRPL. *Id.* at 37 & Appendix A, Policy § 4.2.

Staff also identified another method for phasing in the Power CRAC threshold in its Alternative Option. Harris *et al.*, BP-18-E-BPA-33, at 145-46. In that option, Staff proposes to replace the IRPL and Good Year Ratchet with \$20 million in PNRR and a one-time ratchet that would take effect when the projection of financial reserves for Power Services is above the Power lower threshold. *Id.* PNRR would be included in the revenue requirement in Power rate proceedings until the Power CRAC threshold has been increased to the Power lower threshold. *Id.* at 146.

Evaluation of Positions

To meet the lower threshold called for in Staff’s initial proposal, the Power CRAC threshold would need to be set to 60 days cash on hand, which would be \$309 million. Harris *et al.*, BP-18-E-BPA-17, at 36-37. However, Power financial reserves have declined sharply, as much lower-than-expected natural gas prices have reduced market prices for power and thus reduced Power’s net secondary energy revenue. *Id.* at 37. Setting the Power CRAC Threshold at \$309 million would be highly likely to cause a very large Power rate increase for FY 2018, during a time when BPA is working diligently to keep rate increases as low as possible. *Id.* Therefore, Staff proposed that the increase in the Power CRAC threshold to the Power lower threshold level of 60 days cash be phased in over approximately 10 years, using two mechanisms: (1) the Good Year Ratchet, and (2) the IRPL. *Id.* at 37 & Appendix A, Policy § 4.2.

The IRPL limits the amount of incremental rate pressure that can be created by increasing the Power CRAC threshold in any given rate period. *Id.* at 37. In general, the IRPL would allow Power rates to be increased to collect additional financial reserves if such rates were otherwise increasing by less than 3 percent. *Id.* at 37-38.

The Good Year Ratchet increases the Power CRAC threshold without creating any incremental rate pressure in the first year of a rate period. *Id.* at 39. For example, if FY 2017 is a good year financially for Power Services, such that ending 2017 Power reserves are forecast to be above the status quo CRAC threshold of \$0 set for the BP-16 rates, then the Power CRAC threshold would be set to the forecast of ending FY 2017 financial reserves (or higher if there is room under the IRPL for incremental rate pressure from collecting additional financial reserves). *Id.*

JP07, WPAG, and ICNU, which collectively represent Power customers and industrial customers of Power customers, generally argued that the IRPL and Good Year Ratchet were too harsh on Power customers due to the anticipated upward rate pressure. Harris *et al.*, BP-18-E-BPA-33, at 73-74; *see also* Deen *et al.*, BP-18-E-JP05-01, at 16-17; Saleba *et al.*, BP-18-E-WG-01, at 8; Mullins, BP-18-E-IN-01, at 39-40, 52-54. These parties argued that the phase-in would strain BPA's Power rates, guaranteeing 3 percent rate increases for each rate period over the next 10 years, and destabilize rates through the forced accumulation and holding of financial reserves through bad financial years. Harris *et al.*, BP-18-E-BPA-33, at 73-74. In their initial briefs, JP07 (formerly JP05), WPAG, and ICNU reiterated their concerns with the Good Year Ratchet and the IRPL. JP07 Br., BP-18-B-JP07-01, at 8-9; WPAG Br., BP-18-B-WG-01, at 16-18; ICNU Br., BP-18-B-IN-01, at 1, 24, 28, 52, 65.

JP05 and WPAG also suggested adjustments to the phase-in in their direct cases. Deen *et al.*, BP-18-E-JP05-01, at 18-20; Saleba *et al.*, BP-18-E-WG-01, at 9-11. In particular, JP05 proposed that BPA replace its proposed reliance on CRAC adjustments with PNRR to maintain financial reserves. Deen *et al.*, BP-18-E-JP05-01, at 18-20. PNRR is an expense line item in the revenue requirement without a corresponding planned cash disbursement. Harris *et al.*, BP-18-E-BPA-17, at 8. It has the effect of raising base rates above the level necessary to recover all other costs, resulting in a planned increase in financial reserves throughout the rate period. *Id.*

JP02 and M-S-R, which are transmission customers of BPA, also oppose Staff's proposed phase-in. M-S-R Br., BP-18-B-MS-01, at 12-13; JP02 Br., BP-18-B-JP02-01, at 9-11. While recognizing the need for a phase-in, these parties expressed concern that the phased-in FRP would not adequately address the imbalance in business line contributions to the agency's financial reserves. Harris *et al.*, BP-18-E-BPA-33, at 73; M-S-R Br., BP-18-B-MS-01, at 12-13; JP02 Br., BP-18-B-JP02-01, at 9-11. In general, these parties were concerned that the proposed phase-in was unlikely to result in Power reserves reaching the Power lower threshold and that the IRPL and Good Year Ratchet would prevent Power financial reserves from increasing, thereby perpetuating the inequity of sustaining comparatively high levels of Transmission financial reserves to support agency financial reserves and thus support BPA's credit rating. Harris *et al.*, BP-18-E-BPA-33, at 73; M-S-R Br., BP-18-B-MS-01, at 12-13; JP02 Br., BP-18-B-JP02-01, at 9-11. JP02 argues a policy that is "dependent, in large part, on 'good financial luck,'" may be inconsistent with sound business principles. JP02 Br., BP-18-B-JP02-01, at 9-10.

Powerex generally supported Staff's proposal to include the IRPL and the Good Year Ratchet. Powerex Br., BP-18-B-PX-01, at 21.

In response to the parties' proposed alternatives, Staff suggested an Alternative Option that eliminates the IRPL and Good Year Ratchet and replaces them with \$20 million in PNRR and a

one-time ratchet that would take effect when the projection of financial reserves for Power Services is above the Power lower threshold. Harris *et al.*, BP-18-E-BPA-33, at 145-46. PNRR would continue to be included in the revenue requirement in Power rate proceedings until the Power CRAC threshold has been increased to the Power lower threshold. *Id.* at 146.

Several parties support Staff's Alternative Option to eliminate the IRPL and Good Year Ratchet and replace them with a fixed amount of PNRR. JP07 states it "much prefer[s this] option's predictable approach of increasing reserves through a steady amount of PNRR." JP07 Br., BP-18-B-JP07-01, at 20. JP07 states, "Power customers advocated for this approach all along because it has 'the benefit of being fully transparent and known during the course of a rate period as well as decreasing the likelihood of a CRAC, thereby enhancing the rate stability at the same time as taking action to support BPA's credit rating.'" *Id.* at 20 (citing Deen *et al.*, BP-18-E-JP05-01, at 24). JP06 similarly supports elimination of the Good Year Ratchet and IRPL. JP06 Br., BP-18-B-JP06-01, at 6-7. JP06 notes that it "support[s] the unconditional PNRR element of Staff's Alternative Option because it also reduces rate instability." *Id.* at 7. WPAG also supports using PNRR in lieu of the IRPL and Good Year Ratchet. WPAG Br., BP-18-B-WG-01, at 16-18. WPAG notes the inclusion of \$20 million a year of PNRR "addresses the concern under the initial proposal that the financial reserves policy would effectively 'lock-in' successive 3 percent power rate increases for the foreseeable future, and thereby harm BPA's rate competitiveness." *Id.* at 16-17.

M-S-R and JP02 similarly acknowledge that PNRR is preferable to the IRPL and Good Year Ratchet in achieving the lower threshold for Power Services. M-S-R notes that the Alternative Option "is an improvement because it appears to increase the likelihood that Power's reserves would be funded in a way that its financial reserves at least reach the Power lower threshold by the end of the ten year phase-in period, and it would provide more predictability in rates, which some Power customers requested." M-S-R Br., BP-18-B-MS-01, at 14. JP02 notes that PNRR "could increase the certainty surrounding the accumulation of Power financial reserves during the phase-in period [if included] in the Financial Reserve Policy" JP02 Br., BP-18-B-JP02-01, at 10, n.56.

While there is general alignment that Staff's IRPL and Good Year Ratchet should be replaced with PNRR, JP07, JP06, and WPAG suggest further adjustments to the one-time ratchet. JP07 proposed one modification to the Alternative Option to address the problem that "the one-time ratchet would still expose power customers to excessive and unwarranted rate shock." JP07 Br., BP-18-B-JP07-01, at 21. JP07 proposed BPA "phase in the CRAC threshold in two steps with a buffer in reserves, rather than in one step." *Id.* at 23. JP06 also recommends that BPA modify the Power CRAC in the Alternative Option to restrict the rate increase allowed by the Power CRAC for the period after the phase-in to either (1) \$20 million per year or (2) the amount needed to maintain the 95 percent TPP, whichever is higher. JP06 Br., BP-18-B-JP06-01, at 7-8. JP06 explains that this modification to the phase-in of the Power CRAC threshold would adjust after the phase-in period exactly as described by Staff in Harris *et al.*, BP-18-E-BPA-33, at 143. *Id.* However, if the CRAC triggers when Power's TPP has not dropped below the 95 percent level, then the resulting CRAC-driven rate increase would be limited to \$20 million per year. This rate of cash infusion should be adequate to protect BPA's credit rating because it is the

same annual planned cash infusion that Staff proposed in the Alternative Option to build up cash reserves to the Power lower threshold during the phase-in period. *Id.* WPAG similarly proposes changes to the one-time ratchet. WPAG Br., BP-18-B-WG-01, at 18-19. WPAG argues that a “more nuanced CRAC is needed to recognize the distinct dual purposes of the CRAC under the alternative proposal.” *Id.* at 19.

BPA agrees that a phase-in of the Power CRAC threshold should occur. Harris *et al.*, BP-18-E-BPA-17, at 36-37. Avoiding rate shock and maintaining rate stability are legitimate considerations for BPA as it determines the implementation features of the FRP. The IRPL and Good Year Ratchet, though reasonable proposals, have been largely criticized as being too rigid in some circumstances and not rigid enough in others. Staff, in turn, agrees that other methods of phasing in the Power CRAC threshold are available that may be able to better address the parties’ concerns. Harris *et al.*, BP-18-E-BPA-33, at 140-46.

BPA will adopt the PNRR proposal from Staff’s Alternative Option. *Id.* at 143-44. That is, BPA will include \$20 million in PNRR per year as part of the phase-in of the Power CRAC threshold until that threshold has been increased to the Power lower threshold. *Id.* The PNRR approach is preferable to the IRPL and Good Year Ratchet proposed by Staff because it will cause an incremental increase in Power rates only once; after that, it would remain a constant component of the revenue requirement until the phase-in ends, and would not cause further incremental rate increases. *Id.* at 143. BPA finds that this feature, therefore, provides greater rate stability to customers. Moreover, the PNRR approach ensures that BPA is building financial reserves in a measured way through affirmative rate action in each rate case. This is because PNRR will be included in Power Services’ revenue requirement as an expense item and will generate an incremental \$20 million of cash per year until the Power CRAC threshold is raised to the Power lower threshold. Threshold adjustments that reset the CRAC, as proposed for the Good Year Ratchet, are reactive in that the threshold increases after financial results are better than expected. While both methods are appropriate means of phasing in the Power CRAC threshold, BPA finds the PNRR approach preferable because of the rate-stability benefits described above and because Power customers have generally supported PNRR over the IRPL and Good Year Ratchet. JP07 Br., BP-18-B-JP07-01, at 20; JP06 Br., BP-18-B-JP06-01, at 7; WPAG Br., BP-18-B-WG-01, at 16-18.

In supporting the proposal to include PNRR, Staff noted that PNRR “is suitable as a phase-in, but the plan should also specify when to increase the Power CRAC threshold from its current level of \$0 to the lower threshold for Power as determined in the FRP.” Harris *et al.*, BP-18-E-BPA-33, at 143. Staff suggested that the PNRR proposal be combined with a one-time ratchet that would take effect when Power’s forecast end-of-year financial reserves reach or exceed the lower threshold for Power. *Id.*

BPA agrees that a ratchet feature be adopted as part of the phase-in for the Power CRAC threshold. Without a feature that increases, in some fashion, the Power CRAC threshold over time, Power Services could “remain perpetually below its threshold, spinning its wheels (so to speak) as financial reserves [are] accumulated, then consumed, on Power’s net revenue variability.” *Id.* at 75. As discussed above, Power customers have presented a variety of ideas on how BPA could phase in the Power CRAC threshold by raising it from its current level of \$0

to the Power lower threshold. JP07 Br., BP-18-B-JP07-01, at 21; JP06 Br., BP-18-B-JP06-01, at 7-8; WPAG Br., BP-18-B-WG-01, at 17-19. Many of these ideas have merit and warrant further discussion. WPAG suggests BPA conduct additional workshops prior to the BP-20 case to address these issues. *Id.* at 19. More generally, ICNU makes a similar comment, arguing that BPA should defer any decision on the FRP to a more holistic regional process. ICNU Br., BP-18-B-IN-01, at 5. While BPA does not agree that a deferral of the entire FRP is appropriate, *see* Issue 6.6.5.4 (reasons for deciding FRP in rate case), BPA agrees with WPAG and ICNU that an additional process regarding the phase in of the Power lower threshold is warranted. Thus, BPA will decide in a separate process how and when to increase the Power CRAC threshold above the current level of \$0 for purposes of the FRP.

In adopting this proposal, BPA recognizes that the phase-in does not address all of the concerns raised by parties and is incomplete in some respects. Nonetheless, there is significant value in adopting the FRP in this proceeding and implementing the PNRR component of the phase-in for this rate period. As described at length in Section 6.4 (need for FRP), having a financial reserves policy fills a significant gap in BPA's existing policies. Without the FRP, BPA has no policy direction on upper thresholds or lower thresholds for the agency or the business lines. The clarity and certainty that the FRP will bring to BPA's financial reserves, as well as the positive credit aspects of having such a policy, all support adopting and implementing the FRP now and further discussing phase-in proposals in a subsequent process. Also, the rate actions that occur when a business line has financial reserves below its CRAC threshold remain a rate-period by rate-period decision. Concepts such as a more nuanced CRAC as proposed by WPAG and a modified Power CRAC for the period after the phase-in as recommended by JP06 are not limited by the FRP.

BPA also recognizes that the proposal to include \$20 million in PNRR is different than Staff's recommendation that the phase-in should include "\$20 million or \$30 million in annual PNRR, depending on the allocation methodology adopted and the corresponding level of the lower threshold." Harris *et al.*, BP-18-E-BPA-33, at 144. "If the goal is to have a Power CRAC threshold of about \$300 million . . . then . . . \$30 million would be more prudent." *Id.* As noted in Issue 6.6.4.2.2.1 (lower threshold—days cash or capex), BPA has adopted the proposal that the lower threshold be determined based on days cash, which means the Power lower threshold is approximately \$300 million.

BPA recognizes that the need to fully phase in the FRP and to support equity between business lines requires additional mechanisms to be considered and, therefore is committed to addressing these phase-in issues in a separate public process. Even so, implementing \$20 million in PNRR in power rates is a substantial and appropriate action as it begins the process of realigning Power Services' contribution to agency financial reserves. By including \$20 million in PNRR, BPA is signifying a policy change from the status quo, which would otherwise permit Power Services' contributions to agency financial reserves to be as low as \$0. *See* Section 6.4.3 (credit rating and FRP); Section 6.4.4 (equity and FRP).

M-S-R argues that Staff's proposal of phasing in the FRP for Power Services over 10 years is too slow and there is little certainty that the phase-in would reach the Power lower threshold. M-S-R Br., BP-18-B-MS-01, at 12-13. JP02 raises a similar concern. JP02 Br., BP-18-B-

JP02-01, at 9-10. M-S-R and JP02 contend that the delay in implementing the Power lower threshold would continue the status quo inequity of disproportionately relying on Transmission Services' financial reserves for supporting the agency's credit rating and financial health. M-S-R Br., BP-18-B-MS-01, at 12-13; JP02 Br., BP-18-B-JP02-01, at 9-10.

The concerns M-S-R and JP02 raise with regard to Staff's initial phase-in proposal would likely be raised by those parties in reference to BPA's proposed phase-in described above. While BPA recognizes that the equity concerns posed by these parties are valid and should be addressed, *see* Section 6.4.4 (equity and FRP) and Section 6.5.3 (staff's equity objective), BPA does not agree that this correction must come immediately or at the cost of rate shock to Power customers. Harris *et al.*, BP-18-E-BPA-33, at 81. As discussed earlier, BPA views the status quo as inequitable *because* it is not subject to any sort of corrective action. *Id.* at 116-17. A temporary imbalance between business line contributions to the agency's financial reserves is acceptable so long as it is not systemic or long-term, and both business lines continue to contribute reasonable amounts. *Id.* at 98. To that end, the FRP is designed to address the imbalance in business line contributions to agency financial reserves over time, at a moderate pace and taking into account the immediate rate impacts of the FRP. *Id.* at 72, 83.

The phase-in proposal described above, coupled with the commitment to develop additional rate features in a separate process, strikes the proper balance between the interests of those who want the imbalance in agency financial reserves contributions corrected immediately (primarily Transmission customers) with those who want to avoid or mitigate the rate pressure caused by such a correction (primarily Power customers). This proposal would begin the process of correcting the imbalance between business lines by applying a common metric for determining the lower thresholds (60 days cash), and would make progress toward a more equitable contribution to agency reserves by requiring Power Services to include \$20 million of PNR. Both of these features are significant improvements over the status quo, which contains no uniform methods for upper or lower thresholds and requires Power Services to contribute no more to agency financial reserves than what is required by the TPP standard (*e.g.*, \$0). Harris *et al.*, BP-18-E-BPA-17, at 12. Moreover, BPA is committed to discussing through a separate process the timing and mechanism that will be used to increase the Power CRAC threshold to the Power lower threshold.

BPA also will not include in the final FRP a commitment on the timing of the Power CRAC threshold phase-in. JP07 argues BPA should not limit the phase-in to less than 10 years. JP07 Br., BP-18-B-JP07-01, at 15-16. JP02, however, argues that Staff's initial proposal to phase in the FRP for Power Services over 10 years is inequitable, and BPA should adopt measures, such as a shorter phase-in period, to ensure Power Services is at its lower threshold by FY 2028. JP02 Br., BP-18-B-JP02-01, at 10. JP02, however, does not provide any additional insight on what mechanisms should be adopted or how "short" the time period should be. *Id.* at 9-10; *see also* Harris *et al.*, BP-18-E-BPA-33, at 127 (noting JP02 "did not propose any changes to these mechanisms, nor any new mechanisms, designed to" ensure a successful phase-in).

BPA finds that a 10-year phase-in remains an important goal of the FRP, but will not include in the final FRP a binding commitment to achieve full implementation by that time. Even without

this commitment, it is likely that the FRP will be implemented within 10 years. As Staff points out, a ratchet mechanism is a primary method by which Power would make progress toward its lower threshold because it captures the increase in financial reserves that result from a good year and builds financial reserves without, in and of itself, raising rates. *Id.* at 75. Staff also determined, through its modeling of Staff’s initial proposal, that a ratchet mechanism alone gave Power a 79 percent chance of reaching the lower threshold within the next 10 years. *Id.* at 84. In the final FRP, BPA is proposing to develop a ratchet mechanism *and include* \$20 million in PNRR. Together, these features—PNRR and a phase-in for the CRAC threshold (once fully developed)—should further increase the probability that Power reserves will reach the lower threshold within the next 10 years. These issues can be further addressed through the public process that will develop the mechanism(s) for phasing in the Power CRAC threshold to the Power lower threshold.

JP02 also argues that if a business line is below its lower threshold, the FRP should require a CRAC for that business line. JP02 Br., BP-18-B-JP02-01, at 10-11. As noted above, BPA is including a CRAC for each business line, and will address the mechanism for increasing the Power CRAC threshold in the subsequent process.

In its Brief on Exceptions, M-S-R requests further clarification of certain aspects of the phase-in and the follow-on process. M-S-R Br. Ex., BP-18-R-MS-01, at 2-3. First, M-S-R asks “what the Power CRAC threshold will be until the public process concludes.” *Id.* at 3. As noted above in the Section 6.6.4, the “Power CRAC threshold will be \$0 for the BP-18 period, and thereafter no less than \$0.” The Power CRAC threshold will remain at zero for the entire BP-18 rate period. Second, M-S-R asks “whether the proposed mechanism will be adopted at the close of a workshop process or through the BP-20 rate proceeding.” M-S-R Br. Ex., BP-18-R-MS-01, at 3. BPA intends to determine the mechanism at the close of the public process, outside the BP-20 rate case process, with its implementation beginning in the BP-20 rate period. Some implementation details may need to be resolved in the BP-20 rate proceeding, such as the rate implementation terms for the GRSPs, but generally the mechanism and most of its features should be known by the close of the process. Third, M-S-R asks whether “there are any limits on what can be proposed as a phase-in mechanism.” *Id.* Stakeholders participating in the public process may propose any mechanism within the scope of the process. There are no limits on what can be proposed for the phase-in mechanism; proposals could include a single ratchet, multiple ratchets, or some other mechanism to increase the Power CRAC threshold to the Power lower threshold.

Decision

BPA will not adopt the phase-in of the Power CRAC threshold with the IRPL and Good Year Ratchet as described in Staff’s initial proposal. BPA will adopt a phase-in that requires \$20 million of PNRR per year in the Power Services revenue requirement until the Power CRAC threshold has been increased to the Power lower threshold, with a mechanism to increase the Power CRAC threshold to be determined after a public process.

6.6.4.4 Target Days Cash on Hand

Issue 6.6.4.4.1

Whether the financial reserves target of 90 days cash is adequately supported by the record.

Parties' Positions

JP02 argues that Staff has not adequately justified its initially proposed financial reserves target of 90 days cash. JP02 Br., BP-18-B-JP02-01, at 13. JP02 contends that the 90 days cash target is simply a multiple of 30 days cash, which JP02 contends is a suitable financial reserves level to meet BPA's goals. *Id.*

BPA Staff's Position

The 90 days cash target is just a target. Harris *et al.*, BP-18-E-BPA-33, at 87. The FRP does not require financial reserves to reach 90 days cash. See Harris *et al.*, BP-18-E-BPA-17, at 29. Instead, as established in the FRP, the 90 days cash target is used to calculate the business lines' (and BPA's) upper and lower reserves thresholds.

Evaluation of Positions

JP02 argues that BPA has not adequately justified using the 90 days cash target to validate BPA's goals. JP02 Br., BP-18-B-JP02-01, at 13. JP02 notes that BPA refers to guidance from the Moody's rating agency that 30 days cash on hand is a suitable financial reserves level to meet the agency's financial reserves goals. *Id.* JP02 notes, however, that the 90 days cash on hand standard is based solely on business judgment and is simply a multiple of the 30 days standard. *Id.* As such, JP02 argues that BPA has not adequately justified its financial target of 90 days cash, particularly when 30 days cash is a suitable financial reserves level. *Id.*

The 90 days cash target is just that—a target. The FRP does not require either business line to achieve 90 days cash. Rather, the lower threshold (the level of financial reserves below which rate action to replenish reserves is required) is the higher of 60 days cash or the amount of financial reserves required by BPA's TPP, and the upper threshold (the amount above which BPA may repurpose financial reserves) is 60 days cash above that (*e.g.*, 120 days cash). Harris *et al.*, BP-18-E-BPA-17, at 23, 29, 31. Other than serving as the midpoint in the range between these two values, the 90 days cash target has no independent purpose. *Id.* at 29 (“The financial reserves target simply establishes the midpoint for the acceptable range of financial reserves for each business line.”). BPA recognizes that this is a confusing feature of Staff's initial proposal and intends to modify it in the final FRP. BPA will make clear that the lower threshold is simply the higher of 60 days cash or the amount needed for TPP, and the upper threshold for each business line is 60 days cash above the business line's lower threshold (*e.g.*, 120 days cash when the lower threshold is set at 60 days cash). BPA will not reference the 90 days target in the final FRP. BPA has addressed JP02's arguments that 30 days cash is an appropriate level for financial reserves in Issue 6.6.4.2.2.3 (lower threshold and 30 days cash).

Decision

BPA will remove references to the 90 days cash target in the FRP.

6.6.4.5 Upper Threshold

Issue 6.6.4.5.1

*Whether the upper threshold for the FRP should be set at 90 days cash on hand for the agency and 120 days cash on hand for each business line.*⁵

Parties' Positions

Several parties oppose Staff's initial FRP proposal to set the agency upper threshold at 120 days cash. M-S-R Br., BP-18-B-MS-01, at 14; Powerex Br., BP-18-B-PX-01, at 1, 21-22; JP02 Br., BP-18-B-JP02-01, at 14-15; JP07 Br., BP-18-B-JP07-01, at 11. However, many parties support Staff's Alternative Option to lower the agency upper threshold from 120 days cash to 90 days cash. M-S-R Br., BP-18-B-MS-01, at 14; Powerex Br., BP-18-B-PX-01, at 1, 21-22; JP02 Br., BP-18-B-JP02-01, at 14-15; WPAG Br., BP-18-B-WG-01, at 12.

M-S-R describes the FRP's 60, 90, and 120 days cash thresholds as "excessive," but recognizes that during the phase-in period they may be appropriate. M-S-R Br. Ex., BP--18-R-MS-01, at 3. M-S-R recommends BPA revisit the thresholds after the imbalance in business line financial reserves is eliminated. *Id.* at 3-4.

JP07 opposes, in general, an upper threshold of 120 days cash. JP07 Br., BP-18-B-JP07-01, at 11.

BPA Staff's Position

Staff's initial FRP proposal set the agency and business lines' upper thresholds at 120 days cash. Harris *et al.*, BP-18-E-BPA-17, at 22-23. However, in rebuttal testimony, Staff suggested the upper threshold for the agency could be reduced to 90 days cash. Harris *et al.*, BP-18-E-BPA-33, at 145.

⁵ For purposes of this issue, BPA refers to the upper thresholds as equivalent to 90 or 120 days cash. While this is generally accurate, there are instances when the upper threshold could be higher. The test for determining the upper thresholds in both the initial FRP proposal and in the final FRP are in reference to the business lines' lower thresholds. *See Harris et al.*, BP-18-E-BPA-17, at 22-23; *see also* Section 6.6.4.1. The upper threshold for the business line is the lower threshold plus 60 days cash; the upper threshold for the agency is the sum of the business lines' lower thresholds plus 30 days cash. The lower threshold is set as the higher of 60 days cash on hand for the business line *or* the financial reserves necessary to meet the TPP standard. Harris *et al.*, BP-18-E-BPA-33, at 96; *see also* Issue 6.6.4.2.1.2. In other words, the lower threshold could be set by the TPP standard, which would mean the lower threshold is *higher* than 60 days cash. In that instance, the upper thresholds for the agency and the business line would be above 90 and 120 days respectively.

Evaluation of Positions

BPA does not have a methodology for calculating an upper limit on the amount of financial reserves BPA should hold before considering other uses for those funds. Harris *et al.*, BP-18-E-BPA-17, at 20. The Power Dividend Distribution Clause (DDC) has served as such a limit for Power, but it is not the product of a repeatable methodology, and Transmission rates have not included a DDC. *Id.* The lack of a comprehensive policy applicable to both business lines has led to uncertainty regarding whether and when BPA should consider taking actions to release financial reserves attributed to a business line for other purposes. *Id.*

In its initial FRP proposal, Staff proposed to create upper thresholds for BPA and business line financial reserves. *Id.* at 23. Staff proposed to set the agency upper threshold as the sum of the business lines' upper thresholds. *Id.* If (1) financial reserves for a business line are above the upper threshold for that business line, and (2) BPA's financial reserves are above the BPA upper threshold, a Reserves Distribution Clause (RDC) would trigger, and the above-threshold financial reserves would be considered for investment in other high-value purposes, such as debt retirement, incremental capital investment, or rate reduction. *Id.* Staff proposed to set both the agency and business line upper threshold at 120 days cash (60 days above the business line's lower threshold). *See Id.* at 22-23. Thus, for financial reserves to be eligible for the RDC, BPA's total reserves must be above a 120 days cash threshold for the agency, *and* a business line's financial reserves must be above its 120 days cash upper threshold. *Id.*

Parties almost uniformly opposed Staff's proposed 120 days cash upper threshold and proposed that BPA lower the upper thresholds. *See, e.g.,* Deen *et al.*, BP-18-E-JP05-01, at 18, 25 (suggesting 95 days cash for upper threshold); Saleba *et al.*, BP-18-E-WG-01, at 10 (105 days cash for upper threshold); Wrigley *et al.*, BP-18-E-JP02-01, at 16 (sum of business line targets, approximately 90 days); M-S-R, BP-18-E-MS-12, at 33 (agency threshold should be set at an agency target of 45 days).

In response, Staff proposed lowering the upper threshold for the agency from 120 days cash to 90 days as part of its Alternative Option. Harris *et al.*, BP-18-E-BPA-33, at 145. The test for an RDC would continue to be a two-part test: (1) the financial reserves attributed to a business line must be above its upper threshold (120 days cash); and (2) agency financial reserves must be above the agency upper threshold of 90 days cash (currently about \$600 million). Distributions under the RDC would continue to be subject to the Administrator's discretion. *Id.*

Several parties support Staff's proposal to lower the agency upper threshold from 120 days cash to 90 days cash. M-S-R Br., BP-18-B-MS-01, at 14; Powerex Br., BP-18-B-PX-01, at 1, 21-22; JP02 Br., BP-18-B-JP02-01, at 14-15; WPAG Br., BP-18-B-WG-01, at 12.

BPA agrees that setting the upper threshold for the agency at 120 days cash was a conservative measure. Staff's rationale for setting the upper threshold at 120 days cash was to ensure financial reserves were "robust" before such reserves were used for other purposes. Harris *et al.*, BP-18-E-BPA-17, at 34. Staff performed an analysis to determine the effects of reducing the upper threshold for the agency from 120 days to 90 days cash. Staff's analysis indicated that reducing the number of days cash did have a significant net effect on the probability that BPA's

financial reserves would remain at levels that would protect the agency's credit rating. Harris *et al.*, BP-18-E-BPA-33, at 144. Staff commented that the negative impact of this change on BPA's credit rating would likely be mitigated by the combination of other features that strengthen agency financial reserves. *Id.* Thus, BPA agrees that the agency upper threshold should be lowered to 90 days cash. To recognize that either TPP or the FRP can set the lower threshold, the FRP will state that the agency upper threshold will be as follows: "The Agency upper threshold is the sum of Power and Transmission's lower thresholds plus 30 days cash (Agency cash)."

In making this change, BPA reaffirms Staff's finding that the business line upper thresholds should continue to be 120 days cash. *Id.* at 89-90. The requirement that the business lines must exceed their upper threshold of 120 days cash (roughly \$600 million for Power Services, and \$200 million for Transmission Services in this rate period) before financial reserves become eligible for repurposing under the RDC protects BPA's credit rating and provides greater rate stability. *See* Power and Transmission Risk Study, BP-18-E-BPA-05, at 114-15, Tables 11 & 12; *see also* Harris *et al.*, BP-18-E-BPA-17, at 16. Maintaining the business line upper thresholds at 120 days cash ensures that BPA has a robust amount of financial reserves before repurposing them for other uses. Harris *et al.*, BP-18-E-BPA-17, at 34-35. This approach also protects BPA's credit rating and reduces the likelihood of BPA repurposing financial reserves in one year, and then increasing rates in the next to replenish financial reserves.

JP07 argues BPA did not sufficiently justify why 120 days cash is the appropriate upper threshold. JP07 Br., BP-18-B-JP07-01, at 11-12. JP07 cites Staff's testimony that "the 120 days cash on hand is a safe place to set the upper financial reserves threshold, as this would equate roughly to over four times the absolute minimum level of days cash on hand required by Moody's." *Id.* (citing Harris *et al.*, BP-18-E-BPA-17, at 33). JP07 also cites to Staff having "analyzed how often the Reserves Distribution Clause (RDC) would have triggered with the 120-day upper threshold since 2004, and 'the RDC would have triggered 25 percent of the time over the last 12 years.'" *Id.* at 11 (quoting Data Response NR-BPA-26-16). JP07 argues, "[b]ut again, Staff failed to explain why 25 percent is the appropriate frequency for the RDC to trigger." *Id.*

BPA disagrees that Staff has not justified using 120 day cash as the upper threshold for the business lines. Staff's determination of the upper threshold was not done based upon a single factor or an uninformed multiple of 30 days cash on hand. Harris *et al.*, BP-18-E-BPA-33, at 89. Rather, it was based on multiple factors, including primarily:

[H]istorical financial reserves amounts; historical financial variability for both the Power and Transmission business units; forecast financial variability for the Power and Transmission business units; the known one-year recovery time for the CRAC mechanism; and the proposed lower threshold amounts for both business lines.

Id. Further, Staff performed a quantitative analysis based on forecast financial uncertainty as described in Harris *et al.*, BP-18-E-BPA-33, Attachment 11, Data Response PP-BPA-26-20, Attachment 21, Data Response PS-BPA-26-12, and Attachment 22, Data Response

PS-BPA-26-13, to justify the upper threshold of 120 days cash. Staff also assessed the parties' alternative proposals, including the likelihood that the parties' proposals (which proposed lowering the upper thresholds) would *increase* the likelihood that BPA's financial reserves would fall below 30 days cash on a sustained basis. *Id.*, Attachment 7. This analysis demonstrates that multiple policy parameters were considered simultaneously to determine that 120 days cash was the appropriate upper financial threshold. *Id.* at 89-90.

In addition, the 120 days cash requirement for each business line is not high by industry standards. Other large utilities with high credit ratings hold significantly more in financial reserves than what BPA is proposing. As Staff explained:

According to one of the three primary credit rating agencies, Moody's, entities similar to BPA hold between 150 and 250 days cash on hand One hundred and fifty days cash on hand for BPA computes to roughly \$1 billion in financial reserves, and 250 days cash computes to \$1.6 billion.

Harris *et al.*, BP-18-E-BPA-17, at 13; *see also* Harris *et al.*, BP-18-E-BPA-33, at 62-63 (describing other utilities' days cash). Moreover, the 120 days cash value for Power Services (roughly \$600 million in this rate period) is significantly below the status quo rate mechanism—*e.g.*, the DDC—which is set at \$750 million for Power Services. Harris *et al.*, BP-18-E-BPA-17, at 12.

Finally, one of Staff's considerations in setting the business line upper and lower thresholds was to create a reasonable deadband within which no rate action would be taken, for rate stability. *See* Harris *et al.*, BP-18-E-BPA-33, at 40. In that sense, the upper threshold is further justified by reference to the lower threshold. BPA rejected proposals that included narrow deadbands, such that Power could easily find itself triggering an RDC in one year and then triggering a CRAC in the very next year. *Id.* at 115. JP05 (the predecessor to JP07) agreed with Staff's rationale for a wide deadband: “[w]e agree with BPA staff's proposal that a ‘deadband’ of 60 days’ cash on hand appears reasonable and results in an upper threshold adequately higher than the lower.” Deen *et al.*, BP-18-E-JP05-01, at 25. Consistent with JP05's comment, retaining the 120 days cash upper threshold ensures there is a deadband of 60 days cash between the lower threshold (60 days cash) and the upper threshold (120 days cash). Having this wide deadband is important to avoid triggering the RDC in one year, and then potentially increasing rates the next, or vice versa.

An example will illustrate the need for a wide deadband. Under the FRP, the agency upper threshold is the sum of the business lines' lower thresholds, plus 30 days cash (*i.e.*, 90 days cash unless the CRAC threshold for a business line is higher than 60 days cash to meet the 95 percent TPP standard), which is approximately \$600 million in this rate period. The business line upper thresholds are 120 days cash. The Power upper threshold is approximately \$600 million in this rate period. *See* Power and Transmission Risk Study, BP-18-E-BPA-05, at 114, Table 11. The Transmission upper threshold is approximately \$200 million in this rate period. *Id.* at 115, Table 12. Assuming that both business lines' financial reserves were at their upper thresholds, total agency financial reserves would be \$800 million (\$600 million Power Services, and

\$200 million Transmission Services). In this case, no action would be taken because neither business line exceeds its individual upper threshold.

Assume now that in the next fiscal year the cash flows for both business lines are at least one standard deviation below the rate case estimate (–\$250 million for Power Services, and –\$24 million for Transmission Services). *See Harris et al.*, BP-18-E-BPA-17, at 16; Power and Transmission Risk Study, BP-18-E-BPA-05, at 83. Cash flow for a business line has about a one-in-six chance of being at least one standard deviation below the rate case estimate each year. *See Harris et al.*, BP-18-E-BPA-17, at 16. Because of the wide deadband under the FRP, BPA would not need to take any rate action with either business line to replenish the lost financial reserves. BPA would still have a robust cushion of \$526 million in financial reserves to support its credit rating (composed of \$350 million for Power Services and \$176 million for Transmission Services), and both business lines would be above their respective lower thresholds (Power lower threshold of \$300 million, Transmission lower threshold of \$100 million). Power and Transmission Risk Study, BP-18-E-BPA-05, at 114-15, Tables 11 & 12.

If the upper threshold were reduced to 90 days cash for both business lines, then the deadband shrinks to 30 days cash, and a very different result occurs from the above hypothetical. Assume both business lines' financial reserves were at the same values described above (\$600 million Power Services, \$200 million Transmission Services). Both business lines would have exceeded their upper thresholds (the Power 90 days cash upper threshold is approximately \$450 million, the Transmission upper threshold is approximately \$150 million), and the total agency reserves (\$800 million) would have exceeded the agency upper threshold (\$600 million). BPA could decide to repurpose \$200 million in financial reserves, dropping Power's financial reserves to \$450 million, and Transmission's reserves to \$150 million. The next fiscal year, assume BPA experiences the same negative cash flows (–\$250 million for Power, and –\$24 million for Transmission), where total agency financial reserves decline to \$326 million, composed of \$200 million for Power and \$126 million for Transmission. Power is below its lower threshold (\$300 million), and now BPA would need to increase Power rates to raise financial reserves back to the Power lower threshold.

JP07 has emphasized the importance of rate stability in its brief. JP07 Br., BP-18-B-JP07-01, at 5. BPA finds that greater rate stability, and credit protection, can be afforded under Staff's Alternative Option (which retains the 120 days cash upper threshold for the business lines) when compared with a proposal that increases the chances that BPA could release financial reserves to customers in one year, only to increase rates in the next to replenish those financial reserves to healthy levels.

In its Brief on Exceptions, M-S-R argues that nearly every party agrees that the FRP's 60, 90, and 120 days cash thresholds are excessive. M-S-R Br. Ex., BP-18-R-MS-01, at 3. M-S-R acknowledges, though, that given the projected zero financial reserves for Power, higher levels of financial reserves are needed during the phase-in because otherwise Power reserves could remain at zero while a portion of Transmission's reserves could be repurposed. *Id.* M-S-R, however, recommends that, after the imbalance in financial reserves is eliminated, BPA should revisit the financial reserves thresholds so that excessive reserves can be repurposed. *Id.* at 3-4.

BPA does not agree that revisiting the thresholds if and when the imbalance in business line financial reserves is eliminated would be either reasonable or prudent. First, BPA does not agree that the thresholds established by the FRP are “excessive” for the reasons described in this issue as well as in Issue 6.6.4.2.2.3 (lower threshold and 30 days cash). Indeed, the record in this case establishes that the financial thresholds adopted in the FRP are very conservative by industry standards. According to Moody’s, entities similar to BPA hold between 150 and 250 days cash on hand. Harris *et al.*, BP-18-E-BPA-17, at 13; *see also* Harris *et al.*, BP-18-E-BPA-33, at 62-63. Second, as described in Issue 6.6.4.5.1, BPA has addressed parties’ concerns with the agency upper threshold by reducing the upper threshold from 120 days cash to 90 days cash.

Third, revisiting the thresholds established in the FRP after the imbalance in business line contributions is eliminated will undermine one of the key purposes of the FRP, which is establishing durable, long-term financial reserves thresholds to support BPA’s financial health. Agreeing to revisit the financial reserves thresholds at a future time would inject additional uncertainty into BPA’s financial health, credit support, and ratemaking. For instance, by setting the FRP thresholds now, BPA and its customers and stakeholders can work together to determine the best ways of achieving those levels. However, if BPA were to make those thresholds subject to change when the imbalance between business line financial reserves is eliminated, then the focus of BPA’s customers and stakeholders could easily turn to how to simply eliminate the imbalance. One obvious way of eliminating this imbalance would be to reduce Transmission reserves so that they are more comparable with Power’s reserves, which are very low. The end result would be an overall reduction in financial reserves, which would eliminate the imbalance in business line financial reserves, but at the expense of BPA’s overall financial health and credit rating. Moreover, revisiting the thresholds could also cause uncertainty in the costs of the FRP to customers. While M-S-R presumes revisiting the financial reserves thresholds would *reduce* the days cash requirements of the FRP, nothing would prohibit BPA from later concluding that the 60, 90, and 120 days cash values were *insufficient*. Thus, revisiting the FRP’s thresholds could, in fact, increase the days cash needs of BPA and, in turn, decrease the likelihood of BPA repurposing financial reserves. For these reasons, BPA does not agree that revisiting the FRP’s thresholds after the phase-in is reasonable or prudent.

Decision

Unless an amount greater than 60 days cash is necessary for a business line to meet the TPP Standard, the upper thresholds for the FRP will be set at 90 days cash on hand for the agency (30 days cash above the sum of the business lines’ lower thresholds) and 120 days cash for each business line (60 days cash above the business line’s lower threshold).

Issue 6.6.4.5.2

Whether the Administrator should have discretion to determine the use of financial reserves eligible for repurposing under the RDC.

Parties' Positions

JP02 argues that the FRP should be revised to make application of the RDC mandatory and used only for rate reduction. JP02 Br., BP-18-B-JP02-01, at 12.

Powerex requests BPA hold workshops before determining the purpose of financial reserves eligible for the RDC. Powerex Br., BP-18-B-PX-01, at 23.

BPA Staff's Position

The FRP should retain the Administrator's discretion for determining the use of funds eligible for repurposing under the RDC. Harris *et al.*, BP-18-E-BPA-17, at 22-23; Harris *et al.*, BP-18-E-BPA-33, at 145.

Evaluation of Positions

If a business line's financial reserves exceed its upper threshold (120 days cash) and total agency financial reserves exceed the agency upper threshold (90 days cash), then the financial reserves above both thresholds are eligible for repurposing under the RDC. Harris *et al.*, BP-18-E-BPA-33, at 145. The FRP retains from Staff's initial proposal the Administrator's discretion to determine what, if any, repurposing of eligible financial reserves may be chosen. Staff identified a few examples of high-value purposes that such financial reserves may be used for, including debt retirement, incremental capital investment, or rate reduction. Harris *et al.*, BP-18-E-BPA-17, at 23.

JP02 argues that the FRP should be revised to make clear that financial reserves above the RDC mechanism threshold will be applied to rate reduction. JP02 Br., BP-18-B-JP02-01, at 12. JP02 argues that excess financial reserves of a business line represent amounts paid by customers of that business line in excess of the cost of service of that business line. *Id.* Use of excess financial reserves of a business line to reduce the rates of that business line appropriately returns those excess funds to the customer classes that paid those excess funds. *Id.* Using excess financial reserves of a business line to reduce the rates that customers of that business line pay is consistent with the ratemaking principle of intergenerational equity among customers of that business line. *Id.*

BPA does not agree that the RDC should be revised to remove the Administrator's discretion. The Administrator should have the discretion to consider BPA's present financial condition to determine what use, if any, the RDC funds should be committed to, keeping in mind the agency's overall financial health. Harris *et al.*, BP-18-E-BPA-33, at 90. Retaining this discretion will ensure that the Administrator can factor in prevailing financial circumstances and any extenuating circumstances that militate against spending financial reserves. *Id.*

Moreover, this is the first time in BPA’s history that BPA is setting an upper threshold on financial reserves that is applicable to both business lines. As explained extensively in Section 6.4 (need for FRP), Section 6.5.2 (staff’s liquidity objective), reductions in financial reserves can have an effect on BPA’s overall financial health, including its credit rating and liquidity. While the FRP contains safeguards to ensure both BPA’s credit rating and liquidity are protected, BPA cannot foresee all of the potential circumstances that may occur to warrant retaining financial reserves. BPA expects that the normal operation of the RDC will result in the repurposing of financial reserves, but does not want to remove the ability of the Administrator to respond to the business and financial realities at the time. Retaining the Administrator’s discretion is, therefore, a prudent business measure.

BPA also does not agree that the repurposing of such financial reserves should be limited to rate reduction. BPA’s business environment and business needs change over time. Harris *et al.*, BP-18-E-BPA-17, at 34. BPA’s business lines have gone through periods of increased capital investment and periods of maintenance of the existing capital investment. *Id.* As Staff described, the RDC is designed to repurpose financial reserves for “other high-value purposes” *Id.* at 26. The Administrator should be able to determine that “high-value purpose” in reference to the business needs of BPA at the time. This leaves to the Administrator the discretion to determine whether to use financial reserves for near-term benefits, such as rate reductions, or long-term benefits, such as debt retirement, additional capital investments, or some combination of these or other uses. *Id.*

JP02 also cites intergenerational equity issues in support of rate reduction. JP02 Br., BP-18-B-JP02-01, at 12. However, providing rate relief without considering current financial needs could also cause intergenerational equity issues. For instance, providing short-term rate relief without considering the full financial picture could result in costs incurred by the current generation to be borne by future generations. Harris *et al.*, BP-18-E-BPA-33, at 90. The Administrator should be able to determine at the time of the RDC which use of financial reserves is in BPA’s and its customers’ best interests. To that end, and in response to Powerex, BPA intends to seek customer feedback regarding what to do with financial reserves eligible for the RDC. Powerex Br., BP-18-B-PX-01, at 23. Powerex asks the Administrator to engage with customers in a stakeholder process to determine the best use of above-threshold financial reserves. *Id.* BPA agrees and has included in the General Rate Schedule Provisions applicable to the RDC a public process for considering how to use RDC-eligible funds. Harris *et al.*, BP-18-E-BPA-33, at 91; *see* 2018 Transmission, Ancillary, and Control Areas Service Rate Schedules and GRSPs, BP-18-A-04-AP04, § II.I.2.b.

Finally, JP02 also notes that its approach would be consistent with the implementation of the current DDC, where amounts above a threshold are applied to rate reduction. JP02 Br., BP-18-B-JP02-01, at 12. JP02 argues that BPA has not adequately explained why a different approach is now appropriate. *Id.* The RDC and DDC, however, are designed from very different constructs. The RDC is a component of a comprehensive financial reserves policy that uses uniform metrics to set upper and lower thresholds that apply across business lines. Harris *et al.*, BP-18-E-BPA-17, at 22-23; *see also* Section 6.6.4.1 (Final FRP overview). The DDC, in contrast, was a rate-period-by-rate-period determination applicable only to Power Services and

not the product of a “repeatable methodology.” Harris *et al.*, BP-18-E-BPA-17, at 20. Moreover, the DDC had a significantly higher threshold than the RDC. Power’s financial reserves would need to exceed \$750 million to be eligible for the DDC, which is equivalent to 150 days cash for Power Services. *Id.* at 11; Power and Transmission Risk Study, BP-18-E-BPA-05, at 114, Table 11 (noting Power Services’ day cash on hand value). The RDC, however, only requires financial reserves to exceed 120 days cash for the business line and only 90 days cash for the agency (\$600 million). Harris *et al.*, BP-18-E-BPA-33, at 145; *see also* Power and Transmission Risk Study, BP-18-E-BPA-05, at 114-15, Tables 11 & 12. Because the RDC includes a lower threshold for its application, and is now applicable to both business lines, there is a higher likelihood that the RDC will trigger. For these reasons, it is both reasonable and prudent to allow the Administrator greater flexibility and discretion in implementing the terms of the RDC.

Decision

The Administrator will retain discretion to determine the use of financial reserves eligible for repurposing under the RDC.

Issue 6.6.4.5.3

Whether the FRP should include a cap on financial reserves attributable to Transmission Services.

Parties’ Positions

Powerex argues that, while BPA is proposing to phase in Power’s contribution to the lower threshold defined in the FRP for Power Services, BPA will be immediately applying the FRP to Transmission Services. Powerex Br., BP-18-B-PX-01, at 22. Powerex contends a more evenhanded approach would be to cap Transmission’s financial reserves at current level of \$444 million during the Power phase-in. *Id.* Powerex argues this is equivalent of 270 days cash for Transmission, and 65 days cash for BPA as an agency, which is well above the 30 days cash needed to support BPA’s credit rating. *Id.* Powerex contends that this cap places a meaningful limit on the amount of excess financial reserves BPA could accumulate. *Id.* In addition, Powerex argues this approach will provide some assurance to Transmission customers that a limit was being phased in, just as the Power CRAC threshold was to be phased in. *Id.* at 22-23.

JP02 similarly argues for capping Transmission’s financial reserves at \$444 million for FY 2018. JP02 Br., BP-18-B-JP02-01, at 36. JP02 also suggests that this cap be reduced each subsequent fiscal year by \$15 million during the phase-in period for Power. *Id.* JP02 suggests the cap could stop at the Transmission upper threshold. *Id.* By 2027, if the phase-in had not been completed, the cap would be \$309 million for Transmission, which is slightly more than the amount of agency financial reserves WPAG suggested was adequate. *Id.* at 36-37.

BPA Staff's Position

The upper threshold of 90 days cash for the agency and 120 days cash for each business line are appropriate. Harris *et al.*, BP-18-E-BPA-33, at 145. The FRP phases in Power's financial reserves to the lower threshold, which begins to address the imbalance between the business lines. *Id.* at 145-46. Capping Transmission's financial reserves would accelerate the decline of agency financial reserves, which could harm BPA's credit rating and financial health.

Evaluation of Positions

Powerex's proposal is a variation on the proposal it offered in its direct case. See Opatrny, BP-18-E-PX-01, at 17-19. In its direct case, Powerex suggested capping Transmission's financial reserves at its FY 2016 levels (\$444 million) and also using \$58 million for other purposes. *Id.* at 18. Staff analyzed Powerex's proposal and found that it would not have improved BPA's financial reserves for credit support purposes above the status quo. Harris *et al.*, BP-18-E-BPA-33, at 133. Staff explained that it did not apply Powerex's \$444 million cap because of "the complexity with how it would interact with the business lines' and agency's 120 days cash upper threshold, and further because it likely would have minimal effect on aggregate modeling results because it provides protection for some low-probability events." *Id.* at 133.

In its brief, Powerex proposes only the cap on Transmission's financial reserves at \$444 million and is not proposing to reduce Transmission's reserves by \$58 million. Powerex Br., BP-18-B-PX-01, at 22-23.

BPA acknowledges that Powerex's proposal is not unreasonable. Harris *et al.*, BP-18-E-BPA-33, at 132. However, BPA does not agree that the FRP should be modified to include a separate cap on Transmission's financial reserves.

First, BPA is beginning to address the imbalance between the business line contributions to agency reserves through the phase-in for Power. The final FRP will require Power to contribute to agency financial reserves through an addition of \$20 million in PNRR. *Id.* at 145-46; *see also* Section 6.6.4.3 (phase-in). This contribution will begin the process of rebalancing the business line contributions to agency financial reserves. Harris *et al.*, BP-18-E-BPA-33, at 145-46. In addition, BPA intends to conduct a separate process to continue developing the phase-in for the Power CRAC Threshold. *Id.* These two components, once fully developed, should gradually resolve the imbalance in business line contributions, thereby obviating the need to cap Transmission's reserves at a specific value.

Moreover, as the phase-in for Power begins to take effect, RDC distributions are more likely to occur. This is because, in addition to requiring contributions from Power, BPA has decided to reduce the upper threshold for the agency from 120 days cash to 90 days cash. This adjustment will also increase the chances of Transmission customers receiving the benefits of the RDC. For instance, under Staff's Alternative Option, which BPA is, in part, adopting in this case, the likelihood of the RDC triggering for Transmission was 72 percent. *Id.*, Attachment 7.

Considering that Transmission had no RDC or RDC-like mechanism in place before, this is a significant improvement over the status quo.

Second, BPA does not agree that considerations of equity require it to take actions that are potentially deleterious to the agency's overall financial health and credit rating. The FRP is attempting to balance multiple objectives. *Id.* at 71. As it pertains to equity, the FRP rebalances the business line contributions by requiring Power to contribute more to agency financial reserves, which also supports BPA's objective to support the agency's credit rating. Powerex and JP02 note that reducing Transmission's financial reserves would be more equitable as it reduces the imbalance between the business lines. JP02 Br., BP-18-B-JP02-01, at 36-37; Powerex Br., BP-18-B-PX-01, at 22. But reducing agency financial reserves to address an imbalance in business line contributions comes at the cost of reducing total financial reserves that support the agency's overall financial health.

While Powerex and JP02 note that a cap on Transmission reserves of \$444 million would still be above 60 days cash on hand for the agency, it would nonetheless require BPA to adopt a policy of accelerated financial reserves distributions under certain circumstances that are *below* the 90 days cash agency threshold that BPA (and most parties) agree is an appropriate upper threshold. *See* Issue 6.6.4.5.1 (upper threshold—90 or 120 days cash). This completely divorces the Transmission upper threshold from the agency upper threshold. As discussed extensively above, the agency upper threshold of 90 days cash ensures that BPA has a robust cushion of financial reserves to support the agency's financial health and credit rating *before* voluntarily reducing financial reserves for other purposes. Harris *et al.*, BP-18-E-BPA-17, at 34. Powerex's and JP02's proposal, however, would require BPA to repurpose Transmission's financial reserves above the cap, regardless of whether BPA has sufficient reserves to support its credit rating. JP02 Br., BP-18-B-JP02-01, at 36; Powerex Br., BP-18-B-PX-01, at 22.

To that end, BPA finds that as a policy and sound business matter, it is better to address the imbalance in business line contributions by establishing a plan to increase contributions from the business line that is under-contributing while maintaining current agency reserves levels. This approach is more reasonable and a safer business choice than a plan that addresses the imbalance by intentionally decreasing agency financial reserves even when financial reserves are below the thresholds set in the FRP, *i.e.*, below 90 days cash on hand.

For similar reasons, BPA also disagrees with JP02's proposal that Transmission's financial reserves be capped at \$444 million in FY 2018, and subsequently reduced over time by \$15 million each fiscal year, but not less than Transmission's upper threshold, until the phase-in is complete. JP02 Br., BP-18-B-JP02-01, at 36-37. JP02's proposal is even more problematic than Powerex's proposal in terms of reducing total financial reserves to support agency financial health. The FRP establishes the lower threshold for each business line as 60 days cash which, for the agency, would be approximately \$400 million (for this rate period). However, JP02's proposal would allow agency reserves to drop below this amount (\$309 million). *Id.* at 36-37. While maintaining equity between the business lines is *one* of the objectives of the FRP, it is not the *sole* objective. Harris *et al.*, BP-18-E-BPA-17, at 24. Other objectives, like establishing "prudent" upper and lower thresholds, and support for BPA's credit rating, also factor in to

determining the appropriate structure for the RDC. *Id.* The FRP BPA adopts herein properly balances those objectives.

Decision

The FRP will not include a cap on financial reserves attributable to Transmission Services.

6.6.5 Parties' Alternative Proposals

Issue 6.6.5.1

Whether BPA should have considered expanding the Treasury Facility to support the agency's credit rating.

Parties' Positions

ICNU argues BPA should attempt to expand the Treasury Facility before adopting the FRP. ICNU Br., BP-18-B-IN-01, at 80-85.

BPA Staff's Position

The Treasury Facility is not an appropriate substitute for financial reserves for purposes of supporting BPA's credit rating. Harris *et al.*, BP-18-E-BPA-17, at 15.

Evaluation of Positions

The Treasury Facility is a line of credit BPA has with the Treasury. *Id.* at 4. The line of credit can be used to fund expenses recognized under the Northwest Power Act and is limited to a maximum amount outstanding of \$750 million or the amount of BPA's remaining borrowing authority, whichever is smaller. *Id.* at 4-5 The maximum borrowing term is two years. *Id.* at 5. BPA pays an interest rate from the applicable U.S. agency yield curve corresponding to the borrowing term. *Id.*

ICNU argues that BPA should have considered expanding the Treasury Facility. ICNU Br., BP-18-B-IN-01, at 80. ICNU notes that Moody's considers "the beneficial U.S. Treasury borrowing line" to be a positive "offset" to other weaknesses exhibited by BPA. *Id.* Thus, ICNU argues that it would have been consistent with sound business principles for BPA to attempt to support "its credit rating via an expansion to this 'positive' ratings factor and this recognized means of '[s]upplementing BPA's internal liquidity . . . to fund operating expenses.'" *Id.* at 80-81.

BPA disagrees with ICNU's arguments. First, the Treasury Facility is not an appropriate substitute for financial reserves for purposes of supporting BPA's credit rating. Staff explained that while BPA counts the Treasury Facility as part of the liquidity that supports BPA's TPP standard, "[t]he rating agencies do not consider the Treasury Facility line of credit in their calculations of days cash on hand." Harris *et al.*, BP-18-E-BPA-17, at 15. The credit rating

agencies have expressed concern, not only with BPA’s liquidity generally, but specifically with BPA’s levels of financial reserves. In its March 2017 credit report, Moody’s notes concern with BPA’s deteriorating financial reserves: “BPA’s rapid decline in its reserves for risk is a credit negative and an inability to ensure internal reserves at or near current levels could lead to a negative rating action.” Motion for Official Notice of Credit Rating Agency Reports, BP-18-M-BPA-09, Attachment A, at 4. Fitch cited, as a “rating sensitivity,” “[t]he failure of Bonneville Power Administration to adopt sufficient rate increases to reverse the decline in *cash* reserves” *Id.*, Attachment B, at 2 (emphasis added).

ICNU specifically asked Staff if a larger Treasury Facility was considered as a means of reducing the level of financial reserves under the FRP. *See* Mullins, BP-18-E-IN-01-AT01, at 28. Staff responded in the negative, because increasing financial reserves through a larger Treasury Facility would not help BPA’s credit rating:

One of the key factors taken into account by the agencies that rate BPA’s credit is the amount of unrestricted cash on hand, or Reserves Available For Risk in BPA’s terms. The rating agencies do not consider the Treasury Facility as a form of cash, so the Treasury Facility does not augment the amount of cash considered by the rating agencies. As such, a larger Treasury Facility would not have helped support BPA’s credit rating.

Id. Thus, in simple terms, the Treasury Facility is not considered the same as financial reserves from the perspective of the credit rating agencies and, therefore, is not a substitute for it. Harris *et al.*, BP-18-E-BPA-17, at 15.

In addition, if BPA borrowed from the Treasury Facility in an attempt to generate cash, this would not increase BPA’s financial reserves. This is because, in performing the calculation for financial reserves, BPA *removes* any outstanding debt on the Treasury Facility: “BPA’s definition of Financial Reserves Available for Risk is Total Financial Reserves less Reserves Not Available for Risk less outstanding balances on the Treasury Facility.” Harris *et al.*, BP-18-E-BPA-33, Attachment 8, Data Response IN-BPA-26-29; *see also* Harris *et al.*, BP-18-E-BPA-33, at 68-69. For instance, if BPA were to draw \$200 million on the Treasury Facility, BPA’s total financial reserves would not be any higher because BPA would also subtract \$200 million from the financial reserves calculation to reflect the outstanding debt on the Treasury Facility. Thus, expanding the Treasury Facility would do nothing to support or increase BPA’s financial reserves.

Second, expanding the Treasury Facility in-and-of-itself would not have supported BPA’s credit rating. ICNU notes that Moody’s considers the Treasury Facility a credit positive. ICNU Br., BP-18-B-IN-01, at 80. ICNU also argues that Moody’s expressly states the Facility supplements liquidity and, as a component of BPA’s overall borrowing authority, creates an offsetting benefit to other agency weaknesses. *Id.* at 81. BPA agrees that the Treasury Facility is a credit positive and the effect of the unique Treasury Facility is already reflected in BPA’s credit rating. BPA has maintained its Aa1 credit rating despite declining financial reserves, and despite having only \$394 million in financial reserves (projected end-of-fiscal year 2017), which is only approximately 60 days cash on hand. Harris *et al.*, BP-18-E-BPA-33, at 4. Moody’s has stated

that BPA’s Aa1 credit rating reflects—among other factors—its U.S. Government support features, and that BPA’s financial metrics alone range in the ‘Ba’ to ‘A’ category. Motion for Official Notice of Credit Rating Agency Reports, BP-18-M-BPA-09, Attachment A, at 1.

Moreover, even though the Treasury Facility is a credit positive, BPA does not agree that expanding the Treasury Facility would obviate the need to take steps to support BPA’s financial reserves. Intuitively, this is clear from the fact that the credit rating agencies have expressed concerns with BPA’s financial reserves levels despite BPA’s access to the Treasury Facility. *See, e.g., Harris et al., BP-18-E-BPA-33, Attachment 5, Moody’s BPA Credit Rating Report (June 14, 2016), at 3.* In the most recent credit rating reports, Fitch made this point even clearer when it found that *even with* the Treasury Facility, BPA’s declining financial reserves are a concern:

[U]nrestricted cash reserves are at their lowest level since 2007, which is a concern *even with* the \$750 million federal line of credit that provides additional liquidity. . . . [W]hile the line of credit provides short-term borrowing liquidity, it is *not designed* to compensate for Bonneville's inherent power revenue variability.

Motion for Official Notice of Credit Rating Agency Reports, BP-18-M-BPA-09, Attachment B, at 2-3 (emphasis added). Thus, it is the nature of the Treasury Facility, not its size, that is a limitation.

ICNU also argues BPA “rushed into” adopting a financial reserves policy without “even exploring” alternatives. ICNU Br., BP-18-B-IN-01, at 82. BPA addresses the process for developing the FRP in Issue 6.6.5.4 (reasons for deciding FRP in rate case).

ICNU notes that renewal of the Treasury Facility is an annual process, and BPA could have begun negotiations within the year. *Id.* ICNU also notes that the amount BPA could receive under the Treasury Facility is not capped by legislation. *Id.*

BPA agrees that negotiations with the Treasury are possible. However, as noted above, expanding the Treasury Facility would not address the credit rating agencies’ concerns with BPA’s credit rating. ICNU also erroneously cites Staff as stating that “the amount BPA could receive under the Facility is not capped by legislation.” ICNU misunderstood Staff’s data response. It is correct that the \$750 million limit is not in legislation. However, use of the Treasury Facility requires borrowing authority to be available, *and BPA’s borrowing authority is capped by legislation.* As Staff stated in its data response: “The Treasury Facility is not capped by legislation. The Treasury Facility is capped at \$750 million under the terms of the facility BPA has negotiated with the Treasury. BPA’s total borrowing authority is capped by legislation.” Mullins, BP-18-E-IN-01-AT01, at 26. The limitation on the Treasury Facility and BPA’s borrowing authority was also discussed in Staff’s testimony: “The [Treasury Facility] can be used to fund expenses recognized under the Northwest Power Act and *is limited to a maximum amount outstanding of \$750 million or the amount of BPA’s remaining borrowing authority, whichever is smaller.*” *Harris et al., BP-18-E-BPA-17, at 4-5 (emphasis added).*

ICNU then argues that expanding the Treasury Facility is “good policy” because the Treasury Facility is unique, and allows BPA to supplement liquidity needs in a manner separate from any remotely comparable entity, which must rely, instead, completely on traditional reserve levels to meet liquidity needs. ICNU Br., BP-18-B-IN-01, at 83. Further, ICNU contends that the Treasury Facility provides BPA with “a stable and low cost source of financing, *even in a financial crisis*, which . . . describes an option that ought to be considered for expansion, rather than ignored.” *Id.* (original emphasis).

While there may be some advantages to a higher limit on the Treasury Facility, a higher limit would not fix any immediate solvency problems or credit rating problems. As noted before, the current Treasury Facility provides BPA with sufficient liquidity for its solvency needs; therefore, BPA does not have a solvency problem. *See* Section 6.4.5 (liquidity and a financial reserves policy); Issue 6.5.2.1 (liquidity objective’s usefulness). Also, as noted above, expanding the Treasury Facility would do nothing to mitigate the credit rating agencies’ concerns over BPA’s reserve levels because rating agencies do not consider lines of credit to be a form of cash (or financial reserves).

ICNU also argues that Staff’s “counterarguments” to an expansion of the Treasury Facility are not supportable. ICNU Br., BP-18-B-IN-01, at 83. ICNU claims that Staff’s reason for not seeking to expand the facility was because “career staff” at Treasury had since retired. *Id.* ICNU’s arguments are specious. Staff did not seek an expansion of the Treasury Facility for the reasons noted above. Moreover, Staff explained that even if negotiations took place, there is no requirement that Treasury must agree to additional terms. As noted by Staff:

Changes to the Treasury Facility that expand the size or flexibility would be more challenging today. Treasury is not required to offer BPA the Treasury Facility. Instead, BPA is authorized to sell to the Treasury bonds, notes, and other forms of indebtedness, but only to the extent such amounts are agreeable to Treasury. Authorization for these transactions is provided for in 16 U.S.C. § 838k(a), which states in relevant part that BPA’s ability to borrow from the Treasury “shall be in such forms and denominations, bear such maturities, and be subject to such terms and conditions, as may be prescribed by the Secretary of the Treasury taking into account terms and conditions prevailing in the market for similar bonds, the useful life of the facilities for which the bonds are issued, and financing practices of the utility industry.

Mullins, BP-18-E-IN-01-AT01, at 38 (Data Response NR-BPA-26-9).

Finally, ICNU contends that Staff presented the FRP to one of the credit rating agencies, Fitch, as a “foregone conclusion.” ICNU Br., BP-18-B-IN-01, at 80. For support, ICNU cites a presentation in which Staff noted that the FRP “will be established either in the BP-18 rate case or a notice and comment proceeding.” *Id.* ICNU argues this presentation demonstrates that Staff believes the “Administrator will simply rubber stamp any proposal Staff supports in one forum or another,” and thus explains why Staff did not consider “obvious alternatives” that would accomplish the same liquidity and credit rating goals. *Id.*

ICNU's characterization of Staff as presenting a "foregone conclusion" is without merit. First, when an agency begins developing a policy, it assumes that a policy is necessary and should be established in some form. This may not occur, of course, if during the process to develop the policy the agency determines that the policy is not needed. To make this determination, however, the agency must go through the process. Stating that the FRP would be established in the BP-18 rate case or in a notice and comment proceeding simply identifies the process for considering the establishment of the policy; it did not mean that the policy as initially proposed was going to be adopted or adopted without change. This is determined during the administrative proceeding.

In the instant case, ICNU omitted a few critical words from the bullet from Staff's presentation: "After feedback, BPA's final reserves proposal will be established either in the BP-18 rate case or a notice and comment proceeding." Mullins, BP-18-E-IN-01-AT01, at 60. As the full text of the bullet makes clear, the FRP proposal would be developed "after feedback" from participants. Moreover, Staff can be excused for not laying out the full context of the follow-on process as this presentation was simply a high-level, bulleted overview of the process Staff intended to use to develop the FRP. *See id.* Indeed, the process for developing the FRP had not been determined at the point of the presentation. *Id.* ("either in the BP-18 rate case or notice and comment proceeding.") Moreover, Staff's representation of the process options to a third-party credit rating agency had no bearing on the ultimate decision to adopt the FRP.

Decision

Staff properly addressed expansion of the Treasury Facility. Expanding the Treasury Facility would not have removed the need to develop the FRP to support BPA's financial reserves.

Issue 6.6.5.2

Whether BPA should adopt M-S-R's proposed modifications to the FRP.

Parties' Positions

M-S-R argues that its proposed modifications to the FRP should be adopted. M-S-R Br., BP-18-B-MS-01, at 2-3. M-S-R proposes to set lower overall thresholds for the business lines and the agency. *Id.* at 22. In addition, M-S-R proposes to allow the business lines to compensate each other when financial reserves fall below the thresholds. *Id.*

JP07 opposes M-S-R's proposal. JP07 Br., BP-18-B-JP07-01, at 17.

BPA Staff's Position

M-S-R's proposal should not be adopted. Harris *et al.*, BP-18-E-BPA-33, at 134-35. M-S-R's proposal would significantly undermine several of the policy objectives identified by Staff. *Id.*

Evaluation of Positions

M-S-R is concerned that BPA's FRP, as initially proposed, would not actually change the current circumstance "where Transmission is contributing to the Agency's reserves but Power is not." M-S-R Br., BP-18-B-MS-01, at 22. M-S-R contends that BPA has acknowledged that it is inequitable for one business line to maintain reserves while the other does not carry its share beyond short-term reliance. *Id.* M-S-R argues the targets in BPA's initially proposed FRP did not appear to be reachable given BPA's concerns about rate shock for Power customers. *Id.* M-S-R notes that, given the implementation exceptions in the phase-in, it is unlikely that the targets would be reached. *Id.* M-S-R argues that setting aggressive targets that could not be reached seems counter-productive. *Id.*

To better reflect a policy that it believes could actually be implemented, M-S-R proposes changes to three elements of BPA's original proposal:

- Revisions to the lower, target, and upper and lower thresholds from 60, 90 and 120 days cash on hand, to 30, 60 and 90 days cash on hand, taking into account BPA's indication that 30 days cash on hand may be enough to support the Agency's credit rating.
- Modifications to the RDC two-factor test to reduce the impact of one business line being lower in reserves than the other when determining if excess reserves can be repurposed.
- Compensation between business lines when the reserves of one are deemed necessary to offset deficiencies of the other to preserve the agency's credit rating.

Id.

JP07 opposes M-S-R's proposal. JP07 Br., BP-18-B-JP07-01, at 17. JP07 states that M-S-R's lending construct "illustrates [M-S-R's] misunderstanding of BPA's financial management." *Id.* BPA is "a single entity, with one account responsible to meet all expenses from both Transmission Services and Power Services and, therefore, its creditworthiness is based on BPA as one entity." *Id.* In addition, JP07 notes that BPA already attributes interest credits to each business line based on the amount of reserves that are attributed to that business line. *Id.* This means that each business line is already receiving fair value from any reserves that are attributable to that business line in the form of lower net interest expenses. *Id.* JP07 also opposes M-S-R's proposal for the reasons identified in Staff's rebuttal testimony. *Id.*

As discussed below, M-S-R's proposal undermines several of the policy objectives that the FRP is designed to achieve and, therefore, BPA will not adopt M-S-R's proposal.

To begin, M-S-R's proposal fundamentally undermines the credit support objective of the FRP. Harris *et al.*, BP-18-E-BPA-17, at 24; Harris *et al.*, BP-18-E-BPA-33, at 135. M-S-R proposes to reduce the lower threshold in the FRP from 60 days cash to 30 days cash. M-S-R Br., BP-18-B-MS-01, at 22. As Staff explained, setting the lower threshold to 30 days cash would allow BPA's financial reserves to fall below a level that credit rating agencies have warned could

threaten BPA’s strong credit rating. Harris *et al.*, BP-18-E-BPA-33, at 135; *see also* Harris *et al.*, BP-18-E-BPA-17, at 14-15. The CRAC threshold is not a floor; financial reserves may fall below the CRAC threshold, at which time rate action is taken to replenish reserves. Harris *et al.*, BP-18-E-BPA-33, at 135. A crucial element of the credit support feature of the FRP is that it directs BPA’s action *before* BPA’s financial reserves reach (or fall below) levels that the credit rating agencies have warned would result in negative rating pressure. Staff proposed 60 days cash as the lower threshold because this created a 30 days cash “buffer” above levels of financial reserves that could result in a significant downgrade in BPA’s credit rating (*i.e.*, if BPA’s financial reserves fall below 30 days cash). *Id.* at 70. M-S-R’s proposal would eliminate that buffer, and leave no margin between financial reserves that support BPA’s credit rating (60 days cash) and financial reserves that are critically low such that they threatened BPA’s credit rating (below 30 days cash). Moody’s 2017 report confirms that it is important for BPA to have reserves above 60 days cash. *See* Motion for Official Notice of Credit Rating Agency Reports, BP-18-M-BPA-09, Attachment A, at 3 (“BPA’s ratings could be lowered . . . if we expect internal liquidity to fall below 60 days . . .”).

Moreover, Staff performed an analysis using M-S-R’s proposed thresholds and found that M-S-R’s proposal would, in fact, be more detrimental to supporting BPA’s credit rating than the status quo without a financial reserves policy. Harris *et al.*, BP-18-E-BPA-33, at 137; *see also* Harris *et al.*, BP-18-E-BPA-33, Attachment 7. Under the status quo, Staff calculated there was a 20 percent chance of financial reserves falling below 30 days cash on a sustained basis. *Id.* at 137. M-S-R’s proposal, however, increased the chances of financial reserves falling below 30 days cash to 49 percent. *Id.*; *see also id.*, Attachment 7. Thus, BPA’s credit rating objective would be better served by retaining the status quo, which has no thresholds, when compared to adopting M-S-R’s proposed thresholds. *Id.* at 137.

M-S-R portrays its proposal as more realistic, arguing that Staff’s proposal does not appear “reachable” and that “[s]etting aggressive targets that could not be reached seem[s] counter-productive.” M-S-R Br., BP-18-B-MS-01, at 22. BPA’s targets are modest in comparison to similar entities. According to Moody’s, entities similar to BPA hold between 150 and 250 days cash on hand. Harris *et al.*, BP-18-E-BPA-17, at 13; *see also* Harris *et al.*, BP-18-E-BPA-33, at 62-63. Further, BPA is not intending the FRP to solve overnight the financial reserves concerns addressed by the policy. Rather, the FRP is intended to cause a change in financial reserves levels over time. Harris *et al.*, BP-18-E-BPA-33, at 134. While M-S-R’s proposal lowers the overall bar to reaching the thresholds, making them easier to achieve, BPA does not view this “race to the bottom” as an advantage, but a drawback of M-S-R’s proposal. *Id.* M-S-R’s proposal sets the threshold so low that BPA’s objective to maintain its credit rating would be under constant pressure.

M-S-R proposes that BPA reduce the agency and business line upper thresholds from 120 days cash to 90 days cash. M-S-R Br., BP-18-B-MS-01, at 22. This proposal, as used in the context of M-S-R’s overall lower thresholds, would not achieve Staff’s fifth objective of setting prudent upper financial thresholds. M-S-R’s agency test for the RDC is \$301 million, which mean M-S-R’s proposal would allow BPA’s financial reserves to be reduced through repurposing until agency financial reserves were at the equivalent of 45 days cash. Harris *et al.*, BP-18-E-BPA-33,

at 136. Intentionally reducing financial reserves through RDC disbursements to such a low level—which is even below the FRP’s 60 days cash lower threshold—would create significant risk to BPA’s ability to maintain sufficient financial reserves to support the objectives of the FRP. Also, as noted in Section 6.6.4.5 (upper threshold), it is important to maintain a significant “deadband” between financial reserves needed for credit support and overall financial health, and financial reserves that may be repurposed without threatening those objectives. M-S-R’s proposal constricts that deadband such that both an RDC and a CRAC could trigger over the same rate period, undermining rate stability.

M-S-R also proposes eliminating Staff’s phase-in proposal and replacing it with a lending paradigm that allows the Administrator to exercise discretion to “lend” excess reserves from one business line to the other if one business line had excess reserves while the other was below its lower threshold. M-S-R Br., BP-18-B-MS-01, at 22-23. M-S-R argues that this proposal is beneficial because it results in a “feasible outcomes without imposing rate shock.” *Id.* at 23. M-S-R also argues it is equitable because “it does not allow one business line to not contribute to reserves, and it compensates the business line whose excess reserves are being used by the deficient business line at its opportunity cost.” *Id.* M-S-R notes that there is an opportunity cost to holding financial reserves, which M-S-R claims is not properly compensated through the existing interest rates BPA receives on its financial reserves. *Id.* at 23-24.

BPA does not agree that M-S-R’s lending paradigm is reasonable or an appropriate substitute for the FRP. First, BPA does not agree that short-term imbalances between the business lines’ contribution to agency financial reserves are inequitable provided there are provisions in place to ensure that such reliance is short-term. Harris *et al.*, BP-18-E-BPA-33, at 136. The FRP is designed to ensure that any reliance is short-term by addressing the imbalance over time in a manner that is responsive to the needs of both the Power customers and the Transmission customers. To that end, BPA is adopting certain improvements to Staff’s original proposal that will immediately lessen the imbalance through concrete rate action. For instance, BPA will be including \$20 million of PNRR in Power rates until Power Services’ financial reserves exceed its lower threshold. *See* Section 6.6.4.3 (phase-in). Thus, the FRP already includes features that address the concerns M-S-R has raised regarding business line contributions to the agency’s financial reserves.

Additionally, BPA does not agree that the “lending” feature M-S-R proposes is an acceptable feature for the FRP. Specifically, BPA disagrees with the “lending” proposal because it further compounds the imbalance between the business lines. M-S-R’s proposal includes CRAC thresholds, but these thresholds can be ignored so long as Power Services is paying to use the financial reserves of Transmission Services. M-S-R Br., BP-18-B-MS-01, at 22-23. M-S-R’s proposal would allow for the status quo imbalance to be institutionalized, with the only difference between M-S-R’s proposal and the status quo being the rent that Power Services pays Transmission Services to rely on Transmission Services’ financial reserves. Those rent payments would add to Transmission Services’ financial reserves (and decrease Power Services’ financial reserves), further compounding the imbalance between the business lines. The FRP that BPA is adopting in this case, in contrast, seeks to *remedy* this imbalance through the

inclusion of PNRR in Power rates and the development of a phase-in of the CRAC for Power Services. *See* Section 6.6.4.3 (phase-in).

BPA also fundamentally disagrees with M-S-R’s view that BPA must require “compensation” between its own business lines for financial reserves held for purposes of the FRP. M-S-R argues there is an opportunity cost for holding financial reserves. M-S-R Br., BP-18-B-MS-01, at 23-24. But M-S-R fails to recognize that the financial reserves in the BPA fund are first and foremost *BPA’s* financial reserves—not Transmission Services’ financial reserves. Harris *et al.*, BP-18-E-BPA-17, at 2-3. As Staff explained:

Power Services and Transmission Services have separate reserves only in the sense that BPA tracks them separately. All of BPA’s financial reserves are held in the same account, the Bonneville Fund, however, and all BPA financial reserves are available to the Administrator to meet payment obligations regardless of business unit accounting.

Id. at 3. To be clear, BPA agrees that financial reserves attributable to Transmission Services could not be *consumed* for Power Services’ needs without replenishment. For instance, in 2002, Power Services’ financial reserves were negative \$9 million, meaning that Power Services had actually consumed a portion of financial reserves attributable to Transmission Services. *See* Arthur, BP-18-E-MS-12, Exhibit 20 (Data Response MS-BPA-26-4). In that instance, Power Services was charged with both replenishing those financial reserves *and* paying an interest expense: “Power would be assessed an interest expense for the \$9 million in Transmission reserves Power used.” *Id.* Paying interest in this context made sense because the financial reserves were actually *consumed* by Power Services, making them unavailable for any purpose for Transmission Services.

M-S-R appears to be attempting to assert that the FRP’s financial reserves thresholds are a new form of “use” of financial reserves that must be compensated. They are not. The FRP only sets upper and lower thresholds for financial reserves. Harris *et al.*, BP-18-E-BPA-17, at 22-23. It does not change what Transmission Services may or may not do with its financial reserves. Financial reserves attributable to Transmission Services will continue to be available to meet the liquidity needs of Transmission Services. Harris *et al.*, BP-18-E-BPA-33, at 32 (“BPA’s TPP standard is currently BPA’s primary way of assessing its need for liquidity . . .”). The FRP does not allow Power Services to rely on Transmission Services’ financial reserves any more than it does today, and to the extent Power Services actually consumes Transmission Services’ financial reserves, Power Services will replenish them (with interest) as it did in 2002. In this way, the FRP neither expands nor contracts the availability of financial reserves for use by BPA to address either of its business line’s needs. Instead, the FRP establishes “common metrics between the business lines and . . . set[s] and phas[es] in lower thresholds to ensure both business lines contribute a reasonable amount to financial reserves.” *Id.* at 82-83.

Also, M-S-R’s proposal oversimplifies the causal connection between one business line’s financial reserves being below its lower threshold and BPA’s decision not to use the other business line’s above-threshold financial reserves for other purposes. This causal connection is rife with speculation and subjectivity. BPA may have any number of reasons to hold on to

financial reserves above M-S-R's proposed upper threshold. For instance, a large settlement or write-off might be expected in the next rate period, neither of which is certain or in current rates. BPA may choose to hold additional financial reserves to prepare for such a contingency.

While BPA understands M-S-R's lending paradigm is one approach to responding to the equity concerns of the status quo, BPA does not agree that M-S-R's approach is superior to the FRP. BPA finds that the FRP, which addresses the risk of inequity up front through measurable rate actions, is a far better approach when compared to M-S-R's more "complicated inter-business line arrangement that would be highly dependent on assumptions about opportunity costs and probably very contentious to implement." *Id.* at 136.

In its Brief on Exceptions, M-S-R clarifies that it did not propose the lending mechanism as a substitute for the FRP. M-S-R Br. Ex., BP-18-R-MS-01, at 4. Instead, M-S-R proposed the mechanism as an additional feature to be added to the FRP, as a means to meet the goal of equity between the business lines during a sustained phase-in period. *Id.* In response to BPA's observation that the lending proposal would exacerbate the imbalance, not address it, M-S-R notes that its proposal was not intended to be a "long-term fix to the imbalance." *Id.* at 5. M-S-R describes its proposal as addressing the equity issue without imposing rate shock, while other components of the FRP would address the imbalance. *Id.* M-S-R contends that, depending on how the phase-in mechanism is established, the lending mechanism could still serve a purpose. *Id.*

BPA maintains, for the reasons described above, that M-S-R's "lending" paradigm should not be a component of the FRP. The FRP contains provisions designed to address the imbalance between business line contributions over time, such as the requirement that both business lines contribute to agency financial reserves, and the proposal to include \$20 million of PNRR in power rates. *See* Section 6.6.4 (final FRP). Adding to these features a "lending" construct would go far beyond the equity concerns BPA sought to address through the FRP. That is, the equity concerns BPA sought to address through the FRP were the lack of participation by both business lines in supporting agency reserves, the lack of symmetry in the rate mechanisms used to build and distribute financial reserves, and the imbalance between business lines in contributing to those financial reserves. *See* Section 6.5.3.1 (staff's equity objective).

Compensating one business line for the other's lack of financial reserves is not an issue BPA believes needs to be addressed through the FRP. As a practical matter, M-S-R's lending mechanism, if included as an additional phase-in feature, would likely delay the phase-in of Power's CRAC threshold and could potentially become a *de facto* substitute to the phase-in. That is, funds recovered from Power rates that could otherwise have gone to replenish Power financial reserves would instead be applied to the Transmission Services business unit.

Decision

BPA will not adopt M-S-R's proposed modifications to the FRP.

Issue 6.6.5.3

Whether BPA should adopt WPAG's proposal.

Parties' Positions

WPAG argues that in the event the Administrator elects not to adopt Staff's Alternative Option, the Administrator should adopt the proposal made by WPAG in its direct testimony for the reasons stated therein. WPAG Br., BP-18-B-WG-01, at 20.

M-S-R, JP02, and Powerex oppose WPAG's proposal, particularly WPAG's proposal to allocate the lower threshold based on projected capital expenditures. M-S-R Br., BP-18-B-MS-01, at 15-19; JP02 Br., BP-18-B-JP02-01, at 16-18, 28-34, 39-41; Powerex Br., BP-18-B-PX-01, at 13-21.

BPA Staff's Position

The FRP will include features from both the Alternative Option and Staff's initial FRP proposal. WPAG's proposal should not be adopted because it does not meet the stated policy objectives. Harris *et al.*, BP-18-E-BPA-33, at 119-25.

Evaluation of Positions

WPAG argues that if the Staff's Alternative Option is not adopted, then the Administrator should adopt WPAG's proposal as discussed in its direct testimony. WPAG Br., BP-18-B-WG-01, at 20. M-S-R, JP02, and Powerex oppose WPAG's proposal, particularly WPAG's proposal to allocate the FRP's lower threshold based on capital expenditures. M-S-R Br., BP-18-B-MS-01, at 15-19; JP02 Br., BP-18-B-JP02-01, at 16-18, 28-34, 39-41; Powerex Br., BP-18-B-PX-01, at 13-21.

BPA has already explained the rationale for determining the FRP's lower thresholds based on days cash on hand. *See* Issue 6.6.4.2.2.1 (lower threshold—days cash or capex). This component of WPAG's proposal will not be adopted for the reasons stated above.

As to the remaining portions of WPAG's proposal, Staff responded to WPAG's direct case in Staff's rebuttal testimony, noting that "WPAG's proposal compromises two of our objectives; namely, our first and third objectives, credit rating and business line equity." Harris *et al.*, BP-18-E-BPA-33, at 119. Staff explained its rationale for not adopting WPAG's proposal. *Id.* at 119-25. BPA finds Staff's analysis to be sound and hereby adopts it.

Moreover, Staff found that WPAG's proposal only marginally improved the probability of BPA retaining sufficient financial reserves to support the agency's credit rating. *Id.* at 125. Under the status quo, with no FRP, there is a 20 percent probability that BPA will experience a sustained period of low financial reserves (30 days cash or less). *Id.* WPAG's proposal resulted in a 19 percent probability of this occurring. *Id.* Staff correctly noted that WPAG's proposal does not significantly improve BPA's financial position compared to the "no action" alternative and,

therefore, is not a viable alternative to the FRP, which significantly improves BPA’s financial position vis-a-vis the “no action alternative.” *Id.* at 119.

Decision

BPA will not adopt WPAG’s proposal.

Issue 6.6.5.4

Whether BPA should defer a decision on the FRP to a separate process for policy reasons.

Parties’ Positions

ICNU argues that, for various policy reasons, BPA should defer a determination on adopting the FRP to a separate process. ICNU Br., BP-18-B-IN-01, at 78-80.

In their Briefs on Exceptions, WPAG, JP07, and JP06 argue that, for various policy reasons, BPA should defer a decision on the FRP’s method for determining business line lower thresholds to a separate process. WPAG Br. Ex., BP-18-R-WG-01, at 2; JP07 Br. Ex., BP-18-R-JP07-01, at 9-11; JP06 Br. Ex., BP-18-R-JP06-01, at 4-5.

In their Briefs on Exceptions, JP06 and JP07 argue that BPA should not make a decision on the FRP’s method for determining the business line lower thresholds in the Final Record of Decision, but should defer this decision to the follow-on process that will address the phase-in mechanism for Power Services. JP06 Br. Ex., BP-18-R-JP06-01, at 4-5; JP07 Br. Ex., BP-18-R-JP07-01, at 9-11. JP06 and JP07 argue that the FRP need not address the allocation of the lower threshold between the business lines to address the credit rating agencies’ concerns. JP06 Br. Ex., BP-18-R-JP06-01, at 5; JP07 Br. Ex., BP-18-R-JP07-01, at 10-11. Instead, the credit rating agencies’ concerns can be addressed through the adoption of an FRP that includes upper and lower agency thresholds and \$20 million in PNRR. *Id.*

WPAG similarly argues that if BPA does not adopt the capex proposal, it should defer the allocation decision to the subsequent process. WPAG Br. Ex., BP-18-R-WG-01, at 5.

BPA Staff’s Position

The rate case record supports BPA’s adoption of a financial reserves policy, and Staff recommends the Administrator adopt the FRP in this proceeding. Harris *et al.*, BP-18-E-BPA-33, at 2.

The issue of deferring a decision on the FRP’s method for determining business line lower thresholds was raised for the first time in the parties’ Briefs on Exceptions.

Evaluation of Positions

Whether to defer a decision on adopting the FRP

ICNU argues that, apart from its arguments regarding the “lack of legal and factual support” for Staff’s FRP, the Administrator would have a strong basis for deferring a determination on the FRP, purely from a policy standpoint. ICNU Br., BP-18-B-IN-01, at 5. Indeed, ICNU’s *primary* recommendation is *not* for the Administrator to reject the FRP on an evidentiary, prejudicial, or “on the merits” basis. *Id.* at 78. Instead, ICNU maintains that the best path forward is to defer an immediate determination on the FRP for policy reasons. *Id.* In its place, ICNU suggests the FRP be addressed in a separate forum “after the conclusion of the BP-18 rate case,” *Id.* at 79, wherein a “fully integrated regional process,” *id.*, would be commenced to allow for “holistic consideration of long-term agency strategy.” *Id.* at 5.

In support of this separate process, ICNU sets forth a myriad of reasons for delaying development of the FRP. In general, ICNU raises four arguments for deferring a decision on the FRP to another, yet-to-be determined, regional process. BPA understands these arguments as follows:

1. BPA “needlessly rushed” into the FRP. *Id.* at 5, 78.
2. Evidentiary deficiencies in the record support delaying a decision on the FRP. *Id.* at 7.
3. A process other than the rate case process should be used to develop the FRP. *Id.* at 9-10.
4. New events, outside of BPA’s control, support delaying a decision on the FRP. *Id.* at 79, 80, 86-88.

BPA responds to each of these arguments below. While BPA generally disagrees with ICNU that the FRP should be deferred or that its development in this proceeding was in any way improper, BPA agrees that one feature of the FRP’s implementation should be deferred to a separate process. As discussed in Section 6.6.4.3 (phase-in), BPA will defer the development of the phase-in ratchet for the CRAC threshold to a subsequent process.

a. Whether BPA “needlessly rushed” into the FRP

First, ICNU argues that Staff asked the Administrator to “needlessly rush into a 10-year policy commitment” and that ICNU has been “constrained to adamantly oppose a needlessly rushed and anomalous policy development in this proceeding” ICNU Br., BP-18-B-IN-01, at 5, 78 (emphasis omitted). ICNU argues that deferring a decision would be a cautious and prudent “middle ground” when compared to the “false dichotomy presented by Staff.” *Id.* at 5. The false dichotomy, according to ICNU, was Staff’s contention that the Administrator had the binary option to either “sit idly by” or “charge headlong into a decade’s worth of ‘binding . . . [p]recedent that BPA will adhere to in future rate cases.’” *Id.* ICNU asserts that Staff employs this construct to imply that only an immediate solution to the alleged problem, through either the adoption of Staff’s FRP proposal or a counterproposal, ought to be considered by the Administrator. *Id.* at 5-6.

ICNU’s arguments, however, are both incorrect and unsupported by the record. First, ICNU claims Staff “needlessly rushed” into developing a financial reserves policy. *Id.* at 5, 78. The “need” for such a policy, however, has been extensively demonstrated in the record, as explained in Section 6.4 (need for FRP). Thus, the need for the FRP has been established.

As to ICNU’s charge that the development of the FRP was “rushed,” the facts demonstrate otherwise. *See Id.* at 5, 78. BPA notified customers of its intent to begin developing a financial reserves policy in the BP-16 ROD, wherein BPA deferred a decision on repurposing financial reserves attributable to Transmission Services in order to “work[] with the parties after the rate case to develop a financial reserves policy.” Administrator’s Final Record of Decision, BP-16-A-02, at 89. Development of the FRP, thereafter, began in earnest in the spring of 2016, with BPA holding three workshops on March 29, 2016, May 10, 2016, and June 15, 2016—dedicated to discussing the development of a financial reserves policy. Harris *et al.*, BP-18-E-BPA-17, at 23; *see also* <https://www.bpa.gov/Finance/FinancialPublicProcesses/Pages/Access-to-Capital.aspx>. In the final workshop, BPA proposed a draft policy and asked for stakeholder comment. Harris *et al.*, BP-18-E-BPA-17, at 23. BPA received 14 written comments and used those comments to inform Staff’s initial FRP proposal included in this rate case. *Id.* A final rate case workshop was held on September 14, 2016, providing an overview of the primary components of the policy, as well as examples. *See* https://www.bpa.gov/Finance/RateCases/BP-18/bp18/BP-18_RateCaseWorkshop_revised%2020160920.pdf.

On November 17, 2016, Staff issued its proposed FRP, along with Staff’s supportive testimony. On January 31, 2017, parties filed direct cases responding to Staff’s proposed FRP, among other issues. *See* Order Establishing Schedule, BP-18-HOO-01, at 1. Staff responded to parties’ direct cases in rebuttal testimony filed on March 14, 2017. Harris *et al.*, BP-18-E-BPA-33. Parties filed briefs on May 2, 2017, addressing (among other issues) the FRP. *See* Order Establishing Schedule, BP-18-HOO-01, at 1. The Draft ROD was issued on June 13, 2017, and the Final ROD issued on July 26, 2017. All told, from the initial workshop (March 2016) to the issuance of the Final ROD (July 2017), BPA and regional parties will have spent over 16 months publicly developing the terms of a financial reserves policy. The FRP has not been needlessly rushed.

ICNU also asserts that Staff presented a “false dichotomy” to the Administrator because Staff presented the Administrator a binary option to either “sit idly by” or “charge headlong into a decade’s worth of ‘binding . . . [p]recedent that BPA will adhere to in future rate cases.’” *Id.* at 5.

ICNU’s argument is again mistaken. First, ICNU’s reference to Staff’s testimony is incorrect. The referenced testimony responded to ICNU’s assertion that BPA did not have the authority to include in rates financial reserves to support BPA’s credit rating. Harris *et al.*, BP-18-E-BPA-33, at 6. BPA responded that, insofar as BPA has authority to incur third-party debt, BPA would have the authority to take actions to allow it to receive reasonable terms and conditions from third-parties. *Id.* To ICNU’s assertion that such action was beyond BPA’s authority, BPA Staff noted:

While ICNU may wish us to presume this limitation exists, we find no support for the proposition that BPA should sit idly by and accept whatever terms the third-party debt market may give to the Agency. We believe Congress intended BPA to take reasonable business steps to fulfill its statutory mission, which would include developing policies, like a financial reserves policy, to ensure BPA's long-term financial health and financial independence.

Id. As the context of Staff's testimony makes clear, Staff did not suggest to the Administrator that he either "sit idly by" or adopt the FRP. Staff was clear that the reference was to ICNU's suggestion that BPA had no authority to take positive action to support the agency's ability to receive favorable terms and conditions from "the third party debt market . . ." *Id.*

Second, BPA disagrees with ICNU's characterization of Staff's proposal as either "binary" or a "false dichotomy." ICNU Br., BP-18-B-IN-01, at 5-6. Staff made a strong case that the current practices and policies were not sustainable, that a solution was necessary, and that such a solution should come through either Staff's proposal or a counterproposal. *See Harris et al.*, BP-18-E-BPA-17; *Harris et al.*, BP-18-E-BPA-33; *see also* Section 6.6.6 (FRP and policy objectives). Proposing an answer to an identified problem did not present the Administrator a "binary" option or a "false dichotomy." Staff identified a gap in BPA's existing policies and proposed a new policy to fill that gap. *Harris et al.*, BP-18-E-BPA-33, at 25.

Moreover, Staff in no way indicated that there was only *one possible* approach to a financial reserves policy or that the Administrator's choices were limited to either adopting Staff's proposal or not addressing the policy gap. Any question as to Staff's willingness to consider, and even support, alternatives to its proposal should have been answered in Staff's rebuttal testimony, when Staff developed an Alternative Option built largely from features of the parties' counterproposals. *See Id.* at 139-52. Indeed, BPA remains willing to consider alternatives, and has again adjusted the FRP to reflect the comments of parties to this proceeding, and to consider additional alternatives in a separate process. *See* Section 6.6.4.2 (lower threshold); *see also* Section 6.6.4.3 (phase-in). Thus, ICNU's criticism of Staff as presenting limited options or a false dichotomy to the Administrator is incorrect.

b. Whether evidentiary deficiencies in the record support delaying a decision on the FRP.

ICNU next contends that deficiencies in the record support delaying a decision on the FRP. ICNU Br., BP-18-B-IN-01, at 7. ICNU claims these contentions are shared by BPA's preference customers. *Id.* ICNU then quotes testimony from both JP05 and WPAG, noting that Staff's initially proposed FRP would not meet the goals Staff identified. *Id.* ICNU then asserts that these statements "support[] ICNU's position" that the record would not support the adoption of the FRP. *Id.*

ICNU's alleged policy reason is derivative of ICNU's primary challenge that the record does not support the development of a financial reserves policy. For the reasons discussed in Section 6.4 (need for FRP), ICNU's claims are unsupported.

In addition, ICNU makes the unfounded contention that Power customers offered counterproposals only for *business relationship* reasons, not because Staff had sufficiently

demonstrated the need or factual justification for a new policy adoption, or had actually persuaded its power customers by compelling testimony. *Id.* at 7-8. Instead, ICNU claims these proposals were offered because these customers valued BPA as a “business partner.” *Id.*

Staff appreciated these counterproposals, noting how they aided Staff in considering alternatives to Staff’s original proposal. Harris *et al.*, BP-18-E-BPA-33, at 139. ICNU, however, objects to the encouragement Staff gave to parties for offering counterproposals, and took Staff’s praise as “taunting” ICNU for not offering its own proposal. ICNU Br., BP-18-B-IN-01, at 6. ICNU explains it was not only criticizing Staff’s work, but seeking “sound decision-making” that will endure challenge and ensure that BPA can achieve its goals. *Id.* at 8. ICNU asserts it has offered a consistent alternative on how a financial reserves policy should be developed, that is, through the context of the Focus 2028 process. *Id.* at 8-9.

ICNU reads too much into Staff’s testimony. Staff merely acknowledged the parties’ efforts in providing counterproposals to Staff’s original proposal. Harris *et al.*, BP-18-E-BPA-33, at 139. Parties are not required to make such counterproposals and, in doing so, may expose themselves to a certain degree of risk of criticism from BPA and others. Thus, Staff was simply acknowledging the extra step these parties took in preparing their cases. ICNU, of course, was within its procedural rights as a party not to provide a proposal, and BPA agrees it has provided a substantial amount of material for the record. To that end, BPA appreciates the efforts and resources ICNU has expended to fully develop the record in this case.

ICNU next argues that in praising the crafting of “solution-orientated counterproposals,” Staff engaged in another logical fallacy, this one being “assuming the conclusion.” ICNU Br., BP-18-B-IN-01, at 6. That is, ICNU claims “Staff assumes that a ‘problem’ has been sufficiently demonstrated by evidence in the initial proposal, thereby implying that the need to craft ‘solutions’—*e.g.*, in the form of counterproposals—is self-evident.” *Id.* ICNU claims Staff did not understand that the record must show a financial reserves policy is needed, and that the solution must first be “justified.” *Id.* ICNU ignores the record and, as discussed in Section 6.4 (need for FRP), its arguments are without merit. Staff’s statements cannot be viewed in a vacuum. Staff made its statements about counterproposals only after it had presented its direct case and more than 100 pages of rebuttal testimony, in which the case *for* a financial reserves policy was soundly established. *See generally* Harris *et al.*, BP-18-E-BPA-17, at 1-56; Harris *et al.*, BP-18-E-BPA-33, at 1-156.

ICNU next asserts that adopting a financial reserves policy that was developed based on “business relationship” grounds, rather than evidentiary grounds, would likely be rejected by the Ninth Circuit under *Pac. Nw. Generating Coop. v. BPA*, 580 F.3d 792 (9th Cir. 2009) (“*PNGC I*”). ICNU Br., BP-18-B-IN-01, at 8, 32. ICNU’s argument again is without merit. In *PNGC I*, the Court rejected BPA’s attempt to subsidize the power rate of a direct service industrial customer through a monetized service benefit, which effectively resulted in BPA “giving away money.” *PNGC I*, 580 F.3d at 822. The Court acknowledged that it would “defer[] to the [BPA]’s actions in furthering its business interests,” but found that outside of BPA’s “historic relationship with the DSIs” BPA had “identified no business interests forwarded by its actions.” *Id.* at 823. The Court found BPA’s actions were inconsistent with its obligation

to “further[] BPA's business interests consistent with its public mission.” *Id.* at 823 (citing *Ass'n of Pub. Agency Customers, Inc. v. BPA*, 126 F.3d 1158, 1171 (9th Cir. 1997)).

In this case, BPA is not proposing to adopt a policy by which BPA would lose money contrary to its business interests. Instead, as described fully in Section 6.4 (need for FRP) and Section 6.6.6 (FRP and policy objectives), the FRP will shore up BPA’s financial reserves and will “establish[] a framework for managing financial reserve levels over time, ensuring adequate liquidity, credit rating support, business line equity and the opportunity for rate stability.” Harris *et al.*, BP-18-E-BPA-33, at 4. These reasons squarely show BPA is seeking to develop the FRP to further its “business interests,” and not simply to garner support for some amorphous “historic relationship” with its customers.

c. Whether a process other than the rate case should be used to develop the FRP.

ICNU’s third general policy argument for delaying a decision on the FRP to a separate process relates to the process Staff used to develop the FRP. ICNU Br., BP-18-B-IN-01, at 9-10. ICNU notes that Staff concedes the placement of the FRP in this proceeding is anomalous, and BPA has publicly stated that development of the FRP could take place in a “separate, public process.” *Id.* As such, ICNU contends the Administrator would be doing nothing improper or unconventional by determining that the FRP needs further development in just such a separate, public process, and one which presents all of the agency’s challenges to the region in a forum allowing for truly cooperative and collaborative resolution. *Id.* at 10.

ICNU’s criticism of Staff’s choice of the BP-18 rate case as the forum to address the FRP is misplaced. First, ICNU is wrong to assert that the FRP has been developed *only* in this rate proceeding. In fact, as noted above, BPA engaged in roughly eight months of pre-rate case dialogue and workshops, including public comment, on the FRP. This public process, which was not unlike the “regional process” ICNU now argues BPA should have engaged in, provided BPA with an opportunity to explain the need for the FRP and explore potential features of such a policy with stakeholders.

Second, Staff’s choice to use the BP-18 rate case was appropriate considering the timing of the BP-18 rate proceeding and the need to include mechanisms in the rate case (such as General Rate Schedule Provisions) that would allow BPA to implement the features of a policy such as the FRP, if ultimately adopted by the Administrator. ICNU is correct that BPA’s financial policies generally are not rate case issues. In the Federal Register Notice, BPA specifically noted that BPA proposed to include the FRP within the BP-18 proceeding for “administrative convenience.”

[F]inancial policies are normally not within the scope of BPA’s rate cases; however, for administrative convenience BPA is using the BP-18 rate case process to develop the Financial Reserves Policy in lieu of conducting a parallel, but separate, public process. Therefore, the Financial Reserves Policy, and its implementation in the BP-18 rates, is within the scope of this rate proceeding.

81 Fed. Reg. 78,999, 79,002 (Nov. 10, 2016). Staff similarly explained that the rate case process was chosen because it afforded the “timeliest opportunity for parties to express their views on the

proposal.” Harris *et al.*, BP-18-E-BPA-17, at 24. Both “administrative convenience” and “timeli[ness]” considerations were served by including the FRP within the scope of the BP-18 rate proceeding.

Administrative convenience was served by developing the FRP in an already scheduled hearing process. This allowed all relevant issues regarding the FRP to be addressed in a single forum. That is, Staff’s approach allowed parties to develop the record and address the foundational issues of *whether* to adopt such a policy, *what features* that policy should include, and *how* that policy should be implemented in the BP-18 rate period. Had these issues been addressed in a separate process, parties (and Staff) would have had to file multiple documents in different processes. As these processes would have overlapped in both scope and content, conflicts and confusion as to whether a particular point or argument should have been raised in one proceeding versus the other easily could have occurred.

The rate case also provided the timeliest opportunity to develop the FRP. The BP-18 was the next major administrative process BPA had scheduled for the fall of 2016. BPA’s rate cases tend to require both Staff and parties to dedicate significant resources. As such, obtaining customer feedback on an important policy matter in a separate process can be difficult when customers are already fully engaged in a contested rate case. Bringing that important policy question within the rate hearing allowed parties the opportunity to express their views on the FRP, while also addressing their general rate case issues.

Timeliness was also a factor for BPA in its decision to include the FRP proposal in the BP-18 rate proceeding. Staff intended to propose that the features of the FRP be incorporated into rates, which meant that such features would need to be considered in the BP-18 rate case. Had BPA waited to develop the FRP outside of the BP-18 rate case, BPA would have had to wait at least until the BP-20 rate case (FY 2020–2021), to implement the FRP.

In any event, how BPA structures its proceedings is left to the discretion of the Administrator. As BPA explained in the 2007 Supplemental Wholesale Power Rate Case Record of Decision:

The law, however, does not require BPA to follow a prescribed method for conducting its proceedings. Rather, agencies are afforded discretion to determine how best to handle related, yet discrete, issues in terms of procedures. *Mobil Oil Exploration & Producing S.E., Inc. v. United Distrib. Cos.*, 498 U.S. 211, 230, 111 S. Ct. 615, 112 L.Ed.2d 636 (1991). Courts defer to the agency to determine whether to conduct a proceeding through a consolidated hearing or through individual proceedings. *See American Airlines, Inc. v. CAB*, 495 F.2d 1010 (D.C. Cir. 1974). Either way, unless interested parties will be precluded from participating in the hearing by the particular arrangement of the proceeding, or the proceeding will unreasonably delay a resolution, it is left to the agency’s discretion as how best to arrange its business and order its dockets. *See La. Public Service Com’n v. FERC*, 482 F.3d 510, 520-522 (D.C. Cir. 2007); *Northern Border Pipeline Co. v. FERC*, 129 F.3d 1315, 1319 (D.C. Cir. 1997). These matters are, as one court put it, “housekeeping details addressed to the

discretion of the agency.” *Assn. of Mass Consumers, Inc. v. SEC*, 516 F.2d 711 (D.C. Cir. 1975).

Administrator’s Final Record of Decision, WP-07-A-05, at 88.

Indeed, although ICNU calls BPA’s use of this rate case process to develop the FRP “anomalous,” ICNU Br., BP-18-B-IN-01, at 9, and “unconventional,” *Id.* at n.25, BPA has previously used rate case procedures to develop policies. For example, BPA’s TPP standard was developed as part of BPA’s 1993 rate case. *See Harris et al.*, BP-18-E-BPA-17, at 6; *see also* 1993 Final Rate Proposal, Administrator’s Record of Decision, WP-93-A-02, at 72. BPA has also used rate case procedures to develop other important policy decisions, such as whether to adopt the 2012 Residential Exchange Program settlement. *See Residential Exchange Program Settlement Agreement Proceeding (REP-12)*, Administrator’s Final Record of Decision, REP-12-A-02. The Ninth Circuit ultimately sustained BPA’s decision to adopt the 2012 REP Settlement based on the record developed in the REP-12 proceeding. *See Ass’n of Pub. Agency Customers v. BPA*, 733 F.3d 939 (9th Cir. 2013).

ICNU also argues that a non-adjudicatory process would have allowed “freer cooperation and collaboration with Staff than under the current *ex parte* rules, and [would] allow for the notable gulf between power and transmission customers to be potentially bridged in a mutually satisfactory manner” ICNU Br., BP-18-B-IN-01, at 79. ICNU argues such an outcome “is almost inconceivable if a policy is approved on an evidentiary record that is far more successful in drawing entrenched ‘zero sum game’ parameters around FRP costs and benefits between business lines.” *Id.* ICNU also calls Staff’s use of the rate proceeding “unjustified” considering BPA acknowledged that the FRP would likely be the “most contentious portion of the rate case” because it will have BP-18 rate implications for Power customers and “long-term rate implications” for both Power and Transmission customers. *Id.* at 9, n.25.

Once again, BPA’s decision to address the FRP in this proceeding was reasonable and justified. Indeed, in light of the “contentious” nature of the issues in this proceeding, *id.*, a formal decision-making forum with more process—not less—was the right approach to ensure that parties’ issues and concerns with the FRP were fully vetted and considered. BPA’s rate proceedings provide a robust set of procedures for developing a record. BPA’s Rules of Procedure Governing Rate Hearings, 51 Fed. Reg. 7,611-01 (Mar. 5, 1986); *see* Special Rules of Practice Governing This Proceeding, BP-18-HOO-02. These rules provide for the filing of initial testimony and studies of Staff, direct testimony of parties, rebuttal testimony, clarification, formal discovery, cross-examination, oral argument before the Administrator, initial briefs, a Draft ROD, briefs on exceptions, and a Final ROD. *See Order Establishing Schedule*, BP-18-HOO-01, at 1-2. The resulting record of over 1000 pages of testimony, briefs, and other material on the FRP speak to the volume of materials created and submitted in this case as a result of the rate case procedures.

In contrast, BPA’s informal notice and comment processes have no formal rules for comments, no set number of opportunities to file comments, have no opportunities for discovery, have no sworn testimony, do not provide an opportunity for briefing, do not require the presence of the Administrator at any point, and allow BPA to end (or extend) the process at any time.

Considering the “contentious” nature of the FRP, it is unclear to BPA how a better record could have been developed in an informal process, given that none of the rigors of the rate case process would have been present.

ICNU recommends that the Administrator incorporate further exploration of FRP objectives within a “fully integrated regional process” as soon as possible, after the conclusion of the BP-18 rate case, which will allow BPA and all interested stakeholders to “holistically craft strategic solutions” to set BPA on course to truly become cost competitive, and the regional provider of choice, before Regional Dialogue (RD) contracts must be renegotiated. ICNU Br., BP-18-B-IN-01, at 79. ICNU suggests that a “reinvigorated renewal of the now dormant Focus 2028 process, adapted to include more substantive process and ambitious goals, might be the best means to this end, especially as BPA has explicitly ‘presented both the “Reserves Policy” and Focus 2028 as a part of the “Regional Dialogue Process.”’” *Id.*

BPA disagrees that it should abandon the progress that has already been achieved in this case, in favor of an unknown “middle ground” to be achieved through some alternative process. *Id.* at 5-6. Other than delaying a decision on the FRP, which would leave the policy gap unfilled and allow BPA’s financial reserves to continue to decline, it is unclear what additional processes and analysis would achieve. (ICNU suggests one option in its brief, which is expanding the Treasury Facility. *Id.* at 79-85. This option was discussed in Issue 6.6.5.1 (expand Treasury Facility) above. The JP02 parties, however, oppose BPA’s *current* use of the Treasury Facility, and as such, would likely oppose *expanding* the Treasury Facility. *See* Issue 6.6.4.2.2.2 (lower threshold and Treasury Facility). It thus remains unclear what “middle ground” could be achieved through a follow-on process.) Absent concrete solutions that will address the current problems with the status quo—problems which ICNU does not agree exist, *see* Section 6.4 (need for FRP)—BPA prefers to develop the FRP as part of the BP-18 process. While unanimity has not been reached on all components of the FRP, parties’ voices have been heard and thoughtfully considered, and progress has been made on reaching consensus on many features. To that end, BPA finds that developing the FRP as part of this process is appropriate.

As noted in Issue 6.6.4.3.1 (phase-in), BPA will defer a decision on one FRP implementation feature to an additional process. BPA’s decision to defer this issue is not due to a lack of evidence or any other deficiency in the record. The record contains sufficient information from which BPA could adopt one of the various proposals based on the arguments and evidence presented by Staff and the parties. However, as a matter of policy, BPA finds that this issue would benefit from more consideration in another forum. The parties presented a number of new concepts in their briefs that BPA would like to explore more fully with its customers and stakeholders. This one implementation issue, however, is the only feature of the FRP that BPA finds would benefit from additional process. All other components of the FRP have been fully discussed and addressed in the record.

d. Whether new events, outside of BPA’s control, support delaying a decision on the FRP.

Finally, ICNU argues that, as a matter of policy, the Administrator should defer a decision on the FRP because new events will likely put additional pressure on BPA’s rates. First, ICNU identifies new cost impacts that may arise from the Spill Surcharge BPA has developed in

response to the U.S. District Court for the District of Oregon’s decision in *National Wildlife Federation*. ICNU Br., BP-18-B-IN-01, at 85. ICNU readily notes that it is not addressing the merits of BPA’s Spill Surcharge in its brief at this point. *Id.* at 85-86. However, ICNU argues that, in light of the potential substantial cost impacts from the surcharge, “something must give from a bottom-line, rate increase perspective . . . if anything is to be done to successfully prevent ‘the unsustainable rate trajectory of the past four rate periods’ from continuing unabated into a fifth consecutive rate period.” *Id.* at 86 (citing Mullins, BP-18-E-IN-01-AT01, at 129-30 (IPR/CIR Close-out Report Oct. 2016, Letter from the Administrator, at 1)). To the extent the Administrator finds it necessary to approve a surcharge mechanism to “ensure that BPA’s rates recover BPA’s total cost,” ICNU strongly recommends that any potential adoption of the FRP be deferred, lest customers be compounded with the rate burdens of both Staff proposals in the BP-18 rate period. *Id.*

ICNU notes that other factors are changing that could affect BPA’s rates, such as “recent market results” and “recent oversupply management protocol effects.” *Id.* at 88. These events, as ICNU notes, are “outside of BPA’s control.” *Id.* For that reason, ICNU argues that these factors stand in contrast to the discretionary FRP proposal. *Id.* “Putting the potential impacts of both the spill increase and market results together, therefore, in addition to any other cost pressures resulting from recent oversupply management protocol effects, a decision to add still further rate pressure through immediate implementation of the FRP would beg the question of when the agency would ever deem rate pressure too much, or refrain from discretionary rate increases for the benefit of customers and to ensure the health of the region.” *Id.* ICNU argues that deferral of the fully discretionary cost and timing impacts of the FRP would be “consistent with a sound business-orientated philosophy.” *Id.* at 79-80.

BPA recognizes that new events have placed additional pressure on BPA’s rates. The effect of these events, however, has been mitigated in part through aggressive cost-cutting. *See* Section 3.1. Thus, the immediate rate pressure effects of these new events have been addressed to the best of BPA’s ability. Nonetheless, BPA acknowledges that the FRP is a new policy, one which will guide BPA’s financial reserves for the foreseeable future. Harris *et al.*, BP-18-E-BPA-17, at 27. However, the need to shore up BPA’s financial reserves through a policy cannot wait. As indicated in Section 6.4 (need for FRP), BPA’s financial reserves continue to be at historically low levels. Moreover, also as described in Section 6.4 (need for FRP), BPA’s current policy gap would allow BPA’s reserves to continue to decline without any formal policy or plan to return to a healthy level, which could do long-term damage to BPA’s credit rating, undermine BPA’s liquidity, harm rate stability, and continue the inequity in contributions to the agency’s financial reserves levels from the business lines.

Whether to defer a decision on the method for determining business line lower thresholds

JP07 and JP06 argue that BPA’s decision on the method for determining business line lower thresholds is not well supported and propose BPA defer this decision. JP07 Br. Ex., BP-18-R-JP07-01, at 9-11; JP06 Br. Ex., BP-18-R-JP06-01, at 4-5. JP07 and JP06 argue that the days cash method and capex method are not binary or mutually exclusive. JP07 Br. Ex., BP-18-R-JP07-01, at 9-10; JP06 Br. Ex., BP-18-R-JP06-01, at 4. JP07 and JP06 support BPA adopting certain aspects of the FRP at this time, namely the agency-level upper and lower thresholds and

inclusion of \$20 million in PNR in power rates, to resolve credit rating agencies' concerns. JP07 Br. Ex., BP-18-R-JP07-01, at 10; JP06 Br. Ex., BP-18-R-JP06-01, at 5. JP07 and JP06 note that the credit rating agencies appear indifferent to inter-business line issues. *Id.* JP07 notes BPA acknowledged that the allocation issue was one of the most difficult issues in the case, that both methods could be valid, and that BPA has already decided that certain aspects would be better suited for discussion and decision after the rate proceeding. JP07 Br. Ex., BP-18-R-JP07-01, at 9-10. JP07 and JP06 therefore request BPA also defer decision on the method for determining business line lower thresholds. JP07 Br. Ex., BP-18-R-JP07-01, at 10-11; JP06 Br. Ex., BP-18-R-JP06-01, at 5.

Similarly, WPAG argues that if BPA does not adopt the capex methodology for allocating the business lines' lower threshold, BPA should reserve making a decision on how to allocate the agency's lower reserve threshold to the process following the rate case in order to address the concerns raised in the Briefs on Exceptions. WPAG Br. Ex., BP-18-R-WG-01, at 5.

After extensive debate on this topic, BPA disagrees that deferring a decision on the method for determining business line lower thresholds is either necessary or warranted and, therefore, will not defer this decision. JP07 argues that deferral of a decision on the allocation of the lower threshold is necessary because BPA's decision is not "well-supported." JP07 Br. Ex., BP-18-R-JP07-01, at 10. JP06 similarly argues it does not agree with BPA's view that the days cash method is superior to the capex method. JP06 Br. Ex., BP-18-R-JP06-01, at 4. BPA disagrees. For the reasons stated in Issue 6.6.4.2.2.1 (lower threshold—days cash or capex), BPA is convinced that the days cash method is the proper method for determining the business line lower thresholds. Thus, BPA concludes that no defect in its analysis or the record compels it to defer a decision on the allocation.

BPA has also considered JP06's and JP07's policy arguments for deferring this decision. JP06 and JP07 both contend that BPA can establish the FRP without addressing the allocation question between the business lines at this time. JP06 Br. Ex., BP-18-R-JP06-01, at 5; JP07 Br. Ex., BP-18-R-JP07-01, at 10-11. That is, these parties contend that BPA can satisfy the concerns of the credit rating agencies by adopting a slimmed down version of the FRP that only sets upper and lower thresholds for BPA as an agency and includes \$20 million in PNR. *Id.* The allocation between business lines, these parties argue, is of no interest to the credit rating agencies. *Id.* Thus, these parties assert there would be no harm in deferring this decision to a subsequent process. *Id.* In addition, allowing more time for the development of the allocation would, in JP07's view, produce a more "well-balanced policy that reasonably impacts and could be supported by all of BPA's customers." JP07 Br. Ex., BP-18-R-JP07-01, at 11.

BPA is generally supportive of proposals that will create broader consensus and regional support for BPA's policies. Thus, JP06's and JP07's recommendation for deferring to a subsequent process a decision on this controversial issue is not without merit. However, putting aside parties' arguments regarding the logic behind their preferred method, the parties have conflicting interests in the allocation methods' results. BPA is concerned that, because no such regional consensus has emerged thus far in this process, further delaying this decision may simply be delaying the inevitable conclusion that BPA must find for one side or the other.

JP07 contends that the days cash method and the capex method are not “mutually exclusive” and that a “well-balanced” policy could be produced consistent with cost causation and equity principles if more time is given. JP07 Br. Ex., BP-18-R-JP07-01, at 10. JP06 makes a similar argument. JP06 Br. Ex., BP-18-R-JP06-01, at 4. BPA does not disagree that other methods could potentially be crafted. But, in the absence of unanimous consensus, BPA would need a defensible basis for any “compromise” allocation method. Further, as a practical matter, there would be no basis for limiting new proposals to compromises within the ranges resulting from days cash and capex methods. Proposals might be justified that result in business line lower thresholds being above or below the bounds of *either* the days cash or capex methods.

Here, the BP-18 rate case process has produced a robust record demonstrating that the days cash method is reasonable and appropriate. The FRP is the result of considerable thought and public process. BPA is not required to delay a decision to open up discussion on some yet-to-be-described policy. BPA is convinced that the days cash method is the appropriate method for determining business line lower thresholds.

JP06 also argues that BPA should defer the decision on the allocation because it will affect the phase-in of the CRAC for Power, which is also being deferred. JP06 Br. Ex., BP-18-R-JP06-01, at 2, 4-5. The benefits of rate stability and additional liquidity, according to JP06, depend on how the phase-in CRAC issues are resolved. *Id.* Greater rate instability could occur through the implementation of the phase-in, as was the case with BPA’s initial proposal and the Good Year Ratchet. *Id.* at 5.

BPA, however, does not agree that simply because it is deferring the phase-in question, which is an implementation issue, BPA similarly must defer the question of how to determine the business line lower thresholds, which is a substantive feature of the FRP. As JP06 notes, the allocation issue certainly affects the phase-in, since it sets the business line lower threshold that the phase-in is intended to reach. But this connection is no different than any other aspect of the FRP, such as the decision to set the agency lower threshold at 60 days cash. Following JP06’s logic, because the allocation decision affects the phase-in, any aspect of the FRP that affects the phase-in should similarly be reconsidered in the subsequent process—including whether BPA should hold 60 days cash at the agency level.

BPA appreciates the parties’ work in developing the FRP, but BPA is now convinced that the days cash method is the appropriate method for determining business line lower thresholds. The phase-in public process will be sufficiently complex without adding to its scope reconsiderations of substantive features of the FRP. Deferring the allocation question would change the nature of the phase-in public process. Indeed, BPA is concerned that the timely completion of that public process may be jeopardized if BPA and the parties must not only address the issue of phasing in the Power CRAC threshold, but must do this in a context where the threshold level itself is uncertain. Having determined the end goal of phasing in Power’s CRAC threshold to Power’s 60 days cash lower threshold, parties will be more able to creatively and collaboratively work towards that goal.

BPA also does not agree with JP06’s and JP07’s contention that a slimmed down FRP, which does not adopt a method for determining business line lower thresholds, would provide the same

credit support benefits as BPA's final FRP. *See* JP06 Br. Ex., BP-18-R-JP06-01, at 5; JP07 Br. Ex., BP-18-R-JP07-01, at 10-11. Importantly, deferring this decision would mean deferring the realization of BPA's objectives to establish prudent lower and upper financial reserves thresholds for the business lines. *See* Section 6.5.1. For the FRP to support the credit rating objective, BPA believes it must have meaningful terms that have a practical effect on BPA's rates. Adopting a financial reserves policy that simply establishes *agency* thresholds that BPA has no means of achieving, and that has no effect on rates, would be of little value. JP06 and JP07 contend that an FRP that establishes thresholds at the agency level and that provides \$20 million in PNRR will provide this practical effect. *Id.* However, BPA does not agree that the agency thresholds will have the same meaning without a decision on the method for determining business line lower thresholds or that inclusion of \$20 PNRR would be supportable without first establishing a lower threshold for the business lines.

First, if BPA defers its decision on the method for determining business line lower thresholds, then all of the rate mechanisms that BPA had intended to have in place to implement the FRP for this rate period would be undermined and have to be removed. The CRAC thresholds used in the rate case are calculated, in part, by the lower thresholds determined through the FRP. The lower threshold for a business line is the higher of (1) 60 days cash, or (2) the amount of financial reserves needed to satisfy the TPP Standard. For Power, a phase-in process will establish how the CRAC threshold will be phased in. Thus, Power's CRAC threshold has been set to \$0, consistent with past rate cases. Transmission's financial reserves are above its threshold, so its CRAC threshold has been set to recover 60 days cash consistent with the FRP. Deferring the allocation of the lower threshold at this stage, however, would require eliminating the newly established CRAC threshold for Transmission.

A similar problem would occur in the context of the upper threshold and the RDC. The RDC is eligible to trigger if two conditions are met: (1) the agency's financial reserves exceed 90 days cash; and (2) a business line is above its upper threshold (*i.e.*, it has 60 days cash above its lower threshold). *See* Section 6.6.4.1 (Overview of FRP). However, if BPA does not determine business line lower thresholds, then the basis for establishing the RDC thresholds for both business lines similarly becomes unwound; there would be no way to calculate the business line's upper threshold. BPA's current status quo of no upper limit on Transmission financial reserves would continue.

Second, deferring a decision on the method for determining the lower threshold would undermine BPA's record basis for including \$20 million of PNRR in rates. Both JP06 and JP07 assert that BPA could continue to include \$20 million of PNRR even without a decision on an allocation between the business lines. JP06 Br. Ex., BP-18-R-JP06-01, at 5; JP07 Br. Ex., BP-18-R-JP07-01, at 10-11. BPA, however, is unclear how this could be supported. BPA included \$20 million in PNRR as a means of beginning to build financial reserves for Power Services until it reaches its lower threshold. *See* Issue 6.6.4.3.1 (phase-in). Thus, the record basis for including \$20 million in PNRR is the fact that Power services is below its business line lower threshold. If BPA defers making a decision on *what* Power's lower threshold is, then BPA would have no basis for asserting that Power Services is *below* that lower threshold, or by *how much*, so as to justify taking rate action by including \$20 million in PNRR in power rates. While

JP06's and JP07's representations of support would likely preclude them from disputing the inclusion of \$20 million in PNRR in power rates, BPA has received no such assurances from other parties in this case that have opposed BPA's FRP. Including \$20 million of PNRR in power rates would expose BPA to claims that it had pre-determined the subsequent process and excluded the option of Power providing *no* additional financial reserves (as advocated by certain parties. *See* Issue 6.6.5.1 (expand Treasury Facility). Thus, following JP06's and JP07's proposal, BPA's power rate would not only be exposed to reversal on appeal, but the follow-on process would also be subject to claims of "pre-decision" and partiality.

Taken together, deferring this decision would result in an inferior policy being put in place and would entail significant practical and legal risk without a clear reason to expect a more satisfying outcome on the other end. More importantly, for the reasons stated in Issue 6.6.4.2.2.1 (lower threshold—days cash or capex), BPA is convinced that the days cash method is the appropriate method for determining the business line lower thresholds.

Decision

BPA will not defer a decision on whether to adopt the FRP to a separate process. BPA will also not defer a decision on the method for determining business line lower thresholds to a separate process. As explained in Issue 6.6.4.3.1 (phase-in), BPA will defer development of one implementation feature of the FRP to a separate process.

6.6.6 The FRP and BPA's Policy Objectives

Issue 6.6.6.1

Whether the FRP satisfies Staff's six policy objectives.

Parties' Positions

JP02, JP06, JP07, ICNU, M-S-R, Powerex, and WPAG argue that the FRP, in various ways, does not achieve Staff's six policy objectives. JP02 Br., BP-18-B-JP02-01; JP06 Br., BP-18-B-JP06-01; JP07 Br., BP-18-B-JP07-01; ICNU Br., BP-18-B-IN-01; M-S-R Br., BP-18-B-MS-01; Powerex Br., BP-18-B-PX-01; WPAG Br., BP-18-B-WG-01. Kalispel supports JP06's arguments and positions. Kalispel Br., BP-18-B-KT-01, at 2-3.

BPA Staff's Position

The FRP achieves Staff's six policy objectives and should be adopted. Harris *et al.*, BP-18-E-BPA-33, at 146-52. The parties' arguments have been addressed in previous sections.

Evaluation of Positions

At the outset of this process, Staff identified six policy objectives the FRP is intended to achieve:

1. Maintain sufficient financial reserves levels to support BPA's credit rating.

2. Ensure adequate liquidity throughout each rate period.
3. Maintain equity between business lines.
4. Establish prudent lower financial reserves thresholds and actions supporting objectives 1 and 2.
5. Establish prudent upper financial reserves thresholds so that financial reserves are efficiently redeployed for other high-value purposes.
6. Be compatible with BPA's existing 95 percent TPP standard.

Harris *et al.*, BP-18-E-BPA-17, at 24.

A number of parties argue that Staff's initial FRP proposal or Alternative Option fails to meet one or more of the stated objectives. JP02 Br., BP-18-B-JP02-01; JP06 Br., BP-18-B-JP06-01; JP07 Br., BP-18-B-JP07-01; ICNU Br., BP-18-B-IN-01; M-S-R Br., BP-18-B-MS-01; Powerex Br., BP-18-B-PX-01; WPAG Br., BP-18-B-WG-01. BPA has responded to these concerns in this Final ROD under the particular feature of the FRP the parties have challenged. The following is a summary of how the FRP satisfies the six objectives identified by Staff. The parties' arguments, which are described and addressed in the referenced sections, will not be repeated here.

The final FRP satisfies Staff's objectives as follows:

1. Maintain sufficient financial reserves levels to support BPA's credit rating.

The final FRP is expected to maintain sufficient financial reserves levels to support BPA's credit rating. The final FRP will establish lower thresholds for both business lines based on 60 days cash on hand. Harris *et al.*, BP-18-E-BPA-17, at 22. As discussed in Section 6.4.3 (credit rating and FRP), the credit rating agencies have warned that if BPA's financial reserves fall below 30 days cash on a sustained basis, BPA's credit rating could be downgraded. The 60 days cash lower threshold ensures that there is a buffer against the threat of a significant downgrade to BPA's credit rating. *See* Issue 6.6.4.2.2.3 (lower threshold and 30 days cash). The 120 days cash upper threshold for the business lines and the 90 days cash upper threshold for the agency also ensure that BPA is not repurposing financial reserves in a manner that would jeopardize BPA's credit rating. *See* Issue 6.6.4.5.1 (upper threshold—90 or 120 days cash). In addition, having a financial reserves policy would be viewed by the credit rating agencies as a positive factor in BPA's credit rating. *See* Issue 6.4.3.2.1 (FRP support for BPA's credit rating); *see also* Issue 6.4.3.2.4 (financial reserves levels and credit rating agencies' concerns).

2. Ensure adequate liquidity throughout each rate period.

The final FRP will contribute to ensuring adequate liquidity throughout each rate period. As discussed in Issue 6.4.5.1 (liquidity and a financial reserves policy), Issue 6.5.2.1 (liquidity objective's usefulness), and Issue 6.6.4.2.2.2 (lower threshold and Treasury Facility), the FRP is not designed to replace or supplant the TPP standard, which is BPA's current test for liquidity. Nevertheless, financial reserves are BPA's primary and preferred source of liquidity. To that end, the FRP must be designed such that it does not degrade BPA's liquidity, and if possible,

enhances it. *Harris et al.*, BP-18-E-BPA-33, at 32. The FRP achieves this objective. As discussed in Issue 6.6.4.2.2 (lower threshold and Treasury Facility), the FRP’s lower threshold is set by comparing the higher of what is necessary to satisfy the TPP standard or 60 days cash. *See also Harris et al.*, BP-18-E-BPA-17, at 35. This “higher of” test ensures that the financial reserves thresholds set by the FRP will never be below the amount of financial reserves necessary to meet a 95 percent chance of paying the Treasury in full, and on time, during the rate period. *Id.* The FRP also has the ability to enhance BPA’s liquidity. *See* Issue 6.4.5.1 (liquidity and a financial reserves policy). Because the lower threshold is set on the “higher of” the FRP and TPP standards, it is entirely possible, and indeed likely, that the FRP will raise the minimum level of financial reserves BPA holds. Increasing the minimum amount of financial reserves that BPA retains will increase BPA’s liquidity.

3. Maintain equity between business lines.

The final FRP is expected to enhance equity between the business lines in terms of contributions to agency financial reserves. This is an important feature of the FRP because the status quo allows an imbalance to exist between business line contributions to the agency’s financial reserves. *See* Section 6.4.4 (equity and FRP); *see also* Issue 6.4.4.2.1 (equity issue between business lines). BPA’s credit rating is determined, in part, on having a healthy level of financial reserves. The need for financial reserves is calculated using a “days cash on hand” metric, which is measured as the sum of BPA’s business lines’ operating expenses divided by 365 days. BPA’s credit rating applies to the agency, and both business lines derive a benefit from BPA’s current strong credit rating through, for example, lower interest costs and greater access to the third-party debt market. *See* Section 6.4.3 (credit rating and FRP). Since both business lines contribute to the costs that make up BPA’s days cash on hand need, and both business lines benefit from BPA’s credit rating, it is important for equity reasons that they each contribute to the agency’s financial reserves. *See* Section 6.4.4 (equity and FRP); Issue 6.4.4.2.1 (equity issue between business lines).

Under the final FRP, both business lines will contribute to the agency’s financial reserves. *See* Section 6.6.4 (Final FRP); Section 6.6.4.3 (phase-in). Transmission Services is already above its lower threshold for financial reserves. Power Services, which is below its lower threshold, will begin to contribute in the BP-18 rate period no less than \$20 million per year to agency financial reserves because of the FRP. *Id.* This requirement will continue so long as Power Services is below its lower threshold as established by the FRP. No such requirement exists under the status quo.

The lower thresholds for each business line are also equitable in two distinct ways. First, the FRP sets the amount of each business line’s contribution based on that business line’s days cash. As discussed in Issue 6.6.4.2.2.1 (lower threshold - days cash or capex), this approach equitably aligns the responsibility for financial reserves with the business lines’ relative contribution to the agency’s need for financial reserves. Second, BPA recognizes that the FRP is a new policy and that immediate application to Power Services, which has seen a dramatic decrease in its financial reserves, would not be appropriate. *See* Issue 6.6.4.3.1 (phase-in). Thus, as described in Issue 6.6.4.3.1 (phase-in), the FRP includes a phase-in that allows Power Services to gradually work up to its lower threshold. The phase-in is necessary to balance unnecessary rate shock with

the implementation of the FRP. BPA also recognized that the phase-in feature of the FRP would benefit from further stakeholder input and thus will defer to a subsequent process a decision on determining the method for phasing in the Power CRAC threshold to the Power lower threshold. *Id.*

The FRP also provides equity in applying symmetrical treatment between the business lines. The FRP applies the same days cash metric to determine the lower and upper thresholds for both business lines. *See* Section 6.5.3.1 (staff’s equity objective). No such standard exists today. The FRP also creates symmetry in the rate mechanisms applicable to the business lines for increasing (and redistributing) financial reserves. *Id.* Under the FRP, both business lines will now have symmetrical mechanisms to increase rates (CRACs) and repurpose financial reserves (RDCs). *Id.* No such symmetry existed under the status quo. *Id.*

4. *Establish prudent lower financial reserves thresholds and actions supporting objectives 1 and 2.*

The FRP establishes prudent lower financial reserves thresholds and actions supporting objectives 1 and 2. This can be seen from the decision to set the lower threshold at 60 days cash (or higher if needed for TPP), which ensures that a buffer is retained between healthy financial reserves and low financial reserves that could result in a significant downgrade. *See* Section 6.4.3 (credit rating and FRP); *see also* Section 6.6.4.2 (lower threshold).

5. *Establish prudent upper financial reserves thresholds so that financial reserves are efficiently redeployed for other high-value purposes.*

The FRP establishes prudent upper financial reserves thresholds so that financial reserves are efficiently used for other high-value purposes. As explained in Issue 6.6.4.5.1 (upper threshold—90 or 120 days cash), the upper threshold for the agency will be 30 days above the sum of the business lines’ lower thresholds (*e.g.*, 90 days cash). The business lines’ upper thresholds will be 60 days above their respective lower thresholds (*e.g.*, 120 days cash). *Id.* For financial reserves to be redeployed, a business line must have financial reserves above its upper threshold (120 days cash), and the agency must have total financial reserves above the agency upper threshold (90 days cash). *Id.* This approach ensures that BPA has robust financial reserves before voluntarily redeploying them for other high-value purposes. *Id.* The two-part test for repurposing financial reserves also protects BPA’s credit rating and supports rate stability in that it reduces the risk of BPA repurposing financial reserves in one year, only to increase rates in the next. *Id.* The FRP retains the Administrator’s discretion to determine the uses of financial reserves eligible for redeployment. *See* Issue 6.6.4.5.2 (BPA RDC discretion). Retaining this discretion ensures that the Administrator has the flexibility to determine which “high-value purpose” the financial reserves should be directed to based on the facts and circumstances at the time. *Id.*

6. *Be compatible with BPA’s existing 95 percent TPP standard.*

The FRP is compatible with BPA’s existing 95 percent TPP standard. As described earlier, the lower threshold is designed specifically to integrate with the provisions of the TPP standard to ensure that the policy objectives of both the TPP standard and the FRP are achieved: the lower

threshold will be the higher of the level needed under the FRP threshold guidelines and the level needed for TPP. *See* Issue 6.6.4.2.2.2 (lower threshold and Treasury Facility). The FRP also does not alter BPA’s existing methodology for calculating TPP. *Id.* Thus, for instance, BPA’s decision to utilize the Treasury Facility in the calculation of the TPP standard is unaffected by the FRP. *Id.* It is in these ways that the FRP and the TPP standard are “complementary financial management tools” that “work together.” Harris *et al.*, BP-18-E-BPA-33, at 26.

Finally, BPA considered other means of achieving the six objectives that have been proposed, and whether BPA should make a decision on the FRP in another process. *See* Section 6.6.5 (parties’ alternative proposals). BPA concludes in Section 6.6.5 that proposed alternatives are not superior to the FRP that is being adopted in this case and, except for one implementation feature of the Power CRAC lower threshold, a delay of the FRP is not necessary or helpful. *See* Issue 6.6.5.4 (reasons for deciding FRP in rate case).

Decision

The FRP meets the six policy objectives identified by Staff.

Issue 6.6.6.2

Whether adoption of the FRP is consistent with BPA’s statutory obligation to establish the lowest possible rates to consumers consistent with sound business principles.

Parties’ Positions

WPAG, JP07, and ICNU argue that the FRP is inconsistent with BPA’s statutory obligation to set rates at the lowest cost consistent with sound business principles. WPAG Br., BP-18-B-WG-01, at 11-12; JP07 Br., BP-18-B-JP07-01, at 16; ICNU Br., BP-18-B-IN-01, at 4. Kalispel states, “A Financial Reserves Policy is consistent with BPA’s obligation to ‘transmit and dispose of such power and energy in such manner as to encourage the most widespread use thereof at the lowest possible rates to consumers consistent with sound business principles.’” Kalispel, BP-18-B-KT-01, at 2.

In its Brief on Exceptions, M-S-R agrees that “the FRP is consistent with sound business policies such as supporting liquidity and rate stability, which will in turn support BPA’s credit rating.” M-S-R Br. Ex., BP-18-R-MS-01, at 2.

In its Brief on Exceptions, JP07 argues the FRP’s inclusion of the days cash method for determining business line lower thresholds “presents a dreadful business case for the power customers” JP07 Br. Ex., BP-18-R-JP07-01, at 6. JP07 argues that “power customers are unable to support a financial reserves policy that looks to collect \$300 million, or an average of \$30 million per year, over the remaining life of the RD Contracts but is expected to yield a benefit of at most \$160 million, or \$16 million per year, from a credit support perspective.” *Id.* at 5.

BPA Staff's Position

The FRP is consistent with BPA's statutory direction to establish the lowest possible rates to consumers consistent with sound business principles. Harris *et al.*, BP-18-E-BPA-33 at 6-8, 52-63.

Evaluation of Positions

WPAG, JP07, and ICNU argue that the FRP's impact on rates is at odds with BPA's 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" WPAG Br., BP-18-B-WG-01, at 11-12; JP07 Br., BP-18-B-JP07-01, at 16; ICNU Br., BP-18-B-IN-01, at 4; 16 U.S.C. § 838g; *see also* 16 U.S.C. § 839e(a)(1); 16 U.S.C. § 825s.

BPA understands the parties' concern with the FRP's near-term rate impacts, which will require an increase to Power rates to begin the process of rebuilding financial reserves. *See* Section 6.6.4.3 (phase-in). At the same time, if the gaps in BPA's current policies are left unaddressed, BPA's overall financial health and its ability to set its rates in accordance with sound business principles will be impaired. *See* 16 U.S.C. § 838g; 16 U.S.C. § 839e(a)(1); 16 U.S.C. § 825s. The FRP fills these gaps and aligns with the Administrator's authority to operate BPA consistent with sound business principles and in a businesslike fashion. *See Ass'n of Pub. Agency Customers, Inc. v. BPA*, 126 F.3d 1158, 1171 (9th Cir. 1997) ("although Congress did not prescribe the parameters of the Administrator's authority, it granted BPA an unusually expansive mandate to operate with a business-oriented philosophy."). To that end, BPA's "statutes do not dictate that BPA always charge the lowest possible rates." *Cal. Energy Comm'n. v. BPA*, 909 F.2d 1298, 1308 (9th Cir. 1990). Instead, BPA's authority allows it to be forward-looking and make reasoned business decisions. *See Ass'n of Pub. Agency Customers, Inc.*, 126 F.3d at 1182. As noted below, the FRP supports BPA's business interests and furthers BPA's ability to operate with a "business-oriented philosophy" in several ways. *Id.* at 1171.

First, the FRP will support BPA's credit rating. Harris *et al.*, BP-18-E-BPA-33, at 52. BPA is authorized to incur third-party debt to support its mission of providing power and transmission services to regional customers. *Id.* Third-party borrowing is used to finance a considerable portion of BPA's capital program; BPA recovers these costs in its rates. *Id.*; *see also* Section 6.4.3 (credit rating and FRP). BPA's strong credit rating allows BPA to (1) gain access to capital from third-parties, and (2) receive favorable interest rates when borrowing. Harris *et al.*, BP-18-E-BPA-33, at 52. As explained in Section 6.4.3 (credit rating and FRP), BPA must, among other things, retain a reasonable amount of financial reserves to maintain its credit rating. *Id.*; *see also* Section 6.4.3 (credit rating and FRP). Having a policy regarding financial reserves, and setting rates consistent with that policy, protects BPA's strong credit rating. Harris *et al.*, BP-18-E-BPA-33, at 52. This in turn supports BPA's access to non-Federal capital at competitive rates. *Id.* Borrowing at competitive rates allows BPA to minimize its interest expense, which furthers BPA's mission of providing power and transmission service to the region at rates that are as low as possible consistent with sound business principles. *Id.* at 53; *see also* Section 6.4.3 (credit rating and FRP).

In addition, the FRP defines the levels of financial reserves BPA needs to maintain its financial health and conduct its business consistent with its statutory obligations. *Harris et al.*, BP-18-E-BPA-33, at 7. BPA will retain these financial reserves to support the agency’s long-term ability to operate its business. *Id.* Raising the minimum amount of financial reserves BPA holds will result in a number of benefits beyond credit support, including additional liquidity, support for equity between the business lines, and, once fully implemented, rate stability. *See* Section 6.4 (need for FRP). These expected benefits from the FRP are a far cry from “receiv[ing] nothing in return.” *See* ICNU Br., BP-18-B-IN-01, at 16, n.52 (citing *Nw. Requirements Utils. v. FERC*, 798 F.3d 796, 807 (9th Cir. 2015)).

Further, holding financial reserves is a sound business and standard industry practice. *Harris et al.*, BP-18-E-BPA-33, at 62. Entities similar to BPA hold financial reserves significantly higher than the FRP’s 60 days cash lower thresholds. *Id.* (citing Attachment 14, Data Responses NR-BPA-26-13 & Attachment 15, Data Response NR-BPA-26-19). For example, the New York Power Authority, which is predominantly a hydro-based utility with generation and transmission assets, had 208 days cash on hand at the end of FY 2013. *Id.* at 62-63 (citing Attachment 16, NYPA Debt Management Plan Update (Dec. 17, 2013) & Attachment 17, NYPA 2015 Annual Report). Chelan PUD at the end of 2015 had 456 days cash on hand. *Id.* at 63 (citing Attachment 18, Moody’s Chelan PUD Credit Rating Report (Sept. 27, 2016)). The Long Island Power Authority had 120 days cash on hand at the end of 2015. *Id.* (citing Attachment 19, Moody’s LIPA Credit Rating Upgrade Report (Aug. 12, 2016)). Compared to these utilities’ levels of financial reserves, BPA’s FRP is quite modest. *Id.*

A number of parties contend that the FRP is not a sound business decision because it will not result in a net benefit to Power customers. ICNU Br., BP-18-B-IN-01, at 16, 65; *see* JP07 Br., BP-18-B-JP07-01, at 16; WPAG Br., BP-18-B-WG-01, at 10. There is no statutory requirement that a financial reserves policy must produce a net benefit to BPA’s Power customers for BPA to adopt such a policy (although, as noted below, Staff demonstrated that the FRP provides a net benefit). Rather, BPA is required to operate in a manner that assures it remains fiscally self-supporting. *See Dep’t of Water & Power of the City of Los Angeles v. BPA*, 759 F.2d 684, 693 (9th Cir. 1985) (“The history of BPA’s enabling legislation further demonstrates that Congress has repeatedly required BPA to operate in a manner which assures that the agency is fiscally self-supporting.”). In making a business decision to support its statutory objectives, BPA must provide a rational business justification for its actions that is supported by the record. *See Pac. Nw. Generating Co-op v. BPA*, 596 F.3d 1065, 1085 (9th Cir. 2010). BPA has done so. The record establishes a need for a financial reserves policy, Section 6.1 (introduction), Section 6.4 (need for FRP); the objectives that policy should achieve, Section 6.5 (Staff’s objectives and the FRP); and how the various features of that policy support the agency’s business, Section 6.6.6 (FRP and policy objectives). BPA has also considered and responded to the arguments of (and incorporated suggestions from) the parties. *See, e.g.*, Section 6.6.4 (final FRP). BPA has considered all relevant factors and explained its positions regarding the FRP based on the evidence. *Indus. Customers of Nw. Utils. v. BPA*, 767 F.3d 912, 922 (9th Cir. 2014); *see* Sections 6.4-6.6.

Moreover, while there is no statutory requirement that BPA must demonstrate a net benefit in order for a policy to be justified on sound-business reasons, BPA nonetheless considered this concern and conducted 168 cost-benefit analyses comparing the opportunity cost of holding financial reserves with the higher interest expense resulting from a downgrade. Harris *et al.*, BP-18-E-BPA-33, at 56 & Attachment 13. Even under Staff’s conservative assumptions, these analyses demonstrated the FRP provides a net benefit to customers under all but the most extreme conditions. *Id.* at 57-59 & Attachment 13. The Net Present Value analysis further substantiates that the FRP provides value to BPA’s customers. *Id.*

WPAG, JP07, and JP06 do not necessarily dispute that the FRP may provide a net benefit to BPA overall (Power Services and Transmission Services). See WPAG Br., BP-18-B-WG-01, at 10; JP07 Br., BP-18-B-JP07-01, at 16; JP06 Br., BP-18-B-JP06-01, at 4. Instead, they focus their arguments on the FRP’s impact on power customers’ rates. One of WPAG’s chief concerns is that “the presumed benefits to Power customers from the proposal would be outweighed by its costs.” WPAG Br., BP-18-B-WG-01, at 10. JP07 argues Staff’s initial FRP proposal did not align costs with benefits, and that “risking a downgrade would be financially preferable for power customers.” JP07 Br., BP-18-B-JP07-01, at 10, 18. JP06 conditioned its support for the FRP on whether, among other things, it “avoided subjecting Power customers to undue rate pressure or rate instability.” JP06 Br., BP-18-B-JP06-01, at 5. JP07 limits its analysis to comparing the benefit of \$16 million per year average avoided interest cost against an assumed average rate impact. See JP07 Br., BP-18-B-JP07-01, at 10. In its Brief on Exceptions, JP07 argues that the FRP does not properly align costs with benefits. JP07 Br. Ex., BP-18-R-JP07-01, at 3-6.

JP07’s analysis, however, is too limited from both a benefit and a cost perspective. That is, JP07 would have BPA only consider the “the cost of *maintaining the credit rating* with the benefit of *borrowing lower-cost money . . .*” *Id.* at 4 (emphasis added). Beginning first with the benefits, the FRP will, as JP07 notes, benefit long-term Power rates through lower interest expense. Harris *et al.*, BP-18-E-BPA-33, at 58; JP07 Br., BP-18-B-JP07-01, at 10. The FRP will also benefit long-term Power rates by helping to ensure a stable credit rating and, therefore, continued access to low-cost borrowing, while improving agency liquidity and providing flexibility to adapt in the future. Harris *et al.*, BP-18-E-BPA-33, at 67. JP07’s analysis also fails to account for the benefits of a diversified bond purchasing pool, the impact BPA’s credit rating has on its customers’ credit ratings, demand for BPA’s debt in the marketplace even when market conditions are challenging, and access to alternative forms of financing like lease financing lines of credit and favorable credit requirements with BPA’s various trading partners. See *id.*, Attachment 13, at 1 (benefits not quantified in NPV analysis); see also Section 6.4.3 (credit rating and FRP).

As to costs, JP07’s accounting does not recognize the difference between increased interest expense and increased financial reserves. As JP02 recognized, “increased interest expense is just that—an expense—whereas increased financial reserves are an asset.” JP02 Br., BP-18-B-JP02-01, at 25. If BPA’s credit rating were downgraded, borrowing costs would rise without customers experiencing any offsetting value. Alternatively, financial reserves are an asset that provides security to those investing in BPA, which supports lower interest expenses for BPA,

and also provides security to BPA itself by being available to pay for unexpected net revenue shortfalls if and when incurred. Because financial reserves are an asset that remains available for later use, the cost of holding financial reserves is equal to the opportunity cost and not the magnitude of the financial reserves themselves. Harris *et al.*, BP-18-E-BPA-33, at 56. Staff evaluated this opportunity cost and conservatively demonstrated that this cost was less than the benefit received. *Id.* at 57.

WPAG, JP07, and ICNU also raise a number of arguments regarding “sound business principles” and whether BPA considered relevant factors in developing the FRP. These arguments have been addressed in other sections of this Final ROD. BPA notes them below.

WPAG expresses its concern that the FRP “will be a source of upward rate pressure that, when combined with the many other sources of such pressure, will add to BPA’s difficulties in ensuring competitive rates and the lowest possible rates consistent with sound business principles” WPAG Br., BP-18-B-WG-01, at 11-12; *see also* WPAG Br., BP-18-B-WG-01, at 15-16. JP07 and WPAG cite BPA’s 1996 ROD as demonstrating that “[t]he Administrator at that time was unequivocal that BPA’s ability to meet its statutory obligations is directly connected to whether its rates are competitive.” JP07 Br., BP-18-B-JP07-01, at 3; *see* WPAG Br., BP-18-B-WG-01, at 5. For the reasons stated in Section 3.1, BPA is aware of the pressures on its rates and has taken significant steps to reduce its costs. Moreover, as stated in Issue 6.6.6.3 (FRP and competitiveness), BPA expects the FRP to enhance its competitiveness.

JP07 emphasizes “[i]t is critical that BPA take into account cost and rate impacts associated with any financial reserves policy” and that failing to so consider “would constitute unsound financial management.” JP07 Br., BP-18-B-JP07-01, at 16. Similarly, “ignoring actual financial conditions at the time when the rates are set is not a sound business practice.” *Id.* at 4. BPA considered these relevant factors in choosing to adopt the FRP. *See* Issue 6.6.6.3 (FRP and competitiveness). ICNU points to certain credit rating factors it believes BPA failed to consider as evidence that the FRP is inconsistent with a “‘sound’ business-orientated philosophy” or “‘sound business’ practice.” ICNU Br., BP-18-B-IN-01, at 56, 61. These factors are discussed in Section 6.4.3 (credit rating and FRP).

ICNU argues that “needlessly rush[ing] into a 10-year policy commitment is inconsistent with the fundamental statutory principle . . . [that] BPA must enact any future FRP ‘at the lowest possible rates to consumers consistent with sound business principles.’” *Id.* at 5. ICNU makes several conditional arguments that rate increases caused by the FRP would be inconsistent with sound business principles if (1) “reserve levels are already sufficient to meet [BPA’s credit rating objective,];” (2) their benefits do not justify their costs; or (3) “reserves levels will naturally increase.” *Id.* at 15, 46, 63, 65. BPA has addressed each of these conditions in this Final ROD. *See* Issue 6.4.3.2.1 (FRP support for BPA’s credit rating), Issue 6.4.3.2.2 (relevance of credit rating agencies’ factors); Issue 6.4.3.2.3 (weight of 2017 credit rating reports); Issue 6.4.3.2.4 (financial reserves levels and credit rating agencies’ concerns); Issue 6.4.3.2.5 (FRP and cost competitiveness credit rating factor); Issue 6.4.4.2.1 (equity issue between business lines); Issue 6.6.6.3 (FRP and competitiveness).

ICNU also argues the evidentiary record is insufficient for BPA’s adoption of the FRP to be consistent with sound business principles. *Id.* at 63, 72, 74, 84. BPA discusses the sufficiency of the record throughout this Final ROD. Conversely, ICNU argues deferral of the FRP “would be consistent with a sound business-orientated philosophy.” *Id.* at 79-80, 88. BPA has determined it is appropriate to take action now. *See* Issue 6.6.5.4 (reasons for deciding FRP in rate case) in which BPA concludes deferral is not justified.

Decision

The FRP is consistent with BPA’s statutory direction to establish the lowest possible rates to consumers consistent with sound business principles.

Issue 6.6.6.3

Whether the FRP will support BPA’s competitiveness.

Parties’ Positions

WPAG, JP07, and JP06 raise concerns that the FRP will hurt BPA’s ability to be cost-competitive. WPAG Br., BP-18-B-WG-01, at 10; JP07 Br., BP-18-B-JP07-01, at 2; JP06 Br., BP-18-B-JP06-01, at 5 (discussing “undue rate pressure”).

Kalispel supports JP06’s arguments and positions. Kalispel Br., BP-18-B-KT-01, at 2-3.

ICNU argues BPA did not properly consider the FRP’s impact on the credit rating factor of cost-competitiveness. ICNU Br., BP-18-B-IN-01, at 48-62.

BPA Staff’s Position

The FRP will support BPA’s competitiveness. Harris *et al.*, BP-18-E-BPA-33, at 63-68.

Evaluation of Positions

WPAG, JP07, and JP06 raise concerns that the FRP will hurt BPA’s ability to be cost-competitive. WPAG Br., BP-18-B-WG-01, at 10; JP07 Br., BP-18-B-JP07-01, at 2; JP06 Br., BP-18-B-JP06-01, at 5. ICNU raises similar arguments in the context of the FRP’s impact on BPA’s competitiveness as a credit rating factor, which is further discussed in Issue 6.4.3.2.5 (FRP and cost-competitiveness credit rating factor). ICNU Br., BP-18-B-IN-01, at 48-62.

WPAG emphasizes the importance of, and challenges to, BPA remaining competitive. WPAG Br., BP-18-B-WG-01, at 3-9. JP07 notes that “a Financial Reserves Policy should help, not hinder, BPA’s cost-competitiveness efforts.” JP07 Br., BP-18-B-JP07-01, at 2. JP06 conditioned its support for the FRP on whether, among other things, it “avoided subjecting Power customers to undue rate pressure or rate instability.” JP06 Br., BP-18-B-JP06-01, at 5.

BPA agrees that competitiveness is an important agency priority and is crucial to BPA's long-term success. Harris *et al.*, BP-18-E-BPA-33, at 64. BPA continues to make every effort to ensure the long-term competitiveness of its Power rates. *Id.* at 30. Doing so is crucial to retaining as many customers as possible, especially when the current RD Contracts expire in 2028. *Id.* BPA understands that the retention of customers is an important factor considered by the credit rating agencies, in addition to being inherently important to BPA's business success. *Id.* BPA is committed to its competitiveness and will continue to make every effort to respond effectively to factors that may threaten its cost-competitiveness as the market environment continues to change and evolve over time. *Id.* at 64.

Nevertheless, many of the market forces that impact BPA's competitiveness are beyond BPA's control. *See id.* at 3. WPAG aptly describes many of the challenges BPA faces:

Historically and persistently low natural gas prices, the rise of renewable energy, multiplying carbon-free initiatives, and reduced demand have fundamentally changed energy markets throughout the West, significantly lowering both (i) the price BPA can receive for its secondary energy and (ii) the measuring stick by which BPA's rates are compared. Meanwhile, the costs incurred and the revenues forgone by BPA to satisfy its regulatory and legal obligations, and to otherwise provide public benefits, continue to rise.

WPAG Br., BP-18-B-WG-01, at 3-4.

Despite these many challenges, BPA must be prepared in the coming years to weather uncertainty and remain steadfast in meeting its statutory obligations. Harris *et al.*, BP-18-E-BPA-33, at 3. The FRP is a financial tool that complements, rather than contradicts, BPA's cost-competitiveness efforts. *Id.* at 66. Numerous exogenous factors—unrelated to the FRP—will continue to affect BPA's long-term cost-competitiveness. *Id.* at 64. For example, BPA cannot control market prices. However, BPA can influence its access to cash. *Id.* And BPA can take steps to keep its interest expense low. *Id.* at 30. If BPA's currently strong credit rating were to decline, borrowing would become more expensive, leading to less competitive rates, all else being equal. *Id.* Having a financial reserves policy is one tool that BPA can use to help ensure competitive rates on a long-term basis. *Id.* The FRP represents an area where BPA can take action now to ensure a firm foundation for long-term fiscal health.

Competitive long-term power rates are a critically important factor in BPA's long-term success. *Id.* at 66. One way BPA can support the competitiveness of its rates is by managing its costs. As discussed in Section 3.1, BPA continues to look for ways to ensure its costs are aligned with the agency's needs. But cost reductions are not the only way BPA will be able to maintain its competitiveness. As the credit rating agencies note, the adequacy of financial reserves and the stability of financial reserves are also important in determining BPA's overall creditworthiness. *Id.* BPA's FRP is intended to support the agency's credit rating, liquidity, and equity between business lines while minimizing negative impacts on other areas of the business. *Id.* at 67. BPA believes the FRP would benefit long-term rates by helping to assure a stable credit rating and, therefore, continued access to low-cost borrowing, while improving agency liquidity, and

providing flexibility to adapt in the future. *Id.* While the FRP would also create short-term upward pressure on power rates, the rate pressure is expected to be limited and temporary. *Id.*

JP07 recognizes the value of long-term competitiveness when it argues “[t]he fundamental financial strength of BPA is its long-term contracts with its preference customers.” JP07 Br., BP-18-B-JP07-01, at 2. Fundamentally, regarding the FRP, BPA is presented with two potential futures. In one, BPA has adopted the FRP. In this future, BPA has developed a policy with defined upper and lower financial reserves thresholds that protect the agency’s strong credit rating, provide additional liquidity, and resolve the imbalance in business line contributions to agency reserves. *See* Section 6.4 (need for FRP). Through the adoption of the lower thresholds and the phase-in of the Power CRAC threshold to the Power lower threshold, BPA will gradually build Power financial reserves over time so that by the end of the current power sales contracts, BPA will be positioned to be the supplier of choice, with a healthy balance sheet, strong credit rating, and financial reserves in the BPA fund to support future rate development. *See* Section 6.6.4.2 (lower threshold); Section 6.6.4.3 (phase-in). With financial reserves BPA has options— it can offset unanticipated expenses, smooth rate impacts, defer capital borrowings to later periods resulting in lower interest charges, and earn higher interest income. Harris *et al.*, BP-18-E-BPA-33, at 67. All of these options lower rates and support competitiveness. *Id.*

In the other future, BPA does not adopt a financial reserves policy and the status quo policy gap remains. Under the status quo, no policy prevents or addresses the recent declines in financial reserves, *see* Issue 6.4.4.2.1 (equity issue between business lines), thereby leaving BPA exposed to the possibility of having very low or no financial reserves when current power contracts expire. Harris *et al.*, BP-18-E-BPA-17, at 12. In this future, BPA’s credit rating either has been downgraded or is in a constant threat of a downgrade. Further, without a minimal level of financial reserves, Power Services’ only option for addressing uncertainty would be to borrow from the Treasury Facility; thus, BPA would incur a debt obligation that would need to be paid back with interest within a year or two. Harris *et al.*, BP-18-E-BPA-33, at 67-68. BPA could easily find itself at the end of the current power sales contracts with little to no financial reserves attributable to Power Services, a lower credit rating, high borrowing costs, and an outstanding balance on the Treasury Facility that must be paid back in future rates. Parties may contend that this “parade of horrors” is unlikely to occur, but the key point is that the gaps in BPA’s current financial policies do not prevent it and the FRP does.

BPA’s overall financial health directly impacts whether its customers will have confidence to sign new long-term sales contracts with BPA in the future. For the reasons stated herein, the FRP will support BPA’s competitiveness efforts and help secure BPA’s overall financial health. As already noted, this is in line with setting the lowest possible rates consistent with sound business principles. *See* Issue 6.6.6.1 (FRP and policy objectives).

Moreover, BPA did not ignore competitiveness in proposing the FRP, but took steps to moderate the FRP’s impact on power rates. Harris *et al.*, BP-18-E-BPA-33, at 65. Specifically, both of Staff’s proposals for the FRP included a phase-in of Power’s CRAC threshold. *See* Section 6.1 (Staff’s initial FRP); Section 6.6.3 (Alternative Option). Staff rejected an immediate implementation that, although resulting from an equitable allocation of the lower threshold, would have resulted in approximately \$300 million of additional cost to Power this rate period.

See Harris *et al.*, BP-18-E-BPA-33, at 65. Thus, Staff has always proposed to phase-in the lower threshold component of the FRP to moderate impacts on power rates, rather than immediately and fully recovering business line minimum thresholds. *Id.* In addition, a phase-in is included in the final FRP. See Section 6.6.4 (Final FRP); Issue 6.6.4.3.1 (phase-in). As discussed in Issue 6.6.4.3.1, a part of this phase-in will be developed in a subsequent process, where concerns over how the CRAC adjustment features of the FRP affect BPA’s cost competitiveness can be considered and addressed.

Finally, in advocating for Staff’s Alternative Option over the initial FRP proposal, WPAG argues that, since “the alternative proposal would be \$9 million less” and “performs as well or better than the initial proposal . . . BPA should adopt the better performing, lower cost alternative proposal.” WPAG Br., BP-18-B-WG-01, at 16. As WPAG acknowledges, the Administrator must balance competing objectives. *Id.* at 3. As discussed in Issue 6.6.4.2.2.1 (lower threshold--days cash or capex), the days cash method more equitably balances the FRP’s costs and benefits and, as discussed herein, is expected to result in benefits to Power customers. Adopting such a policy is consistent with BPA’s statutory obligations and supports BPA’s commitment to remain cost competitive.

Decision

The FRP will support BPA’s competitiveness.

Issue 6.6.6.4

Whether BPA has a statutory obligation to consider impacts on end-use consumers in BPA’s decision-making and failed to do so.

Parties’ Positions

ICNU argues that BPA has disregarded end-use consumer impacts, contrary to the agency’s statutory mandates. ICNU Br. Ex., BP-18-R-IN-01, at 7-11.

BPA Staff’s Position

ICNU first raises this statutory argument in its Brief on Exceptions.

Evaluation of Positions

ICNU argues that “BPA is statutorily obligated to analyze the FRP’s potential impacts on end-use consumers as part of its decision-making process. BPA has not done so, and it must.” *Id.* at 11. ICNU cites Ninth Circuit precedent, which states, “[i]n reviewing these arguments, we consider merely whether ‘the agency considered the relevant factors and articulated a rational connection between the facts found and the choices made’; we do not second-guess its policy judgments.” *Alcoa, Inc. v. BPA*, 698 F.3d 774, 788 (9th Cir. 2012) (internal citations omitted). ICNU highlights references in BPA’s organic statutes to “consumers” in the Federal Columbia River Transmission System Act, 16 U.S.C. § 838g (2014), and Pacific Northwest Electric Power

Planning and Conservation Act, 16 U.S.C. § 839(4) (2014), and to “the general public” in the Bonneville Project Act, 16 U.S.C. § 832 (2014). ICNU Br. Ex., BP-18-R-IN-01, at 7-8. ICNU thus argues that “end-use consumer impacts” is a relevant factor here, and that BPA has failed to consider it. *Id.* at 7.

ICNU also relies on *APAC v. BPA*, 733 F.3d 939 (9th Cir. 2013). ICNU Br. Ex., BP-18-R-IN-01, at 9. ICNU overstates *APAC*’s holding. Contrary to ICNU’s claims, the Court did not set forth a new statutory mandate that BPA must consider “impacts on end-use consumers as part of its decision-making process” whenever BPA developed a policy that affected its rates. *See* ICNU Br. Ex., BP-18-R-IN-01, at 11. Rather, the Court addressed whether APAC—an unincorporated *ad hoc* organization of member groups that own and operate industrial facilities in the Pacific Northwest and purchase electricity from BPA’s preference customers—had standing to challenge the 2012 REP Settlement Agreement. *APAC*, 733 F.3d at 949. The Court agreed that APAC could proceed with its challenge because of “the ‘pass-through’ contracts under which its members pay rates that directly reflect the rates BPA charges its direct customers.” *Id.* at 949-55.

ICNU, however, conflates this simple finding of standing into an entirely new (and unsupported) statutory test for BPA decision-making. ICNU claims “the Ninth Circuit determined that these statutory sections *prohibit* BPA from relying on ‘technicalities’ to excuse the agency from its obligation to consider how its decisions affect end-use consumers.” ICNU Br. Ex., BP-18-R-IN-01, at 9 (emphasis in original) (citing *APAC*, 733 F.3d at 952). This argument is specious. The Court’s statements regarding “technicalities” were made in the context of responding to an argument BPA had made regarding whether APAC’s alleged injury was “concrete and particularized” and “actual or imminent, not conjectural or hypothetical.” *APAC*, 733 F.3d at 952. BPA had argued that “any burden imposed on APAC’s members comes from the COUs [consumer-owned utilities] that sell power to them,” to which the Court responded that BPA’s argument was not persuasive because it “relies on technicalities at the expense of common sense. Under the terms of the Settlement, [an APAC member] will almost certainly be charged a rate that directly reflects the rates BPA charges the COUs.” *Id.* The Court also found APAC was within the “zone of interests” for prudential standing, based in part on legislative history that “Congress intended for the customers of COUs to benefit from [the Northwest Power Act’s] protections.” *APAC*, 733 F.3d at 954-55; *cited by* ICNU Br. Ex., BP-18-R-IN-01, at 9. This test “is not meant to be especially demanding . . . keeping with Congress’s evident intent when enacting the APA to make agency action presumptively reviewable.” *APAC*, 733 F.3d at 954 (internal citations omitted).

The import of this holding was that APAC could, just like a BPA power customer, *also* challenge the 2012 REP Settlement and whether it complied with BPA’s statutory mandates. In finding that APAC could challenge BPA’s decision, the Court did not create a new statutory obligation to analyze every decision’s effects on end-use consumers separately and distinctly from its analysis of the impact on BPA’s direct customers. Thus, ICNU incorrectly interprets *APAC* as creating some entirely new body of law requiring BPA to specifically consider its actions’ impact on end-use consumers. Here, BPA has analyzed the FRP’s impact on its power

customers in its evaluation of cost-competitiveness, which implicitly considers the impact on end-use consumers. *See* Issues 6.4.3.2.5, 6.4.3.2.6, 6.6.6.3.

ICNU continues to misinterpret BPA’s statements regarding the relevance of certain credit rating factors as an “attempt to abandon [BPA’s] important connection with the region . . .” ICNU Br. Ex., BP-18-R-IN-01, at 8. BPA urges ICNU to re-read the factors in the credit rating reports and BPA’s analysis. Certain credit rating factors cited by ICNU are either subsumed within cost-competitiveness concerns or are not relevant considerations. *See* Issue 6.4.3.2.6. BPA is by no means disclaiming its regional concern; it is BPA’s intent to maintain the economic benefits it provides the region over the long-term. BPA understands its statutory purpose to operate for the benefit of the general public by giving preference and priority to public bodies and cooperatives in the disposition of Federal power. BPA rejects ICNU’s assertion that providing benefits to the general public is a restraint on pursuing cost-competitiveness efforts that will impact the region. As an overarching principle, BPA understands that public service is a public trust. BPA has analyzed the FRP’s impact on BPA’s cost-competitiveness and for consistency with its statutory obligations. BPA is cognizant of the FRP’s impact on its wholesale power rates, including some costs which may be passed through to ICNU’s members by their local utility. But BPA’s decision to adopt the FRP is not, therefore, faulty for having fully considered the FRP’s impact—including cost-competitiveness—without separately analyzing those impacts on specific retail end-user sectors within BPA’s customers’ service areas.

Finally, in addition to arguing that end-use consumer impact is a “relevant factor” BPA must have considered here under *Alcoa, Inc. v. BPA*, 698 F.3d at 788, ICNU appears to argue that BPA has a direct statutory mandate to perform a separate end-use consumer impact analysis as part of *every* BPA decision. *See* ICNU Br. Ex., BP-18-R-IN-01, at 10 (“The agency’s outright refusal to consider how the FRP might impact the end-use consumers or the general public *also* raises serious doubts as to whether BPA has complied with its obligation to consider all relevant factors in the course of its decision-making, as it must do.”) (emphasis added). To the extent it so argues, ICNU is incorrect. Whether a factor is relevant to a BPA decision will depend on the specific facts. ICNU’s logic would require BPA to perform a separate analysis for a multiplicity of potentially impacted entities extending far beyond ICNU’s members, notwithstanding whether the matters within BPA’s control remained the same for each. Whether such analysis would be helpful is doubtful. Whether such analysis is statutorily mandated is clearly erroneous.

Decision

BPA considered all relevant and statutorily mandated factors in adopting the FRP.

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7.0 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 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 November 10, 2016, BPA published in the Federal Register a Notice of “Fiscal Year (FY) 2018–2019 Proposed Power and Transmission Rate Adjustments Public Hearing and Opportunities for Public Review and Comment.” 81 Fed. Reg. 78,999 (2016). The Federal Register notice may be viewed at the link: <https://www.federalregister.gov/documents/2016/11/10/2016-27181/fiscal-year-fy-2018-2019-proposed-power-and-transmission-rate-adjustments-public-hearing-and>. The Federal Register notice set a deadline of February 17, 2017 for participant comments.

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

1. Comment BP1816003. Participant Pace expressed three concerns: (1) “BP18 suffers from a problem that goes back to the 2008 fish and wildlife accords: How to equitably allocate the burden between various customer groups of payments to purchase the silence of amici tribes and other litigants in a case BPA is not even party too [sic];” (2) BPA is making “payments to the Northwest Power Council in excess of the Administrator’s statutory authority,” and it is not clear how BPA should equitably allocate spending that violates the Northwest Power Act; and (3) BPA is violating the procedural requirements of the Northwest Power Act by “distinguishing between parties and participants and then preventing participants from exercising their right to comment, cross examine, etc.”

Response to Comment BP1816003. BPA assumes that the first concern stated in Mr. Pace’s comments refers to the Columbia Basin Fish Accords that BPA signed in 2008 with tribes, states, and other Federal agencies. The Accords, however, are not an effort to purchase the silence of any stakeholder. The Accords brought together Federal agencies, states, and tribes to achieve desirable and statutorily required biological objectives for fish. BPA decided to participate in the Accords after thoughtful consideration of many factors, including comments from interested persons and organizations. BPA’s reasons for entering into the Accords are set forth in a record of decision: https://www.bpa.gov/news/pubs/PastRecordsofDecision/2008/MOA_ROD.pdf. The costs of expenditures made pursuant to the Accords are included in the revenue requirement used to develop BPA’s wholesale power rates and are recovered from customers paying those rates.

BPA disagrees with Mr. Pace’s comment that BPA is making excess payments to the Council in violation of the Northwest Power Act or otherwise in excess of the Administrator’s statutory authority. Mr. Pace does not sufficiently explain his claim to allow BPA to evaluate or respond to it; *i.e.*, Mr. Pace does not explain why BPA’s payment of the Council’s costs would be unlawful. BPA funds the Council as mandated by the Northwest Power Act, and Council

funding is a BPA cost determined outside BPA's rate cases. BPA is not making payments in violation of the law, and the concern about the allocation of such costs is inapposite.

With respect to Mr. Pace's third comment, the Northwest Power Act requires a hearing officer to conduct a hearing to "develop a full and complete record and to receive public comment in the form of written and oral presentation of views, data, questions, and argument related to such proposed rates." 16 U.S.C. § 839e(i)(2). However, the Administrator has discretion to create the procedural rules for ratemaking proceedings. There are millions of potential participants in the Pacific Northwest region. It would be unwieldy and administratively burdensome to allow participants to take part in the hearing and to conduct cross-examination, particularly where they lack the training necessary to participate in a formal evidentiary hearing. 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.

2. Comment BP18160004. Participant McPherson previously requested information at a meeting in Boise, Idaho and is again requesting the following information: "For the following years, what is the actual cost per megawatt hour for each Dam? Not the price to customers. The actual total cost to taxpayers before sales of megawatt hours. What is the nameplate capacity of each dam? What is the actual capacity factor for each dam for years [2000–2016]?" The comments also expressed concern that some ratepayers are essentially charged twice for electricity because they are taxpayers as well.

Response to Comment BP18160004. The process for submitting participant comments is intended to provide an opportunity for persons that are not parties to the rate case to provide feedback on BPA's rate proposal. The process is not intended as an avenue for participants to request information. Participants are free to file requests for information with BPA outside of the BP-18 rate proceeding.

The Northwest Power Act requires the Administrator to set rates that recover BPA's costs. Comments about taxpayer equity are outside the scope of this proceeding.

3. Comment BP18160008. The Montana Public Service Commission (Commission) filed a participant comment stating that "BPA should eliminate the Eastern Intertie rate (IM rate) that applies to the 90-mile, Townsend-to-Garrison segment of the Colstrip 500-kV line, and instead charge BPA's network rate for transmission service starting at Townsend." The Commission stated:

The presence of unsubscribed BPA capacity over an otherwise frequently congested transmission path (Path 8) during such a considerable span of time provides prima facie evidence of an uneconomic rate. The Commission submits that the marginal cost of making this capacity available to a long-term subscriber is approximately zero. Virtually any revenue that BPA receives for this capacity would exceed its marginal cost. While utility regulators must also consider the necessity of covering the embedded costs of such transmission investment in ratemaking, the Commission regards that this consideration is not a prerequisite to BPA's ratemaking decision here, because a contractual provision exists to cover

all of the intertie's revenue requirement through the Montana Intertie Users' transmission agreement. Rates should therefore, with this safeguard in place, be set at marginal cost; in other words, the IM rate should be eliminated.

(Footnote omitted.) In addition, the Commission suggests that "any collections in excess of the revenue requirement should be refunded to the Montana Intertie Users and, thus, their customers." The Commission recognizes other factors at play but asks that the IM rate issue be regarded on its own merits and provides arguments against the assertion that "a Network roll-in of the Eastern Intertie would set a precedent for rolling in the Southern Intertie."

Response to Comment BP18160008. These issues have been litigated in the BP-18 rate proceeding and are addressed in Section 5.2.1 of this Final ROD.

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8.0 NATIONAL ENVIRONMENTAL POLICY ACT ANALYSIS

Consistent with the National Environmental Policy Act (NEPA), 42 U.S.C. § 4321, *et seq.*, BPA has assessed the potential environmental effects that could result from implementation of BPA's FY 2018–2019 proposed power and transmission rate adjustments (BP-18). The NEPA analysis was conducted separately from the formal ratemaking process.

In the Federal Register notice for the BP-18 rate adjustment proposal, BPA provided interested persons the opportunity to submit public comments concerning potential environmental effects of the proposal, which would be considered by BPA's NEPA compliance staff in the NEPA process for the proposal. 81 Fed. Reg. 78,999, 79,003 (2016). No comments concerning NEPA compliance or potential environmental effects of the proposal were received before the comment deadline of February 17, 2017.

The decision to implement the proposed rate adjustments is primarily administrative and financial in nature. The rate proposal also largely continues the same rate construct as in previous years, albeit at adjusted rate levels as described elsewhere in this Final ROD. As such, its implementation is not expected to result in reasonably foreseeable environmental effects. Furthermore, the proposal involves changes to BPA's rates to ensure that there are sufficient revenues to meet BPA's financial obligations and other costs and expenses, while using existing generation sources operating within normal limits.

Accordingly, BPA has determined that the BP-18 rate adjustment proposal falls within a class of actions excluded from further NEPA review pursuant to U.S. Department of Energy NEPA regulations, which are applicable to BPA. More specifically, this proposal falls within Categorical Exclusion *B4.3 Electric power marketing rate changes*, found at 10 C.F.R. § 1021, Subpart D, Appendix B, which provides for the categorical exclusion from further NEPA review of “[r]ate changes for electric power, power transmission, and other products or services provided by a Power Marketing Administration that are based on a change in revenue requirements if the operations of generation projects would remain within normal operating limits.” BPA has prepared a categorical exclusion determination memorandum that documents this categorical exclusion from further NEPA review, which is available at BPA's website: <https://www.bpa.gov/efw/Analysis/CategoricalExclusions/Pages/2017.aspx>.

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9.0 CONCLUSION

As required by law, the rates established and adopted in this Final Record of Decision have been set to recover the costs associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the FCRPS (including irrigation costs required to be repaid out of power revenues) over a reasonable period of years and the other costs and expenses incurred by the Administrator in carrying out the requirements of the Northwest Power Act and other provisions of law. In addition, these rates have been designed to be the lowest possible rates consistent with sound business principles, to encourage the widest possible use of BPA's power, and to satisfy BPA's other ratemaking obligations. The transmission and ancillary services rates have been designed to equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing such system. Finally, all interested parties and participants were afforded the opportunity for a full and fair evidentiary hearing, as required by law.

BPA has established its rates pursuant to Section 7(i) of the Northwest Power Act. Consistent with NEPA, BPA has evaluated the potential environmental impacts that could result from implementation of the FY 2018–2019 proposed power and transmission rate adjustments.

Based upon the record compiled in this proceeding, the decisions expressed herein, and all requirements of law, I hereby adopt the accompanying 2018 Power Rate Schedules and General Rate Schedule Provisions and the 2018 Transmission, Ancillary and Control Area Service Rate Schedules and General Rate Schedule Provisions as final Bonneville Power Administration rates. In accordance with Federal Energy Regulatory Commission requirements, 18 C.F.R. § 300.10(g), I hereby certify that the power and transmission rate schedules and GRSPs adopted herein contain the lowest possible rates consistent with sound business principles and are consistent with other applicable laws.

Issued at Portland, Oregon, this 26th day of July, 2017.

/s/Elliot E. Mainzer

Elliot E. Mainzer

Administrator and Chief Executive Officer

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Appendix A

Financial Reserves Policy

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FINANCIAL RESERVES POLICY

1. Background and Purpose

The Financial Reserves Policy (Policy) provides a consistent, transparent, and financially prudent method for determining BPA's target ranges for financial reserves available for risk (financial reserves). The Policy establishes upper and lower financial reserves thresholds for Power Services, Transmission Services, and the agency as a whole, which define the target ranges. The Policy also describes the actions BPA may take when financial reserves levels either fall below a lower threshold or exceed an upper threshold. The Policy supports BPA's requirement to establish the lowest possible rates consistent with sound business principles.

Prior to the Policy, BPA did not have a consistent way to establish financial reserves target ranges and upper and lower financial reserves thresholds for each business line and BPA. This is of particular importance because financial reserves levels and financial reserves policies and practices have a direct effect on BPA's credit rating, which is determined at the aggregate BPA level. BPA, however, sets rates to recover costs for each business line individually. The lack of a consistent policy across the business lines and for BPA as a whole allows for *ad hoc* financial reserves decisions and different treatment for each business line.

Establishing prudent financial reserves lower thresholds over time for the business lines helps to maintain BPA's credit rating, solvency, and rate stability, which is consistent with sound business principles. Establishing prudent financial reserves upper thresholds for the business lines and BPA as a whole ensures that financial reserves do not grow to unnecessarily high levels but rather are invested back into the business or distributed as rate reductions, both of which lower revenue requirement costs.

2. Scope of the Financial Reserves Policy

The Policy affects financial reserves available for risk (financial reserves) attributed to Power Services (Power) and Transmission Services (Transmission).

The Policy establishes lower and upper financial reserves thresholds for Power Services and Transmission Services, and upper financial reserves thresholds for the agency at the ends of fiscal years. The Policy also provides guidance on the actions BPA should take when financial reserves fall below established lower threshold levels or rise above established upper threshold levels at the ends of fiscal years.

The Policy does not preclude or hinder in any way the Administrator's authority to use financial reserves for purposes deemed necessary by the Administrator.

The Policy is intended to provide a consistent framework within which BPA can manage its financial reserves. To that end, the Policy will constitute precedent that BPA will adhere to in future rate cases absent a determination by the Administrator that the Policy must be modified to meet BPA's changing operating environment.

3. Financial Reserves Thresholds

3.1 Definitions

Financial reserves available for risk. Financial reserves available for risk (financial reserves) consist of cash, market-based special investments, and deferred borrowing, all of which are highly liquid and unobligated for BPA to use to mitigate financial risk, less any outstanding balance on the Treasury Facility.

Days Cash on Hand Metric. Days cash on hand is the number of days a business can continue to operate using its own cash on hand with no new revenue. Days cash on hand is a common industry liquidity metric measuring the relationship between the amount of cash a business holds and the amount of average daily expenses incurred in operating the business.

3.2 Business Line Financial Target Ranges

Financial reserves target ranges for each business line shall be calculated independently each rate period, and consist of upper and lower financial reserves thresholds, which define the upper and lower ends of the target ranges.

3.3 Lower Financial Reserves Thresholds

Lower financial reserves thresholds shall be calculated independently for Power and Transmission each rate period based on the greater of: (1) 60 days cash on hand, and (2) what is necessary to meet the Treasury Payment Probability Standard. For each business line, if financial reserves fall below the lower threshold, a rate action shall trigger the following fiscal year to recover, in part or in whole, the shortfall.

3.4 Upper Financial Reserves Thresholds

Upper financial reserves thresholds shall be calculated independently for Power and Transmission each rate period and will be the financial reserves' equivalent of 60 days cash on hand above the lower financial reserves thresholds. The agency upper threshold is the sum of Power and Transmission's lower thresholds plus 30 days cash on hand for the agency.

3.4.1 Financial Reserves Distributions

If business line financial reserves and agency financial reserves are above their respective upper thresholds, the Administrator shall consider the above-threshold financial reserves for investment in other high-value business line-specific purposes including, but not limited to, debt retirement, incremental capital investment, or rate reduction.

3.5 Calculation of Lower and Upper Financial Reserves Thresholds

3.5.1 - Power Services		
Power lower financial reserves threshold	=	The greater of: (1) 60 days * (Power operating expenses / 365 days), and (2) the threshold needed to achieve a 95% TPP.
Power upper financial reserves threshold	=	Power lower financial reserves threshold plus 60 days * (Power operating expenses / 365 days)
<i>Where:</i>		
Power operating expenses	=	Power total expenses – (Power depreciation and amortization + Power net interest expense + Power non-federal debt service + Power purchases)

3.5.2 - Transmission Services		
Transmission lower financial reserves threshold	=	The greater of: (1) 60 days * (Transmission operating expenses / 365 days), and (2) the threshold needed to achieve a 95% TPP.
Transmission upper financial reserves threshold	=	Transmission lower financial reserves threshold plus 60 days * (Transmission operating expenses / 365 days)
<i>Where:</i>		
Transmission operating expenses	=	Transmission total expenses – (Transmission depreciation & amortization + Transmission net interest expense)

3.5.3 - Agency		
Agency upper financial reserves threshold	=	The sum of the Power lower financial reserves threshold and the Transmission lower financial reserves threshold plus 30 days cash on hand for the agency
<i>Where:</i>		
30 days cash on hand for the agency	=	30 days * (agency operating expenses / 365 days)
Agency operating expenses	=	Power operating expenses + Transmission operating expenses

4. Implementation

4.1 Overview

The Policy will be implemented each rate period through the Power and Transmission rate schedules and GRSPs. The lower and upper financial reserves thresholds for each business line will be recalculated each time BPA establishes new Power and Transmission rates. Lower and upper financial reserves thresholds will remain constant throughout each rate period. Lower and upper financial reserves thresholds will be computed using forecast rate period average operating expenses from the Power and Transmission revised revenue tests.

Except as noted in Section 4.2, implementation shall include parallel Cost Recovery Adjustment Clauses (CRAC) (or equivalent rate mechanisms) for each business line each rate period that will trigger if financial reserves are below the lower financial reserves thresholds. Implementation shall also include development of parallel Reserves Distribution Clauses (RDCs) (or equivalent rate mechanisms) for each business line each rate period that will trigger if financial reserves are above upper financial reserves thresholds.

The specifics of how the Power and Transmission CRACs (or equivalent rate action) recover shortfalls are not limited by this policy.

4.2 Financial Reserves Policy Phase-in Provision for Power

The CRAC is the rate mechanism BPA expects to use to adjust rates to increase financial reserves when they are below the lower financial reserves threshold. In the long term, the Power lower financial reserves threshold would determine the point at which the Power CRAC triggers, and thus the Power lower financial reserves threshold would be the same as the Power CRAC threshold.

To mitigate the risk of very large Power rate increases if the Power CRAC threshold were to increase to the lower threshold in one rate period, the increase in the Power CRAC threshold from the BP-16 value of \$0 to the Power lower financial reserves threshold will be phased in, unless an increase is necessary to achieve the 95 percent TPP standard. The rate action for Power during the phase-in will use two mechanisms:

- (1) \$20 million of PNRR per year in the revenue requirement used to set Power rates, and
- (2) a methodology for increasing the Power CRAC threshold to the lower financial reserves threshold.

4.2.1 \$20 Million per Year of PNRR

The Power revenue requirement will include \$20 million of PNRR per year, until the Power CRAC threshold has been increased to the Power lower financial reserves threshold.

4.2.2 Methodology for Increasing the Power CRAC Threshold

The methodology for increasing the Power CRAC threshold to the Power lower threshold will be discussed in a public process between the BP-18 and BP-20 rate proceedings. When the Power CRAC threshold has been increased to the Power lower threshold value, the \$20 million per year of PNRR will be discontinued. One potential option for the methodology is a ratchet (or more than one) which would describe financial reserves levels that, if exceeded, would trigger an increase in the CRAC threshold for the next rate period. The phase-in will not modify any upper or lower thresholds.

Appendix B

BP-18 Generation Inputs And Transmission Ancillary And Control Area Services Rates Settlement

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**BP-18 Generation Inputs and Transmission Ancillary and Control Area Services Rates
Settlement Agreement**

THIS SETTLEMENT AGREEMENT, including Attachments 1, 2, and 3 (“AGREEMENT”), dated and effective as of the date established pursuant to section 3 of this Agreement, is among the Bonneville Power Administration (“Bonneville”) and the BP-18 rate case parties (in the singular, “Party,” in the plural, “Parties”).

WHEREAS

- A. Starting in January 2016, Bonneville and the Parties have been engaged in public meetings to reach agreement on the rates for certain transmission ancillary and control area services for the FY 2018-2019 Rate Period (“Rate Period”);
- B. Bonneville and the Parties wish to settle their disputes concerning generation inputs and transmission ancillary and control area services rates for the Rate Period;
- C. Bonneville and the Parties recognize that both the rate structure and the operations related to the integration of variable energy resources and dispatchable energy resources in Bonneville’s balancing authority area are in a transitional period; that there is considerable disagreement about how to design Bonneville’s transmission ancillary and control area services rates, terms and conditions; and that there is disagreement about the allocation of balancing reserve capacity and energy costs; and
- D. The purpose of this Agreement is to settle those differences for the Rate Period, without precedent for subsequent rate periods, so that Bonneville and the Parties can work collaboratively on developing operational tools, terms and conditions, and proposals for rates and the allocation of costs for the services necessary to balance the system in future rate periods.

NOW, THEREFORE, Bonneville, the undersigned Party signatories (“Party Signatories”), and Parties who otherwise indicate assent to this Agreement by not objecting to this Agreement or the Settlement Proposal (as defined in section 1) on the record of the BP-18 rate proceeding pursuant to section 3 (“Non-Objecting Parties”, and collectively with the Party Signatories, the “Assenting Parties”) agree to the following:

- 1. In the BP-18 rate proceeding, Bonneville staff will propose that the Administrator adopt a proposal to establish the costs of generation inputs and rates for transmission ancillary and control area services for the Rate Period (“Settlement Proposal”). The Settlement

Proposal will include only the terms specified in Attachment 1, the rate schedules and general rate schedule provisions specified in Attachment 2, the terms in Attachment 3, and the terms of this Agreement.

2. During the Rate Period, Bonneville and the Assenting Parties will abide by the terms specified in this Agreement.
3. Bonneville will notify the Hearing Officer of the Agreement and move the Hearing Officer to: (1) require any Party that did not sign or assent to the Agreement to state its objection to the Settlement Proposal, the basis for its objection, and to identify each issue included in the Settlement Proposal that such Party chooses to preserve in the BP-18 rate proceeding within 5 days of the date interventions are granted in the rate proceeding; and (2) specify that any Party that does not state its objection to the Settlement Proposal on such date will waive its rights to preserve any objections to the Settlement Proposal and shall be treated as an Assenting Party for all purposes under this Agreement and on the record in the BP-18 rate proceeding. Unless this Agreement terminates under the terms set forth in sections 4 and 5 below, this Agreement will become effective on November 10, 2016, and will terminate on September 30, 2019. If a Party has not preserved any issues originally through an objection to the Settlement Proposal, the Party waives its right to preserve such issue.
4. If, in response to the Hearing Officer's order made pursuant to section 3, any Party states an objection to the Settlement Proposal, Bonneville or any Assenting Party will have three business days from the date of the objection to withdraw its assent to the settlement. If Bonneville or any Assenting Party withdraws its assent to the settlement, Bonneville shall promptly meet with any other interested rate case parties to discuss how to proceed.
5. If the Administrator does not adopt the Settlement Proposal in the BP-18 Final Record of Decision, this Agreement and the Settlement Proposal will terminate upon the date the Administrator declines to adopt the Settlement Proposal.
6. Waiver
 - a. Preservation of BP-18 ACS Rates and Settlement Proposal
 - i. The Parties agree that this is a black box settlement. If the Administrator adopts the Settlement Proposal, Bonneville and the Assenting Parties

agree not to contest this Agreement or its implementation pursuant to its terms, including the Settlement Proposal and rates and rate schedule provisions in Attachment 2, from the effective date through September 30, 2019.

- ii. The Assenting Parties agree to waive their rights to cross-examination and discovery with respect to the Settlement Proposal, except in response to issues raised by any party in the BP-18 rate proceeding that is not an Assenting Party to this Agreement.

b. No Precedent or Issue Preclusion beyond the Rate Period

- i. Bonneville and the Assenting Parties understand, and will not argue otherwise, that this Agreement does not constitute consent or agreement in any future rate proceedings to the transmission ancillary and control area services rates and rate schedule provisions in Attachment 2 or to any rate, charge, or rate schedule provision, and that they retain all of their rights to take and argue whatever position they believe appropriate as to such proceedings; and
- ii. The Assenting Parties and Bonneville acknowledge that this Agreement is a package, and that acceptance of the package does not create or imply any agreement with individual components of the package. Therefore, the Assenting Parties and Bonneville agree that they will not assert in any forum that anything in the Settlement Proposal, or that any action taken or not taken with regard to this Agreement by any Assenting Party, the Hearing Officer, the Administrator, the Federal Energy Regulatory Commission (“Commission”), or a court, creates or implies: (1) any procedural or substantive precedent; (2) agreement to any particular or individual treatment of costs, expenses, or revenues; (3) agreement to any particular interpretation of Bonneville’s statutes; (4) any precedent under any contract or otherwise between Bonneville and any Party; or (5) any basis for supporting any Bonneville rate, terms or conditions for any period after the Rate Period.

7. Reservation of rights

- a. Except as provided in section 6(a) above, no Assenting Party waives any of its rights, under Bonneville’s enabling statutes, the Federal Power Act, or other applicable law, or to pursue dispute resolution procedures consistent with Bonneville’s open access transmission tariff, or to pursue any claim that a particular charge, methodology, practice, or rate schedule has been improperly implemented.
 - b. Bonneville and the Assenting Parties reserve the right to respond during the Rate Period to any new filings, protests, or claims, by Bonneville or others; however, Bonneville and the Assenting Parties will not support a challenge to any rates, terms and conditions, or other matters described in this Agreement.
8. If because of a legal challenge, Bonneville is otherwise required to materially modify or discontinue the rates, terms, and conditions provided in this Agreement, Bonneville will seek, and the Assenting Parties agree to support, or not contest, a stay of enforcement of that ruling until after the Rate Period.
9. Attachment 1 (Rate Period Terms), Attachment 2 (Transmission Ancillary and Control Area Services Rate Schedules and General Rate Schedule Provisions) and Attachment 3 (Inter-Business Line Allocations) are part of this Agreement.
10. Section 6(b) (No Precedent or Issue Preclusion beyond the Rate Period) of this Agreement will survive termination or expiration of this Agreement.
11. Nothing in this Agreement is intended in any way to alter the Administrator’s authority and responsibility to periodically review and revise the Administrator’s rates or the Assenting Parties’ rights to challenge such revisions.

This Agreement may be executed in counterparts.

[Print Party Name]

By: _____

Name: _____

(Print/Type)

Title: _____

Date: _____

ATTACHMENTS

Attachment 1, Rate Period Terms

Attachment 2, Transmission Ancillary and Control Area Services Rate Schedules and General Rate Schedule Provisions

Attachment 3, Inter-Business Line Allocations

ATTACHMENT 1, RATE PERIOD TERMS

1. **Term.** The terms and conditions in this Attachment 1 will apply to and will be binding on Bonneville and the Assenting Parties during the Fiscal Year (FY) 2018-2019 Rate Period (“Rate Period”), but must expire and not survive in any form after September 30, 2019.
2. **Imbalance Service.** Bonneville shall attempt to provide an imbalance service based on the incremental (*inc*) and decremental (*dec*) reserve quantities needed to support Bonneville’s 99.7% planning standard. This is estimated to be less than 110 curtailment events in a year.
3. **Dec Reserve.** Bonneville will use reasonable efforts to provide *dec* balancing reserve capacity consistent with Bonneville’s 99.7% planning standard from the Federal Columbia River Power System (“FCRPS”) during all hours of the Rate Period. Bonneville and the Assenting Parties acknowledge that operational constraints and significant energy imbalance accumulations during operationally constrained periods of the year may limit Bonneville’s ability to provide *dec* balancing reserve capacity from the FCRPS at times during the Rate Period. Bonneville shall not make any *dec* balancing reserve capacity acquisitions unless Bonneville determines *dec* balancing reserve capacity acquisitions are necessary to maintain system reliability.
4. **Inc Reserve.** Bonneville will use reasonable efforts to provide *inc* balancing reserve capacity consistent with Bonneville’s 99.7% planning standard, as described in section 2 of this Attachment 1, from the FCRPS during all hours of the Rate Period. Bonneville is not obligated to provide more than the *inc* balancing reserve capacity amount as calculated with Bonneville’s 99.7% planning standard. To the extent Bonneville cannot meet the capacity amount consistent with the 99.7% planning standard from the FCRPS, Bonneville will use reasonable efforts to acquire third-party sources to meet the 99.7% planning standard at Transmission Services’ expense, taking into account the following factors in making such acquisitions :
 - a. availability of *inc* balancing reserve capacity;
 - b. cost of acquired *inc* balancing reserve capacity;
 - c. reserve needs; and
 - d. operational impacts during the affected timeframe.
5. **Inter-Business Line Allocations.**
 - a. *Inc* balancing reserve capacity provided from the FCRPS will be at a cost of \$0.305/kW/day. Power Services shall be compensated only for *Inc* balancing reserves provided.
 - b. The cost of *Dec* balancing reserve capacity provided from the FCRPS is included in the cost of *Inc* balancing reserve capacity.
 - c. Transmission Services shall be responsible for 3.48 percent of the Power Cost Recovery Adjustment Clause, Dividend Distribution Clause, and National Marine Fishery Service Federal

Columbia River Power System Biological Opinion (“NFB”) Mechanisms (the NFB Adjustment and the Emergency NFB Surcharge), however designated. Such amount will apply to the capacity-based rates specified in section 9 of this Attachment 1.

- d. The rates under this Agreement are based on the assumption that Bonneville’s power revenue requirement will not contain Planned Net Revenues for Risk or any risk mitigation tool that: (1) supports Bonneville’s power Treasury Payment Probability; (2) supports Bonneville’s credit rating; or (3) enhances Bonneville’s financial strength or financial standing by improving Bonneville’s cash position (“Risk Mitigation Tool” or “RMT”). If Bonneville adopts any RMT in its overall power revenue requirement as determined in the BP-18 Final Proposal, then Transmission Services shall be responsible for 3.48 percent of such RMT. Such amount will be allocated to capacity-based Ancillary and Control Area Service rates pursuant to section 9 of this Attachment 1. Variable Energy Resource Balancing Service for Wind, Variable Energy Resource Balancing Service for Solar, and Dispatchable Energy Resource Balancing Service are exempt.
 - e. Bonneville and Assenting Parties agree to the Inter-Business Line Allocations described in Attachment 3.
 - f. Transmission Services will pay Power Services an additional \$700,000 per year in exchange for a lower ACS risk share. This additional amount is reflected in the Variable Energy Resource Balancing Service and Dispatchable Energy Resources Balancing Service rates in section 8 of this Attachment 1.
6. **Intentional Deviation.** One Hundred Percent (100%) of the revenue that Bonneville receives through the Intentional Deviation Charge shall remain with Transmission Services. Revenue that Bonneville receives from Energy Imbalance (“Elrev”), Generation Imbalance (“Glrev”), and Persistent Deviation (“PDrev”) will be split between Power Services and Transmission Services. Power Services’ share (“PSshare”) in such revenue will equal:

$$PSshare = [Elrev + Glrev + PDrev] - \sum Hr3PSD \times HrIndex$$

Where:

Hr3PSD = The MWh amount of third-party *inc* balancing reserve capacity deployed each hour.

HrIndex = The hourly energy index in the Pacific Northwest during the hour when the third-party *inc* balancing reserve capacity was deployed.

7. **Revenue Credit.** Power Services will set power rates with the revenue credit expectation that all planned *inc* balancing capacity will be sourced from the FCRPS.

8. **Settlement Rates.** The following are the settlement rates prior to any rate adjustments in section 9 of this Attachment 1:

Service	Monthly Rates
Variable Energy Resource Balancing Service (VERBS) 30/15 Committed	\$0.71/kW of nameplate
VERBS 30/60 Committed	\$1.01/kW of nameplate
VERBS Uncommitted	\$1.22/kW of nameplate
VERBS CSGI	\$0.49/kW of nameplate
VERBS Solar 15-Minute	\$0.21/kW of nameplate
VERBS Solar Hourly	\$0.28/kW of nameplate
Dispatchable Energy Resource Balancing Service (DERBS) Inc	20.42 mills/kW
DERBS Dec	3.43 mills/kW
Regulation and Frequency Response	0.13 mills/kWh
Operating Reserve - Spinning	11.82 mills/kWh
Operating Reserve – Spinning default	13.59 mills/kWh
Operating Reserve - Supplemental	9.76 mills/kWh
Operating Reserve – Supplemental default	11.22 mills/kWh

9. **Adjusting Settlement Rates.** The ancillary and control area service rates listed below will increase to collect each rate’s percentage share of Transmission Services’ 3.48 percent amount of any rate or revenue requirement adjustment made under sections 5.c and 5.d of this Attachment 1. The rates will increase based on the following table:

Rates	Percent Share
Regulating and Frequency Response Service	0.38%
Operating Reserve - Spinning	1.55%
Operating Reserve - Supplemental	1.55%

10. **Solar Technical Work.** By January 2018, Bonneville will study and produce analysis on solar integration in Bonneville’s Balancing Authority Area (BAA), though this is not a commitment to conduct a comprehensive integration study. The intent of Bonneville’s analytical work will be to enhance Bonneville’s current methodology and inform Bonneville and stakeholders prior to workshops leading to the BP-20 Initial Proposal. This analytical work will include:

- a. A focus on the unique characteristics of integrating solar energy generation in Bonneville’s BAA contrasted to that of wind energy in the Bonneville BAA.
- b. The creation of a robust synthetic solar generation data set representative of a prospective geographically diverse build out of solar generation in Bonneville’s BAA, forecasted based on the growth of Bonneville’s interconnection queue through FY2025 as it exists on July 1, 2017 and through utilization of the University of Oregon’s Solar Radiation Monitoring Laboratory datasets.

- c. Analysis of the impacts on balancing reserves necessary to integrate solar energy in Bonneville's BAA with regards to solar scheduling best practices and geographic diversity benefits as shown in section 10(b) of this Attachment 1.

Bonneville will also hold stakeholder workshop(s) regarding solar generation prior to the BP-20 Initial Proposal to discuss (1) potential actions that can be taken by generators and Bonneville to reduce the balancing reserve requirement, (2) solar rate design, (3) the impact of the variable cost methodology and the incremental standard deviation methodology on balancing reserves held, and (4) the potential impact of planned reserves held in shaped amounts.

ACS-186
ANCILLARY AND CONTROL AREA SERVICE RATES

SECTION I. AVAILABILITY

This schedule supersedes the ACS-164 rate schedule. It is available to all Transmission Customers taking service under the Open Access Transmission Tariff and other contractual arrangements. This schedule also is available for transmission service of a similar nature that may be ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§ 824j and 824k). Service under this schedule is subject to BPA's General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

A. ANCILLARY SERVICES

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

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

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

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

Ancillary Services available under this rate schedule are:

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

B. CONTROL AREA SERVICES

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

Control Area Services available under this rate schedule are:

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

SECTION II. ANCILLARY SERVICE RATES**C. REGULATION AND FREQUENCY RESPONSE SERVICE**

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

1. RATE

The rate shall not exceed ~~0.130.12~~ mills per kilowatthour.

2. BILLING FACTOR

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

D. ENERGY IMBALANCE SERVICE

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

1. RATES

a. Imbalances Within Deviation Band 1

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

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

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

b. Imbalances Within Deviation Band 2

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

- (1) When energy taken by the Transmission Customer in a schedule period is greater than the energy scheduled, the charge is 110 percent of BPA's incremental cost.
- (2) When energy taken by the Transmission Customer in a schedule period is less than the scheduled amount, the credit is 90 percent of BPA's incremental cost.

c. Imbalances Within Deviation Band 3

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

- (1) When energy taken by the Transmission Customer in a schedule period is greater than the energy scheduled, the charge is 125 percent of BPA's highest incremental cost that occurs during that day. The highest daily incremental cost shall be determined separately for HLH and LLH.
- (2) When energy taken by the Transmission Customer in a schedule period is less than the scheduled amount, the credit is 75 percent of BPA's lowest incremental cost that occurs during that day. The lowest daily incremental cost shall be determined separately for HLH and LLH.

2. OTHER RATE PROVISIONS

a. BPA Incremental Cost

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

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

b. Spill Conditions

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

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

- (1) For negative deviations (energy taken is less than the scheduled energy) within Band 1, no credit will be given.
- (2) For negative deviations (energy taken is less than the scheduled energy) within Band 2, the charge is the energy index for that hour.
- (3) For negative deviations (energy taken is less than the scheduled energy) within Band 3, the charge is the energy index for that hour.

c. Persistent Deviation

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

- (1) No credit is given when energy taken is less than the scheduled energy.
- (2) When energy taken exceeds the scheduled energy, the charge is the greater of (i) 125 percent of BPA's highest incremental cost that occurs during that day, or (ii) 100 mills per kilowatthour.

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

If BPA assesses a persistent deviation penalty charge in any scheduled period for a positive deviation, BPA will not also assess a charge pursuant to section II.D.1. of this ACS-186 schedule.

Reduction or Waiver of Persistent Deviation Penalty

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

E. OPERATING RESERVE – SPINNING RESERVE SERVICE

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

1. RATES

- a. For customers that elect to purchase Operating Reserve – Spinning Reserve Service from BPA, the rate shall not exceed ~~11.82~~~~11.40~~ mills per kilowatthour.
- b. For customers that are required to purchase Operating Reserve – Spinning Reserve Service from BPA because they defaulted on their self-supply or third-party supply obligations, the rate shall be ~~13.59~~~~13.11~~ mills per kilowatthour.

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

- (1) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or
- (2) Return the energy at the times specified by BPA.

2. BILLING FACTORS

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

F. OPERATING RESERVE – SUPPLEMENTAL RESERVE SERVICE

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

1. RATES

- a. For customers that elect to purchase Operating Reserve – Supplemental Reserve Service from BPA, the rate shall not exceed ~~9.76~~10.45 mills per kilowatthour.
- b. For customers that are required to purchase Operating Reserve – Supplemental Reserve Service from BPA because they defaulted on their self-supply or third-party supply obligations, the rate shall be ~~11.22~~12.02 mills per kilowatthour.

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

- (1) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or
- (2) Return the energy at the times specified by BPA.

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

2. BILLING FACTORS

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

SECTION III. CONTROL AREA SERVICE RATES**A. REGULATION AND FREQUENCY RESPONSE SERVICE**

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

1. RATE

The rate shall not exceed ~~0.130.12~~ mills per kilowatthour.

2. BILLING FACTOR

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

B. GENERATION IMBALANCE SERVICE

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

1. RATES

a. Imbalances Within Deviation Band 1

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

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

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

b. Imbalances Within Deviation Band 2

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

of the scheduled amount of energy or (ii) ± 10 MW, whichever is larger in absolute value.

- (1) When energy delivered in a schedule period from the generation resource is less than the energy scheduled, the charge is 110 percent of BPA's incremental cost.
- (2) When energy delivered in a schedule period from the generation resource is greater than the scheduled amount, the credit is 90 percent of BPA's incremental cost.

c. Imbalances Within Deviation Band 3

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

- (1) When energy delivered in a schedule period from the generation resource is less than the energy scheduled, the charge is 125 percent of BPA's highest incremental cost that occurs during that day. The highest daily incremental cost shall be determined separately for HLH and LLH.
- (2) When energy delivered in a schedule period from the generation resource is greater than the scheduled amount, the credit is 75 percent of BPA's lowest incremental cost that occurs during that day. The lowest daily incremental cost shall be determined separately for HLH and LLH.

2. OTHER RATE PROVISIONS

a. BPA Incremental Cost

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

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

b. Spill Conditions

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

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

- (1) For negative deviations (actual generation greater than scheduled) within Band 1, no credit will be given.
- (2) For negative deviations (actual generation greater than scheduled) within Band 2, the charge is the energy index for that hour.
- (3) For negative deviations (actual generation greater than scheduled) within Band 3, the charge is the energy index for that hour.

c. Persistent Deviation for Generation

Persistent Deviation for generation applies to (i) Dispatchable Energy Resources operating in the BPA Balancing Authority Area and (ii) Variable Energy Resources operating in the BPA Balancing Authority Area that are participating in the Customer Supplied Generation Imbalance (“CSGI”) Pilot Program. are not subject to the Intentional Deviation Penalty Charge specified in GRSP II.H.

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

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

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

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

If BPA assesses a Persistent Deviation Penalty charge in any scheduled period for a positive deviation, BPA will not also assess a charge pursuant to section 1 of this ACS-186 Generation Imbalance Service rate schedule.

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

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

Reduction or Waiver of Persistent Deviation Penalty

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

d. No Credit for Negative Deviations During Curtailments

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

e. Exemption from Deviation Band 2

The 10 percent penalty charge under section 1.b., Imbalances Within Deviation Band 2, will not apply to customers participating in a committed 15-minute scheduling program in accordance with the ACS-186 Variable Energy Resources Balancing Service rates, section III.E.2.a.(2) and III.E.3.a.(1).

f. Exemptions from Deviation Band 3

The following resources are not subject to Deviation Band 3:

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

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

C. OPERATING RESERVE – SPINNING RESERVE SERVICE

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

1. RATES

- a. For customers that elect to purchase Operating Reserve – Spinning Reserves from BPA, the rate shall not exceed ~~11.82~~11.40 mills per kilowatthour.
- b. For customers that are required to purchase Operating Reserve – Spinning Reserve Service from BPA because they defaulted on their self-supply or third-party supply obligations, the rate shall be ~~13.59~~13.11 mills per kilowatthour.

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

- (1) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or
- (2) Return the energy at the times specified by BPA.

2. BILLING FACTORS

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

D. OPERATING RESERVE – SUPPLEMENTAL RESERVE SERVICE

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

1. RATES

- a. For customers that elect to purchase Operating Reserve – Supplemental Reserve Service from BPA, the rate shall not exceed ~~9.76~~10.45 mills per kilowatthour.
- b. For customers that are required to purchase Operating Reserve – Supplemental Reserve Service from BPA because they defaulted on their self-supply or third-party supply obligations, the rate shall be ~~11.22~~12.02 mills per kilowatthour.

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

- (1) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or
- (2) Return the energy at the times specified by BPA.

2. BILLING FACTORS

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

E. VARIABLE ENERGY RESOURCE BALANCING SERVICE

1. APPLICABILITY

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

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

2. BALANCING SERVICE FOR WIND RESOURCES

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

a. BALANCING SERVICE RATES

(1) Rate for 30/60 Committed Scheduling

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

- (a) Regulating Reserves ~~\$0.130.08~~ per kilowatt per month
- (b) Following Reserves ~~\$0.42.32~~ per kilowatt per month
- (c) Imbalance Reserves ~~\$0.460.80~~ per kilowatt per month

~~(2) Rate for 40/15 Committed Scheduling~~

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

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

(32) Rate for 30/15 Committed Scheduling

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

- (a) Regulating Reserves \$0.130.08 per kilowatt per month
 (b) Following Reserves \$0.42 0.32 per kilowatt per month
 (c) Imbalance Reserves \$0.16 0.33 per kilowatt per month

(43) Rate for Uncommitted Scheduling

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

- (a) Regulating Reserves \$0.130.08 per kilowatt per month
 (b) Following Reserves \$0.420.32 per kilowatt per month
 (c) Imbalance Reserves \$0.674.08 per kilowatt per month
 (d) ~~Opt Out Fee~~

~~The fee for customers that opt out of the Intentional Deviation Penalty Charge (GRSP II.H) shall be \$0.20 per kilowatt per month.~~

(4) Rate for Customer Supplied Generation Imbalance

This rate is applicable to customers taking Balancing Service under the Customer Supplied Generation Imbalance Pilot Program.

The rate shall be \$0.49 per kilowatt per month.

b. BILLING FACTOR

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

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

(corrected 11/04/2016)

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

- (2) For each wind plant, or phase of a wind plant, for which some but not all units have been installed by the 15th day of the month prior to the billing month, the billing factor will be the maximum measured hourly output of the plant through the 15th day of the prior month in kW.
- (3) For each wind plant, or phase of a wind plant, where none of the units have been installed on or before the 15th of the month prior to the billing month, but some units have been installed before the start of the billing month, the billing factor will be zero.

c. EXCEPTIONS

- (1) The rates under section 2.a. above will not apply to a Variable Energy Resource, or portion of a Variable Energy Resource, that, in BPA's determination, has put in place, tested, and successfully implemented in conformance to the criteria specified in BPA business practices, no later than the 15th day of the month prior to the billing month, the dynamic transfer of plant output out of BPA's Balancing Authority Area to another Balancing Authority Area.
- (2) Individual rate components under section 2.a.(1)-~~(35)~~ above will not apply to a Variable Energy Resource, or portion of a Variable Energy Resource, that, in BPA's determination, has put in place, tested, and successfully implemented in conformance to criteria specified in BPA business practices, no later than the 15th day of the month prior to the billing month, self-supply of that component of Balancing Service, including by contractual arrangements for third-party supply.

3. BALANCING SERVICE FOR SOLAR RESOURCES

The total charge for this service is the applicable rates in section 3.a. below, plus Direct Assignment Charges under section 4 and Intentional Deviation Penalty Charges under section 5.

a. RATES

- ~~(1) — Regulating Reserves \$0.04 per kilowatt per month~~
~~(2) — Following Reserves \$0.17 per kilowatt per month~~

(1) Rate for 30/15 Committed Scheduling

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

\$0.21 per kilowatt per month

(2) Rate for Hourly Scheduling

This rate is applicable to customers taking Balancing Service that do not commit to 30/15 scheduling.

\$0.28 per kilowatt per month

b. BILLING FACTOR

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

c. EXCEPTIONS

See section 2.c. above.

4. DIRECT ASSIGNMENT CHARGES

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

- a. the customer elected to self-supply in accordance with section 2.c. but is unable to self-supply one or more components to Variable Energy Resource Balancing Service; or
- b. the customer has a projected generator interconnection date after FY 201~~97~~, but chooses to interconnect during the FY 201~~86~~–201~~97~~ rate period; or

- c. the customer elected to take service under section 2.a.(1), 2.a.(2), or ~~2.a.(3)~~3.a.(1) above, but fails to conform to the committed scheduling criteria specified in BPA business practices; or
- d. the customer elected to take service under section 2.a.(1), 2.a.(2), or ~~2.a.(3)~~3.a.(1) above, but chooses to take a Balancing Service scheduling option with a longer scheduling period in accordance with the criteria specified in BPA business practices; or
- e. the customer ~~either~~ elected to dynamically transfer its resource out of BPA's Balancing Authority Area, but the resource remains in the BPA Balancing Authority Area after the date specified in the customer election. ~~or has successfully dynamically transferred its resource out of BPA's Balancing Authority Area, but chooses to keep its resource in BPA's Balancing Authority Area.~~

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

Customers that are subject to direct assignment charges will be billed for all costs incurred above ~~\$0.3050~~0.29 per kilowatt-day for any incremental balancing reserve capacity acquisitions. Customers billed for direct assignment charges will also be billed at the applicable VERBS rate in section 2.

5. INTENTIONAL DEVIATION PENALTY CHARGE

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

F. DISPATCHABLE ENERGY RESOURCE BALANCING SERVICE

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

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

1. RATES

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

- a. Incremental Reserves ~~20.42~~^{18.15} mills per kW maximum hourly deviation
- b. Decremental Reserves ~~3.433~~⁹⁴ mills per kW maximum hourly deviation

2. BILLING FACTORS

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

3. EXCEPTIONS

- a. This rate will not apply to a Dispatchable Energy Resource, or portion of a Dispatchable Energy Resource, that, in BPA’s determination, has put in place, tested, and successfully implemented no later than the 15th day of the month prior to the billing month the dynamic transfer of plant output out of BPA’s Balancing Authority Area to another Balancing Authority Area.
- b. This rate will not apply to a Dispatchable Energy Resource, or portion of a Dispatchable Energy Resource, for any schedule period in which the Dispatchable Energy Resource has called on contingency reserve.

- c. This rate will not apply to a Dispatchable Energy Resource, or portion of a Dispatchable Energy Resource, for any hour in which the Dispatchable Energy Resource has been ordered by BPA or a host utility within BPA's Balancing Authority Area to generate at a level different from the schedule or generation estimate that the Dispatchable Energy Resource submitted to BPA for any schedule period during that hour.
- d. Five-minute average station control periods where system frequency deviates by more than 68 mHz shall be excluded from determining the maximum positive (Decremental) or negative (Incremental) value of five-minute station control error for the hour.

4. DIRECT ASSIGNMENT CHARGES

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

- a. the customer elected to self-supply but is unable to self-supply the Dispatchable Energy Resource Balancing Service; or
- b. a customer has a projected generator interconnection date after FY 201~~86~~⁹⁷ but chooses to interconnect during the FY 201~~86~~-201~~87~~⁹⁷ rate period;
- c. a customer operating in another Balancing Authority Area chooses to dynamically transfer into the BPA Balancing Authority Area during the FY 201~~86~~-201~~87~~⁹⁷ rate period; or
- d. the customer elected to dynamically transfer its resource out of BPA's Balancing Authority Area but the resource remains in the BPA Balancing Authority Area after the date specified in the customer election. ~~the customer elected to dynamically transfer its resource out of BPA's balancing authority area, but chooses to keep its resource in the BPA balancing authority area.~~

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

Customers that are subject to direct assignment charges will be billed for all costs incurred above \$~~0.3050~~²⁹ per kilowatt-day for any incremental balancing reserve capacity acquisitions. Customers billed for direct assignment charges will also be billed at the DERBS rates in section 1.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS**A. RATE ADJUSTMENT DUE TO FERC ORDER UNDER FPA § 212**

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

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

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

GENERAL RATE SCHEDULE PROVISIONS

SECTION II. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

G. ~~CRAC, DDC, and NFB Mechanisms~~ Power Risk Mechanisms

[Note: The specific terms, descriptions, and section references will be made consistent with those used in the final BP-18 rates.]

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

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

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

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

- ~~Dispatchable Energy Resource Balancing Service (DERBS)~~

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

1. CUSTOMER CHARGES FOR THE ACS CRAC

The ACS CRAC Amount is the share, in dollars, of the total CRAC Amount that is to be recovered from the ACS rates specified above; the balance of the CRAC Amount is to be recovered from specified Power rates. The ACS CRAC Amount is converted to an ACS CRAC Percentage by dividing the ACS CRAC Amount

by the most recent forecast of revenues for the relevant fiscal year at the ACS rates subject to the CRAC.

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

2. CUSTOMER CREDIT FOR THE ACS DDC

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

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

3. CUSTOMER CHARGES FOR THE ACS EMERGENCY NFB SURCHARGE

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

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

4. CRAC, DDC, AND NFB MECHANISM RATE PROVISIONS

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

H. Intentional Deviation Penalty Charge

1. APPLICABILITY

Except as otherwise provided, the Intentional Deviation Penalty Charge applies to Variable Energy Resources taking service at the ACS-186 Variable Energy Resources Balancing Service rate.

Exceptions:

- ~~a. With 90 days' notice before the start of the applicable billing month, customers taking service at the VERBS rate for uncommitted scheduling can elect to opt out of the Intentional Deviation Penalty Charge for an additional Opt Out Fee (ACS 186 VERBS rate schedule, section III.E.2.a.(4)). The opt-out election will remain in place until the customer elects to change its opt-out election with 90 days' notice before the start of the applicable billing month. Once each fiscal year, a customer can: (1) opt out of the Intentional Deviation Penalty Charge, and (2) change its opt-out election. Customers that opt out of the Intentional Deviation Penalty Charge are subject to the Persistent Deviation for Generation penalty charge as specified in the ACS-186 Generation Imbalance Service rate schedule (section III.B.2.e).~~
- ab. New Variable Energy Resources undergoing testing before commercial operation are exempt from the Intentional Deviation Penalty Charge during testing for up to 90 days.
- be. Customers participating in the Customer Supplied Generation Imbalance ("CSGI") Pilot Program are not subject to the Intentional Deviation Penalty Charge.

2. RATE

For each Intentional Deviation event, the Intentional Deviation Penalty Charge rate shall be \$100 per megawatt-hour (MWh).

An Intentional Deviation event occurs when:

$$\text{ABS}(\text{Intentional Deviation Measurement Value} - \text{Resource Schedule}) > 1$$

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

3. BILLING FACTOR

The Billing Factor in MWh shall be:

$ABS(\text{Intentional Deviation Measurement Value} - \text{Resource Schedule}) - 1$

Multiplied by

Minutes of schedule divided by 60 minutes

Where:

ABS = the absolute value of the term in parentheses.

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

- 1) for wind generating customers taking VERBS under rate schedule section 2.a. at a committed scheduling rate (VERBS rate schedule, sections 2.a.(1)-(3)), the applicable ~~committed~~ schedule value provided by BPA;
- ~~2) for wind generating customers taking VERBS at the uncommitted scheduling rate (VERBS rate schedule, section 2.a.(4)), the 40 minute forecast schedule value produced by the Super Forecast Methodology; or~~
- 23) for solar generating customers taking VERBS under rate schedule section 3.a (section 3), the ~~matrix forecast schedule value or~~ applicable ~~committed~~ schedule value provided by BPA.

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

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

4. OTHER PROVISIONS

Exemption from Intentional Deviation Penalty Charge

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

$$\text{ABS}(\text{Station Control Error}) \leq \text{ABS}(\text{Intentional Deviation Measurement Value Error}) + 1 \text{ MW}$$

Where:

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

GRSP SECTION III. DEFINITIONS

(Note: Numbering of definitions may change for final rate proposal.)

1. Ancillary Services

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

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

Ancillary Services are available under the ACS rate schedule.

2. Balancing Authority Area

See definition in Control Area.

4. Control Area

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

- a. match at all times the power output of the generators within the electric power system(s) and the import of energy from entities outside the electric power system(s) with the load within the electric power system(s) and the export of energy to entities outside the electric power system(s);
- b. maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
- c. maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and
- d. provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

5. Control Area Services

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

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

9. Dispatchable Energy Resource

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

10. Dispatchable Energy Resource Balancing Service

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

11. Dynamic Schedule

See definition in Dynamic Transfer Operating and Scheduling Business Practice.

12. Dynamic Transfer

See definition in Dynamic Transfer Operating and Scheduling Business Practice.

14. Energy Imbalance Service

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

17. Generation Imbalance

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

39. Operating Reserve – Spinning Reserve Service

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

40. Operating Reserve – Supplemental Reserve Service

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

41. Operating Reserve Requirement

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

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

42. Persistent Deviation

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

a. For Generation Imbalance Service only:

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

- (1) both 15 percent of the schedule and 20 MW in each scheduled period for three consecutive hours or more in the same direction;
- (2) both 7.5 percent of the schedule and 10 MW in each scheduled period for six consecutive hours or more in the same direction;
- (3) both 1.5 percent of the schedule and 5 MW in each scheduled period for twelve consecutive hours or more in the same direction; or
- (4) both 1.5 percent of the schedule and 2 MW in each scheduled period for twenty-four consecutive hours or more in the same direction.

b. For Energy Imbalance Service only:

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

- (1) both 15 percent of the schedule and 20 MW in each scheduled period for three consecutive hours or more in the same direction;
- (2) both 7.5 percent of the schedule and 10 MW in each scheduled period for six consecutive hours or more in the same direction;
- (3) both 1.5 percent of the schedule and 5 MW in each scheduled period for twelve consecutive hours or more in the same direction; or
- (4) both 1.5 percent of the schedule and 2 MW in each scheduled period for twenty-four consecutive hours or more in the same direction.

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

50. Regulation and Frequency Response Service

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

62. Spill Condition

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

63. Spinning Reserve Requirement

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

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

64. Station Control Error

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

65. Super Forecast Methodology

The Super Forecast Methodology is an algorithm that selects the best forecast for predicting generation from a particular project based on historical performance. The customer may submit its forecast for use by the methodology and its forecast will be used

if it out-performs the BPA forecast vendors. BPA will deliver the model results to the customer each scheduling period electronically.

66. Supplemental Reserve Requirement

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

72. Variable Energy Resource

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

73. Variable Energy Resource Balancing Service

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

Attachment 3 to the Generation Inputs and Transmission Ancillary and Control Area Services Rates Settlement Agreement

Inter-Business Line Allocations			
	A	B	C
	Generation Inputs	Annual Average for FY 2018-2019 Forecast Quantity (MW)	Annual Average for FY 2018-2019 Revenue Forecast
1	Regulating Reserve	60	\$ 6,794,273
2	Balancing Reserve Capacity for VERBS wind, VERBS solar and DERBS	457	\$ 30,821,241
3	Operating Reserve - Spinning	230.7	\$ 23,851,605
4	Operating Reserve - Supplemental	230.7	\$ 19,706,736
5	Operating Reserve Total	461.3	\$ 43,558,341
6	Synchronous Condensing		\$ 1,272,635
7	Generation Dropping		\$ 589,232
8	Redispatch		\$ 225,000
9	Segmentation of COE/Reclamation Network and Delivery Facilities		\$ 8,867,000
10	Station Service		\$ 1,996,009
11	Generation Inputs Total		\$ 94,123,730

[The Inter-Business Line Allocations were updated for the balancing service elections and the Operating Reserve elections in April and May 2017. The amounts used in the Final Proposal are shown in Table 9.9, Power Rates Study Documentation, BP-18-FS-BPA-01A.]

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BP-18 Rate Proceeding

**ADMINISTRATOR'S FINAL
RECORD OF DECISION**

Appendix C: Power Rate Schedules and
General Rate Schedule Provisions

BP-18-A-04-AP03

July 2017



BONNEVILLE POWER ADMINISTRATION
2018 POWER RATE SCHEDULES
AND GENERAL RATE SCHEDULE PROVISIONS

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POWER RATE SCHEDULES

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POWER RATE SCHEDULES

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SCHEDULE PF-18 PRIORITY FIRM POWER RATE

1. Availability

This schedule is available for the contract purchase of Firm Requirements Power by public bodies, cooperatives, and Federal agencies pursuant to Section 5(b) of the Northwest Power Act. 16 U.S.C. § 839c(b). Firm Requirements Power may be purchased for use within the Pacific Northwest by public bodies, cooperatives, and Federal agencies for resale to ultimate consumers; for direct consumption; and for Construction, Test and Start-Up, and Station Service.

This schedule is also available for the contract purchase of Residential Exchange Program Power by utilities participating in the Residential Exchange Program under Section 5(c) of the Northwest Power Act. 16 U.S.C. § 839c(c). Purchases are made pursuant to a Residential Purchase and Sale Agreement or Residential Exchange Program Settlement Implementation Agreement.

With the exception of sales under the Residential Exchange Program, transmission and ancillary services for use of the Federal Columbia River Transmission System facilities shall be charged separately under the applicable rate schedules.

Effective October 1, 2017, this rate schedule supersedes the PF-16 rate schedule. Sales under the PF-18 rate schedule are subject to the General Rate Schedule Provisions (GRSPs). For sales under this rate schedule, bills shall be rendered and payments due pursuant to the GRSPs and billing process.

2. Priority Firm Public Rate

The PF Public Rate is applicable to the sale of Firm Requirements Power under CHWM Contracts for Load Following, Block, and Slice/Block power products.

2.1 Tier 1 Charges

Tier 1 charges for each customer include two of three Customer charges, a Demand charge, and a Load Shaping charge.

2.1.1 Customer Charges

The Customer Charges are applicable to customers that purchase the following products: Load Following, Block, and Slice/Block.

2.1.1.1 Customer Rates

The monthly Composite, Non-Slice, and Slice Customer rates are specified in the following table:

	<i>Customer Charge Rate in dollars per percentage point of billing determinant</i>		
	<i>Composite</i>	<i>Non-Slice</i>	<i>Slice</i>
Customer Rate	2,123,112	(298,634)	0

2.1.1.2 Customer Billing Determinants

The Composite, Non-Slice, and Slice Customer billing determinants are specified in the following table:

	<i>Customer Charge Billing determinant for each rate</i>		
	<i>Composite</i>	<i>Non-Slice</i>	<i>Slice</i>
Load Following	TOCA	TOCA	N/A
Block only	TOCA	TOCA	N/A
Block portion of Slice/Block	Non-Slice TOCA	Non-Slice TOCA	N/A
Slice portion of Slice/Block	Slice %	N/A	Slice %

N/A = Not Applicable

Where:

TOCA = Tier 1 Cost Allocator, expressed as a percentage

For each customer for each Fiscal Year of the Rate Period, the TOCA shall be calculated according to the following formula:

$$\frac{\text{Minimum of the Customer's:} \\ \text{a) RHWM, or} \\ \text{b) Forecast Net Requirement for each Fiscal Year}}{\text{Sum of all Customers' RHWMs}} \times 100$$

The TOCA for a Joint Operating Entity (JOE) is the sum of the TOCAs of the individual members of the JOE.

All customer TOCAs shall be posted on the BPA website. A customer's TOCA may be revised pursuant to the TOCA Adjustment, GRSP II.G.

Slice % = The Slice percentage for the relevant Fiscal Year as specified in Exhibit K of the Slice customer's CHWM Contract.

Non-Slice TOCA = TOCA minus Slice %, expressed as a percentage.

A customer's Non-Slice TOCA may be revised pursuant to the TOCA Adjustment, GRSP II.G.

2.1.2 Demand Charge

The Demand Charge is applicable to customers that purchase the following products: Load Following and Block with Shaping Capacity.

2.1.2.1 Demand Rate

<i>Month</i>	<i>Rate in \$/kW</i>
October	10.45
November	10.65
December	11.83
January	11.45
February	11.15
March	9.28
April	7.68
May	6.49
June	6.92
July	9.63
August	10.98
September	10.91

2.1.2.2 Demand Billing Determinant

The Demand billing determinant for each billing month equals:

$$\textit{Tier 1 CSP} - \textit{aHLH} - \textit{CDQ} - \textit{SuperPeak}$$

Where:

Tier 1 CSP = Tier 1 Customer System Peak; the customer's maximum Actual Hourly Tier 1 Load during the Heavy Load Hours of the month, in kilowatts

aHLH = Average of the customer's Actual Hourly Tier 1 Loads during the HLH, in kilowatts

CDQ = Contract Demand Quantity specified in the customer's CHWM Contract, Exhibit B, Section 2, in kilowatts

SuperPeak = Super Peak Credit, if any, specified in the customer's CHWM Contract, Exhibit A, Section 9, in kilowatts

If the Demand Charge billing determinant calculation results in a value less than zero, the billing determinant is deemed to be zero.

The Demand billing determinant may be adjusted pursuant to the Demand Rate Billing Determinant Adjustments, GRSP II.D.

2.1.3 Load Shaping Charge

The Load Shaping Charge is applicable to customers that purchase the following products: Load Following, Block, and the Block portion of Slice/Block. In any diurnal period (HLH or LLH), the Load Shaping Charge may be a charge or a credit, depending upon whether the Load Shaping billing determinant is positive or negative.

2.1.3.1 Load Shaping Rate

<i>Month</i>	<i>Rate in mills/kWh</i>	
	<i>HLH</i>	<i>LLH</i>
October	26.74	22.49
November	27.27	24.74
December	30.28	26.60
January	29.30	23.94
February	28.54	23.94
March	23.75	20.80
April	19.67	17.54
May	16.63	11.25
June	17.71	9.31
July	24.66	19.05
August	28.11	22.61
September	27.94	22.19

2.1.3.2 Load Shaping Billing Determinant

The Load Shaping billing determinant for each of the two diurnal periods, HLH and LLH, for each month equals:

$$\begin{aligned} & \text{Customer's Actual Monthly/Diurnal Tier 1 Load,} \\ & \text{in kilowatthours} \\ & \textit{minus} \\ & \text{Customer's System Shaped Load for the relevant} \\ & \text{diurnal period, in kilowatthours.} \end{aligned}$$

2.1.3.2.1 System Shaped Load

A System Shaped Load is calculated for each diurnal period of each month. The customer's System Shaped Load for each diurnal period equals:

$$RTISC \times TOCA$$

Where:

RTISC = RHWMTier 1 System Capability for the relevant diurnal period, in kilowatthours. The *RTISC* for each diurnal period of the Rate Period is specified in GRSP II.A.

TOCA = The effective TOCA for a Load Following or Block customer, or the effective Non-Slice TOCA for a Slice/Block customer, expressed as a percentage. The TOCA used in this System Shaped Load calculation shall reflect a customer's Adjusted TOCA pursuant to GRSP II.G.

2.1.3.2.2 Joint Operating Entity (JOE)

For calculating the Load Shaping Charge billing determinant for a JOE, the sum of the Actual Monthly/Diurnal Tier 1 Loads of the JOE's individual members and the sum of System Shaped Loads of the JOE's individual members shall be used.

2.1.4 Product Conversion Charge

Customers that have converted from the Slice product to a Non-Slice product beginning October 1, 2017, are subject to a monthly charge.

The charge for each customer is set forth in GRSP Appendix B.

2.1.5 Spill Surcharge

The Spill Surcharge, specified in GRSP Appendix C, is applicable to customers that purchase the Load Following product, the Block product, or the Slice/Block product for the Block portion of the service.

2.2 Tier 2 Charges

2.2.1 Tier 2 Load Shaping Charge

Pursuant to Section 4.3 of the Tiered Rate Methodology (TRM), 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.

2.2.2 Short-Term Charge

The Short-Term Charge is applicable to customers that have elected to purchase power at the Tier 2 Short-Term Rate, as specified in the customer's CHWM Contract, Exhibit C, Section 2.5.

2.2.2.1 Short-Term Rate

<i>Fiscal Year</i>	<i>Rate in mills/kWh</i>
2018	27.20
2019	24.97

2.2.2.2 Short-Term Billing Determinant

The billing determinant is the annual amount of power specified in the customer's CHWM Contract. For the relevant billing month, the contract amount shall be converted from average megawatts to kilowatthours assuming a Flat Annual Shape.

2.2.3 Load Growth Charge

The Load Growth Charge is applicable to customers that have elected to purchase power at the Tier 2 Load Growth Rate, as specified in the customers' CHWM Contracts, Exhibit C, Section 2.5.

2.2.3.1 Load Growth Rate

<i>Fiscal Year</i>	<i>Rate in mills/kWh</i>
2018	47.68
2019	45.42

2.2.3.2 Load Growth Billing Determinant

The billing determinant is the annual amount of power specified in the customer's CHWM Contract. For the relevant billing month, the contract amount shall be converted from average megawatts to kilowatthours assuming a Flat Annual Shape.

2.2.4 VR1-2014 Charge

The VR1-2014 Charge is applicable to customers that elected to purchase power at the Tier 2 VR1-2014 Rate, as specified in the customers' CHWM Contracts, Exhibit C, Section 2.5.

2.2.4.1 VR1-2014 Rate

<i>Fiscal Year</i>	<i>Rate in mills/kWh</i>
2018	51.40
2019	53.02

2.2.4.2 VR1-2014 Billing Determinant

The billing determinant is the annual amount of power specified in the customer's CHWM Contract. For the relevant billing month, the contract amount shall be converted from average megawatts to kilowatthours assuming a Flat Annual Shape.

2.2.5 VR1-2016 Charge

The VR1-2016 Charge is applicable to customers that have elected to purchase power at the Tier 2 VR1-2016 Rate, as specified in the customers' CHWM Contracts, Exhibit C, Section 2.5.

2.2.5.1 VR1-2016 Rate

<i>Fiscal Year</i>	<i>Rate in mills/kWh</i>
2018	46.50
2019	48.02

2.2.5.2 VR1-2016 Billing Determinant

The billing determinant is the annual amount of power specified in the customer's CHWM Contract. For the relevant billing month, the contract amount shall be converted from average megawatts to kilowatthours assuming a Flat Annual Shape.

3. Priority Firm Melded Rate

The PF Melded rate is applicable to the sale of Firm Requirements Power under contracts other than CHWM Contracts.

Rates under contracts that contain charges that escalate based on BPA's PF rate shall be based on the rates listed in this section in addition to any applicable transmission and ancillary service charges.

The energy rates in Section 3.1.1 are subject to adjustment during the Rate Period pursuant to the Spill Surcharge, specified in GRSP Appendix C.

The PF Melded rate is not available to loads that are considered unanticipated loads as defined in Unanticipated Load Service, GRSP II.M.1.

3.1 Energy Charge

3.1.1 Energy Rate

<i>Month</i>	<i>Rate in mills/kWh</i>	
	<i>HLH</i>	<i>LLH</i>
October	39.40	35.15
November	39.93	37.40
December	42.94	39.26
January	41.96	36.60
February	41.20	36.60
March	36.41	33.46
April	32.33	30.20
May	29.29	23.91
June	30.37	21.97
July	37.32	31.71
August	40.77	35.27
September	40.60	34.85

3.1.2 Energy Billing Determinant

The Energy billing determinant is the total of the hourly loads, as specified in the customer's contract, for each diurnal period, in kilowatthours.

3.2 Demand Charge

3.2.1 Demand Rate

<i>Month</i>	<i>Rate in \$/kW</i>
October	10.45
November	10.65
December	11.83
January	11.45
February	11.15
March	9.28
April	7.68
May	6.49
June	6.92
July	9.63
August	10.98
September	10.91

3.2.2 Demand Billing Determinant

The Demand billing determinant is the maximum hourly load, as specified in the customer's contract, during the HLH of the month, in kilowatts, less the average of the hourly loads during the HLH of the month, in kilowatts.

4. Unanticipated Load Service Charge

The Unanticipated Load Service Charge under the PF-18 Rate Schedule, specified in GRSP II.M.2, is applicable to the sale of Firm Requirements Power to serve Unanticipated Loads.

5. Resource Support Services Rates

Resource Support Services rates are applicable to customers that elect to take Diurnal Flattening Service, Secondary Crediting Service, or Grandfathered Generation Management Service for non-Federal resources. The Resource Shaping Charge and Adjustment are applicable to customers that elect this option to financially convert the output of certain types of non-Federal resources to a flat annual block of power as specified in their CHWM Contracts.

5.1 Diurnal Flattening Service (DFS)

Customers that have elected to take DFS for their non-Federal resources are subject to the DFS Energy and Capacity Charges specified in GRSP II.I.1.

5.2 Resource Shaping Charge and Adjustment

Customers that have elected to take this option for their new resources other than small non-dispatchable resources are subject to the Resource Shaping Charge and Adjustment specified in GRSP II.I.2.

5.3 Secondary Crediting Service (SCS)

Customers that have elected to take SCS for their non-Federal resources are subject to the SCS Shortfall Energy Charge, SCS Secondary Energy Charge, and SCS Administrative Charge specified in GRSP II.I.3.

5.4 Grandfathered Generation Management Service (GMS)

Load Following customers dedicating to their Tier 1 Load the entire output of an Existing Resource that received GMS under Subscription are subject to a GMS Reservation Fee specified in GRSP II.I.6.

6. Priority Firm Exchange Rate

The PF Exchange rate applies to sales of Residential Exchange Program Power under a Residential Purchase and Sale Agreement or Residential Exchange Program Settlement Implementation Agreement.

6.1. Energy Rate

A utility-specific PF Exchange rate is calculated for each utility purchasing Residential Exchange Program Power. For investor-owned utilities, the PF Exchange rate equals the Base PF Exchange rate plus a utility-specific 7(b)(3) Surcharge. For consumer-owned utilities, the PF Exchange rate equals the Base Tier 1 PF Exchange rate plus a utility-specific 7(b)(3) Surcharge.

<i>Investor-Owned Utilities</i>	<i>Rates in mills/kWh</i>		
	<i>Base PF Exchange Rates</i>	<i>7(b)(3) Surcharge</i>	<i>PF Exchange Rates</i>
Avista	50.32	3.5810	53.90370
Idaho Power	50.32	10.7013	61.02400
NorthWestern	50.32	19.0894	69.41220
PacifiCorp	50.32	21.4314	71.75420
Portland General	50.32	17.2283	67.55110
Puget Sound Energy	50.32	14.0924	64.41520
<i>Consumer-Owned Utilities</i>	<i>Base Tier 1 PF Exchange Rates</i>	<i>7(b)(3) Surcharge</i>	<i>PF Exchange Rates</i>
Clark Public Utilities	50.35	3.80	54.15
Snohomish County PUD No 1	50.35	1.43	51.78

6.1.1 7(b)(3) Surcharge for Non-Listed Utilities

For eligible customers not listed in Section 6.1, the applicable 7(b)(3) Surcharge shall equal the customer's Average System Cost minus the applicable Base PF Exchange rate. The customer's Average System Cost shall be determined pursuant to BPA's 2008 Average System Cost Methodology.

6.2 Energy Billing Determinant

The billing determinant for the PF Exchange Power charge is the customer's Residential Load specified in GRSP I.S, Table H.

7. Adjustments, Charges, and Special Rate Provisions

Adjustments, charges, and special rate provisions are applicable to PF rates as shown in the following tables.

GRSP II.	Adjustments, Charges, and Special Rate Provisions	Applicable to:				
		Firm Requirements				REP
		Load Following	Block only and Block Portion of Slice/Block	Slice Portion of Slice/Block	Tier 2	
Calculating Rates (including Discounts and Adjustments)						
A	RHWM Tier 1 System Capability (RT1SC)	X	X			
B	Low Density Discount (LDD)	X	X	X		
C	Irrigation Rate Discount	X	X	X		
D	Demand Rate Billing Determinant Adjustments	X				
E	Load Shaping Charge True-Up Adjustment	X				
F	Tier 2 Rate TCMS Adjustment				X	
G	TOCA Adjustment	X	X	X		
Resource Support Services & Related Services						
I	Resource Support Services and Transmission Scheduling Service	X	X	X		
K	Remarketing	X	X	X		
Transfer Service						
L	Transfer Service Charges	X	X	X		
Other Charges						
M	Unanticipated Load Service	X	X	X		
N	Unauthorized Increase (UAI) Charge	X	X	X		X
Risk Adjustments						
O	Power Cost Recovery Adjustment Clause (Power CRAC)	X	X			
P	Power Reserves Distribution Clause (Power RDC)	X	X			
Q	NFB Mechanisms	X	X			
Slice True-Up						
R	Slice True-Up Adjustment			X		
Residential Exchange Program						
S	Residential Exchange Program Residential Load					X
T	Residential Exchange Program 7(b)(3) Surcharge Adjustment					X

<i>GRSP II.</i>	<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>Applicable to:</i>				
		<i>Firm Requirements</i>				<i>REP</i>
		<i>Load Following</i>	<i>Block only and Block Portion of Slice/Block</i>	<i>Slice Portion of Slice/Block</i>	<i>Tier 2</i>	
Conservation						
U	Conservation Surcharge	X	X	X		
Payment Options						
W	Flexible Priority Firm Power (PF) Rate Option	X	X	X		
X	Priority Firm Power (PF) Shaping Option	X	X	X		
Informational						
Z	Cost Contributions	X	X	X	X	X

<i>GRSP Appendix</i>	<i>Adjustments and Charges</i>	<i>Applicable to:</i>		
		<i>Load Following</i>	<i>Block only and Block Portion of Slice/Block</i>	<i>Slice Portion of Slice/Block</i>
A	REP Settlement Customer Refund Amounts in FY 2018–2019	X	X	X
B	Product Conversion Charge for FY 2018–2019	X	X	
C	Spill Surcharge	X	X	

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SCHEDULE NR-18 NEW RESOURCE FIRM POWER RATE

1. Availability

This schedule is available for the contract purchase of firm power to be used within the Pacific Northwest. New Resource Firm Power (NR) is available to investor-owned utilities under Northwest Power Act Section 5(b) requirements contracts for resale to ultimate consumers; for direct consumption; and for Construction, Test and Start-Up, and Station Service. New Resource Firm Power also is available to any public body, cooperative, or Federal agency to the extent such power is used to serve any new large single load (NLSL), as defined by the Northwest Power Act. This schedule is available for services provided to Load Following customers that are serving NLSLs with non-Federal resources.

Transmission and ancillary services for use of the Federal Columbia River Transmission System facilities shall be charged separately under the applicable rate schedules.

Effective October 1, 2017, this rate schedule supersedes the NR-16 rate schedule. Sales under the NR-18 rate schedule are subject to the GRSPs. For sales under this rate schedule, bills shall be rendered and payments due pursuant to the GRSPs and billing process.

2. New Resource Rates

2.1 Energy Charge

2.1.1 Energy Rate

<i>Month</i>	<i>Rate in mills/kWh</i>	
	<i>HLH</i>	<i>LLH</i>
October	82.70	78.45
November	83.23	80.70
December	86.24	82.56
January	85.26	79.90
February	84.50	79.90
March	79.71	76.76
April	75.63	73.50
May	72.59	67.21
June	73.67	65.27
July	80.62	75.01
August	84.07	78.57
September	83.90	78.15

2.1.1.1 REP Surcharge

Each energy rate in the table above reflects an REP Surcharge of 8.83 mills/kWh.

2.1.1.2 Spill Surcharge

The NR energy rates in Section 2.1.1 are subject to adjustment during the Rate Period pursuant to the Spill Surcharge, specified in GRSP Appendix C.

2.1.2 Energy Billing Determinant

The billing determinant is the total of NR Hourly Loads for each diurnal period.

2.2 Demand Charge

2.2.1 Demand Rate

<i>Month</i>	<i>Rate in \$/kW</i>
October	10.45
November	10.65
December	11.83
January	11.45
February	11.15
March	9.28
April	7.68
May	6.49
June	6.92
July	9.63
August	10.98
September	10.91

2.2.2 Demand Billing Determinant

The billing determinant is the highest NR Hourly Load during HLH, in kilowatts, for the billing period minus the average of the NR Hourly Load during the HLH, in kilowatts.

3. Unanticipated Load Service Charge

The Unanticipated Load Service Charge under the NR-18 Rate Schedule, specified in GRSP II.M.3, is applicable to the sale of Firm Requirements Power to serve Unanticipated Loads.

4. Energy Shaping Service for New Large Single Loads (NLSLs) Charge

The Energy Shaping Service (ESS) for NLSLs Charge, specified in GRSP II.J.1, is applicable to Load Following customers that serve NLSLs with non-Federal resources.

5. NR Resource Flattening Service Charge

The NR Resource Flattening Service charge, specified in GRSP II.J.2, is applicable to Load Following customers that apply the generation output of a non-dispatchable Specified Resource to serve an NLSL.

6. Adjustments, Charges, and Special Rate Provisions

Adjustments, charges, and special rate provisions are applicable as shown in the following table.

<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>GRSP II.</i>
Low Density Discount (LDD)	B
Demand Rate Billing Determinant Adjustments	D
Energy Shaping Service for NLSLs Charge	J.1
NR Resource Flattening Service Charge	J.2
Unanticipated Load Service	M
Unauthorized Increase (UAI) Charge	N
Power Cost Recovery Adjustment Clause (Power CRAC)	O
Power Reserves Distribution Clause (Power RDC)	P
NFB Mechanisms	Q
Conservation Surcharge	U
Flexible New Resource Firm Power (NR) Rate Option	Y
Cost Contributions	Z

<i>GRSP Appendix</i>	<i>Adjustments and Charges</i>
C	Spill Surcharge

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SCHEDULE IP-18 INDUSTRIAL FIRM POWER RATE

1. Availability

This schedule is available to BPA’s direct service industrial (DSI) customers, as defined by the Northwest Power Act, for firm power to be used in their industrial operations in the Pacific Northwest. Industrial Firm Power is available under Northwest Power Act Section 5(d) contracts to DSIs for direct consumption. 16 U.S.C. § 839c(d).

Transmission and ancillary services for use of the Federal Columbia River Transmission System facilities shall be charged separately under the applicable rate schedules.

Effective October 1, 2017, this rate schedule supersedes the IP-16 rate schedule. Sales under the IP-18 rate schedule are subject to the GRSPs. For sales under this rate schedule, bills shall be rendered and payments due pursuant to the GRSPs and billing process.

DSIs purchasing power pursuant to the IP-18 rate schedule shall be required to provide the Minimum DSI Operating Reserve – Supplemental.

2. Industrial Firm Rates

2.1 Energy Charge

2.1.1 Energy Rates

<i>Month</i>	<i>Rate in mills/kWh</i>	
	<i>HLH</i>	<i>LLH</i>
October	48.08	43.83
November	48.61	46.08
December	51.62	47.94
January	50.64	45.28
February	49.88	45.28
March	45.09	42.14
April	41.01	38.88
May	37.97	32.59
June	39.05	30.65
July	46.00	40.39
August	49.45	43.95
September	49.28	43.53

2.1.1.1 REP Surcharge

Each energy rate in the table above reflects an REP Surcharge of 8.83 mills/kWh.

2.1.1.2 Value of Reserves Credit

Each energy rate in the table above reflects a 0.896 mills/kWh credit for the value of the Minimum DSI Operating Reserve – Supplemental.

2.1.1.3 Spill Surcharge

The IP energy rates in Section 2.1.1 are subject to adjustment during the Rate Period pursuant to the Spill Surcharge, specified in GRSP Appendix C.

2.1.2 Energy Billing Determinant

The billing determinant is the Energy Entitlement that is specified in the customer's contract.

2.2 Demand Charge

2.2.1 Demand Rate

<i>Month</i>	<i>Rate in \$/kW</i>
October	10.45
November	10.65
December	11.83
January	11.45
February	11.15
March	9.28
April	7.68
May	6.49
June	6.92
July	9.63
August	10.98
September	10.91

2.2.2 Demand Billing Determinant

The billing determinant is the customer's maximum schedule amount during HLH, in kilowatts, for the billing period minus the average of the customer's monthly schedule amount during the HLH, minus the Industrial Demand Adjuster, if any, in kilowatts.

Port Townsend Paper Corporation's Industrial Demand Adjuster values are specified in the table below.

<i>Month</i>	<i>Industrial Demand Adjuster (kW)</i>
October	2046
November	1646
December	1160
January	1019
February	1115
March	1598
April	795
May	1122
June	763
July	793
August	903
September	731

If Port Townsend Paper's Contract Demand (15.75 MW) is reduced in part or in full by BPA due to a transfer of service to a BPA preference customer, then the Industrial Demand Adjuster value in the above table will be reduced proportionately.

If the Demand Charge billing determinant calculation results in a value less than zero, the billing determinant is deemed to be zero.

3. Adjustments, Charges, and Special Rate Provisions

Adjustments, charges, and special rate provisions are applicable as shown in the following table.

<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>GRSP II.</i>
Demand Rate Billing Determinant Adjustments	D
DSI Reserves	H
Unauthorized Increase (UAI) Charge	N
Power Cost Recovery Adjustment Clause (Power CRAC)	O
Power Reserves Distribution Clause (Power RDC)	P
NFB Mechanisms	Q
Conservation Surcharge	U
Cost Contributions	Z

<i>GRSP Appendix</i>	<i>Adjustments and Charges</i>
C	Spill Surcharge

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SCHEDULE FPS-18

FIRM POWER AND SURPLUS PRODUCTS AND SERVICES RATE

1. Availability

This rate schedule is available for the sale of Firm Power (capacity and/or energy), Capacity Without Energy, Shaping Services, Reservation and Rights to Change Services, Reassignment or Remarketing of Surplus Transmission Capacity, Services for Non-Federal Resources, Unanticipated Load Service, and other capacity, energy, and power scheduling products and services for use inside and outside the Pacific Northwest.

Sales under this rate schedule are discretionary. BPA is not obligated to sell any of these products, even if such sales will not displace PF, NR, or IP sales. Ancillary Services needed for transmission service over Federal Columbia River Transmission System facilities shall be charged separately under the applicable transmission rate schedule.

Effective October 1, 2017, this rate schedule supersedes the FPS-16 rate schedule. Sales under the FPS-18 rate schedule are subject to the GRSPs. For sales under this rate schedule, bills shall be rendered and payments due pursuant to the GRSPs and billing process.

2. Firm Power and Capacity Without Energy

2.1 Flexible Rates and Billing Determinants

Demand and/or energy charges shall be as specified by BPA or as mutually agreed by BPA and the customer. Billing determinants shall be Contract Demand and Contract Energy unless otherwise agreed by BPA and the customer.

3. Shaping Services

3.1 Rates and Billing Determinants

The charge for Shaping Services shall be the applicable rate(s) times the applicable billing determinant(s), pursuant to the agreement between BPA and the customer.

The rate(s) and billing determinant(s) for use of Shaping Services shall be as established by BPA or as mutually agreed by BPA and the customer.

4. Reservations and Rights to Change Services

4.1 Rates and Billing Determinants

The charge for Reservation and Rights to Change Services shall be the applicable rate(s) times the applicable billing determinant(s), pursuant to the agreement between BPA and the customer.

The rate(s) and billing determinant(s) for Reservation and Rights to Change Services shall be as established by BPA or as mutually agreed by BPA and the customer.

5. Reassignment or Remarketing of Surplus Transmission Capacity

Power Services may reassign or remarket surplus transmission capacity that it has reserved for its own use consistent with the terms of the transmission provider's Open Access Transmission Tariff (OATT).

5.1 Rates and Billing Determinants

The charges for Reassignment or Remarketing of Surplus Transmission Capacity shall be the applicable rate(s) times the applicable billing determinant(s), pursuant to the agreement between BPA and the customer.

The rate(s) and billing determinant(s) for Reassignment or Remarketing of Surplus Transmission Capacity shall be as established by BPA or as mutually agreed to by BPA and the customer.

6. Other Capacity, Energy, and Scheduling Products and Services

Power Services may sell energy or capacity (including energy or capacity provided to balancing authorities and transmission providers, other than the BPA Balancing Authority, for use as ancillary services) and power scheduling products and services under this rate schedule. Such products and services may include, but are not limited to: (1) interruptible energy; (2) resource support and scheduling services for non-Federal resources not eligible for services under Section 7 of this FPS rate schedule; and (3) reserve-based products and services (including but not limited to operating reserves, imbalance energy, frequency response reserves, and regulation for use outside the BPA Balancing Authority Area).

6.1 Rates and Billing Determinants

Rate(s) and billing determinant(s) applicable to such products and services shall be as specified by BPA or as agreed to by BPA and the customer. The charge(s) for these services shall be the applicable rate(s) times the applicable billing determinant(s) pursuant to the agreement between BPA and the customer.

7. Services for Non-Federal Resources

7.1 Transmission Scheduling Service/Transmission Curtailment Management Service (TSS/TCMS)

Customers that have elected to take TSS/TCMS for their non-Federal resources are subject to the TSS and TCMS Charges specified in GRSP II.I.5.

7.2 Forced Outage Reserve Service (FORS)

Customers that have elected to take FORS for their non-Federal resources are subject to the FORS Energy and Capacity Charges specified in GRSP II.I.4.

7.3 Resource Remarketing Service (RRS)

Customers that have requested and have been granted permission to take RRS for their non-Federal resources shall receive the RRS credit specified in GRSP II.I.7.

8. Unanticipated Load Service

The Unanticipated Load Service Charge under the FPS-18 Rate Schedule, specified in GRSP II.M.4, is applicable to the sale of firm power to serve Unanticipated Loads resulting from a request for service under Section 9(i) of the Northwest Power Act. 16 U.S.C. § 839f(i).

9. Adjustments, Charges, and Special Rate Provisions

Adjustments, charges, and special rate provisions are applicable as shown in the following table and/or as specified by BPA or as agreed to by BPA and the customer.

<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>GRSP II.</i>
Unauthorized Increase (UAI) Charge	N
Cost Contributions	Z

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GENERAL RATE SCHEDULE PROVISIONS

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GENERAL RATE SCHEDULE PROVISIONS

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GENERAL RATE SCHEDULE PROVISIONS

SECTION I. ADOPTION OF POWER RATE SCHEDULES AND GENERAL RATE SCHEDULE PROVISIONS

A. Approval of Rates

BPA has requested that the Federal Energy Regulatory Commission grant approval to make these rate schedules and GRSPs effective on October 1, 2017. All rate schedules shall remain in effect until they are replaced or expire on their own terms.

B. General Provisions

The Power Rate Schedules and associated GRSPs supersede BPA's 2016 Power rate schedules, which became effective October 1, 2015, to the extent stated in the Availability section of each rate schedule. The schedules and these GRSPs shall be applicable to all BPA contracts, including contracts executed prior to and subsequent to enactment of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act).

All sales under these rate schedules are subject to the following acts, as amended: The Bonneville Project Act (Pub. L. No. 75-329), *codified at* 16 U.S.C. § 832 *et seq.*, the Regional Preference Act (Pub. L. No. 88-552), *codified at* 16 U.S.C. § 837 *et seq.*, the Transmission System Act (Pub. L. No. 93-454), *codified at* 16 U.S.C. § 838 *et seq.*, the Northwest Power Act (Pub. L. No. 96-501), *codified at* 16 U.S.C. § 839 *et seq.*, and the Energy Policy Act of 1992 (Pub. L. No. 102-486), *codified at* 16 U.S.C. § 824(i)-(l).

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

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

C. Bill Payment Provisions

Payment must be received by the 20th day after the issue date of the bill (Due Date). If the 20th day is a Saturday, Sunday, or Federal holiday, the Due Date is the next business day. After the Due Date, a late payment charge shall be applied each day to any unpaid balance. The late payment charge shall be equal to the higher of (1) the Prime Rate (as reported in the Wall Street Journal or successor publication in the first issue published during the month in which payment was due) plus four percent, divided by 365; or (2) the Prime Rate times 1.5, divided by 365. The customer shall pay by electronic funds transfer using BPA's established procedures.

D. Notices

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

E. Supplemental Guidelines for Direct Assignment of Facilities Costs Incurred Under Transfer Agreements

BPA will use this set of Supplemental Guidelines to assign costs to Transfer Service customers. Such costs are comparable to the costs purchasers of Transfer Services would incur if such purchasers were directly connected to the BPA transmission system.

This set of Supplemental Guidelines augments the BPA Transmission Services “Facility Ownership and Cost Assignment Guidelines,” as amended or superseded (Transmission Services Guidelines), currently posted at:

http://www.bpa.gov/transmission/Doing%20Business/Interconnection/Documents/BPA_Facility_Ownership_and_Cost_Assignment_Guidelines.pdf

In determining whether to directly assign to a Transfer customer costs incurred by BPA in providing transfer service to the customer, BPA will apply the current Transmission Services Guidelines and these Supplemental Guidelines. The Supplemental Guidelines apply only to transfer service acquired by BPA from third-party transmission providers for service to Preference customers. The Supplemental Guidelines use some terms defined in the 20-year Agreement Regarding Transfer Service (ARTS). Also, Direct Assignment Facilities, as defined in most pro forma Open-Access Transmission Tariffs (OATT), are:

Facilities or portions of facilities that are constructed by the Transmission Provider for the sole use/benefit of a particular Transmission customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission customer...

These Supplemental Guidelines are designed to supplement, not replace, the Transmission Service Guidelines and to assist in predicting how BPA, as the default transmission customer for transfer arrangements, will recover costs for Direct Assignment Facilities assessed by third-party transmission providers. Unless otherwise specifically excluded in the Transmission Services Guidelines or below, the cost of Direct Assignment Facilities will be passed through to the customer.

Supplemental Guideline Regarding Directly-Assigned Facilities

For new facilities or new service over existing third-party transmission provider facilities that meet the definition of Direct Assignment Facilities, metered quantities for customer deliveries will be adjusted for losses such that BPA is not responsible for losses across such directly assigned facilities. Loss calculations should be similar whether the customer or the transmission provider owns the directly assigned facilities.

Supplemental Guidelines Regarding Replacement with a Higher Capacity Facility or Addition of a Transformer in Parallel

Pursuant to the Transmission Services Guidelines, for a new transmission provider-owned facility that also adds capacity, the costs that exceed the cost of replacing the previous capacity may be directly assigned to the benefiting customer. Alternatively, BPA and the customer may agree to full direct assignment in lieu of payment of the Transfer Service Delivery Charge. Similarly, when a parallel transformer is added, BPA and the customer may agree to a simplified direct assignment of all delivery costs in lieu of some combination of Delivery Charge and direct assignment.

Supplemental Guidelines Regarding Construction Option

The customer may work directly with the third-party transmission provider to develop and select among options regarding construction, cost sharing, and ownership. BPA will work with the customer and the transmission provider to arrive at the best one-utility plan, workable cost-sharing options, equitable ownership, and interconnection arrangements. Due to regulatory issues, it is Power Services' policy not to own facilities.

Additional Guidelines:

Rolled-in Rate Treatment by Transmission Provider

If a customer receives new Transfer Service over new or pre-existing facilities offered by the transmission provider under a rolled-in rate or revenue requirement, BPA reserves the right to assess the Transfer Service Delivery Charge. BPA will not assess the Transfer Service Delivery Charge for a new point of delivery (POD) if specific facilities' costs are not rolled in but are directly assigned to BPA and in turn passed through to the customer.

Wholesale Distribution Facilities Beyond the Step-Down Substation

On any new arrangement for a directly assigned facility (new or pre-existing facilities), the incremental cost for use of any facilities (other than potential transformers or current transformers for revenue metering) beyond the fence of the corresponding step-down transformer substation (or beyond a 20-foot radius of the step-down, for pole-top substations) shall be passed through to the customer, whether such costs are directly assigned to BPA or are imposed pursuant to a discrete wholesale distribution rate or Load Ratio Share of a discrete wholesale distribution revenue requirement.

Customer Arrangements Directly with the Third-Party Transmission Provider

A customer may, in lieu of paying the Transfer Service Delivery Charge, choose to contract directly with the third-party transmission provider for delivery service at an existing POD, but must then do so for all similar PODs with that transmission provider. The customer must take transmission service from BPA at these PODs such that the customer is responsible for costs of and losses through the delivering facilities. A customer contracting

with the third party for a new POD does not create a requirement that the customer contract with the third party for its pre-existing low-voltage PODs.

F. Metering Usage Data Estimation Provision

Pursuant to Section 15.1 of the CHWM Contract for the Load Following product, BPA shall apply the Meter Usage Data Estimations procedures posted on the BPA Metering website.

SECTION II. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

A. RHWL Tier 1 System Capability (RT1SC)

The RT1SC is an element of the Tier 1 Load Shaping Charge billing determinant, described in Section 2.1.3.2 of the PF-18 rate schedule. RT1SC is the Tier 1 System Firm Critical Output plus RHWL Augmentation. The RT1SC values for the FY 2018–2019 rate period are shown in Table A below.

Table A
FY 2018-2019 RHWL Tier 1 System Capability

<i>Month</i>	<i>RT1SC in kWh</i>	
	<i>HLH</i>	<i>LLH</i>
October	3,049,683,621	1,639,154,141
November	3,651,526,424	2,143,520,679
December	3,566,674,910	2,158,780,609
January	3,022,270,092	1,869,585,923
February	2,533,270,239	1,477,102,815
March	3,002,579,936	1,745,556,089
April	2,934,906,901	1,628,742,477
May	4,268,254,324	2,428,578,203
June	3,456,513,955	1,827,109,909
July	3,033,188,044	1,606,277,192
August	3,437,616,056	1,700,777,401
September	2,975,771,428	1,679,408,703

B. Low Density Discount (LDD)

1. Application and Definitions

For eligible customers, as defined in Section 2 below, a Low Density Discount (LDD) shall be applied each billing month to the PF-18 Composite Customer charge, PF-18 Non-Slice Customer charge, PF-18 Load Shaping charge, PF-18 Load Shaping Charge True-Up Adjustment, and PF-18 Demand charge. The LDD also applies to eligible customers under the PF-18 Melded rate schedule and the NR-18 rate schedule. The LDD shall be applied to only those charges listed in this GRSP II.B.

For Load Following and Block purchases, the applicable discount percentage will apply to all charges for purchases by the customer under the Tier 1 rates (Composite Customer charge, Non-Slice Customer charge, Load Shaping charge, Load Shaping Charge True-Up Adjustment, and Demand charge). The applicable discount percentage will be adjusted for Above-RHWL Load, as described in Section 6 below.

For Slice/Block purchases, an LDD dollar benefit will be calculated by BPA as though it was a Load Following purchase. BPA will use the customer's previous fiscal year's load data to calculate an annual LDD dollar benefit amount. This amount will be divided by 12 to derive a monthly LDD dollar credit, which will be applied to the customer's monthly power bills over the next 12 months. There will be no separate Slice and Block LDD benefits calculated. The applicable discount percentage will be adjusted for Above-RHWM Load, as described in Section 6 below.

The eligible and applicable discount percentages shall be revised annually based on data supplied by June 30 of each calendar year (CY) for the previous calendar year and shall become effective on the following October 1.

The calculation of the ratios below shall be based on calendar year data the customer provides from its annual financial and operating reports (*e.g.*, Rural Utilities Service Financial and Operating Report - Electrical Distribution, National Rural Utilities Cooperative Finance Corporation Financial and Statistical Report (CFC Form 7), audited financial report, or annual report). The provided annual financial and operating reports shall include the customer's Total Retail Load, depreciated electric plant, number of consumers, pole miles of distribution lines, total kilowatthours sold, and total electric retail sales revenue. The annual financial and operating report is to be enclosed with the customer's calendar year data if not previously submitted to BPA. The customer shall certify that the data submitted is true and correct.

Load acquired by a customer as a direct result of retail access rights established by Federal, state, or local legislation that would not otherwise have been acquired absent such legislation is not eligible to receive the benefits provided by the LDD. The customer shall certify that the data submitted does not include such load. The customer shall not pass the benefits of the LDD to such acquired consumers.

In calculating the ratios below, BPA shall compile the data submitted by the customer based on the customer's entire electric utility system in the Pacific Northwest (PNW). For customers with service territories that include any areas outside the PNW, BPA shall compile data submitted by the customer separately on the customer's system in the PNW and on the customer's entire electric system, including areas outside the PNW. BPA shall apply the eligibility criteria and discount percentages to the customer's system within the PNW and, where applicable, also to its entire system inside and outside the PNW. The customer's eligibility for the LDD shall be determined by the lesser amount of discount applicable to its PNW system or to its combined system inside and outside the PNW. BPA, in its sole discretion, may waive the requirement to submit separate data for the customer with a small amount of its system outside the PNW. Results of the calculations shall not be rounded.

If a customer does not provide BPA with the requisite information and reports by June 30 of each year for BPA to calculate the K/I and C/M ratios (see below), the customer shall be ineligible for the LDD effective the following October 1. The customer may reapply for the LDD in any subsequent year.

If a customer's data and reports are submitted prior to the June 30 deadline and a revision is necessary, the customer must submit the revised data within 12 months of the original submission date to be considered for an adjustment.

(a) The Kilowatt-hour/Investment (K/I) Ratio

The K/I ratio is calculated annually based on the data the customer supplies by June 30 of each calendar year. The K/I ratio is calculated by dividing the customer's Total Retail Load during the previous calendar year by the value of the customer's depreciated electric plant (excluding generation plant) at the end of the previous calendar year.

(b) The Consumers/Pole (C/M) Miles Ratio

The C/M ratio is calculated annually based on the data the customer supplies by June 30 of each calendar year. The C/M ratio is calculated by dividing the customer's number of consumers within the distribution system at the end of the previous calendar year, as defined below, by the number of pole miles of distribution lines at the end of the previous calendar year.

"Consumers" means the number of consumers, by classification, having a current service connection in December of each year. Residential consumers (seasonal and non-seasonal) are counted on the basis of the number of residences served. If one meter serves two residences, then two consumers are counted. If a water heater is metered separately from other appliances on the same premises, the water heater load will not count as a separate consumer.

Security or safety lights billed to a residential consumer will not be counted as an additional consumer.

Additional meters used for net metering consumers will not be counted as an additional consumer.

Seasonal consumers expected to resume service during the next seasonal period will be counted during off-season periods as well.

A residence and commercial establishment on the same premises receiving service through the same meter and being billed under the same rate schedule would be classified as one consumer based on the rate schedule. If the same rate schedule applies to both the residential and the commercial class, the consumer should be classified according to the principal use.

Consumers for Public Street and Highway Lighting shall be counted by the number of billings, regardless of the number of lights per billing.

Pole miles of distribution lines are defined as lines that deliver electric energy from a substation or metering point at a voltage of 34.5 kV or below to the point of attachment to the consumer's wiring and include primary, secondary, and service facilities. (Service drops are considered service facilities.)

2. Eligibility Criteria

To qualify for a discount, the customer must meet all five of the following eligibility criteria:

- (a) The customer must serve as an electric utility offering power for resale to retail consumers.
- (b) The customer must agree to pass the benefits of the discount through to its eligible consumers within the region served by BPA.
- (c) The customer's average retail rate for the reporting year must exceed BPA's average Priority Firm Power rate for the most closely corresponding fiscal year by at least 25 percent, which is 43.83 mills/kWh for FY 2018 and FY 2019.
- (d) The customer's K/I ratio must be less than 100.
- (e) The customer's C/M ratio must be less than 12.

Each year BPA shall determine whether a customer is eligible for a discount. Such determination shall not be dependent on whether the customer was determined to be eligible in the previous year.

3. Determination of Eligible Discount percentage

For each customer, an eligible discount percentage shall be determined using Table B below. The eligible discount percentage shall be the sum of the two potential discount percentages for which the customer qualifies, based on Table B. The total eligible discount percentage shall not exceed 7 percent and may be adjusted pursuant to Sections 4, 5, and 6 below.

Table B
LDD Eligible Discount percentage

<i>Percentage Discount</i>	<i>Applicable Range for kWh/Investment (K/I) Ratio</i>	<i>Applicable Range for Consumers/Mile (C/M) Ratio</i>
0.0%	$35.0 < X$	$12.0 < X$
0.5%	$31.5 < X \leq 35.0$	$10.8 < X \leq 12.0$
1.0%	$28.0 < X \leq 31.5$	$9.6 < X \leq 10.8$
1.5%	$24.5 < X \leq 28.0$	$8.4 < X \leq 9.6$
2.0%	$21.0 < X \leq 24.5$	$7.2 < X \leq 8.4$
2.5%	$17.5 < X \leq 21.0$	$6.0 < X \leq 7.2$
3.0%	$14.0 < X \leq 17.5$	$4.8 < X \leq 6.0$
3.5%	$10.5 < X \leq 14.0$	$3.6 < X \leq 4.8$
4.0%	$7.0 < X \leq 10.5$	$2.4 < X \leq 3.6$
4.5%	$3.5 < X \leq 7.0$	$1.2 < X \leq 2.4$
5.0%	$X \leq 3.5$	$X \leq 1.2$

4. LDD Phase-In Adjustment

If the customer satisfies the eligibility criteria in Sections 2(a) through (e) above and the calculated eligible discount percentage differs from the existing eligible discount percentage by more than one-half of 1 percentage point, the applicable eligible discount percentage shall be one of the following amounts:

- (a) the existing eligible discount percentage plus a maximum of one-half percent if the calculated eligible discount percentage exceeds the existing discount; or
- (b) the existing eligible discount percentage minus a maximum of one-half percent if the calculated eligible discount percentage is less than the existing discount.

The foregoing formula shall be applied each October 1 until the existing eligible discount percentage is equal to the calculated eligible discount percentage.

The customer is not eligible to receive any discount, effective each October, if the customer fails to meet the eligibility criteria in Sections 2(a) through (e) above. If the customer is eligible to receive a discount in a year following a year in which the customer was not eligible to receive the discount, then the one-half percent phase-in adjustment described above shall apply to the most recent eligible discount.

Customers receiving the LDD for the first time shall receive the full discount amount as determined in Section 3.

When determining the LDD percentage pursuant to Sections 3 and 4, the calculations shall not include any Additional Adjustment for Very Low Densities as determined in Section 5.

5. Additional Adjustment for Very Low Densities

If a customer's C/M ratio is 3 or less and its K/I ratio is 26 or less, after the annual determination of the eligible discount percentage pursuant to Sections 3 and 4 above, an additional one-half percent shall be added to the customer's eligible discount percentage, not to exceed a total eligible discount of 7 percent.

6. Applicable Discount for Customers with Above-RHWM Load

A discount is not provided for the costs of power used to serve the customer's Above-RHWM Load; however, the LDD benefit will be adjusted to be approximately the same as if the Above-RHWM Load was included. This adjustment modifies the customer's eligible discount percentage. The formula used to calculate the applicable discount percentage for eligible purchases on the customer's power bill during the rate period is:

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

Where:

applicableLDD = the discount percentage to be applied to the Tier 1 charges on a customer's bill

eligibleLDD = the customer's eligible discount percentage as computed according to Sections 2 through 5 above

adjTRL = the customer's Total Retail Load less output of Existing Resources and NLSLs, as determined in the RHWM Process for the applicable fiscal year

RHWM = the customer's Rate Period High Water Mark for the applicable fiscal year

Any customer with *adjTRL* less than its *RHWM* will have its applicable discount percentage set equal to its eligible discount percentage.

7. Treatment for Joint Operating Entity

The LDD benefit to a JOE will be equivalent to the sum of LDD benefits for all eligible individual members of the JOE. Except for LDD benefits for Tier 1 demand, the LDD benefits for the JOE will be based on each such individual utility member's applicable discount percentage applied to all charges for purchases by the individual utility member under the Tier 1 rates according to Section 1 above. The monthly LDD benefit for demand for a JOE is calculated as follows:

- (a) Each individual utility member's demand billing determinant is calculated as if such member were not a member of a JOE.
- (b) The demand billing determinants for all individual utility members are summed.
- (c) The individual utility members' calculated demand billing determinants are scaled (up or down) so that the sum of all individual utility members' calculated demand billing determinants equals the JOE's demand billing determinant.

- (d) The demand LDD benefit attributable to each eligible individual member of the JOE is equal to the member's scaled demand billing determinant multiplied by the member's applicable discount percentage and the applicable monthly Tier 1 demand charge.
- (e) The demand LDD benefits of the eligible individual members of the JOE are summed to yield the demand LDD benefit to the JOE.

C. Irrigation Rate Discount

1. Discount for Eligible Customers

Section 3 of Exhibit D of the CHWM Contracts describes Irrigation Rate Mitigation (IRM), and Section 10.3 of the Tiered Rate Methodology describes an Irrigation Rate Mitigation Product (IRMP). Both the IRM and IRMP are implemented through the Irrigation Rate Discount (IRD) set forth in this provision.

In May, June, July, August, and September, an eligible customer shall have the Irrigation Rate Discount of 11.76 mills/kWh applied to the lesser of the amount of energy purchased at Tier 1 rates in the month or the irrigation load amounts listed in Exhibit D of its CHWM Contract.

The eligibility amounts for the Irrigation Rate Discount are set forth in Section 3.1 of Exhibit D of the CHWM Contracts and are subject to the True-Up process referenced in Section 3.2 of the Contract and described more fully below.

For a Load Following or Block customer, the energy purchased at Tier 1 rates will be equal to its Actual Monthly/Diurnal Tier 1 Load used to calculate its Load Shaping billing determinant. For a Slice/Block customer, the energy purchased at Tier 1 rates will be equal to the sum of the customer's monthly Block purchase at Tier 1 rates plus the customer's Slice percentage multiplied by the monthly/diurnal RHWM Tier 1 System Capability.

The Irrigation Rate Discount for a JOE will be calculated based on individual utility members' loads and billed to the JOE and designated for each eligible utility.

BPA requires a participating customer to implement cost-effective conservation measures on eligible irrigation systems in its service territories. The customer may use its Energy Efficiency Incentive fund for this purpose.

2. Metering Requirements

The customer is required to read irrigation meters at the beginning of May and after the end of the Irrigation Rate Discount season (September 30). The customer shall provide to BPA monthly metered irrigation load information for the months of May through September in a form that is acceptable to BPA no later than October 31 of each year to ensure a timely True-Up calculation.

3. Irrigation Rate Discount True-Up and Reimbursement

There will be an assessment of the Irrigation Rate Discount each November to ensure the customer served the full amount of irrigation load for which it received an Irrigation Rate Discount. The actual metered irrigation kilowatt-hour amounts submitted by the customer each year will be increased by 7 percent to account for losses (measured irrigation load) before they are compared to the billed irrigation load amounts.

If the sum of a customer's May through September measured irrigation load is less than the sum of the May through September billed irrigation load amounts, a True-Up calculation is required. However, if the sum of a customer's May through September measured irrigation load is greater than or equal to the sum of the May through September billed irrigation load amounts, a True-Up calculation is not applicable.

The True-Up is calculated as follows. The measured irrigation load for the May through September period will be subtracted from the sum of the May through September billed irrigation load amounts. The result, if positive, will be multiplied by the Irrigation Rate Discount to determine the True-Up reimbursement. The True-Up reimbursement shall appear as a charge on a subsequent monthly power bill.

D. Demand Rate Billing Determinant Adjustments

BPA may adjust customers' bills after the fact for changes to demand charge billing determinants, as described below.

1. Extreme Load Shift Demand Billing Determinant Adjustment

(a) Calculating the Billing Determinant

If a customer's monthly CDQ-adjusted HLH load factor (aHLH divided by the quantity (i) Tier 1 CSP minus (ii) CDQ minus (iii) SuperPeak) is less than 55 percent, BPA may recompute a customer's demand billing determinant for the month. The month shall first be separated into two or more partial-month periods using the extreme load shift events that occur during the month as demarcations for the periods. For each partial-month period, a separate demand value shall be calculated using the same arithmetic method used to compute the customer's demand billing determinant for the full month, but such calculation shall use only the peak and energy consumed during each partial-month period. If BPA agrees to an adjustment, the largest of the partial-month demand values among the partial-month periods shall be used as the customer's demand billing determinant for the entire month.

(b) Notification Requirement

The customer shall be responsible for notifying BPA in the event it believes it may qualify for an extreme load shift demand billing determinant recalculation. BPA shall not be responsible for demand billing determinant recalculation without customer notification. BPA will not consider a customer request to recalculate a demand

billing determinant when such request occurs more than 90 days after the customer's power bill is produced and communicated to the customer.

2. Recovery Peak Demand Billing Determinant Adjustment

(a) Calculating the Billing Determinant

The demand CSP may be reduced by the kilowatt difference between the CSP resulting from a Recovery Peak and the next highest HLH peak during the month that is not a Recovery Peak.

Recovery Peak shall mean an extraordinary CSP measured in a customer's load following return to service from an outage. A Recovery Peak for which BPA would consider a Recovery Peak Demand Billing Determinant Adjustment must have all three of the following characteristics:

- (1) the CSP occurred during one of the two (2) hours immediately following restoration of service after an outage due to an Uncontrollable Force, provided that the outage lasted for two hours or more;
- (2) the outage reduced the utility's Total Retail Load (TRL) by 25 percent or more; and
- (3) the demand billing determinant resulting from such a CSP is 10 percent or more of those CSP kilowatts.

In determining the 25 percent threshold, the TRL reduction is computed by comparing the TRL measured during any hour of the outage to the TRL measured in the hour ended immediately prior to the hour in which the outage began. BPA may consider evidence that an observed CSP is not extraordinary. Such evidence may include that substantial restoration of service occurred more than two hours prior to the potential Recovery Peak hour, the hourly load patterns before and after the outage, and loads of similarly situated customers that did not experience a simultaneous outage due to an Uncontrollable Force.

(b) Notification Requirement

The customer shall be responsible for notifying BPA in the event it believes it may qualify for a demand billing determinant recalculation. BPA shall not be responsible for demand billing determinant recalculation without customer notification. BPA shall not consider a customer request to recalculate a demand billing determinant when such request occurs more than 90 days after the customer's power bill is produced and communicated to the customer.

E. Load Shaping Charge True-Up Adjustment

The Load Shaping Charge True-Up Adjustment is applicable to customers purchasing the Load Following product in specific circumstances. The Adjustment shall be determined following each fiscal year of the rate period and shall appear on the customers' power bills.

1. Load Shaping Charge True-Up Rate

<i>FY</i>	<i>Rate in mills/kWh</i>
2018	-12.75
2019	-12.75

The Load Shaping Charge True-Up rates are subject to adjustment during the Rate Period by the Power CRAC (GRSP II.O); the Power RDC (GRSP II.P); the Emergency NFB Surcharge (GRSP II.Q); and the Spill Surcharge (GRSP Appendix C).

2. Load Shaping Charge True-Up Billing Determinants

(a) Annual Deviation

The Annual Deviation for each customer determines whether the customer may be eligible for a True-Up charge or credit.

$$\text{Annual Deviation} = \frac{\text{Actual Annual Tier 1 Load (measured)}}{\text{TOCA Load (calculated)}} \text{ minus}$$

TOCA Load is the annual amount of energy that is used to calculate the customer's TOCA. If the customer's TOCA is modified pursuant to the TOCA Adjustment, GRSP II.G, TOCA Load will reflect the Adjusted TOCA. If Annual Deviation is zero, there may be no True-Up; see Special Implementation Provision, Section 3 below.

(b) True-Up Credit

If Annual Deviation is positive, the customer is eligible for a True-Up credit if Above-Forecast Amount is positive (greater than zero).

$$\text{Above-Forecast Amount} = \frac{\text{RHWM (calculated)}}{\text{TOCA Load (calculated)}} \text{ minus}$$

If Above-Forecast Amount is positive, the True-Up Credit billing determinant equals negative one (-1) multiplied by the lesser of:

- (1) Annual Deviation, or
- (2) Above-Forecast Amount.

There is no True-Up if Above-Forecast Amount equals zero (0).

(c) True-Up Charge

If Annual Deviation is negative, the customer may be subject to a True-Up charge. If Above-RHWM Load is less than the absolute value of the Annual Deviation, the customer is subject to a True-Up charge.

$$\begin{array}{l} \textit{True-Up Charge} \\ \textit{Billing Determinant} \end{array} = \begin{array}{l} \textit{Absolute value of the Annual Deviation} \\ \textit{minus} \\ \textit{Above-RHWM Load} \end{array}$$

The True-Up Charge billing determinant cannot be less than zero.

3. Special Implementation Provision

Special implementation provisions apply if two conditions are met:

- (a) the customer has Above-RHWM Load, and
- (b) the customer has an Above-Forecast Amount greater than zero.

If both these conditions are met, the customer may be eligible for an additional Load Shaping True-Up credit.

If the Annual Deviation is negative or zero and the absolute value of the Annual Deviation is less than the customer's Above-RHWM Load, then the Special True-Up Credit billing determinant is negative one (-1) multiplied by the least of (i) the customer's Above-RHWM Load; (ii) the Above-RHWM Load minus the absolute value of the Annual Deviation; or (iii) the Above-Forecast Amount.

If the Annual Deviation is positive and the Annual Deviation amount is less than the Above-Forecast amount, then the Special True-Up Credit billing determinant is negative one (-1) multiplied by the lesser of (i) the customer's Above-RHWM Load; or (ii) the Above-Forecast amount minus the Annual Deviation.

4. Load Shaping Charge True-Up Adjustment

The Load Shaping Charge True-Up Adjustment is equal to the Load Shaping Charge True-Up rate multiplied by the sum of (i) the True-Up Credit billing determinant; (ii) the True-Up Charge billing determinant; and (iii) the Special True-Up Credit billing determinant.

The final Load Shaping Charge True-Up Adjustment for each customer shall be applied as either a one-month credit (if the adjustment is negative) or a three-month charge (if the adjustment is positive) spread equally across the three months following the month the final Load Shaping Charge True-Up Adjustment is determined by BPA. Load Shaping customers have the option to pay the entire charge in one month. There shall be no interest component applied to the Load Shaping Charge True-Up payment schedule.

F. Tier 2 Rate TCMS Adjustment

This adjustment will recover the cost BPA incurs as a result of a transmission event (in the form of either a planned transmission outage or a transmission curtailment) along the transmission path, between the Point of Receipt and the Point of Delivery, used to deliver energy associated with the power purchases for the Tier 2 cost pools. In such a transmission event situation, a TCMS adjustment will be applied to customers' bills if they purchase power at the applicable Tier 2 rate. The method used to calculate the aggregate TCMS adjustment is specified in GRSP II.1.5.(b) and (c). The aggregate TCMS adjustment will be allocated to customers based on each customer's proportional energy share of the applicable Tier 2 cost pool.

G. TOCA Adjustment

For each customer purchasing Firm Requirements Power service under a CHWM Contract, a TOCA for each year of the rate period is calculated in the BP-18 7(i) process and will be made available to the customer prior to October 1, 2017. A customer's TOCA for a fiscal year will be revised only as specified below.

The customer's adjusted TOCA will be used to establish the billing determinant for the Composite, Slice, and Non-Slice customer charges for the relevant fiscal year. No other customer's TOCA shall be affected by this TOCA adjustment.

If a TOCA is modified after the October power bill is issued for the fiscal year to which the modified TOCA applies, the customer will be billed retroactively to October 1 of that fiscal year through a one-time billing adjustment. The billing adjustment will be calculated as (i) the sum of the amount billed for the months prior to any mid-year TOCA adjustment minus (ii) the sum of the amount that should have been billed for those same months with the mid-year adjusted TOCA. A positive calculation is a credit to the customer, and a negative calculation is a charge to the customer.

1. Load Following Customers

If there is substantial reason for BPA to believe that the customer's Actual Annual Tier 1 Load will differ from its Forecast Net Requirement determined in the RHW Process for the applicable year, BPA shall calculate an Adjusted TOCA for that Load Following customer using an updated estimate of the customer's Actual Annual Tier 1 Load in place of the customer's Forecast Net Requirement, as follows:

$$\frac{\text{Updated estimate of Customer's Actual Annual Tier 1 Load}}{\text{Sum of all Customers' RHWMs}} \times 100$$

If the resulting TOCA differs from the TOCA calculated in the BP-18 7(i) process by at least 20 percent, this Adjusted TOCA will be used in place of the TOCA calculated in the BP-18 7(i) process.

The Load Following customer and BPA may agree to revise a TOCA for a difference of less than 20 percent

If the customer's CHWM has changed due to (1) acquiring annexed load from a utility with a CHWM, or (2) having its load annexed by a utility with a CHWM, then the customer's RHWM and TOCA will be updated to account for such change. Such TOCA changes may occur prior to the start of the fiscal year or within the fiscal year.

2. Slice/Block or Block Customers

BPA will revise the TOCA of a Slice/Block or Block customer in four circumstances:

- (a) If the customer's Annual Net Requirement is less than its RHWM and differs from the Forecast Net Requirement used in the BP-18 7(i) process, the customer's TOCA shall be recalculated for that fiscal year using the customer's Annual Net Requirement.
- (b) If the customer's Annual Net Requirement equals or exceeds its RHWM, and its Forecast Net Requirement used in the BP-18 7(i) process is less than its RHWM, then the customer's TOCA shall be recalculated for that fiscal year using the customer's RHWM.
- (c) If a customer's Annual Net Requirement changes within a fiscal year due to a change in the customer's Specified Resource amounts within a fiscal year, then the customer's TOCA shall be recalculated.
- (d) If the customer's CHWM has changed due to (1) acquiring annexed load from a utility with a CHWM, or (2) having its load annexed by a utility with a CHWM, then the customer's RHWM and TOCA will be updated to account for such change. Such TOCA changes may occur prior to the start of the fiscal year or within the fiscal year.

H. DSI Reserves

DSI Value of Reserves Adjustment. Pursuant to Section 7(c)(3) of the Northwest Power Act, a DSI customer's wholesale power bill will be adjusted to reflect the value of the Minimum DSI Operating Reserve – Supplemental. 16 U.S.C. § 839e(c)(3). The DSI Operating Reserve – Supplemental is a contractual right for BPA to interrupt DSI load being served with Industrial Firm Power in a megawatt amount equal to 10 percent of the amount

of power scheduled for delivery at the time the interruption request occurs. The Minimum DSI Operating Reserve – Supplemental provided by a DSI customer must be consistent with North American Electric Reliability Corporation (NERC), Western Electricity Coordinating Council (WECC), and Northwest Power Pool (NWPP) standards and criteria, including the following:

1. The interruptible load must be off-line or the increased generation must be on-line within 10 minutes after a call from BPA.
2. In the event of a system disturbance, the interruptible load or increased generation must be accessible in advance of any need for BPA to request reserves from other Northwest Power Pool members.
3. The interruptible load must be available to be off-line for up to 105 minutes, or increased generation must be available to be on-line for up to 105 minutes.
4. There are no limitations on the number of times or aggregate minutes the Minimum DSI Operating Reserve – Supplemental may be utilized.

Optional Reserves. BPA is not obligated to purchase any DSI Reserves(s) beyond the Minimum DSI Operating Reserve – Supplemental. However, BPA’s contracts with DSI customers contain a contingent right to purchase additional reserves to the extent they are needed for operational purposes and can be made available by the customer. These contract provisions are designed to provide flexibility that will allow BPA to negotiate company-specific interruption rights, with the price for such reserves based on the characteristics of the DSI Reserve(s) provided. To ensure that any such purchases by BPA are cost-effective, the maximum amount to be paid by Power Services for Operating Reserves – Supplemental is capped at \$7.12 per kW per month.

The availability of optional DSI Reserve(s) purchased by BPA must be consistent with NERC, WECC, and NWPP standards and criteria specific to balancing authority area Operating Reserve Requirements, including the following characteristics:

1. The interruptible load must be off-line or the increased generation on-line within the period specified for the applicable DSI Reserve purchased.
2. The interruptible load or increased generation must be accessible in advance of any need to request reserves from other Northwest Power Pool members.

In addition to these two characteristics, the issues identified below will guide consideration of when BPA may pay the maximum value for DSI Reserves:

1. The degree to which BPA has discretion with respect to when and how to use the reserves and to determine what resources to call on in the event of system disturbance or for some other purpose specified in any negotiated agreement for optional reserves.
2. Duration of time the interruptible load is available to be off-line or increased generation is available to be on-line.

I. Resource Support Services and Transmission Scheduling Service

Resource-specific RSS rates will be posted on the BPA website. Unless stated otherwise, the resource generation amounts used in the calculations below that are from the customer's CHWM Contract are (1) amounts specified in monthly/diurnal megawatthour amounts and annual average megawatt amounts in Sections 2, 3, and 4 of Exhibit A (Exhibit A amounts); (2) planned amounts specified in monthly/diurnal megawatthour amounts in Section 2.3.6.1(2) of Exhibit D (Exhibit D planned amounts); or (3) planned amounts listed in monthly/diurnal megawatt-per-hour amounts in Section 2.3.6.1(3) of Exhibit D (Exhibit D hourly average planned amounts).

1. Diurnal Flattening Service Charges

DFS financially converts the output of a variable, non-dispatchable generating resource into output that is equivalent to a flat amount of power within each diurnal period of a month. Generally, DFS does not apply to small, non-dispatchable resources as defined in the customer's CHWM Contract. When DFS charges are coupled with Resource Shaping Charges, the variable generating resource is financially converted to one that is equivalent to a flat annual block of power. These charges are applied to each resource that is receiving this service.

DFS shall apply to the non-Federal resource the customer is applying to its load and any portion of the resource remarketed by BPA.

(a) DFS Energy Charge

(1) DFS Energy Rate

The RSS module of BPA's RAM2018 calculates the DFS energy rate for each resource. Generally, for each monthly/diurnal period, the sum of hourly generation in excess of average monthly/diurnal Exhibit D planned amounts is multiplied by 25 percent. The result is multiplied by the applicable monthly/diurnal Resource Shaping rate in GRSP II.I.2(a)(1) below. The monthly/diurnal results are summed for the year and divided by the total Exhibit D planned amounts for that same year to calculate the DFS energy rate.

(2) DFS Energy Billing Determinant

The DFS energy billing determinant is the actual generation for the particular resource during the billing month. The actual generation amounts will be either the resource meter readings, or resource transmission schedules if the resource requires an e-Tag.

(3) Calculation of DFS Energy Charge

For each resource, the DFS energy charge is calculated by multiplying the DFS energy rate by the DFS energy billing determinant for each month.

(b) DFS Capacity Charge

(1) DFS Capacity Rate

The rates are the monthly PF Tier 1 demand rates shown in Section 2.1.2.1 of the PF-18 rate schedule.

(2) DFS Capacity Billing Determinant

The billing determinant is the difference between the resource's monthly average HLH Exhibit D planned amounts in one year and the calculated monthly firm capacity of the resource.

The RSS module of BPA's RAM2018 calculates monthly firm capacity amounts for each resource. Generally, the firm capacity calculation represents the lowest level of historical generation in a HLH period of a month after accounting for planned outages and forced outages.

(3) Calculation of DFS Capacity Charge

For each resource, the DFS Capacity charge is the lesser of:

- (1) the annual sum of (i) the monthly DFS Capacity rates multiplied by (ii) the monthly DFS billing determinants; or
- (2) the annual average Exhibit D planned amount multiplied by the sum of the monthly PF Tier 1 demand rates.

The result is then divided by 12 to calculate a flat monthly charge that will be specified in Exhibit D of the customer's CHWM Contract. This charge is take-or-pay, such that if a customer can no longer apply the resource to load or if its application to load is delayed, the capacity charge shall still apply.

2. Resource Shaping Charge and Resource Shaping Charge Adjustment

(a) Resource Shaping Charge

(1) Resource Shaping Rate

The monthly/diurnal Resource Shaping rates are equal to the PF Tier 1 Load Shaping rates shown in Section 2.1.3.1 of the PF-18 rate schedule.

(2) Resource Shaping Billing Determinant

The billing determinant for each resource is the difference between (1) the monthly/diurnal Exhibit D planned amounts or the monthly/diurnal Exhibit A amounts; and (2) the annual average Exhibit A amount converted to a monthly/diurnal shape (in MWh) using the appropriate monthly/diurnal hours for the same year. Generally, RSC does not apply to small, non-dispatchable

resources as defined in the customer's CHWM Contract. When DFS is provided to a resource to which RRS also applies, the billing determinant for each resource is the difference between (i) the monthly/diurnal Exhibit D planned amounts and (ii) the sum of the annual average Exhibit A amounts and Resource Remarketing amounts in Exhibit D for the same year.

(3) Calculation of Resource Shaping Charge

For each resource, the Resource Shaping Charge is calculated by multiplying the Resource Shaping rate by the Resource Shaping billing determinant for each monthly/diurnal period. The sum of the values is divided by 24 (or 12 if the service applies in only one fiscal year) to calculate a flat monthly charge.

(b) Resource Shaping Charge Adjustment

(1) Resource Shaping Charge Adjustment Rate

The rates are the monthly/diurnal Resource Shaping rates described in GRSP II.I.2(a)(1) above.

(2) Resource Shaping Charge Adjustment Billing Determinant

For each resource, the billing determinant is the difference between Exhibit D planned amounts and the actual monthly/diurnal generation. The actual generation amounts will be either the resource meter readings, or resource transmission schedules if the resource requires an e-Tag. The calculation of the Resource Shaping Charge Adjustment billing determinant will also include energy provided through FORS, TCMS, planned outage replacement, economic dispatch, and unauthorized increases (UAI) in the determination of actual generation.

(3) Calculation of Resource Shaping Charge Adjustment

For each resource, the Resource Shaping Charge Adjustment is calculated by multiplying the Resource Shaping Charge Adjustment rate by the Resource Shaping Charge Adjustment billing determinant for each monthly/diurnal period. On a monthly/diurnal basis this calculation can result in either a charge or a credit.

3. Secondary Crediting Service (SCS) Charges

SCS provides a Load Following customer that dedicates the entire output of a hydroelectric Existing Resource with (1) a credit for the energy produced by that resource that is in excess of the Exhibit A amounts, and (2) a charge for any energy shortfall by the resource from the Exhibit A amounts. There is also an SCS Administrative Charge for providing this service.

When a resource has SCS applied to it, the PF Tier 1 demand and Load Shaping billing determinants will be calculated using the applicable monthly/diurnal Exhibit A amounts instead of either the actual metered values or annual average Exhibit A amounts.

(a) SCS Shortfall Energy Charges and Secondary Energy Credits

(1) SCS Energy Rate

The rates are the monthly/diurnal Resource Shaping rates described in GRSP II.I.2(a)(1) above.

(2) SCS Energy Billing Determinant

For each resource, the billing determinant is the difference between the actual monthly/diurnal generation and monthly/diurnal Exhibit A amounts. The actual generation amounts will be either the resource meter readings, or resource transmission schedules if the resource requires an e-Tag. The actual generation shall include energy amounts provided through TCMS.

(3) Calculation of SCS Shortfall Energy Charge/Secondary Energy Credit

For each resource, the charge or credit is calculated by multiplying the SCS energy rate by the SCS energy billing determinant for each monthly/diurnal period. On a monthly/diurnal basis, this calculation can result in a charge or a credit. If the actual generation exceeds the Exhibit A amount, the customer will receive a credit. If the actual generation is less than the Exhibit A amount, the customer will receive a charge.

(b) SCS Administrative Charge

(1) SCS Administrative Rate

The rate is the monthly PF Tier 1 demand rate shown in Section 2.1.2.1 of the PF-18 rate schedule.

(2) SCS Administrative Charge Billing Determinant

For each resource, the billing determinant is the monthly average HLH Exhibit A amount multiplied by the forced outage rating.

(3) Calculation of SCS Administrative Charge

For each resource, the SCS Administrative Charge is calculated by multiplying the SCS Administrative rate by the SCS Administrative billing determinant for each month. The sum of the values is divided by 12 to calculate a flat monthly charge. The SCS Administrative charge will be specified in Exhibit D of the customer's CHWM Contract.

4. Forced Outage Reserve Service (FORS) Charges

FORS is an optional service to provide an agreed-upon amount of capacity and energy to customers that have a qualifying resource that experiences a forced outage.

(a) FORS Capacity Charge

(1) FORS Capacity Rate

<i>Month</i>	<i>Rate in \$/kW</i>
October	10.45
November	10.65
December	11.83
January	11.45
February	11.15
March	9.28
April	7.68
May	6.49
June	6.92
July	9.63
August	10.98
September	10.91

(2) FORS Capacity Billing Determinant

For each resource, the billing determinant is the monthly firm capacity multiplied by the forced outage rating. The monthly firm capacity is calculated in the manner described under the DFS Capacity billing determinant in GRSP II.I.1.(b)(2).

(3) Calculation of FORS Capacity Charge

For each resource, the FORS Capacity Charge is calculated by multiplying the FORS Capacity rate and the FORS Capacity billing determinant for each month. The sum of the values is divided by 12 to calculate a flat monthly charge. The FORS Capacity charge will be specified in Exhibit D of the customer's CHWM Contract. This charge is take-or-pay, so that if a customer can no longer apply the resource to load or if its application to load is delayed, the capacity charge shall still apply.

(b) FORS Energy Charge

(1) FORS Energy Rate

The rate for the energy provided during the first 24 hours of a forced outage will be the average of the Powerdex Mid-C hourly index prices (or its replacement)

during hours of the forced outage. The rate for energy provided after the first 24 hours of a forced outage will be the diurnal Intercontinental Exchange (ICE) Mid-C Day Ahead Power Price Index (or its replacement) over the applicable diurnal period for which energy is provided. If any Mid-C price used in computing the average is less than zero, the average of the prices will be computed using a zero price for such hours.

(2) FORS Energy Billing Determinant

The FORS energy billing determinant is the total actual replacement generation a resource requires to meet the Exhibit D hourly average planned amount, subject to the FORS energy limits specified therein.

(3) Calculation of FORS Energy Charge

For each resource, the monthly FORS energy charge is calculated by multiplying the FORS energy rate by the FORS energy billing determinant.

5. Transmission Scheduling Service Charge and Transmission Curtailment Management Service Charge

Transmission Scheduling Service (TSS) is a service provided by Power Services to undertake certain scheduling obligations on behalf of the customer. Transmission Curtailment Management Service (TCMS) is a feature of TSS under which BPA provides either replacement transmission or power to customers that have a qualifying resource that experiences a transmission event pursuant to the conditions specified in Exhibit F of the CHWM Contract.

(a) TSS Charge

(1) TSS Rate

<i>Fiscal Year</i>	<i>Rate in mills/kWh</i>
2018	0.14
2019	0.14

(2) TSS Billing Determinant

The TSS billing determinants are the annual Exhibit A amounts in kilowatthours. When TSS is provided to a resource to which RRS also applies, the TSS billing determinant for each resource is (1) the annual Exhibit A amounts in kilowatthours plus (2) the RRS Remarketed amounts that will be included in Exhibit D of the CHWM Contract for the same year.

(3) Calculation of TSS Charge

For each eligible resource, the TSS Charge is calculated by multiplying the TSS rate and the TSS billing determinant for each month of the rate period (or an individual fiscal year if this service applies only in one fiscal year). The sum of the values is divided by 24 (or 12 if the service applies in only one fiscal year) to calculate a flat monthly charge. The charge is subject to a cap (not including OATI registration fee recovery adjustments described below). Charges for Specified Resources and Unspecified Resource Amounts serving Above-RHWM Load are capped such that if the annual cost to the customer using the TSS rate exceeds \$978/month, then the monthly charge is capped at \$978/month. Charges for Unspecified Resource Amounts serving NLSL and 9(c) export decrement obligations are capped such that if the annual cost to the customer using the TSS rate exceeds \$2,934/month, then the monthly charge is capped at \$2,934/month.

For each TSS customer, BPA will determine the number of resources receiving TSS. Then the \$200 annual OATI registration fee is applied evenly across those resources and divided by 12 months in the applicable fiscal years of the rate period.

(b) TCMS Charge if Replacement Power is Provided

If BPA purchases replacement power during a transmission event for a resource supported by TCMS, then the TCMS charge will be the cost of such purchased power. If BPA does not purchase replacement power, then the TCMS charge will be calculated in accordance with the sections below.

(1) TCMS Rate

The TCMS rate will be the Powerdex Mid-C hourly index price (or its replacement) for the hour the event occurred. If any Mid-C price is less than zero, the TCMS energy rate will be zero for that hour.

(2) TCMS Billing Determinant

The TCMS billing determinant is the total actual kilowatthours of replacement power BPA supplies.

(3) Calculation of TCMS Charge

The TCMS Charge shall equal the sum of charges for Bands 1 through 3. For each band, the charge shall be calculated as follows:

Apportioned TCMS billing determinant multiplied by the TCMS Rate multiplied by the Factor.

Where:

Band	Apportioned TCMS Billing Determinant	Factor
	<i>The portion of the TCMS billing determinant that is:</i>	
1	Less than or equal to (i) 1.5 percent of the TSS billing determinant or (ii) 2 MW, whichever is larger	1.00
2	Greater than the apportioned TCMS billing determinant for Band 1, up to and including (i) 7.5 percent of the TSS billing determinant or (ii) 10 MW, whichever is larger	1.10
3	Greater than the apportioned billing determinant for Band 2	1.25

(c) TCMS Charge if Alternative Transmission is Provided

When replacement Point-to-Point transmission is used to deliver the customer’s eligible resource to load using an alternate transmission path, for each resource the TCMS charge is the cost of the additional transmission BPA purchases plus any additional costs, including real power losses associated with using the replacement transmission.

6. Grandfathered Generation Management Service (GMS)

GMS allows a Load Following customer that dedicated the entire output of an Existing Resource that received GMS during Subscription to run that resource against load and offset its Tier 1 Load.

(a) GMS Reservation Rate

The rate is the monthly PF Tier 1 demand rate shown in Section 2.1.2.1 of the PF-18 rate schedule.

(b) GMS Reservation Billing Determinant

For each resource, the billing determinant is the monthly firm capacity multiplied by the forced outage rating. The monthly firm capacity is calculated in the manner described under the DFS Capacity billing determinant in GRSP II.I.1(b)(2).

(c) Calculation of GMS Reservation Fee

For each resource, the GMS Reservation Fee is calculated by multiplying the GMS Reservation rate and the GMS Reservation billing determinant for each month. The sum of the values is divided by 12 to calculate a flat monthly charge. The GMS Reservation Fee will be specified in Exhibit D of the customer's CHWM Contract.

7. Resource Remarketing Service (RRS) Credits

RRS is an optional service to provide a remarketing credit to customers that have a qualifying non-Federal resource to which DFS applies that is expected to generate more than a customer's Above-RHWM Load. The non-Federal resource amounts used in these calculations are those specified in the customer's CHWM Contract Exhibit D RRS section (Exhibit D RRS amounts).

(a) RRS Credit

(1) RRS Rate

For each non-Federal resource, the rate shall be the Remarketing Value in GRSP II.K.3.

(2) RRS Billing Determinant

For each non-Federal resource, the billing determinant is the Exhibit D RRS amount.

(3) Calculation of RRS Credit

For each non-Federal resource, the RRS Credit is calculated by multiplying the RRS rate and the RRS billing determinant for each applicable year of the rate period. The annual value is divided by 12 to calculate a flat monthly credit.

(b) RRS Fee

The fee for providing RRS to customers is determined on a case-by-case basis.

J. NR Services for New Large Single Loads (NLSLs)

NR Services for NLSLs are applicable to Load Following customers serving NLSLs with non-Federal resources.

1. NR Energy Shaping Service for NLSL Charge

1.1 NR Energy Shaping Service Energy Charge

The energy component of the NR Energy Shaping Service either credits or debits the customer for the difference between energy amounts provided by the customer's non-Federal resources serving NLSLs and the measured load of their NLSLs.

The NR ESS energy charge can be either positive or negative and is determined through a two-step process. The first step determines the applicable rate treatment, A or B. The second step applies the rate treatment determined in the first step.

Step 1:

Determine if the customer received energy from BPA or provided energy to BPA on a net monthly basis, calculated as the measured load of the customer's NLSLs in the billing month minus the energy amounts provided by the customer's resources to serve its NLSLs during the same billing month. If this result is greater than zero, energy was purchased from BPA, and Rate Treatment A applies. If this result is zero or negative, Rate Treatment B applies.

Step 2:

ESS Energy Rate Treatment A.

Calculate two energy billing determinants for each month, one for HLH and one for LLH. Each monthly energy billing determinant is equal to (1) the total measured load of the customer's NLSL(s) receiving this service during the monthly/diurnal period minus (2) the energy amounts provided by the customer to serve those NLSLs during that same monthly/diurnal period. The billing determinant for either period can be negative. These billing determinants are multiplied by the applicable monthly/diurnal NR-18 energy rates in Section 2.1.1 of the NR-18 rate schedule to calculate the energy charge (or credit).

ESS Energy Rate Treatment B.

Calculate daily diurnal billing determinants for the month, resulting in two billing determinants for each day with both HLH and LLH periods and one billing determinant for each day with only a LLH period. Each energy billing determinant is equal to (1) the total measured load of the customer's NLSL(s) receiving this service during that daily/diurnal period minus (2) the energy amounts provided by the customer to those NLSLs during that same daily/diurnal period. The billing determinant for any period can be negative. These billing determinants are multiplied by the applicable Intercontinental Exchange (ICE) Mid-C Day Ahead Power Price Index (or its replacement) for the same daily/diurnal period to calculate each

daily/diurnal period energy charge. If a Mid-C price for any period is less than zero, the applicable rate for that period will be zero.

The monthly sum of such daily/diurnal energy charges may be adjusted as follows:

- Threshold 1: No adjustment is made if the absolute value of the monthly sum of the daily HLH plus LLH billing determinants is less than or equal to (1) 1.5 percent of the total monthly measured load of the NLSLs receiving this service, or (2) 1,488 MWh.
- Threshold 2: If Threshold 1 is exceeded, Threshold 2 will apply if the absolute value of the monthly sum of the daily HLH plus LLH billing determinants is less than or equal to (1) 7.5 percent of the total monthly measured load of the NLSLs receiving this service, or (2) 3,720 MWh. If Threshold 2 applies, the monthly sum of the daily/diurnal energy charges will be multiplied by 94 percent if the monthly sum is negative (money owed to the customer) or multiplied by 106 percent if the monthly sum is positive (money owed to BPA).
- Threshold 3: If both Threshold 1 and 2 are exceeded, Threshold 3 applies. When applying Threshold 3, the monthly sum of the daily HLH plus LLH energy charges is multiplied by 84 percent if the monthly sum is negative (money owed to the customer), or multiplied by 116 percent if the monthly sum is positive (money owed to BPA).

1.2 NR Energy Shaping Service Capacity Charge

The billing determinant for the NR ESS Capacity Charge is the amount of capacity the customer requests from BPA for standing ready to serve its NLSLs. The customer must have established monthly capacity amounts for the FY 2018–2019 rate period prior to February 1, 2017. However, at least 30 days prior to any month, the customer may notify BPA of a change to the amount of capacity it is requesting BPA to stand ready to serve its NLSLs for that month.

The billing determinant is multiplied by the applicable monthly NR demand rate (NR-18 rate schedule, Section 2.2.1) to calculate the monthly NR ESS Capacity Charge.

A monthly check will be performed to verify that the customer's actual capacity use did not exceed the monthly amount of capacity it requested BPA to provide. The actual capacity used is equal to (1) the largest hourly energy amount provided by BPA during the HLH of the month through the NR ESS minus (2) the greater of (i) the average HLH energy provided by BPA under Rate Treatment A in that same month, or (ii) zero. The Unauthorized Increase (UAI) Charge for demand will apply to the actual capacity used in excess of the monthly amounts of capacity included in the customer's request to BPA.

2. NR Resource Flattening Service Charge

The NR Resource Flattening Service (NRFS) is applicable to Load Following customers that apply the generation output of a non-dispatchable Specified Resource to serve an NLSL.

2.1 NR Resource Flattening Service Energy Charge

The NRFS energy charge is the product of multiplying the NRFS energy rate by the NRFS energy billing determinant for each month.

2.2 NR Resource Flattening Service Energy Rate

The NRFS energy rate is a unique rate developed for each resource to which NRFS is applied. For each monthly/diurnal period in a year, the sum of the hourly planned generation in excess of average monthly/diurnal planned generation amounts is multiplied by 25 percent (to reflect the energy lost when using a pumped storage hydroelectric unit to perform the energy storage). The result is multiplied by the applicable monthly/diurnal Resource Shaping rate. The monthly/diurnal results are summed for the year and divided by the total planned energy amounts to calculate the NRFS Energy rate.

2.3 NR Resource Flattening Service Energy Billing Determinant

The NRFS energy billing determinant is the total actual generation for the particular resource during the billing month. The actual generation amounts will be either the resource meter readings, or the resource transmission schedules if the resource requires an e-Tag.

K. Remarketing

1. Tier 2 Remarketing for Individual Customers

This credit and fee are applicable to customers when BPA is remarketing their Tier 2 rate purchase amounts pursuant to Section 10 of the CHWM Contract.

(a) Tier 2 Remarketing Rate

(1) For Load Following Customers

For each fiscal year, the Tier 2 Remarketing rate shall be the Remarketing Value in GRSP II.K.3.

(2) For Slice/Block and Block Customers

After notice is provided by the Slice/Block or Block customer, the rate shall be the flat annual equivalent market price forecast, as determined by BPA after the time of the notice, for the applicable fiscal year plus any additional costs incurred by BPA in purchasing power from other entities.

(b) Tier 2 Remarketing Billing Determinant

For each applicable Tier 2 rate, the billing determinant is (i) the customer's contracted annual Tier 2 amount at such rate plus real power losses, less (ii) the customer's annual Tier 2 load at such rate plus real power losses.

(c) Tier 2 Remarketing Credit

For each customer, the Tier 2 Remarketing credit is calculated by multiplying the applicable Tier 2 Remarketing rate and the Tier 2 Remarketing billing determinant. The annual value is divided by 12 to calculate a flat monthly credit.

(d) Tier 2 Remarketing Fee

The fee for remarketing customers' Tier 2 amounts is zero in FY 2018–2019.

2. Non-Federal Resource with DFS Remarketing

This credit and fee are applicable to customers when BPA is remarketing their non-Federal resources to which DFS applies, pursuant to Section 10 of the CHWM Contract.

(a) DFS Remarketing Rate

For each fiscal year, the DFS Remarketing rate shall be the Remarketing Value in GRSP II.K.3.

(b) DFS Remarketing Billing Determinant

For each applicable non-Federal resource to which DFS applies, the billing determinant is (1) the amount of the customer's non-Federal resource, as specified in the customer's CHWM Contract Exhibit A, prior to temporary resource removal; less (2) the amount of the customer's non-Federal resource needed to meet Above-RHWM Load, as specified in the customer's CHWM Contract Exhibit A, when updated for temporary resource removal.

(c) DFS Remarketing Credit

For each customer, the DFS Remarketing credit is calculated by multiplying the applicable DFS Remarketing Rate and the DFS Remarketing billing determinant. The annual value is divided by 12 to calculate a flat monthly credit.

(d) DFS Remarketing Fee

The DFS remarketing fee for a customer with a non-Federal resource supported with DFS is zero in FY 2018–2019.

3. Remarketing Value

For each fiscal year, the Remarketing Value rate shall be:

<i>Fiscal Year</i>	<i>Rate in mills/kWh</i>
2018	25.20
2019	23.00

L. Transfer Service Charges

Transfer Service applies to BPA Power Service customers that are served under non-Federal transmission service agreements.

1. Transfer Service Delivery Charge

The Transfer Service Delivery Charge shall apply to Power Services customers that purchase Federal power that is delivered over non-Federal low-voltage facilities. Low-voltage facilities are generally facilities operated below 34.5 kV.

(a) Transfer Service Delivery Rate

	<i>Rate in \$/kW</i>
All months	1.27

(b) Transfer Service Delivery Billing Determinant

The monthly billing determinant for the Transfer Service Delivery Charge shall be the total load on the hour of the Total Customer System Peak minus behind-the-meter dedicated resources or resources contractually committed to serve customer load at the low-voltage Points of Delivery provided for in non-Federal transmission service arrangements.

2. Transfer Service Operating Reserve Charge

The Transfer Service Operating Reserve Charge shall apply to Public customers that meet the following criteria: (1) BPA serves the customer by transfer service; and (2) the customer is not paying BPA Transmission Services for operating reserve for the customer's load.

(a) Transfer Service Operating Reserve Rate

- (1) The rate for the Transfer Service Spinning Operating Reserve Charge shall be equal to the ACS-18 Operating Reserve – Spinning Reserve Service rate.
- (2) The rate for the Transfer Service Supplemental Operating Reserve Charge shall be equal to the ACS-18 Operating Reserve – Supplemental Reserve Service rate.

(b) Transfer Service Operating Reserve Billing Determinant

- (1) The monthly billing determinant for the Transfer Service Spinning Operating Reserve Charge shall be the same as that used for the applicable ACS-18 Operating Reserve – Spinning Reserve Service rate, except that the load used to calculate the billing determinant for Power Services' charge shall be the metered load of the customer served by transfer (non-BPA Balancing Authority Area load) or a portion thereof (if applicable).
- (2) The monthly billing determinant for the Transfer Service Supplemental Operating Reserve Charge shall be the same as that used for the applicable ACS-18 Operating Reserve – Supplemental Reserve Service rate, except that the load used to calculate the billing determinant for Power Services' charge shall be the metered load of the customer served by transfer (non-BPA Balancing Authority Area load) or a portion thereof (if applicable).

3. Transfer Service WECC Charge

The Transfer Service WECC Charge shall apply to Public customers with load outside the BPA Balancing Authority Area.

(a) Transfer Service WECC Rate

	<i>Rate in mills/kWh</i>
All months	0.03

(b) Transfer Service WECC Billing Determinant

The monthly billing determinant for the Transfer Service WECC Charge shall be the metered load at points of delivery of the public customer served by transfer (non-BPA Balancing Authority Area load).

M. Unanticipated Load Service

1. Availability

Unanticipated Load Service (ULS) applies to any request for Firm Requirements Power received after February 1, 2017, that results in an unanticipated increase in a customer's load placed on BPA during the FY 2018–2019 rate period. Contractual obligations that result from a request for service under Section 9(i) of the Northwest Power Act also will be considered ULS. ULS also may apply to a customer that adds load through retail access, including load that was once served by the customer and returns under retail access. ULS that is used for replacement of a customer's new Specified Resource is available on only a temporary basis for the FY 2018–2019 rate period and only when requested pursuant to the required notice.

The following list includes the only sources of Unanticipated Load that will be served by BPA along with the applicable rate schedule under which each type of unanticipated load will be served.

Under PF-18, Unanticipated Load is:

- Load of a New Public (Load Following customers only)
- Load annexed from investor-owned utilities by a Public (Load Following customers only)

Under NR-18, Unanticipated Load is:

- New Large Single Loads
- Requirements service requested by investor-owned utilities

Under FPS-18, Unanticipated Load is negotiated on a case-by-case basis.

BPA also will review annexations of load between public utility customers to assess if there will be an increase in BPA's Firm Requirements Power that will be considered Unanticipated Load.

To start service for Unanticipated Load, the customer must notify BPA three months in advance of the requested service date for load amounts up to 50 aMW and six months in advance of the requested service date for load amounts greater than 50 aMW. To stop service for Unanticipated Load, the customer must notify BPA three months in advance of the requested stop date.

ULS will apply for the length of the customer's contract for Unanticipated Load Service or the conclusion of the rate period on September 30, 2019, whichever occurs first. ULS is a temporary service and may be adjusted annually. For load annexed from investor-owned utilities by a Public (Load Following customers only) served under PF-18 and for resource replacement of a Public Load Following customer, the ULS and notification requirements will not apply to unanticipated loads less than 1 aMW per year. These loads will be included in the customer's Actual Hourly Tier 1 Loads and Actual

Monthly/Diurnal Tier 1 Load for billing purposes. Any Unanticipated Load Service in a future rate period must comply with the provisions for ULS for that rate period.

2. Unanticipated Load Service Charge Under the PF-18 Rate Schedule

(a) Energy Charge

(1) Energy Rate

The energy rate may be adjusted each fiscal year and will be the greater of:

- (1) the rate for the applicable diurnal period from the table below; or
- (2) the applicable diurnal period forecast market price, as determined by BPA after the time of the request for load service, for purchased power plus any additional costs incurred by BPA in purchasing power from other entities.

<i>Month</i>	<i>Rate in mills/kWh</i>	
	<i>HLH</i>	<i>LLH</i>
October	39.49	35.24
November	40.02	37.49
December	43.03	39.35
January	42.05	36.69
February	41.29	36.69
March	36.50	33.55
April	32.42	30.29
May	29.38	24.00
June	30.46	22.06
July	37.41	31.80
August	40.86	35.36
September	40.69	34.94

(2) Energy Billing Determinant

The energy billing determinant shall be the total amount of Unanticipated Load for each diurnal period, measured in kilowatthours.

(b) Demand Charge

(1) Demand Rate

The Demand Rate is equal to the demand rate included in Section 2.1.2.1 of the PF-18 rate schedule.

(2) Demand Billing Determinant

The demand billing determinant shall be the lesser of:

- (1) the maximum hourly Unanticipated Load in a month during the HLH minus the average HLH Unanticipated Load amount for the month; or
- (2) 20 percent of the highest hourly Unanticipated Load amount in a month during the HLH.

3. Unanticipated Load Service Charge Under the NR-18 Rate Schedule

(a) Energy Charge

(1) Energy Rate

The energy rate may be adjusted each fiscal year and shall be the greater of:

- (1) the rate for the applicable diurnal period from the table below; or
- (2) the applicable diurnal period forecast market price, as determined by BPA after the time of the request for load service, for purchased power plus any additional costs incurred by BPA in purchasing power from other entities.

<i>Month</i>	<i>Rate in mills/kWh</i>	
	<i>HLH</i>	<i>LLH</i>
October	82.70	78.45
November	83.23	80.70
December	86.24	82.56
January	85.26	79.90
February	84.50	79.90
March	79.71	76.76
April	75.63	73.50
May	72.59	67.21
June	73.67	65.27
July	80.62	75.01
August	84.07	78.57
September	83.90	78.15

(2) Energy Billing Determinant

The energy billing determinant is the total of unanticipated NR Hourly Load for each diurnal period, measured in kilowatthours.

(b) Demand Charge

(1) Demand Rate

The Demand Rate is equal to the demand rate included in Section 2.2.1 of the NR-18 rate schedule.

(2) Demand Billing Determinant

The Demand billing determinant is the maximum unanticipated NR Hourly Load in a month during HLH, in kilowatts, for the billing period minus the average of the HLH unanticipated NR Hourly Load in a month.

4. Unanticipated Load Service Charge Under the FPS-18 Rate Schedule

(a) Energy Charge

(1) Energy Rate

The energy rate may be adjusted each fiscal year and shall be the greater of (1) the Resource Replacement rate for the applicable diurnal period (shown in the table below), or (2) the applicable diurnal period forecast market price, as determined by BPA after the time of the request for load service, for purchased power plus any additional costs incurred by BPA in purchasing power from other entities.

<i>Month</i>	<i>Resource Replacement Rate in mills/kWh</i>	
	<i>HLH</i>	<i>LLH</i>
October	39.49	35.24
November	40.02	37.49
December	43.03	39.35
January	42.05	36.69
February	41.29	36.69
March	36.50	33.55
April	32.42	30.29
May	29.38	24.00
June	30.46	22.06
July	37.41	31.80
August	40.86	35.36
September	40.69	34.94

(2) Energy Billing Determinant

The energy billing determinant is the total of Unanticipated Load for each diurnal period, measured in kilowatthours.

(b) Demand Charge

(1) Demand Rate

<i>Month</i>	<i>Rate in \$/kW</i>
October	10.45
November	10.65
December	11.83
January	11.45
February	11.15
March	9.28
April	7.68
May	6.49
June	6.92
July	9.63
August	10.98
September	10.91

(2) Demand Billing Determinant

The Demand billing determinant is the highest maximum unanticipated Resource Replacement load in a month during HLH, in kilowatts, for the billing period minus the average of the HLH unanticipated Resource Replacement load in a month.

N. Unauthorized Increase (UAI) Charge

The Unauthorized Increase Charge is a charge to any customer taking more power from BPA than it is contractually entitled to take.

1. Charge for Unauthorized Increase in Demand

The amount of measured demand during a HLH billing hour that exceeds the amount of demand the customer is contractually entitled to take during that hour shall be billed at 1.25 times the applicable monthly demand rate.

The billing determinant for the UAI demand charge shall be equal to the customer's single highest HLH demand that is in excess of the customer's contractual demand entitlement.

For a Load Following customer, the demand in excess of its demand entitlement shall be the shortfall of its dedicated resources delivered to load on the hour of its Customer System Peak as compared to the customer's CHWM Contract Exhibit A amount or Exhibit D amount, whichever is applicable.

For a Block customer or for the Block portion of the Slice/Block product, the customer's contractual demand entitlement for each HLH shall be the sum of its Tier 1 and Tier 2 HLH predetermined hourly schedule amounts, provided by BPA to the customer in accordance with Exhibit C of the CHWM Contract.

For a Slice customer, the Slice portion of the Slice/Block product will be subject to a demand UAI if the Slice demand is in excess of the Slice entitlement during the peak Delivery Request (Right To Power) HLH of a month. The Slice demand in excess of the Slice entitlement is measured by subtracting (i) the largest final hourly Delivery Request (Right To Power) computed using the Slice Water Routing Simulator for any HLH of a month from (ii) the hourly amount of Slice power delivery (tagged + untagged energy) from BPA for the same HLH of the same month, as such terms are defined in the Slice/Block CHWM Contract.

2. Charge for Unauthorized Increase in Energy

The amount of measured energy or Residential Exchange Program contract load that exceeds the amount of energy the customer is contractually entitled to take during a diurnal billing period shall be billed at the greater of:

- (a) 150 mills/kWh; or
- (b) Two times the highest hourly Powerdex Mid-C Index price for firm power for the month in which the unauthorized increase occurs.

In the event the hourly Powerdex Mid-C price index expires, the index will be replaced for purposes of the Unauthorized Increase charge for energy by the highest price for the month from any applicable new hourly or diurnal energy index at a hub at which Northwest parties can trade between October 1, 2017, and September 30, 2019.

O. Power Cost Recovery Adjustment Clause (Power CRAC)

The Power CRAC is an upward adjustment to certain rates that can apply to rates during FY 2018 or FY 2019 or both. It applies to these Power rates:

- Non-Slice Customer rate (PF-18)
- PF Melded rate (PF-18)
- Industrial Firm Power rate (IP-18)
- New Resource Firm Power rate (NR-18)

The Power CRAC also applies to these Transmission ACS-18 rates:

- Regulating and Frequency Response Service
- Operating Reserve – Spinning
- Operating Reserve – Supplemental

1. Calculations for the Power CRAC

Prior to the beginning of each fiscal year of the rate period (that is, each “applicable year”), BPA will forecast the end-of-year Accumulated Calibrated Net Revenue for Power (Power ACNR) for the fiscal year preceding the applicable year. If the forecast Power ACNR is less than the Power CRAC Threshold for that applicable year by at least \$5 million, the Power CRAC will trigger, and a rate increase will go into effect beginning on October 1 of the applicable year.

(a) Calculating the Power Calibrated Net Revenue (Power CNR) and Accumulated Calibrated Net Revenue (Power ACNR)

The Power CNR is Power Net Revenue (Power NR) plus the Power Net Revenue Calibration (Power NR Calibration).

Power NR for any given fiscal year is defined as generation function accrued revenue less accrued expenses (in accordance with Generally Accepted Accounting Principles).

The Power NR Calibration is the sum of the effects of a class of differences, one difference calculated for each event not forecast in the BP-18 rate case that affects Power NR and Power cash flow differently by more than \$5 million. “Power cash flow” here means changes in Financial Reserves Available for Risk Attributed to Power. Such events include certain debt management transactions, settlements of contracts, and others. For each event, the impact of the event on Power NR will be subtracted from the impact on Power cash flow.

The Power ACNR is Power CNR accumulated since the end of FY 2016. A forecast of Power ACNR is used to determine whether the Power CRAC Threshold has been reached, and if so, the required Power CRAC Amount to be collected. The forecast of Power ACNR for use in determining the Power CRAC that will apply to FY 2018 rates will be the forecast of Power CNR for FY 2017. The forecast of Power ACNR for use in determining the Power CRAC that will apply to FY 2019 rates will be the sum of the actual Power CNR for FY 2017 plus the forecast of Power CNR for FY 2018.

(b) Calculating the Power CRAC Amount

The Power CRAC Threshold is an amount of ACNR, below which Power is considered to have experienced an Underrun. The Underrun amount is equal to the Power CRAC Threshold minus forecast Power ACNR.

The Power CRAC Amount is based on the Underrun, limited by the Maximum Power CRAC Recovery Amount (the Power CRAC Cap.) There are four possibilities:

- (1) If the Underrun is less than \$5 million, there is no Power CRAC.
- (2) If the Underrun is greater than or equal to \$5 million and less than or equal to \$100 million, the Power CRAC Amount is equal to the Underrun.
- (3) If the Underrun is greater than \$100 million and less than \$500 million, the Power CRAC Amount is equal to \$100 million plus one-half of the difference between \$100 million and the Underrun.
- (4) If the Underrun is greater than or equal to \$500 million, the Power CRAC Amount is equal to \$300 million.

NOTE: In cases (2), (3), and (4) above, if an NFB Adjustment increases the Power CRAC Cap from \$300 million to a higher number, the terms will be adjusted. In cases (2) and (3), the “\$100 million” figure will be replaced by \$100 million plus the difference between the new Cap and \$300 million. In cases (3) and (4), the “\$500 million” figure will be replaced by \$500 million plus twice the difference between the new Cap and \$300 million. In case (4), the “\$300 million” figure will be replaced by the new Cap.

The Power CRAC Cap and Thresholds are shown in Table C.

Table C
Power CRAC Annual Thresholds and Caps
(dollars in millions)

<i>ACNR Calculated Near End of Fiscal Year</i>	<i>CRAC Applied to Fiscal Year</i>	<i>Threshold Measured in ACNR</i>	<i>Threshold Measured in Reserves for Risk</i>	<i>Maximum CRAC Recovery Amount (Cap)*</i>
2017	2018	\$249	\$0	\$300
2018	2019	\$464	\$0	\$300

* The Maximum CRAC Recovery Amount (Cap) may be modified by the NFB Adjustment (if triggered).

(c) Calculating the PF/IP/NR CRAC Amount and the ACS CRAC Amount

The PF/IP/NR CRAC Amount is 96.52 percent times the Power CRAC Amount.

The ACS CRAC Amount is 3.48 percent times the Power CRAC Amount.

(d) Converting the PF/IP/NR CRAC Amount to the PF/IP/NR CRAC Surcharge

Once the PF/IP/NR CRAC Amount is determined, that amount will be converted to a mills per kilowatt-hour Surcharge rate added to each of the monthly/diurnal

PF Melded, IP, and NR energy rates. The Surcharge rate will be converted to a monthly dollars per one percentage point of Non-Slice TOCA value and added to the Non-Slice Customer rate.

The PF/IP/NR CRAC Surcharge rate is calculated by dividing the PF/IP/NR CRAC Amount by the most current forecast of kilowatthours of service under the PF Melded, IP, and NR rates and the sum of PF System Shaped Loads for the applicable year.

The PF/IP/NR CRAC Surcharge rate is converted to a monthly dollars per one percentage point of Non-Slice TOCA by:

- (1) Multiplying the sum of PF System Shaped Loads by the PF/IP/NR CRAC Surcharge rate. The product of this calculation is the annual dollar amount to be collected through the Non-Slice TOCA billing determinant.
- (2) Dividing the annual dollar amount to be collected through the Non-Slice TOCA billing determinant by the sum of the Non-Slice TOCAs and dividing the result by 12.

The result of this calculation is a monthly dollars per one percentage point of Non-Slice TOCA rate adjustment.

(e) CRAC Charges for the PF, IP, and NR Rates

For service under the PF Melded, IP, or NR rates: A line item will be added to the bills for the service during the 12 months of the applicable year showing additional charges calculated by multiplying the PF/IP/NR CRAC Surcharge by the applicable kilowatthours of service.

For service under the Non-Slice Customer rate: A line item will be added to the bills for the service during the 12 months of the applicable year showing a charge calculated by multiplying the monthly dollars per one percentage point of Non-Slice TOCA rate adjustment by the Non-Slice TOCA.

(f) Converting the ACS CRAC Amount to Charges on Customers' Bills

Once the ACS CRAC Amount is determined, that amount will be passed to Transmission Services. See Transmission GRSP II.H for details of how those Transmission rates subject to the Power CRAC will be modified.

(g) Other Rate Adjustments

The Surcharge rate, calculated pursuant to GRSP II.O.1(d), will be subtracted from the Load Shaping Charge True-Up rate to create the CRAC-Adjusted Load Shaping True-Up Rate. See GRSP II.E.

The Surcharge rate calculated pursuant to Section 1(c) will be subtracted from the PF Melded Equivalent Energy Scalar to create the CRAC-Adjusted PF Melded Equivalent Energy Scalar. *See* GRSP II.R.1(c).

The Surcharge rate calculated pursuant to GRSP II.O.1(d) will also be added to each of the monthly/diurnal PF Tier 1 Equivalent energy rates. *See* GRSP II.AA.

2. Power CRAC Notification Process

BPA shall follow these notification procedures:

(a) Financial Performance Status Reports

Each quarter, BPA shall post to its external website (www.bpa.gov) preliminary, unaudited, year-to-date aggregate financial results for the generation function, including Power ACNR.

For the Second and Third Quarter Reviews, BPA shall post to its external website (www.bpa.gov) the preliminary, unaudited, end-of-year forecast of Power ACNR.

(b) Notification of Power CRAC Trigger

BPA shall complete a forecast of end-of-year Power ACNR in July 2017 for use in calculating the Power CRAC applicable to rates in FY 2018 and in September 2018 for use in calculating the Power CRAC applicable to rates in FY 2019. If the Power CRAC triggers, then BPA shall notify all customers and rate case parties by late July 2017 of the amount by which BPA intends to adjust rates for FY 2018 due to the Power CRAC, and by late September 2018 of the amount by which BPA intends to adjust rates for FY 2019.

Notification will be posted on BPA's website and will include the following:

1. the forecast of Power ACNR for the current fiscal year
2. the Power NR and the Power NR Calibration for FY 2017 in the case of the Power CRAC applicable to FY 2019 rates
3. the Power CRAC Amount
4. the PF/IP/NR CRAC Amount
5. the PF/IP/NR Surcharge
6. the monthly dollars per one percentage point of Non-Slice TOCA rate adjustment
7. the CRAC-adjusted Load Shaping True-Up Rate
8. the CRAC-adjusted PF Melded Equivalent Energy Scalar
9. the ACS CRAC Amount
10. details about how the ACS CRAC Amount has been used to modify Transmission rates for the subsequent fiscal year

The notification shall also describe the data and assumptions relied upon by BPA for all Power ACNR determinations. BPA shall make such data, assumptions, and documentation, if non-proprietary and non-privileged, available for review upon request.

Associated with any notification of Power CRAC calculations as described above, BPA shall conduct a workshop(s) to explain the Power ACNR calculations, describe the calculation of the Power CRAC Amount and allocations to various rates, and demonstrate that the Power CRAC has been implemented in accordance with these GRSPs. The workshop(s) will provide an opportunity for public comment.

If the Power CRAC applicable to FY 2018 rates triggers, then on or about July 31, 2017, BPA will post to the BPA website the final Power CRAC calculations, including any NFB Adjustment (*see* GRSP II.Q) to the Power CRAC Cap. If the Power CRAC applicable to FY 2019 rates triggers, then on or about September 28, 2018, BPA will post to the BPA website the final Power CRAC calculations, including any NFB Adjustment (*see* GRSP II.Q) to the Power CRAC Cap.

P. Power Reserves Distribution Clause (Power RDC)

The Power RDC is a distribution of financial reserves to purposes such as debt retirement, incremental capital investment, or rate reduction (a Dividend Distribution, or DD) during FY 2018 or FY 2019 or both.

If the RDC quantitative criteria (below) are met, the Administrator will determine how much of any RDC, if any, would be applied to debt reduction, incremental capital investment, a DD, or any other uses.

A DD applies to these Power rates during FY 2018 or FY 2019 or both:

- Non-Slice Customer rate (PF-18)
- PF Melded rate (PF-18)
- Industrial Firm Power rate (IP-18)
- New Resource Firm Power rate (NR-18)

A DD also applies to these Transmission ACS-18 rates:

- Regulating and Frequency Response Service
- Operating Reserve – Spinning Reserve Service
- Operating Reserve – Supplemental Reserve Service

1. Calculations for the Power RDC

Prior to the beginning of each fiscal year of the rate period (that is, each “applicable year”), BPA will forecast the end-of-year Power Accumulated Calibrated Net Revenue

(Power ACNR) and BPA Accumulated Calibrated Net Revenue (BPA ACNR) for the fiscal year preceding the applicable year. If the forecast Power ACNR is greater than the Power RDC Threshold for that applicable year by at least \$5 million, and the forecast BPA ACNR is greater than the BPA RDC Threshold for that applicable year by at least \$5 million, the Administrator will determine the amount, if any, of a Power RDC. If the Administrator determines that part of the RDC will be a DD, the resulting rate decrease will go into effect beginning on October 1 of the applicable year.

(a) Calculating the BPA ACNR

The BPA ACNR is the sum of the Transmission ACNR and the Power ACNR. See Transmission GRSP II.H.1(a) and Power GRSP II.O.1(a).

(b) Calculating the Power RDC Amount

The Power RDC can only trigger if (1) Power ACNR exceeds the Power RDC Threshold, measured in Power ACNR, and (2) BPA ACNR exceeds the BPA RDC Threshold, measured in BPA ACNR.

The Power RDC Amount is the reduction in financial reserves for risk attributed to Power caused by using reserves to retire debt, incrementally fund capital projects, decrease rates by means of a Power DD, or further other Power objectives during the year of application. The Power RDC Amount will be the smallest of the forecast Power ACNR less the Power RDC Threshold, the forecast BPA ACNR less the BPA RDC Threshold, and the Power RDC Cap, or a smaller amount if the Administrator so elects.

Table D
Power RDC Annual Thresholds and Caps
(dollars in millions)

<i>ACNR Calculated Near End of Fiscal Year</i>	<i>RDC Applied to Fiscal Year</i>	<i>Threshold Measured in Power ACNR</i>	<i>Threshold Measured in Power Reserves for Risk</i>	<i>Maximum RDC Amount (Cap)</i>
2017	2018	\$858	\$609	\$500
2018	2019	\$1073	\$609	\$500

Table E
BPA RDC Annual Thresholds
(dollars in millions)

<i>ACNR Calculated Near End of Fiscal Year</i>	<i>RDC Applied to Fiscal Year</i>	<i>Threshold Measured in BPA ACNR</i>	<i>Threshold Measured in BPA Reserves for Risk</i>
2017	2018	\$506	\$606
2018	2019	\$758	\$606

(c) Calculating the PF/IP/NR DD Amount and the ACS DD Amount

The PF/IP/NR DD Amount is 96.52 percent times the Power DD Amount.

The ACS DD Amount is 3.48 percent times the Power DD Amount.

(d) Converting the PF/IP/NR DD Amount to the PF/IP/NR DD Credit

Once the PF/IP/NR DD Amount is determined, that amount will be converted to a mills per kilowatthour PF/IP/NR DD Credit rate and subtracted from each of the monthly/diurnal PF Melded, IP, and NR energy rates. The mills per kilowatthour PF/IP/NR DD Credit will be converted to a monthly dollars per one percentage point of Non-Slice TOCA value and subtracted from the Non-Slice Customer rate.

The PF/IP/NR DD Credit rate is calculated by dividing the PF/IP/NR DD Amount by the most current forecast of kilowatthours of service under the PF Melded, IP, and NR rates and the sum of PF System Shaped Loads for the applicable year.

The PF/IP/NR DD Credit rate is converted to a monthly dollars per one percentage point of Non-Slice TOCA by:

- (1) Multiplying the sum of PF System Shaped Loads by the PF/IP/NR DD Credit rate. The product of this calculation is the annual dollar amount to be distributed through the Non-Slice TOCA billing determinant.
- (2) Dividing the annual dollar amount to be distributed through the Non-Slice TOCA billing determinant by the sum of the Non-Slice TOCAs and dividing the result by 12.

The result of this calculation is a monthly dollars per one percentage point of Non-Slice TOCA rate adjustment.

(e) Power DD Credits for the PF, IP, and NR Rates

For service under PF Merged, IP, or NR rates: A line item will be added to the bills for the service during the 12 months of the applicable year showing credits calculated by multiplying the PF/IP/NR DD Credit by the applicable kilowatthours of service.

For service under the PF Non-Slice Customer rate: A line item will be added to the bills for the service during the 12 months of the applicable year showing a credit calculated by multiplying the monthly dollars per one percentage point of Non-Slice TOCA rate adjustment by the Non-Slice TOCA.

(f) Converting the ACS DD Amount to Charges on Customers' Bills

Once the ACS DD Amount is determined, that amount will be passed to Transmission Services. See Transmission GRSP II.G for details of how the ACS DD Amount affects Transmission ACS-18 rates.

(g) Other Rate Adjustments

The Credit rate calculated pursuant to GRSP II.P.1(d) will be added to the Load Shaping True-Up rate to create the Power DD-Adjusted Load Shaping True-Up rate. See GRSP II.E.

The Credit rate calculated pursuant to GRSP II.P.1(d) will be added to the PF Merged Equivalent Energy Scalar to create the Power DD-Adjusted PF Merged Equivalent Energy Scalar. See GRSP II.R.1(c).

The Credit rate, calculated pursuant to GRSP II.P.1(d), will also be subtracted from each of the monthly/diurnal PF Tier 1 Equivalent energy rates. See GRSP II.AA.

2 Power RDC Notification Process

BPA shall follow these notification procedures:

(a) Financial Performance Status Reports

Each quarter, BPA shall post to its external website (www.bpa.gov) preliminary, unaudited, year-to-date aggregate financial results for the generation function, including Power ACNR and BPA ANR.

For the Second and Third Quarter Reviews, BPA shall post to its external website (www.bpa.gov) the preliminary, unaudited, end-of-year forecast of Power ACNR attributable to the generation function and BPA ACNR.

(b) Notification of Power RDC Trigger

BPA shall complete a forecast of end-of-year Power ACNR and BPA ACNR in July 2017 for use in calculating the Power RDC for FY 2018, and in September 2018 for use in calculating the Power RDC for FY 2019. If the Power RDC triggers, then BPA shall notify all customers and rate case parties by late July 2017 of the amounts BPA intends to use for FY 2018, and by late September 2018 of the amounts BPA intends to use for FY 2019.

Notification will be posted on BPA's website and will include the following:

1. the forecast of Power ACNR and BPA ANR for the current fiscal year
2. the PNR and the PNR Calibration for FY 2017 in the case of the Power RDC applicable to FY 2019 rates
3. the Power RDC Amount
4. the amounts to be used to retire debt, incrementally fund capital projects or other high-value Power purposes, or adjust rates for FY 2018 due to the Power DD
5. the PF/IP/NR DD Amount
6. the PF/IP/NR Surcharge
7. the monthly dollars per one percentage point of Non-Slice TOCA rate adjustment
8. the RDC-adjusted Load Shaping True-Up rate
9. the RDC-adjusted PF Melded Equivalent Energy Scalar
10. the ACS RDC Amount
11. details about how the ACS DD Amount has been used to modify Transmission rates for the subsequent fiscal year

The notification shall also describe the data and assumptions relied upon by BPA for all Power ACNR and BPA ACNR determinations. BPA shall make such data, assumptions, and documentation, if non-proprietary and non-privileged, available for review upon request.

Associated with any notification of Power RDC calculations as described above, BPA shall conduct a workshop(s) to explain the Power ACNR and BPA ACNR calculations, describe the calculation of the Power DD Amount and allocations to various rates, and demonstrate that the Power RDC has been implemented in accordance with these GRSPs. The workshop(s) will provide an opportunity for public comment.

If the Power RDC applicable to FY 2018 rates triggers, then on or about July 31, 2017, BPA will post to the BPA website the final Power RDC calculations. If the Power RDC applicable to FY 2019 rates triggers, then on or about September 28, 2018, BPA will post to the BPA website the final Power RDC calculations.

Q. NFB Mechanisms

The two NFB mechanisms described here are rate features that allow BPA to recover additional revenue if financial impacts (“Financial Effects”) from a specified set of circumstances (“Trigger Events”) in the fish and wildlife arena cause a reduction in Power Services’ forecast Net Revenue. The first mechanism, the NFB Adjustment, would increase the CRAC Cap applicable to the fiscal year(s) following the fiscal year in which an NFB Trigger Event resulting in Financial Effects occurs. The second mechanism, the Emergency NFB Surcharge, would increase rates within the fiscal year in which an NFB Trigger Event resulting in Financial Effects occurs. The latter situation would apply if waiting until the next year for additional cost recovery would be imprudent because BPA is in a “cash crunch” (defined in Section 3 below).

1. Definitions

- (a) An NFB Trigger Event is one of the following events that results in changes to BPA’s FCRPS environmental compliance obligations compared to those adopted in the most recent wholesale power rate proceeding as modified prior to this Trigger Event:
 - (1) A court order in *National Wildlife Federation vs. National Marine Fisheries Service*, No. 3:01-cv-0640-SI, 2017 WL 1829588 (D. Or. Apr. 3, 2017), *amending and superseding* 2017 WL 1135610 (D. Or. Mar. 27, 2017) (“*National Wildlife Federation*”), or any other case filed regarding an FCRPS Biological Opinion (BiOp) issued by NMFS (also known as NOAA Fisheries Service) or the U.S. Fish and Wildlife Service, or any appeal thereof (“Litigation”).
 - (2) An agreement (whether or not approved by the Court) that results in the resolution of issues in, or the withdrawal of parties from, Litigation.
 - (3) A new FCRPS BiOp including unplanned or unexpected implementation measures.
 - (4) Actions needed for meeting obligations for the development of the Columbia River System Operations Environmental Impact Statement.
- (b) Financial Effects of a Trigger Event are net reductions in estimated Power Services’ Net Revenue due to a Trigger Event that affects power sales revenues, fish and wildlife credits, power purchases, direct program expenses of the anadromous fish component of BPA’s fish and wildlife program, USACE and Reclamation O&M expenses, direct program expenses of the USFWS, or amortization of capital costs when compared with the estimate of the foregoing revenues, credits, costs, and obligations adopted in the most recent wholesale power rate proceeding, as modified by any previous Trigger Events and impacts captured by the Spill Surcharge. These effects are the total effects on the BPA System, excluding the operational or expense effects borne by Slice customers.
- (c) The Agency Within-Year TPP is the probability that BPA (including both Power Services and Transmission Services) will be able to meet all agency financial obligations to the Treasury for the fiscal year in which a Trigger Event occurs.

Agency Within-Year TPP takes into account, for the remainder of such fiscal year: (i) all funds reasonably expected to be available to BPA to repay the Treasury, including but not limited to financial reserves (including deferred borrowing), any expense reductions and revenue increases, short-term borrowing available through the Treasury Facility (which availability may be limited by constraints on BPA's remaining borrowing authority), and BPA's then-current best estimate of 4(h)(10)(C) credits for that year; and (ii) all financial obligations reasonably expected to require payment, including but not limited to Treasury payments scheduled in the BP-18 rate proceeding, repayments to Treasury required pursuant to the previous exercise of liquidity tools, and updated forecasts of other reasonably necessary expenses and reasonably necessary uses of cash.

- (d) Surcharge Amount is the amount of money to be collected under the Emergency NFB Surcharge.
- (e) Revenue Basis is the 12-month total of revenue from Power rates subject to the Emergency NFB Surcharge for a specific fiscal year.
- (f) Customer percentage is the Revenue Basis associated with each customer divided by the total Revenue Basis. Each customer percentage shall be rounded to four decimal places.

2. The NFB Adjustment

The NFB Adjustment results in an upward adjustment to the Power CRAC Cap for a fiscal year in the rate period if Financial Effects from an NFB Trigger Event(s) occur. For the BP-18 rates, the NFB Adjustment calculation can result in an increase in the annual Power CRAC Cap set forth in Table C in GRSP II.O if an NFB Trigger Event occurs prior to the fiscal year to which a CRAC is applied.

NFB Adjustment = Financial Effects of Trigger Event(s)

Adjusted Power CRAC Cap = Power CRAC Cap from Table C + NFB Adjustment

See GRSP II.O.1(b) for additional detail.

3. The Emergency NFB Surcharge

The Emergency NFB Surcharge (Surcharge) results in an upward adjustment to specified rates during a year in which (a) Financial Effect(s) occur from a Trigger Event(s) and (b) the Agency Within-Year TPP is below 80 percent (also referred to as a cash crunch). A "cash crunch" means the Agency Within-Year TPP is calculated to be below 80 percent including (1) the Financial Effects of all Trigger Events and (2) all revenues from those, but only those, CRACs and Emergency NFB Surcharges that have already been implemented (*i.e.*, calculated, and scheduled to be affecting rates). The Emergency NFB Surcharge is a separate adjustment from the NFB Adjustment.

For the BP-18 rates, the Surcharge may be implemented in FY 2018 if the (a) and (b) events required to impose the Surcharge occur in that fiscal year, or in FY 2019 if the requisite (a) and (b) events occur in that year.

The Surcharge is an upward adjustment to certain rates for FY 2018 or FY 2019 or both. It applies to these Power rates:

- Non-Slice Customer rate (PF-18)
- PF Melded rate (PF-18)
- Industrial Firm Power rate (IP-18)
- New Resource Firm Power rate (NR-18)

The Surcharge also applies to these Transmission ACS-18 rates:

- Regulating and Frequency Response Service
- Operating Reserve – Spinning Reserve Service
- Operating Reserve – Supplemental Reserve Service

There can be more than one Trigger Event in a year, and therefore there could be more than one Surcharge implemented in a fiscal year.

At the discretion of the Administrator, BPA may collect the Surcharge Amount by modifying the Monthly Surcharge to collect less in earlier months and more in later months of the fiscal year.

No Surcharge will be levied if the Surcharge Amount described below is calculated to be less than \$10 million. If the first month in which the Surcharge bill is sent out occurs during the last quarter of the fiscal year in which the Trigger Event occurred, then the Surcharge Amount in each such month shall not exceed \$25 million.

If Surcharge revenues total less than the total Financial Effects for Trigger Events in that year, the remaining balance of Financial Effects will be included in an NFB Adjustment to the Power CRAC Cap for the subsequent year.

4. Calculations for the NFB Emergency Surcharge

(a) Calculating the NFB Surcharge Amount

NFB Surcharge Amount = Financial Effects of Trigger Event

(b) Calculating the PF/IP/NR Surcharge Amount and the ACS Surcharge Amount

The PF/IP/NR Surcharge Amount is 96.52% times the Surcharge Amount.

The ACS Surcharge Amount is 3.48% times the Surcharge Amount.

(c) Converting the PF/IP/NR Surcharge Amount to the PF/IP/NR Surcharge

Once the PF/IP/NR Surcharge Amount is determined, that amount will be converted to a mills-per-kilowatthour Surcharge rate added to the IP and NR rates. The Surcharge rate will be converted to a monthly dollars per one percentage point of Non-Slice TOCA value and added to the Non-Slice Customer rate (making a negative Non-Slice Customer rate less negative).

The PF/IP/NR Surcharge rate is calculated by dividing the PF/IP/NR Surcharge Amount by the most current forecast of kilowatthours of service under PF Melded, IP, and NR rates and the sum of PF System Shaped Loads for the applicable months of the applicable year.

The PF/IP/NR Surcharge rate is converted to a monthly dollars per one percentage point of Non-Slice TOCA by multiplying the sum of PF System Shaped Loads for the applicable months by the PF/IP/NR Surcharge rate. The product of this calculation is the dollar amount to be collected through the Non-Slice TOCA billing determinant. The dollar amount to be collected through the Non-Slice TOCA billing determinant will be divided by the sum of the Non-Slice TOCAs and divided again by the applicable months in the fiscal year. The result of this calculation is a monthly dollars per one percentage point of Non-Slice TOCA rate adjustment.

(d) Customer Charges for the PF/IP/NR Surcharge

Line items will be added to the bills during the applicable months of the applicable year for service under PF Melded, IP, and NR rates showing additional charges calculated by multiplying the PF/IP/NR Surcharge rate by the applicable kilowatthours of service.

A line item will be added to the bills during the applicable months of the applicable year for service under PF rates showing an additional charge calculated by multiplying the monthly dollars per one percentage point of Non-Slice TOCA rate adjustment by the Non-Slice TOCA.

(e) Converting the ACS Surcharge Amount to Charges on Customers' Bills

Once the ACS Surcharge Amount is determined, that amount will be passed to Transmission Services. *See* GRSP II.P.1(f). *See* Transmission GRSP II.G for details of how those Transmission rates subject to the Surcharge will be modified.

(f) Other Rate Adjustments

The PF/IP/NR Surcharge rate will be converted to an annual Surcharge rate. The annual Surcharge rate is calculated as the PF/IP/NR Surcharge rate multiplied by the quotient of the sum of PF System Shaped Loads for the applicable surcharge months divided by the annual sum of PF System Shaped Loads.

The annual Surcharge rate will be applied to the Load Shaping True-Up Rate to create the Surcharge-Adjusted Load Shaping True-Up rate. The annual Surcharge rate will be applied to the PF Melded Equivalent Energy Scalar, see GRSP II.R.1(c), to create the Surcharge-Adjusted PF Melded Equivalent Energy Scalar.

The PF/IP/NR Surcharge will also be applied to the applicable months of the PF Tier 1 Equivalent energy rates. *See* GRSP II.AA.

5. Criteria for Applying the NFB Adjustment or Assessing the Surcharge

NFB Trigger Events that have Financial Effects can lead to NFB Adjustments or Surcharges according to these GRSPs if they occur in fiscal years 2017, 2018, or 2019. Whether such Trigger Events lead to NFB Adjustments or to Surcharges depends on whether BPA is in a cash crunch in the year in which the Trigger Event occurs.

If a Trigger Event occurs in FY 2017, it may result in a Surcharge for FY 2017 if BPA is in a cash crunch in FY 2017. Such a Surcharge would be governed by the BP-16 GRSPs. If BPA is not in a cash crunch, or if a Surcharge implemented pursuant to the BP-16 GRSPs during FY 2017 collects less than the full amount of the FY 2017 Financial Effects, such a Trigger Event could lead to an NFB Adjustment to the Power CRAC Cap applicable to FY 2018 and 2019, as governed by these BP-18 GRSPs.

If a Trigger Event occurs in FY 2018, it may result in either a Surcharge applicable to FY 2018 rates or an NFB Adjustment to the Power CRAC Cap applicable to FY 2019 rates. Such a Trigger Event may result in both NFB mechanisms being used if some but not all of the Financial Effects were recoverable from a Surcharge in FY 2018. All of these possibilities will be governed by these BP-18 GRSPs.

If a Trigger Event occurs in FY 2019 and BPA is in a cash crunch, the Surcharge procedures defined in these GRSPs will apply. If BPA is not in a cash crunch in FY 2019, these GRSPs are silent on the implications. Any NFB Adjustment that might apply to FY 2020 rates based on Trigger Events occurring in FY 2019 will be defined later by the BP-20 GRSPs.

If a Trigger Event occurs that has Financial Effects in the year of its occurrence and also in later years, the Trigger Event will be deemed to have occurred on the first day of all subsequent years in which it has Financial Effects (*i.e.*, Financial Effects that have not been incorporated into the general rates applicable to that year). If there are, or are deemed to be, multiple Trigger Events in any fiscal year, the Financial Effects of those events will be the net effect for that fiscal year of all Trigger Events combined.

6. NFB Adjustment and Surcharge Notification Processes

BPA shall use the following procedures following a Trigger Event:

(a) Notification of Trigger Event and Related Workshops

BPA will notify customers within 30 days of the occurrence of an NFB Trigger Event in FY 2018 or FY 2019, as defined above, if BPA estimates the Financial Effects of the Trigger Event to be \$10 million or more. This initial notification, posted to BPA's website and provided by e-mail to those listed on the service list for the BP-18 rate proceeding, will include a description of the Trigger Event. BPA may elect not to notify customers of the Trigger Event if BPA estimates the Financial Effects of a Trigger Event to be less than \$10 million or BPA expects that neither a Power CRAC applicable to the subsequent year nor a Surcharge resulting from the Trigger Event applicable to the current year will be implemented.

If BPA does not determine that the Agency Within-Year TPP is below 80 percent at any later time in the fiscal year, a Trigger Event with Financial Effects will result in an NFB Adjustment. The Financial Effects of the Trigger Event will be presented along with the forecast of the end-of-year ACNR calculation in July 2017 (for an FY 2018 Adjustment) or September 2018 (for an FY 2019 Adjustment). There can be more than one NFB Adjustment Trigger Event in a year. There will be only one, if any, calculation of the NFB Adjustment to the Power CRAC Cap applicable to the next year.

If the Power ACNR is forecast to fall below the Power CRAC Threshold applicable to the next year, BPA shall conduct a workshop(s) as called for by the Power CRAC procedures in GRSP II.O.3. At the workshop(s), BPA will explain the Trigger Event and the estimated Financial Effects. BPA will provide and explain the data, models, and assumptions used to calculate the Surcharge Amount. BPA will respond to reasonable requests for data and calculations and will accept comments on any of the foregoing topics. At the customer's request, BPA Account Executives shall provide customers details of their charges under the Surcharge.

If the Power CRAC applicable to FY 2018 rates triggers, then on or about July 31, 2017, BPA will post to the BPA website the final Power CRAC calculations, including any NFB Adjustment (see Section 2 above) to the Power CRAC Cap. If the Power CRAC applicable to FY 2019 rates triggers, then on or about September 28, 2018, BPA will post to the BPA website the final Power CRAC calculations, including any NFB Adjustment (see Section 2 above) to the Power CRAC Cap.

(b) Notification of Agency Within-Year TPP Falling Below 80 percent Following a Trigger Event, and Related Workshops

If, during a fiscal year in which a Trigger Event has occurred, BPA determines that the Agency Within-Year TPP is below 80 percent, BPA will notify customers within seven (7) days of such a determination. In addition, this notification will be posted to

BPA's website and provided by e-mail to parties on the service list for the BP-18 rate proceeding.

This notification will include the time and location of a public workshop to be conducted no later than seven (7) days after the issuance of the notification. This notification will also include updated calculations of the Financial Effects of the Trigger Event(s) and the Agency Within-Year TPP. Concurrently, BPA's Account Executives will inform customers of their charges under the Surcharge.

At this workshop, BPA will explain the calculation of the Agency Within-Year TPP and the Surcharge Amount, including the monthly shape of payments.

BPA will provide data and assumptions used in these calculations. BPA will respond to relevant requests for data and calculations and will accept comments on any of the foregoing topics.

(c) Final Notification Procedures for Monthly Surcharge and Fiscal Year Surcharge Amount to Be Paid By Customers

BPA will provide written Final Notification to each customer in accordance with the notification provisions of the customer's BPA contract no later than 7 days following the conclusion of the workshop described above. Such Final Notification will state the monthly Surcharge Amount and the total Surcharge Amount to be recovered from each customer by September 30 of the fiscal year in which the Surcharge is in effect.

The monthly Surcharge Amount will be included on bills to customers and will be payable in accordance with the applicable payment provisions of the customers' contracts. The first monthly Surcharge Amount will be billed no sooner than 30 days following the Final Notification.

(d) Process Following Implementation of Surcharge

Within 30 days of the Final Notification of implementation of a Surcharge described above, BPA will provide notice of two or more meetings to be completed within 60 days of the Final Notification.

At the first meeting, customers and interested persons may request additional information and explanations about the Trigger Event, its Financial Effects, and the updated Agency Within-Year TPP. Customers and interested persons may also request information regarding BPA's financial performance to date, revenue and expense forecasts for the remainder of the fiscal year, the calculation of the Surcharge Amount, and any other materials related to the Surcharge then in effect. BPA will provide responses to relevant information requests as promptly as possible, but in any case no later than 48 hours prior to the final meeting. Subsequent meetings may be held as necessary.

At the final meeting, customers and interested persons may ask questions of and present their views to the Administrator. Customers and interested persons may also submit their views in writing to the Administrator within 7 days after the meeting.

Based on the information and views presented during the process provided for in this section, and not later than 20 days after the final meeting, the Administrator will issue a close-out letter that addresses the issues raised in the meetings, the need for the Surcharge, and whether the Surcharge is set at the appropriate level, all in accordance with these GRSPs. If the Administrator determines that the Surcharge Amount needs to be adjusted, the close-out letter will establish the refund or credit amount to customers for the amounts over-collected, or adjust the Surcharge then in effect for the remainder of the year. The Administrator may remove the Surcharge entirely if one or both of the following occurs:

- (1) the Agency Within-Year TPP, not including future surcharge payments, is determined at the time of the close-out letter to be greater than 90 percent; or
- (2) an updated calculation indicates that the Financial Effects of the Trigger Event(s) are less than \$10 million for that fiscal year.

R. Slice True-Up Adjustment

Pursuant to Section 2.7 of the TRM, BP-12-A-03, Slice customers shall have an annual Slice True-Up Adjustment for expenses, revenue credits, and adjustments allocated to the Composite cost pool and to the Slice cost pool. The annual Slice True-Up Adjustment shall be calculated for each fiscal year as soon as BPA's audited actual financial data are available (usually in November).

1. Calculation of the Annual Composite Cost Pool True-Up

(a) Calculation of the Slice True-Up Adjustment Charge for the Composite Cost Pool

Following the end of each fiscal year of the rate period, BPA shall:

- (1) subtract:
 - (i) the forecast annual expenses, revenue credits, and adjustments allocated to the Composite cost pool for the applicable fiscal year of the rate period,from
 - (ii) the actual expenses, revenue credits, and adjustments in the applicable fiscal year of the rate period that are allocable to the Composite cost pool;
- (2) divide the difference determined in (1) above by the sum of TOCAs for that fiscal year adjusted in accordance with TRM Section 5.1.1 and the

Load Shaping True-Up methodology set forth in TRM Section 5.2.4.1 for Load Following customers; and

- (3) multiply the dollar amount in (2) above by each Slice customer's Slice percentage for the applicable fiscal year.

For each Slice customer, the dollar amount calculated, which may be positive or negative, constitutes its Slice True-Up Adjustment charge for the Composite cost pool.

The Composite Cost Pool True-Up Table (Table F) contains the forecast expenses, revenue credits, and adjustments that will be the basis, when compared to actual expenses, revenue credits, and adjustments, for the Slice True-Up Adjustment calculation for the Composite cost pool for the applicable fiscal year. Included in these adjustments and credits are the actual Firm Surplus and Secondary Adjustment from Unused RHW and the actual DSI Revenue Credit described in (b) and (c) below.

(b) Calculation of the Actual Firm Surplus and Secondary Adjustment from Unused RHW

For purposes of the annual Composite Cost Pool True-Up, the actual Firm Surplus and Secondary Adjustment from Unused RHW for the applicable fiscal year shall be calculated as the sum of:

- (1) the forecast Firm Surplus and Secondary Adjustment from Unused RHW for the applicable fiscal year developed in the BP-18 7(i) process; and
- (2) the Change in PF Composite Customer Charge Revenue for the applicable fiscal year (change can be positive or negative);

Where:

Change in PF Composite Customer Charge Revenue = (sum of actual TOCAs – sum of forecast TOCAs) × monthly Composite Customer rate × 12 months.

TOCAs are expressed as a percentage, *e.g.*, 95 percent.

Sum of actual TOCAs is calculated after the fiscal year and is equal to the forecast sum of TOCAs for Slice/Block and Block customers, adjusted based on the Annual Net Requirement process in accordance with TRM Section 5.1.1. For Load Following customers, sum of actual TOCAs is adjusted based on TRM Section 2.7.1 using information from the Load Shaping True-Up methodology set forth in TRM Section 5.2.4.1.

Sum of forecast TOCAs is the sum of TOCAs used to set the PF-18 Composite Customer rate; and

- (3) the Change in Unused RHW M Revenue for the applicable fiscal year (change can be positive or negative).

Where:

Change in Unused RHW M Revenue = (Actual Unused RHW M – Forecast Unused RHW M) × 29.91 mills/kWh.

Actual Unused RHW M = (1.00 – sum of actual TOCAs, expressed as a decimal) × RHW M Tier 1 System Capability for the applicable fiscal year (expressed in aMW) × 8,760 hours (8,784 hours if a leap year).

Forecast Unused RHW M = (1.00 – sum of forecast TOCAs, expressed as a decimal) × RHW M Tier 1 System Capability for the applicable fiscal year (expressed in aMW) × 8,760 hours (8,784 hours if a leap year).

(c) Calculation of the Actual DSI Revenue Credit

For purposes of the annual Composite Cost Pool True-Up, the Actual DSI Revenue Credit for the applicable fiscal year shall be calculated as the sum of:

- (1) the forecast DSI Revenue Credit for the applicable fiscal year developed in the BP-18 7(i) process;
- (2) (i) the forecast MWh amount used to calculate (1) above for the applicable fiscal year *minus* (ii) the actual MWh amount of DSI sales for the applicable fiscal year, the result multiplied by –22.24 mills/kWh; and
- (3) DSI Take-or-Pay revenues

Where:

Actual kWh amount of DSI sales and DSI Take-or-Pay revenues shall be obtained from BPA data sources.

–22.24 mills/kWh is calculated by the equation:

$$\text{PFMEES} - 9.58 \text{ mills/kWh}$$

Where:

PFMEES is the PF Melded Equivalent Energy Scalar of –12.66 mills/kWh and is subject to the Power CRAC, the Power RDC, the NFB Emergency Surcharge, and the Spill Surcharge.

2. Calculation of the Annual Slice Cost Pool True-Up

The Slice Cost Pool True-Up Table (Table G) contains the forecast expenses, revenue credits, and adjustments that will be the basis, when compared to actual expenses, revenue credits, and adjustments, for the Slice True-Up Adjustment calculation for the Slice cost pool for the applicable fiscal year.

Following the end of each fiscal year and pursuant to TRM Section 2.7.2, BPA shall:

- (a) subtract:
 - (1) the forecast annual expenses, revenue credits, and adjustments allocated to the Slice cost pool for the applicable fiscal year of the rate period
 - from
 - (2) the actual expenses, revenue credits, and adjustments that are allocated to the Slice cost pool for the applicable fiscal year of the rate period;
 - and
- (b) for each Slice customer, multiply the resulting difference from (a) above by the ratio of (i) the customer's Slice percentage for the fiscal year in Exhibit K of the Slice/Block Contract to (ii) the sum of all customers' Slice percentages for the fiscal year in all Exhibit K of the Slice/Block CHWM Contracts.

For each Slice customer, the dollar amount calculated, which may be positive or negative, constitutes its Slice True-Up Adjustment charge for the Slice cost pool.

**Table F
Composite Cost Pool True-Up Table**

	Actual Data (\$000)	FY 2018 forecast (\$000)	FY 2019 forecast (\$000)
1	Operating Expenses		
2	Power System Generation Resources		
3	Operating Generation		
4	COLUMBIA GENERATING STATION (WNP-2)	270,146	327,354
5	BUREAU OF RECLAMATION	164,609	162,623
6	CORPS OF ENGINEERS	256,057	256,057
7	LONG-TERM CONTRACT GENERATING PROJECTS	12,595	13,687
8	Sub-Total	703,407	759,721
9	Operating Generation Settlement Payment and Other Payments		
10	COLVILLE GENERATION SETTLEMENT	22,612	22,997
11	SPOKANE LEGISLATION PAYMENT	-	-
12	Sub-Total	22,612	22,997
13	Non-Operating Generation		
14	TROJAN DECOMMISSIONING	1,000	1,000
15	WNP-1&3 DECOMMISSIONING	500	534
16	Sub-Total	1,500	1,534
17	Gross Contracted Power Purchases		
18	PNCA HEADWATER BENEFITS	3,100	3,100
19	OTHER POWER PURCHASES (omit, except Designated Obligations or Purchases)	-	-
20	Sub-Total	3,100	3,100
21	Bookout Adjustment to Power Purchases (omit)		
22	Augmentation Power Purchases (omit - calculated below)		
23	AUGMENTATION POWER PURCHASES	-	-
24	Sub-Total	-	-
25	Exchanges and Settlements		
26	RESIDENTIAL EXCHANGE PROGRAM (REP)	242,372	242,112
27	OTHER SETTLEMENTS	-	-
28	Sub-Total	242,372	242,112
29	Renewable Generation		
30	RENEWABLES (excludes Kill)	28,284	28,902
31	Sub-Total	28,284	28,902
32	Generation Conservation		
33	CONSERVATION ACQUISITION (Purchases)	71,785	71,785
34	CONSERVATION INFRASTRUCTURE	27,149	27,283
35	LOW INCOME WEATHERIZATION & TRIBAL	5,523	5,627
36	REIMBURSABLE ENERGY EFFICIENCY DEVELOPMENT	8,000	8,000
37	DR & SMART GRID	856	854
38	LEGACY	590	590
39	MARKET TRANSFORMATION	12,364	12,049
40	Sub-Total	126,267	126,187
41	Power System Generation Sub-Total	1,127,542	1,184,553
42	Power Non-Generation Operations		
43	Power Services System Operations		
44	EFFICIENCIES PROGRAM	-	-
45	INFORMATION TECHNOLOGY	6,976	7,294
46	GENERATION PROJECT COORDINATION	6,174	6,409
47	SLICE IMPLEMENTATION	1,024	1,061
48	Sub-Total	14,174	14,764
49	Power Services Scheduling		
50	OPERATIONS SCHEDULING	10,054	10,404
51	OPERATIONS PLANNING	8,528	8,416
52	Sub-Total	18,582	18,820
53	Power Services Marketing and Business Support		
54	POWER R&D	4,705	4,600
55	SALES & SUPPORT	22,885	23,485
56	STRATEGY, FINANCE & RISK MGMT	15,846	18,305
57	EXECUTIVE AND ADMINISTRATIVE SERVICES	4,119	4,204
58	CONSERVATION SUPPORT	9,094	9,409
59	Sub-Total	56,648	60,002
60	Power Non-Generation Operations Sub-Total	89,404	93,586
61	Power Services Transmission Acquisition and Ancillary Services		
62	TRANSMISSION and ANCILLARY Services - System Obligations	33,857	32,924
63	3RD PARTY GTA WHEELING	91,759	92,516
64	POWER 3RD PARTY TRANS & ANCILLARY SVCS (Composite Cost)	2,251	2,292
65	TRANS ACQ GENERATION INTEGRATION	12,480	12,634
66	TELEMETERING/EQUIP REPLACEMT	-	-
67	Power Services Trans Acquisition and Ancillary Serv Sub-Total	140,346	140,366
68	Fish and Wildlife/USF&W/Planning Council/Environmental Req		
69	Fish & Wildlife		
70	USF&W Lower Snake Hatcheries	276,713	276,704
71	Planning Council	33,483	33,483
72	Environmental Requirements	11,624	11,914
73	Sub-Total	-	-
73	Fish and Wildlife/USF&W/Planning Council Sub-Total	321,821	322,101

Table F, continued
Composite Cost Pool True-Up Table

	Actual Data (\$000)	FY 2018 forecast (\$000)	FY 2019 forecast (\$000)
74			
75		14,962	15,620
76		64,391	65,796
77		79,353	81,417
78		-	-
79		1,772	(13,668)
80		(60,500)	(60,500)
81			
82			
83		184,737	338,592
84		60,431	40,738
85		236,158	32,139
86		481,326	411,469
87			
88		7,302	7,304
89		1,934	1,932
90		9,236	9,235
91		490,562	420,704
92		144,092	144,065
93		86,796	87,458
94		2,421,187	2,400,082
95			
96		94,511	98,711
97		41,010	41,971
98		22,128	22,128
99		157,648	162,809
100		2,578,835	2,562,892
101			
102		108,430	101,519
103		16,829	16,829
104		93,172	91,526
105		4,600	4,600
106		8,000	8,000
107		-	-
108		7,200	7,200
109		-	-
110		-	-
111		395	395
112		15,959	15,959
113		3,082	3,102
114		30,246	13,324
115		(1,364)	8,511
116		31,568	32,060
117		1,076	1,273
118		1	1
119		319,193	304,298
120			
121			
122		12,393	12,503
123		-	12,211
124		12,393	24,714
125			
126			
127		23,140	33,392
128		23,140	33,392
129			
130			
131		135,220	173,621
132		220,252	-
133		27,234	56,573
134		382,706	230,194
135		144,092	144,065
136		86,796	87,458
137		(45,937)	(45,937)
138		-	-
139		-	-
140		-	-
141		(3,524)	(3,524)
142		(30,600)	(30,600)
143		11,628	10,747
144		162,454	162,210
145		220,252	67,984
146		220,252	67,984
147			
148		2,469,148	2,317,899
149			
150			
151			
152			
153			

**Table G
Slice Cost Pool True-Up Table**

	Actual Data (\$000)	FY 2018 forecast (\$000)	FY 2019 forecast (\$000)
1 Slice Expenses			
2			
3			
4 Total Slice Expenses		\$ -	\$ -
5			
6 Slice Credits			
7			
8 Total Slice Credits		\$ -	\$ -
9			
10 Annual Slice Cost Pool (Amounts for each FY)		\$ -	\$ -
11			
12 SLICE TRUE-UP ADJUSTMENT CALCULATION FOR SLICE COST POOL			
13 TRUE UP AMOUNT (Diff. between actual Slice Cost Pool and forecast Slice COST Pool for applicable FY)			
14			
15 TRUE-UP ADJUSTMENT CHARGE BILLED (100 percent)			

S. Residential Exchange Program Residential Load

Residential Loads of investor-owned utilities for the rate period are shown in Table H below. These loads are applicable to each year of the rate period, FY 2018 and FY 2019, and are established pursuant to Section 2 of the 2012 REP Settlement Agreement, REP-12-A-02A (misfiled as REP-12-A-02-AP01) (2012 REP Settlement).

Table H
Residential Load for the BP-18 Rate Period (in kWh)

<i>Month</i>	<i>Avista</i>	<i>Idaho</i>	<i>NorthWestern</i>
October	235,058,847	435,053,509	45,442,425
November	280,401,356	406,737,838	50,050,342
December	402,323,201	546,939,132	65,530,507
January	448,767,477	621,373,273	76,140,905
February	389,685,194	540,206,424	63,494,837
March	323,113,169	457,486,176	57,263,262
April	285,615,055	441,139,602	51,199,781
May	246,791,932	461,080,755	47,548,441
June	250,942,828	535,363,130	49,566,121
July	295,440,073	709,910,515	53,944,669
August	292,870,148	693,674,710	54,789,515
September	276,911,520	625,157,570	49,876,769

<i>Month</i>	<i>PacifiCorp</i>	<i>Portland General</i>	<i>Puget Sound</i>
October	568,701,170	546,339,154	763,865,291
November	646,820,692	610,880,258	904,657,032
December	942,864,884	863,874,792	1,232,152,398
January	987,012,434	929,727,589	1,339,430,067
February	790,439,066	739,082,355	1,168,986,915
March	694,242,108	677,540,079	1,062,152,132
April	620,508,582	623,900,766	914,128,051
May	598,230,633	574,767,922	780,817,339
June	648,469,184	604,283,089	757,238,768
July	767,393,613	669,077,625	763,012,726
August	747,902,078	671,109,286	773,209,333
September	677,968,915	643,249,169	749,716,387

T. Residential Exchange Program 7(b)(3) Surcharge Adjustment

The 7(b)(3) Surcharge is a utility-specific addition to the Base PF Exchange rate that recovers each REP participant's allocated share of the rate protection provided pursuant to the 2012 REP Settlement. As determined in the BP-18 7(i) process, each REP participant's 7(b)(3) Surcharge is based on its Base PF Exchange rate, its Average System Cost (ASC), and its contract exchange loads. Each REP participant's 7(b)(3) Surcharge is displayed in the table in Section 6.1 of the PF-18 rate schedule and is subject to modification under this GRSP.

In implementing the REP, BPA has identified circumstances where a utility's ASC may be modified during the BPA rate period (*e.g.*, new resource additions, new NLSLs, changes in service territory). Subject to limitations in the 2008 ASC Methodology, when BPA modifies a utility's ASC during a BPA rate period, the modified ASC shall be effective on the date specified in BPA's notice to the participating utility confirming the modification of its ASC. Therefore, if a participating utility's ASC differs from the ASC used in establishing rates in Section 6.1 of the PF-18 rate schedule, BPA shall adjust the 7(b)(3) Surcharges of all participating utilities to reflect the new ASC.

Such adjustment of 7(b)(3) Surcharges shall be accomplished by substituting all modified ASCs and recomputing the rates in Section 6.1 of the PF-18 rate schedule. This recomputation shall be accomplished by:

1. Inserting the participating utility's revised ASC, expressed in mills/kWh (equivalent to \$/MWh).
2. Retaining the forecast exchange load for the participating utility, expressed in gigawatthours, as adopted in the BP-18 7(i) proceeding.
3. Multiplying the difference between the ASC and the applicable Base PF Exchange rate by the forecast exchange load to compute the unconstrained benefits for each participant.
4. Summing the unconstrained benefits for each participant to compute total unconstrained benefits.
5. Computing the difference between the total unconstrained benefits and \$482,742,672 (the total REP benefits adopted for the two-year rate period in the BP-18 7(i) proceeding).
6. Allocating the computed difference to participants such that the first \$153,075,234 (the total REP Refund Amounts for the two-year rate period) is allocated to only the IOU participants and the remainder is allocated to all participants on a pro rata basis referenced to unconstrained benefits.
7. Recomputing the IOU adjustments specified in Section 6.2 of the 2012 REP Settlement.

8. Dividing the recomputed allocated dollars by exchange loads to determine the revised 7(b)(3) Surcharge and adding each revised 7(b)(3) Surcharge to the appropriate Base PF Exchange rate to compute the revised utility-specific PF Exchange rates.

The specific computations that will be performed are displayed on Tables 2.4.11 and 2.4.12 of the Power Rates Study Documentation, BP-18-E-BPA-01A. Table 2.4.11 shall be updated as specified above to perform the actual 7(b)(3) Surcharge adjustments. The adjusted 7(b)(3) Surcharges shall take effect on the day that the utility's modified ASC takes effect. This adjustment shall occur as frequently as ASCs are modified during the two-year rate period the PF Exchange rate herein is in effect.

The adjustment of 7(b)(3) Surcharges shall be updated and published as ASCs are modified. The table can be accessed through BPA's Residential Exchange Program website.

U. Conservation Surcharge

The Conservation Surcharge, if implemented, shall be applied in accordance with relevant provisions of the Northwest Power Act, BPA's current Conservation Surcharge policy, and the customer's power sales contract with BPA. The Conservation Surcharge applies to the PF-18 (including Slice purchasers), NR-18, and IP-18 rate schedules.

V. [Reserved for Future Use]

W. Flexible Priority Firm Power (PF) Rate Option

The Flexible PF rate option will be offered at BPA's discretion to a customer that makes a contractual commitment to purchase under this option. The rates and billing determinants under this option shall be specified by BPA at the time the Administrator offers to make power available to a customer under this option. The customer under the Flexible PF rate option shall purchase the same set of power products and services that it would otherwise purchase under the PF-18 rate schedule. The flexible rates and billing determinants will be mutually agreed to by BPA and the customer, subject to satisfying the following conditions:

- Equivalent NPV Revenue: Forecast revenue from a customer under the Flexible PF rate option must be equivalent, on a net present value basis, to the revenue BPA would have received had the appropriate rates specified in Sections 2, 3, 4, and 5 of the PF-18 rate schedule been applied to the same sales.

- The Flexible PF rate contract may establish a limit on the amount of power purchased at the Flexible PF rate. In this case, purchases beyond the contractual limit will be billed at the rates specified in Sections 2, 3, 4, and 5 of the PF-18 rate schedule, unless such power would be charged as an Unauthorized Increase.

Notwithstanding the effective dates of the PF-18 rate and associated GRSPs, any rights and obligations of BPA and a customer arising out of the customer's election to participate in the Flexible PF Rate program by purchasing under the Flexible PF Rate Option shall survive and be fully enforceable until such time as they are fully satisfied.

X. Priority Firm Power (PF) Shaping Option

Prior to the beginning of the rate period, BPA and a customer purchasing Firm Requirements Power charged under Section 2.1 of the PF-18 rate schedule may agree to a PF-18 Tier 1 Customer charge payment schedule for the rate period that differs from the flat monthly charge specified in the PF-18 rate schedule. BPA will, to the maximum extent practicable while ensuring timely BPA cost recovery, accommodate individual customer requests to "shape" certain PF-18 Tier 1 Customer charges within the fiscal year to mitigate adverse cash flow effects on the customer. The shaped payments at PF-18 Tier 1 Customer rates will be mutually agreed to by BPA and the customer. Requests to shape Customer charges during the rate period must be received by BPA no later than September 1, 2017.

This Shaping Option analysis will take into account the cash-flow impacts to the customer of the Tier 1 charges: the Customer charges; a forecast of monthly Load Shaping charges; a forecast of monthly demand charges; and any applicable rate discounts. BPA and the customer may agree to 12 monthly Composite Customer charges that the customer shall pay in each year of the rate period. If further shaping is requested to mitigate a customer's cash-flow impacts, BPA may also agree to shape the Non-Slice Customer charge.

BPA will accommodate requests to shape Customer charges if the following conditions are met:

1. Equivalent Net Present Value: Forecast revenue from the shaped charges must be equivalent, on a net present value basis, to the revenue BPA would have received for each fiscal year without shaping.
2. No Material Adverse Impacts on BPA's Cash Flow: The aggregate shaping requests do not have a material adverse impact on BPA's overall cash flow, as determined solely by BPA. In order to accommodate multiple shaping requests, BPA will take into account the potential offsetting impacts of all shaping requests. If BPA is not able to accommodate all requests in total due to material adverse impacts on BPA's cash flow, BPA may limit the shaping for individual requests.

Y. Flexible New Resource Firm Power (NR) Rate Option

The Flexible NR rate option will be offered at BPA’s discretion to a customer that makes a contractual commitment to purchase under this option. The rates and billing determinants under this option shall be specified by BPA at the time the Administrator offers to make power available to a customer under this option. The customer under the Flexible NR rate option shall purchase the same set of power products and services that it would otherwise purchase under the NR-18 rate schedule. The flexible rates and billing determinants will be mutually agreed to by BPA and the customer, subject to satisfying the following conditions:

- Equivalent NPV Revenue: Forecast revenue from a customer under the Flexible NR rate option must be equivalent, on a net present value basis, to the revenue BPA would have received had the appropriate rates specified in Sections 2, 3, 4 and 5 of the NR-18 rate schedule been applied to the same sales.
- The Flexible NR rate contract may establish a limit on the amount of power purchased at the Flexible NR rate. In this case, purchases beyond the contractual limit will be billed at the rates specified in Sections 2, 3, 4 and 5 of the NR-18 rate schedule, unless such power would be charged as an Unauthorized Increase.

Notwithstanding the effective dates of the NR-18 rate and associated GRSPs, any rights and obligations of BPA and a customer arising out of the customer’s election to participate in the Flexible NR Rate program by purchasing under the Flexible NR Rate Option shall survive and be fully enforceable until such time as they are fully satisfied.

Z. Cost Contributions

Pursuant to Section 7(j) of the Northwest Power Act (16 U.S.C. § 839e(j)), BPA has made the following resource cost determinations:

1. The approximate cost contribution of different resource categories to each rate schedule is:

Table I
Resource Cost Contribution

<i>Rate Schedule</i>	<i>Federal Base System</i>	<i>Exchange Resources</i>	<i>New Resources</i>
PF	41.93%	58.07%	0%
IP	0%	49.17%	50.83%
NR	0%	51.99%	48.01%
FPS	0%	61.76%	38.24%

2. The cost of resources acquired to meet load growth within the region is estimated to be 41.41 mills/kWh, and the forecast average cost of resources available to BPA under average water conditions is 47.10 mills/kWh.

AA. Priority Firm Power (PF) Tier 1 Equivalent Rates

The PF Tier 1 Equivalent rates are an expression of the Non-Slice PF Public Tier 1 rates in a traditional HLH and LLH energy form. These rates can be used as a reference when a need arises for Tier 1 rates to be expressed in this manner.

<i>Month</i>	<i>Energy Rate in mills/kWh</i>		<i>Demand Rate in \$/kW</i>
	<i>HLH</i>	<i>LLH</i>	<i>HLH</i>
October	39.49	35.24	10.45
November	40.02	37.49	10.65
December	43.03	39.35	11.83
January	42.05	36.69	11.45
February	41.29	36.69	11.15
March	36.50	33.55	9.28
April	32.42	30.29	7.68
May	29.38	24.00	6.49
June	30.46	22.06	6.92
July	37.41	31.80	9.63
August	40.86	35.36	10.98
September	40.69	34.94	10.91

These rates are subject to adjustment during the Rate Period pursuant to the Spill Surcharge (GRSP Appendix C); the Power CRAC (GRSP II.O); the Power RDC (GRSP II.P); and the Emergency NFB Surcharge (GRSP II.Q).

SECTION III. DEFINITIONS

A. Power Products and Services Offered By BPA Power Services

1. Block Product

As defined in the TRM, the Block Product is BPA's power product defined in Section 4 of the Block and Slice/Block CHWM Contracts.

2. Capacity Without Energy

Capacity Without Energy is the stand-ready obligation whereby BPA will deliver a contract-specific amount of power upon contract-specific notice provisions. The notice provision may be automated, such as Automatic Generation Control automatic deliveries, phone call schedules, or any other standard utility notice provisions. The notice provision and duration of delivery is contract-specific and will affect the value of the capacity product. No energy is sold with Capacity Without Energy; any energy delivered when the capacity contract is exercised will be returned or paid for under contract terms. The terms of the contract will define all parameters of the required notice provisions and all parameters of the return or payment of any energy delivered when capacity rights are exercised.

3. Construction, Test and Start-Up, and Station Service

Power for the purpose of Construction, Test and Start-Up, and Station Service for a generating resource or transmission facility shall be made available to eligible customers under the Priority Firm Power (PF-18), New Resources Firm Power (NR-18), and Firm Power and Surplus Products and Services (FPS-18) rate schedules. Such power is not available under the PF Exchange rate.

Construction, Test and Start-Up, and Station Service power must be used in the manner specified below:

- (a) Power sold for construction is to be used in the construction of the project.
- (b) Power sold for test and start-up may be used prior to commercial operation, both to bring the project on-line and to ensure that the project is working properly.
- (c) Power sold for station service may be purchased at any time following commercial operation of the project. Once the project has been energized for commercial operation, the customer may use station service power for start-up, shutdown, normal operations, and operations during a shutdown period.
- (d) Power sold for Construction, Test and Start-Up, and Station Service is not available for replacement of lost generation for forced or planned outages or resource underperformance.

4. Energy Shaping Service for NLSL

Energy Shaping Service is an optional service for Load Following customers serving a New Large Single Load (NLSL) with a non-Federal resource. ESS includes a capacity component and an energy component. These services shape a customer's resource energy and capacity output amounts to the actual load of a NLSL.

5. Firm Requirements Power

Firm Requirements Power is Federal power that BPA makes continuously available to a customer to meet BPA's obligations to the customer under Section 5(b) of the Northwest Power Act.

6. Forced Outage Reserve Service (FORS)

As defined in the TRM, FORS is a service that provides an agreed-upon amount of capacity and energy to load during the forced outages of a qualifying resource.

7. Industrial Firm Power (IP)

Industrial Firm Power (IP) is electric power that BPA will make available to a DSI customer subject to the terms of the DSI customer's power sales contract with BPA.

8. Large Project Program (LPP)

The Large Project Program, established in the BPA Revised Energy Efficiency Post-2011 Implementation Program, was discontinued on September 30, 2017.

9. Load Following Product

As defined in the TRM, the Load Following Product is the BPA firm power service under the Load Following CHWM Contract that meets the customer's Total Retail Load less its Non-Federal Resources obligation on a real-time basis.

10. Load Shaping

BPA provides Load Shaping to customers with CHWM Contracts purchasing the Load Following Product, the Block Product, or the Block portion of the Slice/Block Product. Load Shaping shapes the Tier 1 System Capability to the monthly/diurnal shape of a customer's Actual Monthly/Diurnal Tier 1 Load.

11. New Resource Firm Power (NR)

New Resource Firm Power (NR) is electric power (capacity and energy) that BPA will make continuously available:

- (a) for any NLSL, as defined in the Northwest Power Act;
- (b) for Firm Power purchased by IOUs pursuant to power sales contracts with BPA.

NR is to be used to meet the customer's firm power load within the Pacific Northwest. Deliveries of NR may be reduced or interrupted as permitted by the terms of the customer's power sales contract with BPA.

NR is guaranteed to be continuously available to the customer during the period covered by its contractual commitment, except for reasons of certain uncontrollable forces and force majeure events.

12. NR Resource Flattening Service (NRFS)

NR Resource Flattening Service (NRFS) is applicable to Load Following customers that apply the generation output of a non-dispatchable Specified Resource to serve an NLSL.

13. Priority Firm Power (PF)

Priority Firm Power (PF) is electric power (capacity and energy) that BPA will make continuously available for direct consumption or resale by public bodies, cooperatives, and Federal agencies. Utilities participating in the Residential Exchange Program may purchase PF pursuant to their RPSA or REPSIA with BPA. PF is not available to serve New Large Single Loads. Deliveries of PF may be reduced or interrupted as permitted by the terms of the customer's power sales contract with BPA.

PF is guaranteed to be continuously available to the customer during the period covered by its contractual commitment, except for reasons of certain uncontrollable forces and force majeure events.

14. Residential Exchange Program Power

Residential Exchange Program Power is power BPA sells to a customer pursuant to the REP. Under Section 5(c) of the Northwest Power Act, BPA "purchases" power from eligible Pacific Northwest utilities at a utility's Average System Cost (ASC). 16 U.S.C. § 839c(c). BPA then offers, in exchange, to "sell" an equivalent amount of electric power to that customer at BPA's PF rate applicable to exchanging utilities (PF Exchange rate). The amounts of power purchased and sold are both equal to the utility's eligible residential and farm load. Benefits must be passed directly to the utility's residential and farm customers.

15. Resource Remarketing Service (RRS)

Resource Remarketing Service (RRS) is a service that BPA makes available at its discretion to Load Following customers where BPA remarkets non-Federal resources on behalf of customers and provides them with remarketing credits, net of a remarketing fee.

16. Resource Support Services (RSS)

Resource Support Services are used to make resources, either non-Federal or Federal resource acquisitions, financially equivalent to a flat block. RSS are available for all specified non-Federal resources that Load Following customers contractually dedicate to serve their Total Retail Load and for specified new renewable resources Slice/Block and Block customers contractually dedicate to serving their Total Retail Load. RSS includes: Diurnal Flattening Service, Forced Outage Reserve Service, Grandfathered Generation Management Service, Secondary Crediting Service, Transmission Scheduling Service and Transmission Curtailment Management Service.

17. Secondary Crediting Service (SCS)

As defined in the TRM, Secondary Crediting Service (SCS) is the optional service offered by BPA that provides a monetary credit for the secondary output from an existing resource that has a firm critical energy component and a secondary energy component. There are two different options for SCS. Under SCS Option 1, the customer exchanges power generated by its resource with Federal deliveries. Under SCS Option 2, the customer applies its resource directly to load, and Federal deliveries cover the net load.

18. Slice/Block Product

The Slice/Block Product is the customer's purchase obligation under the Slice product and the Block Product to meet the customer's regional consumer load obligation under Section 3.1 of the Slice/Block CHWM Contract.

19. Transfer Service

As defined in the CHWM Contracts, Transfer Service means the transmission, distribution and other services provided by a third party transmission provider to deliver electric energy and capacity over its transmission system.

B. Definition of Rate Schedule Terms

1. Above-RHWM Load

As defined in the TRM, Above-RHWM Load is the forecast annual Total Retail Load, less Existing Resources, New Large Single Loads, and the customer's Rate Period High Water Mark, as determined in the RHWM Process.

2. Actual Monthly/Diurnal Tier 1 Load

As defined in the TRM, the Actual Monthly/Diurnal Tier 1 Load is the amount of the customer's electric load (measured in kilowatt-hours) that was served at Tier 1 rates during the relevant monthly/diurnal period.

3. Billing Determinant

(a) A measure of electric power usage at a customer's metered point of delivery used in the computation of a customer's bill.

(b) As defined in the Tiered Rate Methodology, a unit of measure for sales of a product or service for which a customer is billed by BPA.

4. Charge

A charge is the product of a billing determinant and a rate.

5. Contract Demand

The customer's Contract Demand is the maximum amount of capacity that the customer agrees to purchase and BPA agrees to make available, subject to any limitations included in the applicable contract between BPA and the customer.

6. Contract Demand Quantity (CDQ)

As defined in the TRM, the Contract Demand Quantity is the monthly quantity of demand (expressed in kilowatts) included in each customer's CHWM Contract that is subtracted from the Customer System Peak (CSP) as part of the process of determining the customer's demand charge billing determinant, as calculated in accordance with TRM Section 5.3.5.

7. Contract Energy

Contract Energy is the maximum amount of energy that the customer agrees to purchase and BPA agrees to make available, subject to any limitations included in the applicable contract between BPA and the customer.

8. Contract High Water Mark (CHWM)

As defined in the TRM, the Contract High Water Mark is the amount (expressed in average megawatts) computed for each customer in accordance with TRM Section 4. For each customer with a CHWM Contract, the CHWM is used to calculate each customer's RHW in the RHW Process for each applicable rate period. The CHWM Contract specifies the CHWM for each customer.

9. CHWM Contract

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

10. Customer

Pursuant to the terms of an agreement and applicable rate schedule(s), a customer is the entity that contracts to pay BPA for providing a product or service.

11. DSI Reserve

A DSI Reserve is any interruption right in addition to the Minimum DSI Operating Reserve – Supplemental, consistent with the DSI Reserves Adjustment standards and criteria described in GRSP II.H, that is provided by a DSI in a contract with BPA.

12. Energy Efficiency Incentive

The Energy Efficiency Incentive is a funding mechanism that establishes a budget from which BPA funds energy efficiency incentive payments and associated qualified performance payments for customers with a CHWM Contract.

13. Flat Annual Shape

As defined in the CHWM Contracts, Flat Annual Shape means a distribution of energy having the same average megawatt value of energy in each month of the year.

14. Heavy Load Hours (HLH)

Heavy Load Hours (HLH) are all hours in the on-peak period – the hour ending 7 a.m. through the hour ending 10 p.m., Monday through Saturday, Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable) – except for the six holidays specified in NERC Standards. See also Light Load Hours definition.

15. Intercontinental Exchange (ICE) Mid-C Day Ahead Power Price Index

Average HLH (or on-peak) and average LLH (or off-peak) price indices for firm power sales of electricity at delivery points along the Mid-Columbia River, as published by Intercontinental Exchange, Inc.

16. Light Load Hours (LLH)

Light Load Hours (LLH) are all those hours in the off-peak period – the hour ending 11 p.m. through the hour ending 6 a.m., Monday through Saturday, and all hours Sunday, Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time, as applicable). BPA recognizes six holidays classified according to NERC Standards as LLH. Memorial Day, Labor Day, and Thanksgiving Day occur on the same day each year: Memorial Day is the last Monday in May; Labor Day is the first Monday in September; and Thanksgiving Day is the fourth Thursday in November. New Year's Day, Independence Day, and Christmas Day fall on predetermined dates each year. In the event that the predetermined dates fall on a Sunday, the holiday is recognized as the Monday immediately following that Sunday, so that Monday is also LLH all day. If the predetermined dates fall on a Saturday, the holiday is recognized as that Saturday, and that Saturday is classified as LLH.

17. Metered Demand

The Metered Demand, in kilowatts, shall be the largest of the 60-minute clock hour integrated demands at which electric energy is delivered to a customer:

- (a) at each point of delivery for which the Metered Demand is the basis for determination of the measured demand;
- (b) during each time period specified in the applicable rate schedule; and
- (c) during any billing period.

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

18. Metered Energy

The Metered Energy for a customer shall be the number of kilowatthours recorded on the appropriate metering equipment, adjusted as specified in the applicable agreement and delivered to a customer:

- (a) at all points of delivery for which metered energy is the basis for determination of the measured energy; and
- (b) during any billing period.

19. New Public

As defined in the TRM, a New Public is a Public that is not an Existing Customer. (As defined in the TRM, an Existing Customer is a Public that has a CHWM Contract at the time there is an annexation of some portion of its service territory.)

20. NR Hourly Load

The actual hourly amount (measured in kilowatthours) of (1) a customer's New Large Single Load that is recorded on the metering equipment and adjusted for any applicable resource amounts, as defined in the CHWM Contract; or (2) an investor-owned utility's NR Block amounts as specified in its NR Block Contract.

21. Powerdex Hourly Mid-C Price Index

Average hourly price index for hourly firm power sales of electricity at delivery points along the Mid-Columbia River, as published by Powerdex, Inc.

22. Public

As defined in the TRM, a Public is a public body or cooperative utility or Federal agency eligible to purchase requirements power from BPA pursuant to Section 5(b) of the Northwest Power Act. 16 U.S.C. § 839c(b).

23. Rate Period High Water Mark (RHWM)

As defined in the TRM, the Rate Period High Water Mark is the amount, calculated by BPA in each RHWM Process pursuant to the formula in TRM Section 4.2.1, and expressed in average megawatts, that BPA establishes for each customer based on the customer's CHWM and the RHWM Tier 1 System Capability. The maximum planned amount of power a customer may purchase under Tier 1 rates each fiscal year of the rate period is the RHWM for Load Following customers and the lesser of RHWM or Annual Net Requirement for Block and Slice/Block customers.

24. Remarketing Value

The value BPA provides to customers for remarketed energy (both Tier 2 and non-Federal). This value is also used to calculate the cost of unpurchased amounts of Tier 2 energy. The Remarketing Value for a fiscal year is based on: (1) the rate case market price using the critical water year "augmentation price" when BPA has not yet acquired the power to supply Tier 2 service; (2) the weighted average price of the power purchases BPA has acquired (between October 1, 2016, and June 1, 2017) for the corresponding year to supply Tier 2 service; or (3) the average of the rate case market price using all 80 water years and the rate case market price using the critical water year "augmentation price" when BPA is using firm power from the FCRPS for Tier 2 service and BPA does not make any actual power acquisitions (between October 1, 2016, and June 1, 2017) for the corresponding year to supply Tier 2 service.

25. Resource Shaping Charge

As defined in the TRM, the Resource Shaping Charge is the customer-specific charge or credit as described in TRM Section 8.5 that adjusts for the difference in value between a planned resource energy shape that is flat within each monthly/diurnal period (but not necessarily flat when comparing one monthly/diurnal period to another) and an equivalently sized flat annual block (flat for all hours of the fiscal year).

26. Resource Shaping Rate

As defined in the TRM, the Resource Shaping Rate is the rate that is set, as described in TRM Section 8.5, equal to the Load Shaping Rate for each monthly/diurnal period.

27. Retail Access

Retail Access is non-discriminatory retail distribution access mandated either by Federal or state law that grants retail electric power consumers the right to choose their electricity supplier.

28. RHWMTier 1 System Capability (RT1SC)

As defined in the TRM, RHWMTier 1 System Capability means the Tier 1 System Firm Critical Output plus RHWMTier 1 Augmentation. The RT1SC table of values may be found at GRSP II.A, Table A.

29. Super Peak Credit

As defined in the TRM, the Super Peak Credit is the amount of additional HLH energy, as defined in TRM Section 5.3.4, that a customer contractually commits to provide with non-Federal resources during the Super Peak Period. Such notification must occur by October 31 of the Rate Case Year.

30. Super Peak Period

As defined in the TRM, the Super Peak Period is the hours defined pursuant to the CHWM Contract for each rate period into which a customer must reshape its HLH energy from its Specified Resources and Unspecified Resource Amounts to receive a Super Peak Credit. The hours BPA establishes for the Super Peak Period may vary by month and will be either two 3-hour periods each day or a single 6-hour period each day.

The Super Peak Period hours for FY 2018–2019 are as follows (HE = Hour Ending):

October – May	HE 8 through HE 10 and HE 19 through HE 21
June – September	HE 14 through HE 19

31. System Shaped Load

As defined in the TRM, the System Shaped Load is the amount of energy a Load Following or Block customer would receive from BPA under its Tier 1 rates in each of the monthly/diurnal periods in each fiscal year of the rate period if the customer's TOCA Load was delivered in the shape of the RHWMTier 1 System Capability through such periods.

32. Tier 1 Cost Allocator (TOCA)

As defined in the TRM, the TOCA is the billing determinant for the customer charges for each customer purchasing power at a Tier 1 rate under its CHWM Contract. TOCAs are

expressed as percentages and are calculated as specified in TRM Section 5.1.1. TOCAs are posted on BPA's website.

33. Tier 1 Customer System Peak (Tier 1 CSP)

Tier 1 Customer System Peak is equivalent to Customer System Peak as defined in the TRM. As defined in the TRM, Tier 1 CSP is the customer's maximum Actual Hourly Tier 1 Load (measured in kilowatts) during the Heavy Load Hours of each month.

34. Total Customer System Peak (CSP or Total CSP)

Total Customer System Peak is the largest measured HLH Total Retail Load amount, in kilowatts, for the billing period.

35. Total Retail Load (TRL)

All retail electric power consumption, including electric system losses, within a customer's electrical system, excluding (i) those loads BPA and the customer have agreed are nonfirm or interruptible loads; (ii) transfer loads of other utilities served by such customer; and (iii) any loads not on such customer's electrical system or not within such customer's service territory, unless specifically agreed to by BPA.

36. Unanticipated Load

Unanticipated Load is any request by a customer for Firm Requirements Power received by BPA after February 1 of the ratesetting year that (1) results in an increase in the customer's load placed on BPA during the ensuing rate period, and (2) was not requested and thus not forecast when setting the rates for that rate period.

37. Wheel Turning Load

Wheel Turning Load is that portion of Total Plant Load that is not integral to a customer's industrial process and is not a part of a technological allowance. A megawatt amount of Wheel Turning Load shall be defined in the customer's power sales contract with BPA, unless such amount is self-supplied. Wheel Turning Load shall be exempt from reduction or interruption associated with providing Minimum DSI Operating Reserve – Supplemental.

APPENDICES

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Appendix A: Residential Exchange Program Settlement Customer Refund Amounts in FY 2018–2019

Section 1. Purpose

The Customer Refund Amount in FY 2018–2019 is a credit on a customer’s power bill pursuant to the 2012 REP Settlement Agreement, REP-12-A-02A (misfiled as REP-12-A-02-AP01) (2012 REP Settlement). REP-12-A-02A. The individual customer credit is determined in part on the terms of the Settlement and in part on information developed in each rate proceeding.

Section 2. Terms of the Customer Refund Amount

The Customer Refund Amount applies to customers listed in the table below.

A credit shall appear on the monthly power bills beginning with the month that the rates established in the BP-18 rate proceeding take effect. The total credit for a given fiscal year will be the fiscal year’s Total Refund divided into 12 equal monthly amounts. Monthly amounts shall be rounded to the nearest whole dollar amount on the power bill.

Section 3. Definitions

PF-02 Refund is the portion of the Customer Refund Amount provided pursuant to Exhibit B of the Settlement.

Scaled TOCA is the customer-specific percentage derived from a customer’s BP-18 Final Proposal TOCA as adjusted pursuant to Section 3.4 of the REP Settlement Agreement.

TOCA Refund is the annual Refund Amount from Section 3.2 of the Settlement (\$76,537,617) minus the total annual Customer-Specific PF-02 Refund Amount from Exhibit B of the Settlement (\$38,269,000) multiplied by the Scaled TOCA. Thus, $\$76,537,617 - \$38,269,000 = \$38,268,617$, which then is multiplied by the Scaled TOCA.

Total Refund is the sum of the PF-02 Refund Amount and the TOCA Refund Amount.

Section 4. Customer Refund Amounts

BPA Customer ID Number	BP Customer Name	Customer Specific PF-02 Refund (1)	FY 2018 Scaled TOCA (2)	FY 2019 Scaled TOCA (2)	FY 2018 TOCA Refund	FY 2019 TOCA Refund	FY 2018 Total Refund	FY 2019 Total Refund
10005	Alder Mutual	\$ 3,178	0.0079%	0.0079%	\$ 3,035	\$ 3,036	\$ 6,213	\$ 6,214
10015	Asotin County PUD #1	\$ -	0.0084%	0.0084%	\$ 3,221	\$ 3,201	\$ 3,221	\$ 3,201
10024	Benton County PUD #1	\$1,074,609	2.9560%	2.9381%	\$1,131,209	\$1,124,353	\$2,205,818	\$2,198,962
10025	Benton REA	\$ 365,914	0.8762%	0.8708%	\$ 335,292	\$ 333,260	\$ 701,206	\$ 699,174
10027	Big Bend Elec Coop	\$ 180,557	0.8987%	0.8932%	\$ 343,916	\$ 341,831	\$ 524,473	\$ 522,389
10029	Blachly Lane Elec Coop	\$ 102,877	0.2587%	0.2571%	\$ 99,002	\$ 98,402	\$ 201,879	\$ 201,279
10044	Canby, City of	\$ 146,793	0.2983%	0.2964%	\$ 114,139	\$ 113,447	\$ 260,932	\$ 260,240
10046	Central Electric Coop	\$ 400,537	1.2021%	1.1948%	\$ 460,010	\$ 457,222	\$ 860,547	\$ 857,759
10047	Central Lincoln PUD	\$ 483,285	2.2816%	2.2733%	\$ 873,122	\$ 869,959	\$1,356,406	\$1,353,244
10055	Albion, City of	\$ -	0.0058%	0.0058%	\$ 2,233	\$ 2,224	\$ 2,233	\$ 2,224
10057	Ashland, City of	\$ 161,518	0.3094%	0.3075%	\$ 118,411	\$ 117,693	\$ 279,929	\$ 279,212
10059	Bandon, City of	\$ 55,554	0.1114%	0.1110%	\$ 42,642	\$ 42,486	\$ 98,197	\$ 98,041
10061	Blaine, City of	\$ 60,506	0.1284%	0.1277%	\$ 49,156	\$ 48,858	\$ 109,662	\$ 109,364
10062	Bonnars Ferry, City of	\$ 45,589	0.0781%	0.0777%	\$ 29,897	\$ 29,716	\$ 75,486	\$ 75,305
10064	Burley, City of	\$ 105,386	0.2065%	0.2053%	\$ 79,041	\$ 78,562	\$ 184,427	\$ 183,948
10065	Cascade Locks, City of	\$ 17,913	0.0349%	0.0347%	\$ 13,360	\$ 13,279	\$ 31,273	\$ 31,192
10066	Centralia, City of	\$ 164,230	0.3579%	0.3544%	\$ 136,967	\$ 135,605	\$ 301,198	\$ 299,835
10067	Cheney, City of	\$ 108,606	0.2323%	0.2309%	\$ 88,891	\$ 88,352	\$ 197,497	\$ 196,958
10068	Chewelah, City of	\$ -	0.0393%	0.0392%	\$ 15,050	\$ 14,994	\$ 15,050	\$ 14,994
10070	Declo, City of	\$ -	0.0053%	0.0052%	\$ 2,015	\$ 2,003	\$ 2,015	\$ 2,003
10071	Drain, City of	\$ 19,088	0.0279%	0.0278%	\$ 10,663	\$ 10,629	\$ 29,751	\$ 29,718
10072	Ellensburg, City of	\$ 175,179	0.3522%	0.3501%	\$ 134,782	\$ 133,965	\$ 309,961	\$ 309,144
10074	Forest Grove, City of	\$ 169,141	0.3919%	0.3895%	\$ 149,958	\$ 149,050	\$ 319,099	\$ 318,190
10076	Heyburn, City of	\$ 50,558	0.0707%	0.0703%	\$ 27,073	\$ 26,909	\$ 77,631	\$ 77,467
10078	McCleary, City of	\$ 35,576	0.0546%	0.0543%	\$ 20,893	\$ 20,766	\$ 56,469	\$ 56,342
10079	McMinnville, City of	\$ 593,568	1.2950%	1.2871%	\$ 495,572	\$ 492,568	\$1,089,140	\$1,086,136
10080	Milton, Town of	\$ 53,707	0.1092%	0.1086%	\$ 41,797	\$ 41,544	\$ 95,505	\$ 95,251
10081	Milton-Freewater, City of	\$ 76,961	0.1447%	0.1438%	\$ 55,376	\$ 55,040	\$ 132,337	\$ 132,001
10082	Minidoka, City of	\$ -	0.0015%	0.0015%	\$ 575	\$ 572	\$ 575	\$ 572
10083	Monmouth, City of	\$ 59,603	0.1228%	0.1221%	\$ 47,002	\$ 46,717	\$ 106,605	\$ 106,320
10086	Plummer, City of	\$ 28,254	0.0579%	0.0576%	\$ 22,174	\$ 22,040	\$ 50,428	\$ 50,293
10087	Port Angeles, City of	\$ 517,172	0.4600%	0.4584%	\$ 176,032	\$ 175,406	\$ 693,204	\$ 692,579
10089	Richland, City of	\$ 623,657	1.5252%	1.5160%	\$ 583,685	\$ 580,147	\$1,207,342	\$1,203,805
10091	Rupert, City of	\$ 72,943	0.1384%	0.1375%	\$ 52,952	\$ 52,631	\$ 125,895	\$ 125,574
10094	Soda Springs, City of	\$ -	0.0446%	0.0443%	\$ 17,065	\$ 16,961	\$ 17,065	\$ 16,961

BPA Customer ID Number	BP Customer Name	Customer Specific PF-02 Refund (1)	FY 2018 Scaled TOCA (2)	FY 2019 Scaled TOCA (2)	FY 2018 TOCA Refund	FY 2019 TOCA Refund	FY 2018 Total Refund	FY 2019 Total Refund
10095	Sumas, Town of	\$ 23,429	0.0535%	0.0532%	\$ 20,472	\$ 20,348	\$ 43,901	\$ 43,777
10097	Troy, City of	\$ -	0.0299%	0.0297%	\$ 11,452	\$ 11,383	\$ 11,452	\$ 11,383
10101	Clallam County PUD #1	\$ 520,583	1.1165%	1.1098%	\$ 427,285	\$ 424,695	\$ 947,868	\$ 945,278
10103	Clark County PUD #1	\$2,370,948	4.4577%	4.4446%	\$1,705,886	\$1,700,869	\$4,076,834	\$4,071,818
10105	Clatskanie PUD	\$ 617,393	1.2615%	1.2354%	\$ 482,763	\$ 472,752	\$1,100,156	\$1,090,145
10106	Clearwater Power	\$ 125,833	0.3507%	0.3486%	\$ 134,203	\$ 133,389	\$ 260,036	\$ 259,222
10109	Columbia Basin Elec Coop	\$ -	0.1780%	0.1769%	\$ 68,109	\$ 67,696	\$ 68,109	\$ 67,696
10111	Columbia Power Coop	\$ -	0.0440%	0.0436%	\$ 16,851	\$ 16,674	\$ 16,851	\$ 16,674
10112	Columbia River PUD	\$ 265,444	0.8363%	0.8329%	\$ 320,048	\$ 318,727	\$ 585,492	\$ 584,172
10113	Columbia REA	\$ -	0.5536%	0.5502%	\$ 211,839	\$ 210,556	\$ 211,839	\$ 210,556
10116	Consolidated Irrigation District #19	\$ 1,825	0.0033%	0.0033%	\$ 1,281	\$ 1,273	\$ 3,107	\$ 3,099
10118	Consumers Power	\$ 246,076	0.6708%	0.6667%	\$ 256,691	\$ 255,136	\$ 502,767	\$ 501,212
10121	Coos Curry Elec Coop	\$ 229,267	0.5799%	0.5764%	\$ 221,915	\$ 220,570	\$ 451,182	\$ 449,837
10123	Cowlitz County PUD #1	\$3,446,817	8.0655%	8.0166%	\$3,086,555	\$3,067,848	\$6,533,372	\$6,514,665
10136	Douglas Electric Cooperative	\$ 105,338	0.2704%	0.2694%	\$ 103,464	\$ 103,090	\$ 208,802	\$ 208,428
10142	East End Mutual Electric	\$ -	0.0395%	0.0392%	\$ 15,101	\$ 15,010	\$ 15,101	\$ 15,010
10144	Eatonville, City of	\$ 23,238	0.0487%	0.0485%	\$ 18,636	\$ 18,558	\$ 41,874	\$ 41,796
10156	Elmhurst Mutual P & L	\$ -	0.4720%	0.4706%	\$ 180,621	\$ 180,086	\$ 180,621	\$ 180,086
10157	Emerald PUD	\$ 376,548	0.7337%	0.7292%	\$ 280,769	\$ 279,068	\$ 657,317	\$ 655,615
10158	Energy Northwest	\$ 20,415	0.0394%	0.0391%	\$ 15,062	\$ 14,970	\$ 35,476	\$ 35,385
10170	Eugene Water & Electric Board	\$1,490,101	3.5386%	3.5244%	\$1,354,167	\$1,348,720	\$2,844,268	\$2,838,821
10172	U.S. Airforce Base, Fairchild	\$ 60,465	0.0824%	0.0823%	\$ 31,547	\$ 31,514	\$ 92,013	\$ 91,979
10173	Fall River Elec Coop	\$ 152,407	0.4865%	0.4836%	\$ 186,191	\$ 185,062	\$ 338,597	\$ 337,469
10174	Farmers Elec Coop	\$ -	0.0075%	0.0074%	\$ 2,852	\$ 2,835	\$ 2,852	\$ 2,835
10177	Ferry County PUD #1	\$ 67,875	0.1475%	0.1411%	\$ 56,431	\$ 54,007	\$ 124,306	\$ 121,882
10179	Flathead Elec Coop	\$ 608,080	2.4499%	2.4351%	\$ 937,557	\$ 931,875	\$1,545,637	\$1,539,955
10183	Franklin County PUD #1	\$ 471,954	1.7234%	1.7130%	\$ 659,525	\$ 655,528	\$1,131,479	\$1,127,481
10186	Glacier Elec Coop	\$ -	0.2735%	0.2735%	\$ 104,678	\$ 104,659	\$ 104,678	\$ 104,659
10190	Grant County PUD #2	\$1,146,092	0.6011%	0.5974%	\$ 230,019	\$ 228,625	\$1,376,111	\$1,374,717
10191	Grays Harbor PUD #1	\$ 736,828	1.9093%	1.8973%	\$ 730,656	\$ 726,055	\$1,467,484	\$1,462,882
10197	Harney Elec Coop	\$ 91,382	0.3341%	0.3321%	\$ 127,868	\$ 127,093	\$ 219,250	\$ 218,475
10202	Hood River Elec Coop	\$ 89,783	0.1924%	0.1912%	\$ 73,615	\$ 73,168	\$ 163,398	\$ 162,952
10203	Idaho County L & P	\$ 39,010	0.0913%	0.0907%	\$ 34,923	\$ 34,711	\$ 73,933	\$ 73,721
10204	Idaho Falls Power	\$ 435,271	0.9806%	0.9768%	\$ 375,265	\$ 373,795	\$ 810,536	\$ 809,066
10209	Inland P & L	\$ -	1.5404%	1.5311%	\$ 589,496	\$ 585,923	\$ 589,496	\$ 585,923
10230	Kittitas County PUD #1	\$ 48,061	0.1425%	0.1416%	\$ 54,531	\$ 54,200	\$ 102,591	\$ 102,261

BPA Customer ID Number	BP Customer Name	Customer Specific PF-02 Refund (1)	FY 2018 Scaled TOCA (2)	FY 2019 Scaled TOCA (2)	FY 2018 TOCA Refund	FY 2019 TOCA Refund	FY 2018 Total Refund	FY 2019 Total Refund
10231	Klickitat County PUD #1	\$ 219,238	0.5384%	0.5351%	\$ 206,028	\$ 204,779	\$ 425,266	\$ 424,017
10234	Kootenai Electric Coop	\$ -	0.7490%	0.7444%	\$ 286,620	\$ 284,883	\$ 286,620	\$ 284,883
10235	Lakeview L & P (WA)	\$ 261,953	0.4641%	0.4636%	\$ 177,618	\$ 177,421	\$ 439,571	\$ 439,374
10236	Lane County Elec Coop	\$ 154,159	0.4092%	0.4067%	\$ 156,595	\$ 155,646	\$ 310,753	\$ 309,804
10237	Lewis County PUD #1	\$ 720,554	1.6201%	1.6144%	\$ 619,977	\$ 617,812	\$1,340,531	\$1,338,366
10239	Lincoln Elec Coop (MT)	\$ -	0.2031%	0.2019%	\$ 77,732	\$ 77,261	\$ 77,732	\$ 77,261
10242	Lost River Elec Coop	\$ 50,765	0.1379%	0.1381%	\$ 52,754	\$ 52,856	\$ 103,518	\$ 103,620
10244	Lower Valley Energy	\$ -	1.2635%	1.2559%	\$ 483,541	\$ 480,610	\$ 483,541	\$ 480,610
10246	Mason County PUD #1	\$ 52,092	0.1320%	0.1312%	\$ 50,508	\$ 50,202	\$ 102,601	\$ 102,295
10247	Mason County PUD #3	\$ 544,117	1.1738%	1.1667%	\$ 449,209	\$ 446,486	\$ 993,326	\$ 990,603
10256	Midstate Elec Coop	\$ 287,247	0.6673%	0.6635%	\$ 255,374	\$ 253,917	\$ 542,621	\$ 541,164
10258	Mission Valley	\$ -	0.5574%	0.5540%	\$ 213,295	\$ 212,002	\$ 213,295	\$ 212,002
10259	Missoula Elec Coop	\$ -	0.3963%	0.3939%	\$ 151,660	\$ 150,741	\$ 151,660	\$ 150,741
10260	Modern Elec Coop	\$ -	0.3860%	0.3837%	\$ 147,725	\$ 146,830	\$ 147,725	\$ 146,830
10273	Nespelem Valley Elec Coop	\$ 35,342	0.0864%	0.0859%	\$ 33,055	\$ 32,854	\$ 68,396	\$ 68,196
10278	Northern Lights	\$ 134,905	0.4961%	0.4954%	\$ 189,848	\$ 189,592	\$ 324,753	\$ 324,497
10279	Northern Wasco County PUD	\$ 169,186	0.9511%	0.9454%	\$ 363,983	\$ 361,777	\$ 533,169	\$ 530,963
10284	Ohop Mutual Light Company	\$ -	0.1459%	0.1453%	\$ 55,852	\$ 55,620	\$ 55,852	\$ 55,620
10285	Okanogan County Elec Coop	\$ 33,056	0.0959%	0.0953%	\$ 36,692	\$ 36,470	\$ 69,748	\$ 69,526
10286	Okanogan County PUD #1	\$ 302,445	0.6742%	0.6702%	\$ 258,024	\$ 256,460	\$ 560,469	\$ 558,905
10288	Orcas P & L	\$ -	0.3632%	0.3610%	\$ 139,006	\$ 138,164	\$ 139,006	\$ 138,164
10291	Oregon Trail Coop	\$ 535,684	1.1553%	1.1558%	\$ 442,136	\$ 442,311	\$ 977,820	\$ 977,995
10294	Pacific County PUD #2	\$ 263,432	0.5118%	0.5104%	\$ 195,857	\$ 195,321	\$ 459,289	\$ 458,753
10304	Parkland L & W	\$ -	0.2030%	0.2023%	\$ 77,669	\$ 77,415	\$ 77,669	\$ 77,415
10306	Pend Oreille County PUD #1	\$ 218,512	0.0000%	0.0000%	\$ -	\$ -	\$ 218,512	\$ 218,512
10307	Peninsula Light Company	\$ 484,256	1.0039%	0.9990%	\$ 384,178	\$ 382,315	\$ 868,434	\$ 866,571
10326	U.S. Naval Base, Bremerton	\$ 216,980	0.4277%	0.4251%	\$ 163,671	\$ 162,679	\$ 380,652	\$ 379,660
10331	Raft River Elec Coop	\$ 81,677	0.5375%	0.5343%	\$ 205,711	\$ 204,464	\$ 287,388	\$ 286,141
10333	Ravalli County Elec Coop	\$ -	0.2719%	0.2703%	\$ 104,055	\$ 103,425	\$ 104,055	\$ 103,425
10338	Riverside Elec Coop	\$ -	0.0348%	0.0346%	\$ 13,336	\$ 13,255	\$ 13,336	\$ 13,255
10342	Salem Elec Coop	\$ 342,469	0.5581%	0.5561%	\$ 213,561	\$ 212,803	\$ 556,030	\$ 555,272
10343	Salmon River Elec Coop	\$ 126,695	0.1696%	0.1686%	\$ 64,916	\$ 64,522	\$ 191,610	\$ 191,217
10349	Seattle City Light	\$2,806,762	7.6247%	7.6423%	\$2,917,850	\$2,924,594	\$5,724,612	\$5,731,357
10352	Skamania County PUD #1	\$ 110,458	0.2276%	0.2266%	\$ 87,094	\$ 86,735	\$ 197,552	\$ 197,194
10354	Snohomish County PUD #1	\$4,394,837	11.5548%	11.6241%	\$4,421,849	\$4,448,386	\$8,816,686	\$8,843,223

BPA Customer ID Number	BP Customer Name	Customer Specific PF- 02 Refund (1)	FY 2018 Scaled TOCA (2)	FY 2019 Scaled TOCA (2)	FY 2018 TOCA Refund	FY 2019 TOCA Refund	FY 2018 Total Refund	FY 2019 Total Refund
10360	Southside Elec Lines	\$ -	0.0994%	0.0988%	\$ 38,025	\$ 37,795	\$ 38,025	\$ 37,795
10363	Springfield Utility Board	\$ 490,736	1.4088%	1.4038%	\$ 539,123	\$ 537,196	\$1,029,859	\$1,027,932
10369	Surprise Valley Elec Coop	\$ 81,780	0.2413%	0.2399%	\$ 92,350	\$ 91,790	\$ 174,129	\$ 173,570
10370	Tacoma Public Utilities	\$2,979,021	5.6095%	5.7383%	\$2,146,689	\$2,195,985	\$5,125,710	\$5,175,006
10371	Tanner Elec Coop	\$ 59,409	0.1620%	0.1610%	\$ 62,000	\$ 61,624	\$ 121,409	\$ 121,034
10376	Tillamook PUD #1	\$ 287,525	0.8096%	0.8067%	\$ 309,834	\$ 308,725	\$ 597,359	\$ 596,250
10378	Coulee Dam, City of	\$ -	0.0281%	0.0281%	\$ 10,754	\$ 10,771	\$ 10,754	\$ 10,771
10379	Steilacoom, Town of	\$ 35,527	0.0702%	0.0701%	\$ 26,851	\$ 26,826	\$ 62,378	\$ 62,353
10388	Umatilla Elec Coop	\$ 557,880	1.6628%	1.6527%	\$ 636,324	\$ 632,467	\$1,194,204	\$1,190,347
10391	United Electric Coop	\$ 144,156	0.4402%	0.4376%	\$ 168,475	\$ 167,454	\$ 312,631	\$ 311,610
10406	U.S. DOE Albany Research Center	\$ 3,304	0.0067%	0.0067%	\$ 2,574	\$ 2,559	\$ 5,879	\$ 5,863
10408	U.S. Naval Station, Everett (Jim Creek)	\$ 10,783	0.0215%	0.0214%	\$ 8,243	\$ 8,193	\$ 19,026	\$ 18,976
10409	U.S. Naval Submarine Base, Bangor	\$ 151,547	0.2905%	0.2891%	\$ 111,152	\$ 110,632	\$ 262,699	\$ 262,179
10426	U.S. DOE Richland Operations Office	\$ 193,387	0.2703%	0.4568%	\$ 103,452	\$ 174,823	\$ 296,839	\$ 368,210
10434	Vera Irrigation District	\$ 190,495	0.3988%	0.3964%	\$ 152,624	\$ 151,699	\$ 343,119	\$ 342,194
10436	Vigilante Elec Coop	\$ -	0.2813%	0.2796%	\$ 107,637	\$ 106,985	\$ 107,637	\$ 106,985
10440	Wahkiakum County PUD #1	\$ 32,517	0.0733%	0.0728%	\$ 28,045	\$ 27,875	\$ 60,562	\$ 60,392
10442	Wasco Elec Coop	\$ -	0.1948%	0.1942%	\$ 74,539	\$ 74,336	\$ 74,539	\$ 74,336
10446	Wells Rural Elec Coop	\$ 388,509	1.4065%	1.3980%	\$ 538,242	\$ 534,980	\$ 926,751	\$ 923,489
10448	West Oregon Elec Coop	\$ 48,959	0.1217%	0.1209%	\$ 46,562	\$ 46,279	\$ 95,521	\$ 95,239
10451	Whatcom County PUD #1	\$ 179,980	0.3908%	0.3885%	\$ 149,562	\$ 148,655	\$ 329,542	\$ 328,636
10482	Umpqua Indian Utility Cooperative	\$ 15,681	0.0405%	0.0402%	\$ 15,486	\$ 15,392	\$ 31,167	\$ 31,073
10502	Yakama Power	\$ 7,897	0.2478%	0.2576%	\$ 94,845	\$ 98,583	\$ 102,742	\$ 106,480
10597	Hermiston, City of	\$ 100,167	0.1857%	0.1845%	\$ 71,048	\$ 70,618	\$ 171,215	\$ 170,784
10706	Port of Seattle – SeaTac Int'l. Airport	\$ -	0.2537%	0.2522%	\$ 97,106	\$ 96,517	\$ 97,106	\$ 96,517
11680	Weiser, City of	\$ -	0.0929%	0.0924%	\$ 35,566	\$ 35,350	\$ 35,566	\$ 35,350
12026	Jefferson County PUD #1	\$ -	NA	NA	\$ -	\$ -	\$ -	\$ -
13927	Kalispel Tribe Utility	\$ -	NA	NA	\$ -	\$ -	\$ -	\$ -
Total		\$ 38,269,000	100.0000%	100.0000%	\$ 38,268,617	\$ 38,268,617	\$ 76,537,617	\$ 76,537,617

(1) See Exhibit B of 2012 REP Settlement Agreement, REP-12-A-02A (misfiled as REP-12-A-02-AP01) (2012 REP Settlement). US BIA Wapato CHWM was annexed by Yakama Power; therefore the PF-02 Refund Amount is included under Yakama Power.

(2) Adjusted TOCAs are recomputed with Grant CHWM equal to 41.75 aMW, pursuant to Section 3.4 of the Settlement Agreement. Final Scaled TOCAs reallocate headroom (when customers' net requirement is below their RHWM allocated share of the Tier 1 System) among all customers pro rata to Adjusted TOCA percentages.

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Appendix B: Product Conversion Charge

Section 1. Purpose

Customers that converted from the Slice product to a non-Slice product beginning October 1, 2017, are subject to a customer-specific monthly charge. These customers received benefits associated with Regional Cooperation Debt management actions in FY 2014 and 2015 through the Slice True-Up for those years, while Non-Slice customers receive their share of FY 2014 and FY 2015 benefits in the PF-18 Tier 1 Non-Slice Customer charge. Application of this Product Conversion Charge avoids having the former Slice customers receive benefits twice.

Section 2. Product Conversion Charge

The monthly Product Conversion Charge for each customer is listed on the table below.

<i>Customer Id</i>	<i>Customer</i>	<i>FY 2018-2019 Monthly Charge</i>
10231	Klickitat PUD	\$10,371
10349	Seattle City Light	\$159,059

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Appendix C: Spill Surcharge

A. Availability

The Spill Surcharge applies to customers that purchase the following products under the PF rate: Load Following, Block, or the Block portion of Slice/Block. The Spill Surcharge also applies to power purchased at the PF Merged, IP, and NR rates.

B. Spill Surcharge Amount

The Spill Surcharge Amount is the total additional cost to be charged to customers in a Fiscal Year in which less Federal hydro generation is forecast to be available relative to the amount of Federal hydro generation forecast to be available in the BP-18 Final Proposal due to revised spill assumptions.

For each Fiscal Year of the rate period, the Spill Surcharge Amount shall be:

$$\left(\left(\frac{\sum_{i=1}^{1120} ((BP18FedGen_i - RevFedGen_i) \times BP18Price_i)}{80} \right) - CostR \right) \times \left(1 - \sum Slice\% \right) - SecR$$

Where:

i = a single period for a particular water year. There are 14 periods per year (the months of April and August are split) and 80 water years, which results in an overall summation of 1,120 values. The monthly market price for April of a particular water year will be used twice, once for each split of April. The monthly market price for August of a particular water year will be used twice, once for each split of August.

BP18FedGen (BP-18 Final Proposal Federal Generation) is the Federal regulated hydro generation in average megawatts (aMW) from the BP-18 Final Proposal HYDSIM study, converted to megawatthours (MWh).

The 14 periods of generation for 80 water years for FY 2018 and FY 2019 are shown in the BP-18 Final Power Loads and Resources Study Documentation, BP-18-FS-BPA-03A.

RevFedGen (Revised Federal Generation) is the Federal regulated hydro generation in average megawatts (aMW) from the BP-18 Final Proposal HYDSIM study with revised planned spill assumptions, converted to megawatthours (MWh).

BP18Price (BP-18 Final Proposal Market Price) is the market price forecast from the BP-18 Final Proposal in \$/MWh. The monthly market price forecast is shown in the Power Market Price Study and Documentation, BP-18-FS-BPA-04.

CostR (Cost Reductions) are specific forecast and actual program spending reductions determined by the Administrator that may be used to reduce the cost of the Spill Surcharge Amount. Cost Reductions are not mandatory and are subject to the discretion of the Administrator. The specified program spending reductions are relative to the program spending assumed for purposes of setting the BP-18 Final Proposal rates.

Σ *Slice%* is the sum of customer Slice percentages for the relevant Fiscal Year as specified in Exhibit K of the Slice customer's CHWM Contract.

SecR (Secondary Reduction) is equal to the net impact increased spill has on BPA's forecast balancing purchase costs and forecast revenue from remaining secondary sales due to any changes in the forecast market prices using BP-18 final studies with revised planned spill assumptions. Such amount will be reduced by any Spill Surcharge Amount that is not collected due to the application of the Low Density Discount. If the resulting *SecR* is less than zero, the *SecR* is deemed to be zero.

If the Spill Surcharge Amount calculation results in a value less than \$5 million, the Spill Surcharge Amount is deemed to be zero.

C. Spill Surcharge Rate

The Spill Surcharge rate in mills per kilowatthour shall be:

$$\frac{\text{Spill Surcharge Amount}}{\Sigma \text{BD}}$$

Where:

Σ *BD (Sum of Billing Determinants)* is the most current forecast of service under the PF Melded, IP, and NR rates and the sum of the PF System Shaped Loads for the unbilled remaining portion of the applicable Fiscal Year, in kilowatthours.

D. Billing

For customers taking service at the PF Melded, IP, and NR rates, the Spill Surcharge rate will be added to each of the remaining monthly/diurnal PF Melded, IP and NR energy rates for the applicable Fiscal Year.

For PF customers with a System Shaped Load, the Spill Surcharge rate will be applied to the sum of each customer's HLH and LLH PF System Shaped Load for the remaining months of the applicable Fiscal Year. A customer's Low Density Discount shall be applied to the Spill Surcharge.

For any FY 2018 Spill Surcharge, a PF customer with a System Shaped Load may request a payment schedule of flat monthly amounts that recover its FY 2018 Spill Surcharge over the remaining months in the rate period. BPA will accommodate such requests if, in BPA's sole determination, there are no material adverse impacts on BPA's cash flow, including material increases in the forecast likelihood of triggering the Power Cost Recovery Adjustment Clause (GRSP II.O).

E. Annual Spill Surcharge Rate and Other Adjustments

1. Annual Spill Surcharge Rate

An Annual Spill Surcharge Rate, in mills per kilowatthour, will be calculated so that the Load Shaping Charge True-up rate and PF Melded Equivalent Energy Scalar can be adjusted. The Annual Spill Surcharge Rate is calculated by dividing the Spill Surcharge Amount by the annual forecast, in kilowatthours, made around the beginning of each Fiscal Year of service under the PF Melded, IP, and NR rates and the sum of the PF System Shaped Loads for the applicable year. The Annual Spill Surcharge Rate will be:

- a. Subtracted from the Load Shaping Charge True-Up rate (GRSP II.E, Section 1)
- b. Subtracted from the PF Melded Equivalent Energy Scalar rate (GRSP II.R, Section 1(c)).

2. Adjustment to the PF Tier 1 Equivalent Energy Rates

The Spill Surcharge Rate (Section C, above) will be added to each of the monthly/diurnal PF Tier 1 Equivalent energy rates (GRSP II.AA) for the remaining months of the applicable Fiscal Year.

F. Notification

For each year of the rate period, BPA will notify customers of the preliminary Spill Surcharge Amount to be recovered by the Spill Surcharge for the fiscal year (if any). Such notice will be provided as soon as practicable, but in no case later than May 31 of each Fiscal Year. BPA will make available to customers the preliminary data and

assumptions relied upon to calculate the surcharge including any proposed program spending reductions.

BPA will hold at least one public meeting to review the calculation of the Spill Surcharge Amount, Spill Surcharge Rate, and the Annual Spill Surcharge Rate. BPA will provide at least 10 business days for comment on the preliminary data and assumptions. No later than 14 calendar days after the comment period closes, BPA will issue the final Spill Surcharge Amount, Spill Surcharge Rate, and the Annual Spill Surcharge Rate, and apply such rates in the next available billing cycle.

BP-18 Rate Proceeding

ADMINISTRATOR'S FINAL RECORD OF DECISION

Appendix D: Transmission, Ancillary, and Control Area Service Rate Schedules and General Rate Schedule Provisions

BP-18-A-04-AP04

July 2017



BONNEVILLE POWER ADMINISTRATION

**2018 TRANSMISSION, ANCILLARY, AND
CONTROL AREA SERVICE RATE SCHEDULES
AND GENERAL RATE SCHEDULE PROVISIONS**

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**TRANSMISSION, ANCILLARY, AND CONTROL AREA
SERVICE RATE SCHEDULES**

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FPT-18.1 FORMULA POWER TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes the FPT-16.1 rate schedule for all firm transmission agreements that provide for application of FPT rates that may be adjusted not more frequently than once a year. This schedule is applicable only to such transmission agreements executed prior to October 1, 1996. It is available for firm transmission of non-Federal power using the Main Grid and/or Secondary System of the Federal Columbia River Transmission System. This schedule is for full-year and partial-year service and for either continuous or intermittent service when firm transmission service is required. For facilities at voltages lower than the Secondary System, a different rate schedule may be specified. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATES

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

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

$$\left(1 + \frac{\text{GSR}_q}{\$1.662/\text{kW}/\text{mo}}\right) * \text{FPT Base Charges}$$

Where:

GSR_q = The ACS-18 Reactive Supply and Voltage Control From Generation Sources Service Rate for Long-Term Firm PTP Transmission Service and NT Service, section II.B.1.a., that is effective for the quarter for which the FPT rate is being calculated, in \$/kW/mo.

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

MAIN GRID CHARGES

1. Main Grid Distance	\$0.0701 per mile
2. Main Grid Interconnection Terminal	\$0.73/kW
3. Main Grid Terminal	\$0.81/kW
4. Main Grid Miscellaneous Facilities	\$4.00/kW

SECONDARY SYSTEM CHARGES

1. Secondary System Distance	\$0.6896 per mile
2. Secondary System Transformation	\$7.54/kW
3. Secondary System Intermediate Terminal	\$2.91/kW
4. Secondary System Interconnection Terminal	\$2.06/kW

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

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

SECTION III. BILLING FACTORS

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

- A. The Transmission Demand;
- B. The highest hourly Scheduled Demand for the month; or
- C. The Ratchet Demand.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

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

B. FAILURE TO COMPLY PENALTY

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

C. TRANSMISSION COST RECOVERY ADJUSTMENT CLAUSE

Customers taking service under this rate schedule are subject to the Transmission Cost Recovery Adjustment Clause, specified in GRSP II.H.

D. TRANSMISSION RESERVES DISTRIBUTION CLAUSE

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause, specified in GRSP II.I.

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FPT-18.3 FORMULA POWER TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes the FPT-16.3 rate schedule for all firm transmission agreements that provide for application of FPT rates that may be adjusted not more frequently than once every three years. This schedule is applicable only to such transmission agreements executed prior to October 1, 1996. It is available for firm transmission of non-Federal power using the Main Grid and/or Secondary System of the Federal Columbia River Transmission System. This schedule is for full-year and partial-year service and for either continuous or intermittent service when firm transmission service is required. For facilities at voltages lower than the Secondary System, a different rate schedule may be specified. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATES

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

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

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

Where:

- GSR_q = The ACS-18 Reactive Supply and Voltage Control From Generation Sources Service Rate for Long-Term Firm PTP Transmission Service and NT Service, section II.B.1.a., that is effective for the quarter for which the FPT rate is being calculated, in \$/kW/mo.
- FPT Base Charges = The following annual Main Grid and Secondary System charges:

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

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

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

SECTION III. BILLING FACTORS

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

- A. The Transmission Demand;
- B. The highest hourly Scheduled Demand for the month; or
- C. The Ratchet Demand.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

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

B. FAILURE TO COMPLY PENALTY

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

IR-18

INTEGRATION OF RESOURCES RATE

SECTION I. AVAILABILITY

This schedule supersedes the IR-16 rate schedule and is available for transmission of non-Federal power for full-year firm transmission service and non-firm transmission service in amounts not to exceed the customer's total Transmission Demand using Federal Columbia River Transmission System Network and Delivery facilities. This schedule is applicable only to Integration of Resource (IR) agreements executed prior to October 1, 1996. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATES

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

A. RATE

The rate shall be the sum of:

1. \$1.793 per kilowatt per month (\$/kW/mo); and
2. ACS-18 Reactive Supply and Voltage Control From Generation Sources Service Rate for Long-Term Firm PTP Transmission Service and NT Service, section II.B.1.a., effective for the quarter for which the IR rate is being calculated, in \$/kW/mo.

B. SHORT DISTANCE DISCOUNT (SDD) RATE

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

1. ACS-18 Scheduling, System Control, and Dispatch Rate for Long-Term Firm PTP Transmission Service, section II.A.1.b; and
2. ACS-18 Reactive Supply and Voltage Control From Generation Sources Service Rate for Long-Term Firm PTP Transmission Service and NT Service, section II.B.1.a., effective for the quarter for which the IR rate is being calculated, in \$/kW/mo; and

3. $(0.6 + (0.4 * \text{transmission distance}/75)) * \$1.471/\text{kW}/\text{mo}$

Where:

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

SECTION III. BILLING FACTORS

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

- A. The annual Transmission Demand, or, if defined in the agreement, the annual Total Transmission Demand;
- B. The highest hourly Scheduled Demand for the month; or
- C. The Ratchet Demand.

To the extent that the agreement provides for the IR customer to be billed for transmission service in excess of the Transmission Demand or Total Transmission Demand, as defined in the agreement, at an hourly non-firm rate, such excess transmission service shall not contribute to the Billing Factor for the IR rates in section II, provided that the IR customer requests such treatment and BPA approves such request in accordance with the prescribed provisions in the agreement. The rate for transmission service in excess of the Transmission Demand will be pursuant to the Point-to-Point Rate (PTP-18) for Hourly Non-Firm Service.

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

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

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

B. DELIVERY CHARGE

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

C. FAILURE TO COMPLY PENALTY

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

D. RATCHET DEMAND RELIEF

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

1. The event that resulted in the Ratchet Demand:
 - a. was the result of an equipment failure or outage that could not reasonably have been foreseen by the customer; and
 - b. did not result in harm to BPA's transmission system or transmission services, or to any other Transmission Customer; or

2. The event that resulted in the Ratchet Demand:
 - a. was inadvertent;
 - b. could not have been avoided by the exercise of reasonable care;
 - c. did not result in harm to BPA's transmission system or transmission services, or to any other Transmission Customer; and
 - d. was not part of a recurring pattern of conduct by the IR customer.

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

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

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

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

F. TRANSMISSION COST RECOVERY ADJUSTMENT CLAUSE

Customers taking service under this rate schedule are subject to the Transmission Cost Recovery Adjustment Clause, specified in GRSP II.H.

G. TRANSMISSION RESERVES DISTRIBUTION CLAUSE

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause, specified in GRSP II.I.

NT-18 NETWORK INTEGRATION RATE

SECTION I. AVAILABILITY

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

SECTION II. RATE

\$1.727 per kilowatt per month

SECTION III. BILLING FACTOR

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

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

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

B. DELIVERY CHARGE

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

C. FAILURE TO COMPLY PENALTY

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

D. SHORT-DISTANCE DISCOUNT (SDD)

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

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

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

Where:

Average
Generation

during HLH = The output serving Network Load during HLH on a firm basis over the billing month, divided by the number of HLH during the month, multiplied by the ratio of the Qualifying Capacity of the DNR SD output serving the Customer's Point(s) of Delivery (POD) to the total DNR SD designated capacity.

The output serving Network Load is:

1. in the case of a scheduled DNR SD, the sum of firm schedules to Network Load.
2. in the case of Behind the Meter Resources, the metered output of the resource.

NT Rate = \$1.727 per kilowatt per month

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

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

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

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

E. DIRECT ASSIGNMENT FACILITIES

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

F. INCREMENTAL COST RATES

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

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

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

H. TRANSMISSION COST RECOVERY ADJUSTMENT CLAUSE

Customers taking service under this rate schedule are subject to the Transmission Cost Recovery Adjustment Clause, specified in GRSP II.H.

I. TRANSMISSION RESERVES DISTRIBUTION CLAUSE

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause, specified in GRSP II.I.

PTP-18 POINT-TO-POINT RATE

SECTION I. AVAILABILITY

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

SECTION II. RATES

A. LONG-TERM FIRM PTP TRANSMISSION SERVICE

\$1.471 per kilowatt per month

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

For each reservation, the rates shall not exceed:

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

- a. Days 1 through 5** \$0.068 per kilowatt per day
- b. Day 6 and beyond** \$0.048 per kilowatt per day

2. Hourly Firm and Non-Firm Service

4.23 mills per kilowatthour

SECTION III. BILLING FACTORS

A. ALL FIRM AND NON-FIRM SERVICE

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

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

B. REDIRECT SERVICE

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

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

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

B. DELIVERY CHARGE

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

C. FAILURE TO COMPLY PENALTY

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

D. INTERRUPTION OF NON-FIRM PTP TRANSMISSION SERVICE

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

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

1. If the need for curtailment is caused by conditions on the FCRTS, the Billing Factor will be as follows:
 - a. If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted before the close of the hourly non-firm scheduling window, the Billing Factor will be the Reserved Capacity minus the curtailed capacity.
 - b. If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted after the close of the hourly non-firm scheduling window, the Billing Factor will be the Transmission Customer's actual schedule in the hour.
2. If the need for curtailment is caused by conditions on another transmission provider's transmission system, the Billing Factor will be the Reserved Capacity.

E. RESERVATION FEE

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

F. SHORT-DISTANCE DISCOUNT (SDD)

Reservations for Long-Term Firm PTP Transmission Service that use BPA transmission facilities for a distance of less than 75 circuit miles shall receive a SDD. The SDD shall be designated in the PTP Service Agreement.

For reservations receiving a SDD, BPA will multiply the billing factors in section III.A. by the following factor to calculate the customer's monthly transmission bill:

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

System sales do not qualify for SDD. If a set of contiguous PODs qualifies for an SDD, the transmission distance used in the calculation of the SDD shall be between the POR and the POD farthest from the POR.

If the customer redirects, on a firm or non-firm basis, any portion of Reserved Capacity from a reservation receiving a SDD for any period of time during a month, the SDD shall not be applied to the entire reservation for that month.

G. UNAUTHORIZED INCREASE CHARGE

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

H. DIRECT ASSIGNMENT FACILITIES

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

I. INCREMENTAL COST RATES

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

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

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

K. TRANSMISSION COST RECOVERY ADJUSTMENT CLAUSE

Customers taking service under this rate schedule are subject to the Transmission Cost Recovery Adjustment Clause, specified in GRSP II.H.

L. TRANSMISSION RESERVES DISTRIBUTION CLAUSE

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause, specified in GRSP II.I.

IS-18
SOUTHERN INTERTIE RATE

SECTION I. AVAILABILITY

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

SECTION II. RATES

A. LONG-TERM FIRM PTP TRANSMISSION SERVICE

\$1.038 per kilowatt per month

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

For each reservation, the rates shall not exceed:

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

- a. Days 1 through 5** \$0.048 per kilowatt per day
- b. Day 6 and beyond** \$0.034 per kilowatt per day

2. Hourly Firm and Non-Firm Service

9.56 mills per kilowatthour

BPA intends to provide discounted service for Hourly Non-Firm Service in the south-to-north direction. BPA will post such discount on OASIS pursuant to section II.E of the GSRPs. The following principles will apply to any such discount:

- a. Providing a discount for service in one direction will not require the same discount to be provided in the other direction.
- b. Providing a discount for service on the Southern Intertie will not require a discount to be provided for service on the Network or other segments.

SECTION III. BILLING FACTORS

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

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

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

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

B. REDIRECT SERVICE

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

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

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

B. FAILURE TO COMPLY PENALTY

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

C. INTERRUPTION OF NON-FIRM PTP TRANSMISSION SERVICE

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

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

1. If the need for curtailment is caused by conditions on the FCRTS, the Billing Factor will be as follows:
 - a. If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted before the close of the hourly non-firm scheduling window, the Billing Factor will be the Reserved Capacity minus the curtailed capacity.
 - b. If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted after the close of the hourly non-firm scheduling window, the Billing Factor will be the Transmission Customer's actual schedule in the hour.
2. If the need for curtailment is caused by conditions on another transmission provider's transmission system, the Billing Factor will be the Reserved Capacity.

D. RESERVATION FEE

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

E. UNAUTHORIZED INCREASE CHARGE

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

F. DIRECT ASSIGNMENT FACILITIES

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

G. INCREMENTAL COST RATES

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

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

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

I. TRANSMISSION COST RECOVERY ADJUSTMENT CLAUSE

Customers taking service under this rate schedule are subject to the Transmission Cost Recovery Adjustment Clause, specified in GRSP II.H.

J. TRANSMISSION RESERVES DISTRIBUTION CLAUSE

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause, specified in GRSP II.I.

IM-18
MONTANA INTERTIE RATE

SECTION I. AVAILABILITY

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

SECTION II. RATES

A. LONG-TERM FIRM PTP TRANSMISSION SERVICE

\$0.509 per kilowatt per month

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

For each reservation, the rates shall not exceed:

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

a. Days 1 through 5 \$0.023 per kilowatt per day

b. Day 6 and beyond \$0.017 per kilowatt per day

2. Hourly Firm and Non-Firm Service

1.46 mills per kilowatthour

SECTION III. BILLING FACTORS

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

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

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

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

B. REDIRECT SERVICE

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

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

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

B. FAILURE TO COMPLY PENALTY CHARGE

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

C. INTERRUPTION OF NON-FIRM PTP TRANSMISSION SERVICE

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

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

1. If the need for curtailment is caused by conditions on the Federal Columbia River Transmission System, the Billing Factor will be as follows:
 - a. If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted before the close of the hourly non-firm scheduling window, the Billing Factor will be the Reserved Capacity minus the curtailed capacity.
 - b. If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted after the close of the hourly non-firm scheduling window, the Billing Factor will be the Transmission Customer's actual schedule for the hour.
2. If the need for curtailment is caused by conditions on another transmission provider's transmission system, the Billing Factor will be the Reserved Capacity.

D. RESERVATION FEE

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

E. UNAUTHORIZED INCREASE CHARGE

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

F. DIRECT ASSIGNMENT FACILITIES

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

G. INCREMENTAL COST RATES

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

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

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

I. TRANSMISSION COST RECOVERY ADJUSTMENT CLAUSE

Customers taking service under this rate schedule are subject to the Transmission Cost Recovery Adjustment Clause, specified in GRSP II.H.

J. TRANSMISSION RESERVES DISTRIBUTION CLAUSE

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause, specified in GRSP II.I.

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UFT-18

USE-OF-FACILITIES TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes the UFT-16 rate schedule unless otherwise provided in the agreement, and is available for firm transmission over specified Federal Columbia River Transmission System (FCRTS) facilities. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATE

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

SECTION III. DETERMINATION OF TRANSMISSION RATE

- A. From time to time, but not more often than once a year, BPA shall determine the following data for the facilities that have been constructed or otherwise acquired by BPA and that are used to transmit electric power:
1. The annual cost of the specified FCRTS facilities, as determined from the capital cost of such facilities and annual cost ratios developed from the Federal Columbia River Power System financial statement, including interest and amortization, operation and maintenance, administrative and general, and general plant costs.

The annual cost per kilowatt of facilities listed in the agreement that are owned by another entity and used by BPA for making deliveries to the transferee shall be determined from the costs specified in the agreement between BPA and such other entity.
 2. The yearly noncoincident peak demands of all users of such facilities or other reasonable measurement of the facilities' peak use.
- B. The monthly charge per kilowatt of billing demand shall be one-twelfth of the sum of the annual cost of the FCRTS facilities used, divided by the sum of Transmission Demands/capacity reservations. The annual cost per kilowatt of Transmission

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

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

Where:

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

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

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

SECTION IV. DETERMINATION OF BILLING FACTORS

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

- A. The Transmission Demand/capacity reservation in kilowatts specified in the agreement;
- B. The highest hourly Measured or Scheduled Demand for the month; or
- C. The Ratchet Demand.

SECTION V. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

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

B. FAILURE TO COMPLY PENALTY

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

AF-18
ADVANCE FUNDING RATE

SECTION I. AVAILABILITY

This schedule supersedes the AF-16 rate schedule and is available to customers that execute an agreement that provides for BPA to collect capital and related costs through advance funding or other financial arrangement for specified BPA-owned Federal Columbia River Transmission System (FCRTS) facilities used for:

- A. Interconnection or integration of resources and loads to the FCRTS;
- B. Upgrades, replacements, or reinforcements of the FCRTS for transmission service; or
- C. Other transmission service arrangements, as determined by BPA.

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

SECTION II. CHARGE

The charge is:

- A. The sum of the actual capital and related costs for specified FCRTS facilities, as provided in the agreement. Such actual capital and related costs include, but are not limited to, costs of design, materials, construction, overhead, spare parts, and all incidental costs necessary to provide service as identified in the agreement; or
- B. An advance payment equal to the sum of the capital and related costs for specified FCRTS facilities, as provided in the agreement. A credit for some or all of the amount advanced will be applied against charges for transmission service, as provided in the agreement. The charges for transmission service shall be at the rate for the applicable transmission service.

SECTION III. PAYMENT

A. ADVANCE PAYMENT

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

- 1. A lump sum advance payment;

2. Advance payments pursuant to a schedule of progress payments; or
3. Other payment arrangement, as determined by BPA.

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

B. ADJUSTMENT TO ADVANCE PAYMENT

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

TGT-18 TOWNSEND-GARRISON TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes the TGT-16 rate schedule and is available to companies that are parties to the Montana Intertie Agreement (Contract No. DE-MS79-81BP90210, as amended), which provides for firm transmission over BPA's section (Garrison to Townsend) of the Montana Intertie. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATE

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

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

A. NON-FIRM TRANSMISSION CHARGE

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

B. INTERTIE CHARGE FOR FIRM TRANSMISSION SERVICE

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

SECTION III. DEFINITIONS

- A. TAC = Total Annual Costs of facilities associated with the Townsend-Garrison 500 kV Transmission line including terminals, and prior to extension of the 500 kV portion of the Federal Transmission System to Garrison, the 500/230 kV transformer at Garrison. Such annual costs are the total of: (1) interest and amortization of associated Federal investment and the appropriate allocation of general plant costs; (2) operation and maintenance costs; (3) allowance for BPA's general administrative costs that are appropriately allocable to such facilities, and (4) payments made pursuant to section 7(m) of Public Law 96-501 with respect to these facilities. Total Annual Costs shall be adjusted to reflect reductions to unpaid total costs as a result of any amounts received, under agreements for firm transmission service over the Montana Intertie, by BPA on account of any reduction in Transmission Demand, termination, or partial termination of any such agreement or otherwise to compensate BPA for the unamortized investment, annual cost, removal, salvage, or other cost related to such facilities.
- B. NFR = Non-firm Revenues, which are equal to (1) the product of the Non-firm Transmission Charge described in II.A. above and the total non-firm energy transmitted over the Townsend-Garrison line segment under such charge during such month; plus (2) revenue received by BPA under any other rate schedules for non-firm transmission service in either direction over the Townsend-Garrison line segment during such month.
- C. CR = Capacity Requirement of a customer on the Townsend-Garrison 500 kV transmission facilities as specified in its firm transmission agreement.
- D. TCR = Total Capacity Requirement on the Townsend-Garrison 500-kV transmission facilities as calculated by adding (1) the sum of all Capacity Requirements (CR) specified in transmission agreements described in section I and (2) BPA's firm capacity requirement. BPA's firm capacity requirement shall be no less than the total of the amounts, if any, specified in firm transmission agreements for use of the Montana Intertie.
- E. EC = Exchange Credit for each customer, which is the product of (1) the ratio of investment in the Townsend-Broadview 500 kV transmission line to the investment in the Townsend-Garrison 500 kV transmission line and (2) the capacity BPA obtains in the Townsend-Broadview 500 kV transmission line through exchange with such customer. If no exchange is in effect with a customer, the value of EC for such customer shall be zero.

PW-18
WECC AND PEAK SERVICE RATE

SECTION I. AVAILABILITY

This schedule supersedes the PW-16 rate schedule. The rate below applies to all loads in the BPA Control Area except for loads of customers billed directly by WECC or by Peak Reliability. The WECC and Peak Service rate recovers the costs billed to BPA by WECC and Peak Reliability based on loads in the BPA Control Area. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATES

A. WECC RATE

0.05 mills per kilowatthour

B. PEAK RATE

0.05 mills per kilowatthour

SECTION III. BILLING FACTORS

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

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OS-18 OVERSUPPLY RATE

SECTION I. AVAILABILITY

This schedule supersedes the OS-16 rate schedule. The Oversupply Rate applies to generators in the BPA Balancing Authority Area that are specified as the source on transmission schedules for the hours that BPA displaces generation pursuant to the Open Access Transmission Tariff (OATT), Attachment P (Oversupply Event Hours), and to customers that purchase power under the Priority Firm Power, Industrial Firm Power, or New Resources Firm Power rate, for the charges to BPA Power Services under section II.C.

The Oversupply Charge shall collect the amounts paid pursuant to OATT Attachment P for the period October 1, 2017, through September 30, 2019. The Oversupply Charge shall remain in effect until all costs incurred pursuant to OATT Attachment P during the FY 2018-2019 rate period are billed and fully paid. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. CHARGE

A. OVERSUPPLY RATE

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

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

Where:

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

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

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

$\sum \textit{Scheduled Generation}$ = the sum of all Scheduled Generation, in megawatthours.

B. OVERSUPPLY BILLING FACTORS

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

C. OVERSUPPLY CHARGES TO BPA POWER SERVICES

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

SECTION III. BILLING

A. OVERSUPPLY CHARGE

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

B. BILLING CAP

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

C. BILLING FOR OVERSUPPLY CHARGES TO BPA POWER SERVICES

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

IE-18
EASTERN INTERTIE RATE

SECTION I. AVAILABILITY

This schedule supersedes the IE-16 rate schedule and is available to companies that are parties to the Montana Intertie Agreement (Contract No. DE-MS79-81BP90210, as amended) for non-firm transmission service on the portion of Eastern Intertie capacity that exceeds BPA's firm transmission rights. Service under this schedule is subject to the General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

SECTION II. RATE

The rate shall not exceed 1.46 mills per kilowatthour.

SECTION III. BILLING FACTOR

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

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

A. ANCILLARY SERVICES

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

B. FAILURE TO COMPLY PENALTY

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

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ACS-18

ANCILLARY AND CONTROL AREA SERVICE RATES

SECTION I. AVAILABILITY

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

A. ANCILLARY SERVICES

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

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

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

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

Ancillary Services available under this rate schedule are:

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

B. CONTROL AREA SERVICES

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

Control Area Services available under this rate schedule are:

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

SECTION II. ANCILLARY SERVICE RATES

A. SCHEDULING, SYSTEM CONTROL, AND DISPATCH SERVICE

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

1. RATES

a. NT Service

The rate shall not exceed \$0.376 per kilowatt per month.

b. Long-Term Firm PTP Transmission Service

The rate shall not exceed \$0.322 per kilowatt per month.

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

For each reservation, the rates shall not exceed:

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

(a) Days 1 through 5 \$0.015 per kilowatt per day

(b) Day 6 and beyond \$0.011 per kilowatt per day

(2) Hourly Firm and Non-Firm Service

The rate shall not exceed 0.93 mills per kilowatthour.

2. BILLING FACTORS

a. Point-To-Point Transmission Service

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

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

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

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

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

- (1) If the need for curtailment is caused by conditions on the Federal Columbia River Transmission System, the Billing Factor will be as follows:
 - (a) If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted before the close of the hourly non-firm scheduling window, the Billing Factor will be the Reserved Capacity minus the curtailed capacity.
 - (b) If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted after the close of the hourly non-firm scheduling window, the Billing Factor will be the Transmission Customer's actual schedule in the hour.
- (2) If the need for curtailment is caused by conditions on another transmission provider's transmission system, the Billing Factor will be the Reserved Capacity.

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

b. Network Integration Transmission Service

For Transmission Customers taking Network Integration Transmission Service, the Billing Factor for the rate specified in section 1.a. shall equal the NT rate Billing Factor determined pursuant to section III.A. of the Network Integration Rate Schedule (NT-18).

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

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

B. REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES SERVICE

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

1. RATES

The rates for GSR Service will be calculated for each quarter, beginning October 2017, according to the formulas below. The rates will be posted on BPA's website and updated as needed. Rates for Long-Term PTP and NT Service and for Short-Term Monthly, Weekly and Daily Service (sections a. and b.(1), below) shall be calculated to three decimal places. Rates for Hourly Service (section b.(2), below) shall be calculated to two decimal places.

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

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

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

Where:

bd = 501,314 MW-mo = Average of forecasted FY 2018 and FY 2019 GSR Service billing determinants. Each annual billing determinant is the sum of the 12 monthly billing determinants.

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

U_{q-1} = Payments of non-Federal GSR cost (\$) made in the preceding quarter(s) that were not included in the effective rate for the preceding quarter(s). Any refunds received by BPA would reduce this cost. U_{q-1} is a true-up for any deviation of non-Federal GSR costs from the amount used in a previous quarter's GSR rate calculation. For calculating the GSR rate effective October 1, 2017, U_{q-1} is zero.

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

Z_{q-1} = True-up (\$) for under- or overstatement of reactive self-supply in rate calculations for the preceding quarter(s). For calculating the GSR rate effective October 1, 2017, Z_{q-1} is zero. Z_{q-1} will be calculated by multiplying the under- or overstated megawatt amount of self-supply by the GSR rate that was effective during the quarter of self-supply deviation.

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

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

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

For each reservation, the rates shall not exceed:

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

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

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

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

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

The rate shall not exceed:

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

Where:

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

2. BILLING FACTORS

a. Point-To-Point Transmission Service

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

- (1) the sum of the capacity reservations at the Point(s) of Receipt, or
- (2) the sum of the capacity reservations at the Point(s) of Delivery.

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

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

- (1) If the need for curtailment is caused by conditions on the Federal Columbia River Transmission System, the Billing Factor will be as follows:
 - (a) If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted before the close of the hourly non-firm scheduling window, the Billing Factor will be the Reserved Capacity minus the curtailed capacity.
 - (b) If Hourly Non-Firm PTP Transmission Service is curtailed or interrupted after the close of the hourly non-firm scheduling window, the Billing Factor will be the Transmission Customer's actual schedule in the hour.
- (2) If the need for curtailment is caused by conditions on another transmission provider's transmission system, the Billing Factor will be the Reserved Capacity.

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

b. Network Integration Transmission Service

For Transmission Customers taking Network Integration Transmission Service, the Billing Factor for the rate specified in section 1.a. shall equal the NT rate Billing Factor determined pursuant to section III.A. of the Network Integration Rate Schedule (NT-18).

c. Adjustment for Self-Supply

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

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

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

C. REGULATION AND FREQUENCY RESPONSE SERVICE

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

1. RATE

The rate shall not exceed 0.13 mills per kilowatthour.

2. BILLING FACTOR

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

D. ENERGY IMBALANCE SERVICE

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

1. RATES

a. Imbalances Within Deviation Band 1

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

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

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

b. Imbalances Within Deviation Band 2

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

- (1) When energy taken by the Transmission Customer in a schedule period is greater than the energy scheduled, the charge is 110 percent of BPA's incremental cost.
- (2) When energy taken by the Transmission Customer in a schedule period is less than the scheduled amount, the credit is 90 percent of BPA's incremental cost.

c. Imbalances Within Deviation Band 3

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

- (1) When energy taken by the Transmission Customer in a schedule period is greater than the energy scheduled, the charge is 125 percent of BPA's highest incremental cost that occurs during that day. The highest daily incremental cost shall be determined separately for HLH and LLH.
- (2) When energy taken by the Transmission Customer in a schedule period is less than the scheduled amount, the credit is 75 percent of BPA's lowest incremental cost that occurs during that day. The lowest daily incremental cost shall be determined separately for HLH and LLH.

2. OTHER RATE PROVISIONS

a. BPA Incremental Cost

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

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

b. Spill Conditions

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

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

- (1) For negative deviations (energy taken is less than the scheduled energy) within Band 1, no credit will be given.
- (2) For negative deviations (energy taken is less than the scheduled energy) within Band 2, the charge is the energy index for that hour.
- (3) For negative deviations (energy taken is less than the scheduled energy) within Band 3, the charge is the energy index for that hour.

c. Persistent Deviation

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

- (1) No credit is given when energy taken is less than the scheduled energy.
- (2) When energy taken exceeds the scheduled energy, the charge is the greater of (i) 125 percent of BPA's highest incremental cost that occurs during that day, or (ii) 100 mills per kilowatthour.

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

If BPA assesses a persistent deviation penalty charge in any scheduled period for a positive deviation, BPA will not also assess a charge pursuant to section II.D.1. of this ACS-18 schedule.

Reduction or Waiver of Persistent Deviation Penalty

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

E. OPERATING RESERVE – SPINNING RESERVE SERVICE

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

1. RATES

- a. For customers that elect to purchase Operating Reserve – Spinning Reserve Service from BPA, the rate shall not exceed 11.82 mills per kilowatthour.
- b. For customers that are required to purchase Operating Reserve – Spinning Reserve Service from BPA because they defaulted on their self-supply or third-party supply obligations, the rate shall be 13.59 mills per kilowatthour.

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

- (1) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or
- (2) Return the energy at the times specified by BPA.

2. BILLING FACTORS

- a. The Billing Factor for the rates specified in sections 1.a. and 1.b. is the Transmission Customer’s Spinning Reserve Requirement determined in accordance with applicable NERC, WECC and NWPP standards. BPA will post on its OASIS Web site the Spinning Reserve Requirement.
- b. The Billing Factor for energy delivered when Spinning Reserve Service is called upon is the energy delivered, in kilowatthours.

F. OPERATING RESERVE – SUPPLEMENTAL RESERVE SERVICE

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

1. RATES

- a. For customers that elect to purchase Operating Reserve – Supplemental Reserve Service from BPA, the rate shall not exceed 9.76 mills per kilowatthour.
- b. For customers that are required to purchase Operating Reserve – Supplemental Reserve Service from BPA because they defaulted on their self-supply or third-party supply obligations, the rate shall be 11.22 mills per kilowatthour.

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

- (1) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or
- (2) Return the energy at the times specified by BPA.

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

2. BILLING FACTORS

- a. The Billing Factor for the rates specified in sections 1.a. and 1.b. is the Transmission Customer’s Supplemental Reserve Requirement determined in accordance with applicable NERC, WECC and NWPP standards. BPA will post on its OASIS Web site the Supplemental Reserve Requirement.
- b. The Billing Factor for energy delivered when Supplemental Reserve Service is called upon is the energy delivered, in kilowatthours.

SECTION III. CONTROL AREA SERVICE RATES

A. REGULATION AND FREQUENCY RESPONSE SERVICE

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

1. RATE

The rate shall not exceed 0.13 mills per kilowatthour.

2. BILLING FACTOR

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

B. GENERATION IMBALANCE SERVICE

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

1. RATES

a. Imbalances Within Deviation Band 1

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

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

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

b. Imbalances Within Deviation Band 2

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

of the scheduled amount of energy or (ii) ± 10 MW, whichever is larger in absolute value.

- (1) When energy delivered in a schedule period from the generation resource is less than the energy scheduled, the charge is 110 percent of BPA's incremental cost.
- (2) When energy delivered in a schedule period from the generation resource is greater than the scheduled amount, the credit is 90 percent of BPA's incremental cost.

c. Imbalances Within Deviation Band 3

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

- (1) When energy delivered in a schedule period from the generation resource is less than the energy scheduled, the charge is 125 percent of BPA's highest incremental cost that occurs during that day. The highest daily incremental cost shall be determined separately for HLH and LLH.
- (2) When energy delivered in a schedule period from the generation resource is greater than the scheduled amount, the credit is 75 percent of BPA's lowest incremental cost that occurs during that day. The lowest daily incremental cost shall be determined separately for HLH and LLH.

2. OTHER RATE PROVISIONS

a. BPA Incremental Cost

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

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

b. Spill Conditions

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

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

- (1) For negative deviations (actual generation greater than scheduled) within Band 1, no credit will be given.
- (2) For negative deviations (actual generation greater than scheduled) within Band 2, the charge is the energy index for that hour.
- (3) For negative deviations (actual generation greater than scheduled) within Band 3, the charge is the energy index for that hour.

c. Persistent Deviation for Generation

Persistent Deviation for generation applies to (i) Dispatchable Energy Resources operating in the BPA Balancing Authority Area and (ii) Variable Energy Resources operating in the BPA Balancing Authority Area that are participating in the Customer Supplied Generation Imbalance (“CSGI”) Pilot Program.

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

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

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

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

If BPA assesses a Persistent Deviation Penalty charge in any scheduled period for a positive deviation, BPA will not also assess a charge pursuant to section 1 of this ACS-18 Generation Imbalance Service rate schedule.

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

Reduction or Waiver of Persistent Deviation Penalty

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

d. No Credit for Negative Deviations During Curtailments

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

e. Exemption from Deviation Band 2

The 10 percent penalty charge under section 1.b., Imbalances Within Deviation Band 2, will not apply to customers participating in a committed 15-minute scheduling program in accordance with the ACS-18 Variable Energy Resources Balancing Service rates, section III.E.2.a.(2) and III.E.3.a.(1).

f. Exemptions from Deviation Band 3

The following resources are not subject to Deviation Band 3:

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

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

C. OPERATING RESERVE – SPINNING RESERVE SERVICE

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

1. RATES

- a. For customers that elect to purchase Operating Reserve – Spinning Reserves from BPA, the rate shall not exceed 11.82 mills per kilowatthour.
- b. For customers that are required to purchase Operating Reserve – Spinning Reserve Service from BPA because they defaulted on their self-supply or third-party supply obligations, the rate shall be 13.59 mills per kilowatthour.

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

- (1) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or
- (2) Return the energy at the times specified by BPA.

2. BILLING FACTORS

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

D. OPERATING RESERVE – SUPPLEMENTAL RESERVE SERVICE

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

1. RATES

- a. For customers that elect to purchase Operating Reserve – Supplemental Reserve Service from BPA, the rate shall not exceed 9.76 mills per kilowatthour.
- b. For customers that are required to purchase Operating Reserve – Supplemental Reserve Service from BPA because they defaulted on their self-supply or third-party supply obligations, the rate shall be 11.22 mills per kilowatthour.

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

- (1) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or
- (2) Return the energy at the times specified by BPA.

2. BILLING FACTORS

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

E. VARIABLE ENERGY RESOURCE BALANCING SERVICE

1. APPLICABILITY

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

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

2. BALANCING SERVICE FOR WIND RESOURCES

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

a. BALANCING SERVICE RATES

(1) Rate for 30/60 Committed Scheduling

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

- (a) Regulating Reserves \$0.13 per kilowatt per month
- (b) Following Reserves \$0.42 per kilowatt per month
- (c) Imbalance Reserves \$0.46 per kilowatt per month

(2) Rate for 30/15 Committed Scheduling

This rate is applicable to customers taking Balancing Service that commit to receive BPA’s 30-minute signal for each 15-minute schedule period (30/15 committed scheduling) and submit

schedules that are consistent with the signal or that result in less imbalance for the scheduling period.

- (a) Regulating Reserves \$0.13 per kilowatt per month
- (b) Following Reserves \$0.42 per kilowatt per month
- (c) Imbalance Reserves \$0.16 per kilowatt per month

(3) Rate for Uncommitted Scheduling

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

- (a) Regulating Reserves \$0.13 per kilowatt per month
- (b) Following Reserves \$0.42 per kilowatt per month
- (c) Imbalance Reserves \$0.67 per kilowatt per month

(4) Rate for Customer Supplied Generation Imbalance

This rate is applicable to customers taking Balancing Service under the Customer Supplied Generation Imbalance Pilot Program.

The rate shall be \$0.49 per kilowatt per month.

b. BILLING FACTOR

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

- (1) For each wind plant, or phase of a wind plant, that has completed installation of all units no later than the 15th of the month prior to the billing month, the billing factor in kW will be the greater of the maximum one-hour generation or the nameplate of the plant. A unit has completed installation when it has generated and delivered power to the BPA system.
- (2) For each wind plant, or phase of a wind plant, for which some but not all units have been installed by the 15th day of the month prior to the billing month, the billing factor will be the maximum measured hourly output of the plant through the 15th day of the prior month in kW.
- (3) For each wind plant, or phase of a wind plant, where none of the units have been installed on or before the 15th of the month prior to the billing month, but some units have been installed before the start of the billing month, the billing factor will be zero.

c. EXCEPTIONS

- (1) The rates under section 2.a. above will not apply to a Variable Energy Resource, or portion of a Variable Energy Resource, that, in BPA's determination, has put in place, tested, and successfully implemented in conformance to the criteria specified in BPA business practices, no later than the 15th day of the month prior to the billing month, the dynamic transfer of plant output out of BPA's Balancing Authority Area to another Balancing Authority Area.
- (2) Individual rate components under section 2.a.(1)-(3) above will not apply to a Variable Energy Resource, or portion of a Variable Energy Resource, that, in BPA's determination, has put in place, tested, and successfully implemented in conformance to criteria specified in BPA business practices, no later than the 15th day of the month prior to the billing month, self-supply of that component of Balancing Service, including by contractual arrangements for third-party supply.

3. BALANCING SERVICE FOR SOLAR RESOURCES

The total charge for this service is the applicable rate in section 3.a, below, plus Direct Assignment Charges under section 4 and Intentional Deviation Penalty Charges under section 5.

a. RATES

(1) Rate for 30/15 Committed Scheduling

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

\$0.21 per kilowatt per month

(2) Rate for Hourly Scheduling

This rate is applicable to customers taking Balancing Service that do not commit to 30/15 scheduling.

\$0.28 per kilowatt per month

b. BILLING FACTOR

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

c. EXCEPTIONS

See section 2.c. above.

4. DIRECT ASSIGNMENT CHARGES

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

- a. the customer elected to self-supply in accordance with section 2.c. but is unable to self-supply one or more components to Variable Energy Resource Balancing Service; or
- b. the customer has a projected generator interconnection date after FY 2019, but chooses to interconnect during the FY 2018–2019 rate period; or
- c. the customer elected to take service under section 2.a.(1), 2.a.(2), or 3.a.(1) above, but fails to conform to the committed scheduling criteria specified in BPA business practices; or
- d. the customer elected to take service under section 2.a.(1), 2.a.(2), or 3.a.(1) above, but chooses to take a Balancing Service scheduling option with a longer scheduling period in accordance with the criteria specified in BPA business practices; or
- e. the customer elected to dynamically transfer its resource out of BPA’s Balancing Authority Area, but the resource remains in the BPA Balancing Authority Area after the date specified in the customer election.

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

Customers that are subject to direct assignment charges will be billed for all costs incurred above \$0.305 per kilowatt-day for any incremental balancing reserve capacity acquisitions. Customers billed for direct assignment charges will also be billed at the applicable VERBS rate in section 2.

5. INTENTIONAL DEVIATION PENALTY CHARGE

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

F. DISPATCHABLE ENERGY RESOURCE BALANCING SERVICE

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

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

1. RATES

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

- a. Incremental Reserves 20.42 mills per kW maximum hourly deviation
- b. Decremental Reserves 3.43 mills per kW maximum hourly deviation

2. BILLING FACTORS

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

3. EXCEPTIONS

- a. This rate will not apply to a Dispatchable Energy Resource, or portion of a Dispatchable Energy Resource, that, in BPA’s determination, has put in place, tested, and successfully implemented no later than the 15th day of the month prior to the billing month the dynamic transfer of plant output out of BPA’s Balancing Authority Area to another Balancing Authority Area.
- b. This rate will not apply to a Dispatchable Energy Resource, or portion of a Dispatchable Energy Resource, for any schedule period in which the Dispatchable Energy Resource has called on contingency reserve.
- c. This rate will not apply to a Dispatchable Energy Resource, or portion of a Dispatchable Energy Resource, for any hour in which the Dispatchable Energy Resource has been ordered by BPA or a host utility within BPA’s

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

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

4. DIRECT ASSIGNMENT CHARGES

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

- a. the customer elected to self-supply but is unable to self-supply the Dispatchable Energy Resource Balancing Service; or
- b. a customer has a projected generator interconnection date after FY 2019 but chooses to interconnect during the FY 2018-2019 rate period;
- c. a customer operating in another Balancing Authority Area chooses to dynamically transfer into the BPA Balancing Authority Area during the FY 2018-2019 rate period; or
- d. the customer elected to dynamically transfer its resource out of BPA's Balancing Authority Area but the resource remains in the BPA Balancing Authority Area after the date specified in the customer election.

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

Customers that are subject to direct assignment charges will be billed for all costs incurred above \$0.305 per kilowatt-day for any incremental balancing reserve capacity acquisitions. Customers billed for direct assignment charges will also be billed at the DERBS rates in section 1.

SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

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

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

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

Customers taking Regulation and Frequency Response Service, Operating Reserve – Spinning Reserve Service, or Operating Reserve – Supplemental Reserve Service under this rate schedule are subject to the Power Risk Mechanisms specified in the BPA Power Rate Schedules, specified in GRSPs II.O, II.P, and II.Q.

C. RATE ADJUSTMENT FOR TRANSMISSION COST RECOVERY ADJUSTMENT CLAUSE AND TRANSMISSION RESERVES DISTRIBUTION CLAUSE

Customers taking Scheduling, System Control, and Dispatch Service under this rate schedule are subject to the Transmission Cost Recovery Adjustment Clause and the Transmission Reserves Distribution Clause, specified in GRSPs II.H and II.I.

GENERAL RATE SCHEDULE PROVISIONS

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SECTION I. GENERALLY APPLICABLE PROVISIONS

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A. Approval Of Rates

BPA has requested that the Federal Energy Regulatory Commission grant approval to make these rate schedules and GRSPs effective on October 1, 2017. All rate schedules shall remain in effect until they are replaced or expire on their own terms.

B. General Provisions

These BP-18 rate schedules and the GRSPs associated with these schedules supersede BPA's BP-16 rate schedules (which became effective October 1, 2015) to the extent stated in the Availability section of each rate schedule. These schedules and GRSPs shall be applicable to all BPA contracts, including contracts executed both prior to and subsequent to enactment of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). All sales under these rate schedules are subject to the following acts, as amended: the Bonneville Project Act (P.L. 75-329), 16 U.S.C. § 832; the Pacific Northwest Consumer Power Preference Act (P.L. 88-552), 16 U.S.C. § 837; the Federal Columbia River Transmission System Act (P.L. 93-454), 16 U.S.C. § 838; the Northwest Power Act (P.L. 96-501), 16 U.S.C. § 839; and the Energy Policy Act of 1992 (P.L. 102-486), 16 U.S.C. § 824(i)-(l).

These BP-18 rate schedules do not supersede any previously established rate schedule that is required, by agreement, to remain in effect.

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

C. Notices

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

D. Billing and Payment

1. BILLING PROCEDURE

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

2. INTEREST ON UNPAID BALANCES

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

3. CUSTOMER DEFAULT

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

**SECTION II. ADJUSTMENTS, CHARGES, AND
SPECIAL RATE PROVISIONS**

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A. Delivery Charge

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

1. RATES

a. DSI Delivery

Use-of-Facilities (UFT-18) Rate, section III

b. Utility Delivery

\$1.283 per kilowatt per month

2. BILLING FACTOR

a. Utility Delivery

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

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

3. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

a. Transmission Cost Recovery Adjustment Clause

Customers taking service under this rate schedule are subject to the Transmission Cost Recovery Adjustment Clause, specified in GRSP II.H.

b. Transmission Reserves Distribution Clause

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause, specified in GRSP II.I.

B. Failure To Comply Penalty Charge

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

1. RATES

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

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

2. BILLING FACTOR

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

- a. Failure to shed load when directed to do so by BPA in accordance with the Load Shedding provisions of the Open Access Transmission Tariff or any other applicable agreement between the parties. This includes failure to shed load pursuant to such orders within the time period specified by the North American Electric Reliability Council (NERC), Western Electricity Coordinating Council (WECC), or Northwest Power Pool (NWPP) criteria.
- b. Failure of a generator in the BPA Control Area or which directly interconnects to the FCRTS to change or limit generation levels when directed to do so by BPA in accordance with Good Utility Practice as defined in the OATT. This includes failure to change generation levels pursuant to such orders within the time period specified by NERC, WECC, or NWPP criteria.

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

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

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

D. Reservation Fee

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

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

1. FEE

The Reservation Fee is nonrefundable and equal to one month's charge for each extension of the Service Commencement Date for the requested Long-Term Firm Point-to-Point Transmission Service.

2. PAYMENT

The Reservation Fee payment for an Extension of the Commencement of Service must be received by BPA Transmission Services within 30 calendar days of the Service Commencement Date of the Transmission Service Request being deferred. If the 30th calendar day is on a Saturday, Sunday or Federal Holiday, the Reservation Fee is due no later than the following Business Day.

E. Transmission and Ancillary Services Rate Discounts

BPA may offer discounted rates for transmission service and for ancillary services provided in conjunction with the provision of transmission service. Three principal requirements apply to discounts for transmission and ancillary services, as follows:

1. any offer of a discount made by BPA must be announced to all Eligible Customers solely by posting on the OASIS;
2. any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS; and
3. once a discount is negotiated, details must be immediately posted on the OASIS.

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

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

F. Unauthorized Increase Charge (UIC)

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

1. RATES

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

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

2. BILLING FACTORS

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

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

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

3. UIC RELIEF

a. Criteria for Waiving or Reducing the UIC

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

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

- (1) was inadvertent or was the result of an equipment failure or outage that the Transmission Customer could not have reasonably foreseen;
- (2) could not have been avoided by the exercise of reasonable care; and
- (3) did not result in harm to BPA's transmission system or transmission services, or to any other Transmission Customer.

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

b. Transmission Rate if BPA Waives or Reduces the UIC

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

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

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

G. Power CRAC, Power RDC, and NFB Mechanisms

The Power Cost Recovery Adjustment Clause (Power CRAC), Power Reserves Distribution Clause (Power RDC), and NFB Mechanisms (the NFB Adjustment and the Emergency NFB Surcharge) are detailed in the BPA Power Rate Schedules, GRSPs II.O, II.P, and II.Q.

The Power CRAC and the Emergency NFB Surcharge are upward adjustments to certain Power and Transmission rates. The Power RDC is a deployment of reserves for risk attributed to Power for high-value purposes such as debt retirement and rate reduction. If the Power RDC triggers and the Administrator elects to deploy some reserves under the RDC toward rate reduction, this would be effected through a Dividend Distribution (DD), a downward adjustment to certain Power and Transmission rates. The NFB Adjustment is an upward adjustment to the cap on the amount of incremental BPA revenue that can be generated by a Power CRAC during a fiscal year. Except as otherwise provided, the Power CRAC, Power RDC, and Emergency NFB Surcharge apply to the following Ancillary and Control Area Service (ACS) rate schedules:

- Regulation and Frequency Response Service
- Operating Reserve – Spinning Reserve Service
- Operating Reserve – Supplemental Reserve Service

1. ACS CUSTOMER CHARGES FOR THE POWER CRAC

A specific fraction of the Power CRAC Amount (the total incremental BPA revenue to be collected in a fiscal year if the Power CRAC triggers) will be allocated to each of the three ACS rates subject to the Power CRAC—Regulating and Frequency Response Service (the RFRS CRAC Amount); Operating Reserve – Spinning (the ORSp CRAC Amount); and Operating Reserve – Supplemental (the ORSu CRAC Amount). These rates will be allocated the following fractions of the Power CRAC Amount:

Regulation and Frequency Response Service:	0.38%
Operating Reserve – Spinning Reserve Service:	1.55%
Operating Reserve – Supplemental Reserve Service:	1.55%

The RFRS CRAC Amount, ORSp CRAC Amount, and ORSu CRAC Amount are equal to the Power CRAC multiplied by the respective allocation fractions above. The RFRS, ORSp, and ORSu CRAC Amounts are converted to the RFRS, ORSp, and ORSu CRAC Percentages by dividing the RFRS, ORSp, and ORSu CRAC Amounts by the most recent forecast of revenues for the relevant fiscal year at the RFRS, ORSp, and ORSu rates.

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

2. ACS CUSTOMER CREDIT FOR THE POWER DD

A specific fraction of the Power DD Amount (the total decremental BPA revenue to be collected in a fiscal year if the Power DD triggers) will be allocated to each of the three ACS rates subject to the Power CRAC as described above in Section II.G.1., ACS Customer Charges for the Power CRAC.

The RFRS DD Amount, ORSp DD Amount, and ORSu DD Amount are equal to the Power DD multiplied by the respective allocation fractions above. The RFRS, ORSp, and ORSu DD Amounts are converted to the RFRS, ORSp, and ORSu DD Percentages by dividing the RFRS, ORSp, and ORSu DD Amounts by the most recent forecast of revenues for the relevant fiscal year at the RFRS, ORSp, and ORSu rates.

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

3. ACS CUSTOMER CHARGES FOR THE EMERGENCY NFB SURCHARGE

A specific fraction of the Emergency NFB Surcharge Amount (the total incremental BPA revenue to be collected in a fiscal year if the Emergency NFB Surcharge triggers) will be allocated to each of the three ACS rates subject to the Emergency NFB Surcharge as described above in Section II.G.1., ACS Customer Charges for the Power CRAC.

The RFRS Surcharge Amount, ORSp Surcharge Amount, and ORSu Surcharge Amount are equal to the Power Emergency NFB Surcharge Amount multiplied by the respective allocation fractions above. The RFRS, ORSp, and ORSu Surcharge Amounts are converted to the RFRS, ORSp, and ORSu Surcharge Percentages by dividing the RFRS, ORSp, and ORSu Surcharge Amounts by the most recent forecast of revenues for the relevant fiscal year at the RFRS, ORSp, and ORSu rates.

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

4. POWER CRAC, POWER RDC, AND NFB MECHANISM RATE PROVISIONS

The Power CRAC, Power RDC, and NFB Mechanism rate provisions specified in the Power Rate Schedules, GRSPs II.O, II.P, and II.Q, are incorporated by reference.

H. Transmission Cost Recovery Adjustment Clause (Transmission CRAC)

The Transmission CRAC is an upward adjustment to certain rates that can apply during FY 2018 or FY 2019 or both. It applies to these Transmission rates:

- Network Integration Rate (NT-18)
- Point-to-Point Rate (PTP-18)
- Formula Power Transmission Rate (FPT-18.1)
- Southern Intertie Point-to-Point Rate (IS-18)
- Utility Delivery Rate (GRSPs Section II. A. 1. b.)
- Scheduling, Control, and Dispatch Rate (ACS-18)
- Integration of Resources Rate (IR-18)
- Montana Intertie Rate (IM-18)

1. CALCULATIONS FOR THE TRANSMISSION CRAC

Prior to the beginning of each fiscal year of the rate period (that is, each “applicable year”), BPA will forecast the end-of-year Accumulated Calibrated Net Revenue for Transmission (Transmission ACNR) for the fiscal year preceding the applicable year. If the forecast Transmission ACNR is less than the Transmission CRAC Threshold for that applicable year by at least \$5 million, the Transmission CRAC will trigger and a rate increase will go into effect beginning on October 1 of the applicable year.

a. Calculating the Transmission Calibrated Net Revenue (Transmission CNR) and Transmission Accumulated Calibrated Net Revenue (Transmission ACNR)

The Transmission CNR is the Transmission Net Revenue (NR) plus the Transmission Net Revenue Calibration (Transmission NR Calibration).

Transmission NR for any given fiscal year is defined as transmission function accrued revenue less accrued expenses (in accordance with Generally Accepted Accounting Principles).

The Transmission NR Calibration is the sum of the effects of a class of differences, one difference calculated for each event not forecast in the BP-18 rate case that affects Transmission NR and Transmission cash flow differently by more than \$5 million. “Transmission cash flow” here means changes in Financial Reserves Available for Risk Attributed to Transmission. Such events include certain debt management transactions, settlements of contracts, and others. For each event, the impact of the event on Transmission NR will be subtracted from the impact on Transmission cash flow.

The Transmission ACNR is Transmission CNR accumulated since the end of FY 2016. A forecast of Transmission ACNR is used to determine whether the Transmission CRAC Threshold has been reached, and if so, the required Transmission CRAC Amount to be collected. The forecast of Transmission ACNR for use in determining the Transmission CRAC that will apply to FY 2018 rates will be the forecast of Transmission CNR for FY 2017. The forecast of Transmission ACNR for use in determining the Transmission CRAC that will apply to FY 2019 rates will be the sum of the actual Transmission CNR for FY 2017 plus the forecast of Transmission CNR for FY 2018.

b. Calculating the Transmission CRAC Amount

The Transmission CRAC Threshold is an amount of ACNR below which Transmission is considered to have experienced an Underrun. The Underrun amount is equal to the Transmission CRAC Threshold minus forecast Transmission ACNR.

The Transmission CRAC Amount is based on the Underrun, limited by the Maximum Transmission CRAC Recovery Amount (the Transmission CRAC Cap). There are three possibilities:

- (1) If the Underrun is less than \$5 million, there is no Transmission CRAC.
- (2) If the Underrun is greater than or equal to \$5 million and less than or equal to \$100 million, the Transmission CRAC Amount is equal to the Underrun.
- (3) If the Underrun is equal to or greater than \$100 million, the Transmission CRAC Amount is equal to \$100 million.

The Transmission CRAC Cap and Thresholds are shown in Table B

Table B
Transmission CRAC Annual Thresholds and Caps
(dollars in millions)

<i>ACNR Calculated Near End of Fiscal Year</i>	<i>CRAC Applied to Fiscal Year</i>	<i>Threshold Measured in ACNR</i>	<i>Threshold Measured in Reserves for Risk</i>	<i>Maximum CRAC Amount (Cap)</i>
2017	2018	(\$249)	\$99	\$100
2018	2019	(\$212)	\$99	\$100

c. Converting the Transmission CRAC Amount to the Transmission CRAC Percentage and Calculating Revised Rates

The Transmission CRAC percentage is calculated by dividing the Transmission CRAC Amount by the sum of the most recent forecasts of revenues from the applicable rates for the applicable year.

The Transmission CRAC percentage plus 1.0 is then multiplied by each of the applicable rates, which yields revised rates.

2. TRANSMISSION CRAC NOTIFICATION PROCESS

BPA shall follow these notification procedures:

a. Financial Performance Status Reports

Each quarter, BPA shall post to its external Web site (www.bpa.gov) preliminary, unaudited, year-to-date aggregate financial results for the transmission function, including Transmission ACNR.

For the Second and Third Quarter Reviews, BPA shall post to its external Web site (www.bpa.gov) the preliminary, unaudited, end-of-year forecast of Transmission ACNR.

b. Notification of Transmission CRAC Trigger

BPA shall complete a forecast of end-of-year Transmission ACNR in July 2017 for use in calculating the Transmission CRAC applicable to rates in FY 2018, and in September 2018 for use in calculating the Transmission CRAC applicable to rates in FY 2019. If the Transmission CRAC triggers, then BPA shall notify all Customers and rate case parties by late July 2017 of the amount by which BPA intends to adjust rates for FY 2018 due to the Transmission CRAC, and by late September 2018 of the amount by which BPA intends to adjust rates for FY 2019.

Notification will be posted on BPA's Web site and will include the following:

- 1) the forecast of Transmission ACNR for the current fiscal year;
- 2) the Transmission NR and the Transmission NR Calibration for FY 2017 in the case of the Transmission CRAC applicable to FY 2019 rates;

- 3) the Transmission CRAC Amount; and
- 4) the Transmission CRAC Percentage.

The notification shall also describe the data and assumptions relied upon by BPA for all Transmission ACNR determinations. BPA shall make such data, assumptions, and documentation, if non-proprietary and non-privileged, available for review upon request.

Associated with any notification of Transmission CRAC calculations as described above, BPA shall conduct a workshop(s) to explain the Transmission ACNR calculations, describe the calculation of the Transmission CRAC Amount and allocations to various rates, and demonstrate that the Transmission CRAC has been implemented in accordance with these GRSPs. The workshop(s) will provide an opportunity for public comment.

If the Transmission CRAC applicable to FY 2018 rates triggers, then on or about July 31, 2017, BPA will post to the BPA Web site the final Transmission CRAC calculations. If the Transmission CRAC applicable to FY 2019 rates triggers, then on or about September 28, 2018, BPA will post to the BPA Web site the final Transmission CRAC calculations.

I. Transmission Reserves Distribution Clause (Transmission RDC)

The Transmission RDC is a distribution of financial reserves to purposes such as debt retirement, incremental capital investment, or rate reduction (a Dividend Distribution, or DD) during FY 2018 or FY 2019 or both.

If the RDC quantitative criteria (below) are met, the Administrator will determine how much of any RDC, if any, would be applied to debt reduction, incremental capital investment, a DD, or any other uses.

A DD applies to these Transmission rates:

- Network Integration Rate (NT-18)
- Point-to-Point Rate (PTP-18)
- Formula Power Transmission Rate (FPT-18.1)
- Southern Intertie Point-to-Point Rate (IS-18)
- Utility Delivery Rate (GRSPs Section II. A. 1. b.)
- Scheduling, System Control, and Dispatch Rate (ACS-18)
- Integration of Resources Rate (IR-18)
- Montana Intertie Rate (IM-18)

1. CALCULATIONS FOR THE TRANSMISSION RDC

Prior to the beginning of each fiscal year of the rate period (that is, each “applicable year”), BPA will forecast the end-of-year Transmission Accumulated Calibrated Net Revenue (Transmission ACNR) and BPA Accumulated Calibrated Net Revenue (BPA ACNR) for the fiscal year preceding the applicable year. If the forecast Transmission ACNR is greater than the Transmission RDC Threshold for that applicable year by at least \$5 million and the forecast BPA ACNR is greater than the BPA RDC Threshold for that applicable year by at least \$5 million, the Administrator will determine the amount, if any, of a Transmission RDC. If the Administrator determines that part of the RDC will be a DD, the resulting rate decrease will go into effect beginning on October 1 of the applicable year.

a. Calculating the BPA ACNR

The BPA ACNR is the sum of the Transmission ACNR and the Power ACNR. *See* Transmission GRSP II.H.1(a) and Power GRSP II.O.1(a).

b. Calculating the Transmission RDC Amount

The Transmission RDC can only trigger if (1) Transmission ACNR exceeds the Transmission RDC Threshold, measured in Transmission

ACNR, and (2) BPA ACNR exceeds the BPA RDC Threshold, measured in BPA ACNR.

The Transmission RDC Amount is the reduction in financial reserves for risk attributed to Transmission caused by using reserves to retire debt, incrementally fund capital projects, decrease rates by means of a Transmission DD, or further other Transmission objectives during the year of application. The Transmission RDC Amount will be the smallest of the forecast Transmission ACNR less the Transmission RDC Threshold, the forecast BPA ACNR less the BPA RDC Threshold, and the Transmission RDC Cap, or a smaller amount if the Administrator so elects.

Table C
Transmission RDC Annual Thresholds and Caps
(dollars in millions)

<i>ACNR Calculated Near End of Fiscal Year</i>	<i>RDC Applied to Fiscal Year</i>	<i>Threshold Measured in Transmission ACNR</i>	<i>Threshold Measured in Transmission Reserves for Risk</i>	<i>Maximum RDC Amount (Cap)</i>
2017	2018	(\$150)	\$199	\$200
2018	2019	(\$113)	\$199	\$200

Table D
BPA RDC Annual Thresholds
(dollars in millions)

<i>Calculated Near End of Fiscal Year</i>	<i>RDC Applied to Fiscal Year</i>	<i>Threshold Measured in BPA ACNR</i>	<i>Threshold Measured in BPA Reserves for Risk</i>
2017	2018	\$506	\$606
2018	2019	\$758	\$606

c. Converting a Transmission DD to the Transmission DD Percentage and Calculating Revised Rates

The Transmission DD percentage is calculated by dividing the Transmission DD Amount by the sum of the most recent forecasts of revenues from the applicable rates for the applicable year.

The Transmission DD percentage minus 1.0 is then multiplied by each of the applicable rates, which yields revised rates.

2. TRANSMISSION RDC NOTIFICATION PROCESS

BPA shall follow these notification procedures:

a. Financial Performance Status Reports

Each quarter, BPA shall post to its external Web site (www.bpa.gov) preliminary, unaudited, year-to-date aggregate financial results for the transmission function, including Transmission ACNR and BPA ANR.

For the Second and Third Quarter Reviews, BPA shall post to its external Web site (www.bpa.gov) the preliminary, unaudited, end-of-year forecast of Transmission ACNR and BPA ACNR.

b. Notification of Transmission RDC Trigger

BPA shall complete a forecast of end-of-year Transmission ACNR and BPA ACNR in July 2017 for use in calculating the Transmission RDC for FY 2018, and in September 2018 for use in calculating the Transmission RDC for FY 2019. If the Transmission RDC triggers, BPA shall notify all Customers and rate case parties by late July 2017 of the amounts BPA intends to use, and by late September 2018 of the amounts BPA intends to use in these ways for FY 2019.

Notification will be posted on BPA's Web site and will include the following:

- 1) the forecast of Transmission ACNR and BPA ACNR for the current fiscal year;
- 2) the Transmission NR and the Transmission NR Calibration for FY 2017 in the case of the Transmission RDC applicable to FY 2019;
- 3) the Transmission RDC Amount;
- 4) the amounts to be used to retire debt, incrementally fund capital projects or other high-value Transmission purposes, or adjust rates for FY 2018 due to the Transmission DD Amount; and
- 5) the Transmission DD Percentage.

The notification shall also describe the data and assumptions relied upon by BPA for all Transmission ACNR and BPA ACNR determinations.

BPA shall make such data, assumptions, and documentation, if non-proprietary and non-privileged, available for review upon request.

Associated with any notification of Transmission RDC calculations as described above, BPA shall conduct a workshop(s) to explain the Transmission ACNR and BPA ACNR calculations, describe the calculation of the Transmission DD Amount and allocations to various rates, and demonstrate that the Transmission RDC has been implemented in accordance with these GRSPs. The workshop(s) will provide an opportunity for public comment.

If the Transmission RDC applicable to FY 2018 rates triggers, then on or about July 31, 2017, BPA will post to the BPA Web site the final Transmission RDC calculations. If the Transmission RDC applicable to FY 2019 rates triggers, then on or about September 28, 2018, BPA will post to the BPA Web site the final Transmission RDC calculations.

J. Intentional Deviation Penalty Charge

1. APPLICABILITY

Except as otherwise provided, the Intentional Deviation Penalty Charge applies to Variable Energy Resources taking service at the ACS-18 Variable Energy Resources Balancing Service rate.

Exceptions:

- a. New Variable Energy Resources undergoing testing before commercial operation are exempt from the Intentional Deviation Penalty Charge during testing for up to 90 days.
- b. Customers participating in the Customer Supplied Generation Imbalance (“CSGI”) Pilot Program are not subject to the Intentional Deviation Penalty Charge.

2. RATE

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

An Intentional Deviation event occurs when:

$$\text{ABS}(\text{Intentional Deviation Measurement Value} - \text{Resource Schedule}) > 1$$

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

3. BILLING FACTOR

The Billing Factor in MWh shall be:

$$\text{ABS}(\text{Intentional Deviation Measurement Value} - \text{Resource Schedule}) - 1$$

Multiplied by

Minutes of schedule divided by 60 minutes

Where:

ABS = the absolute value of the term in parentheses.

Intentional Deviation Measurement Value = one of the following:

- 1) for wind generating customers taking VERBS under rate schedule section 2.a., the applicable schedule value provided by BPA;
- 2) for solar generating customers taking VERBS under rate schedule section 3.a., the applicable schedule value provided by BPA.

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

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

4. OTHER PROVISIONS

Exemption from Intentional Deviation Penalty Charge

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

$$\text{ABS}(\text{Station Control Error}) \leq \text{ABS}(\text{Intentional Deviation Measurement Value Error}) + 1 \text{ MW}$$

Where:

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

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

BPA Customer ID	Customer Name	Modified TOCAs	
		FY 2018	FY 2019
10005	Alder Mutual	0.0000784	0.0000782
10015	Asotin County PUD #1	0.0000833	0.0000824
10024	Benton County PUD #1	0.0292395	0.0289494
10025	Benton REA	0.0086666	0.0085806
10027	Big Bend Elec Coop	0.0088895	0.0088013
10029	Blachly Lane Elec Coop	0.0025590	0.0025336
10044	Canby, City of	0.0029503	0.0029210
10046	Central Electric Coop	0.0118903	0.0117724
10047	Central Lincoln PUD	0.0225684	0.0223993
10055	Albion, City of	0.0000577	0.0000573
10057	Ashland, City of	0.0030607	0.0030303
10059	Bandon, City of	0.0011022	0.0010939
10061	Blaine, City of	0.0012706	0.0012580
10062	Bonnars Ferry, City of	0.0007728	0.0007651
10064	Burley, City of	0.0020431	0.0020228
10065	Cascade Locks, City of	0.0003453	0.0003419
10066	Centralia, City of	0.0035403	0.0034915
10067	Cheney, City of	0.0022976	0.0022748
10068	Chewelah, City of	0.0003890	0.0003861
10070	Declo, City of	0.0000521	0.0000516
10071	Drain, City of	0.0002756	0.0002737
10072	Ellensburg, City of	0.0034838	0.0034493
10074	Forest Grove, City of	0.0038761	0.0038377
10076	Heyburn, City of	0.0006998	0.0006928
10078	McCleary, City of	0.0005400	0.0005347
10079	McMinnville, City of	0.0128095	0.0126824
10080	Milton, Town of	0.0010804	0.0010697
10081	Milton-Freewater, City of	0.0014313	0.0014171
10082	Minidoka, City of	0.0000149	0.0000147
10083	Monmouth, City of	0.0012149	0.0012028
10086	Plummer, City of	0.0005732	0.0005675
10087	Port Angeles, City of	0.0045501	0.0045163
10089	Richland, City of	0.0150871	0.0149374
10091	Rupert, City of	0.0013687	0.0013551
10094	Soda Springs, City of	0.0004411	0.0004367
10095	Sumas, Town of	0.0005292	0.0005239
10097	Troy, City of	0.0002960	0.0002931
10101	Clallam County PUD #1	0.0110445	0.0109349
10103	Clark County PUD #1	0.0440937	0.0437933

BPA Customer ID	Customer Name	Modified TOCAs	
		FY 2018	FY 2019
10105	Clatskanie PUD	0.0124785	0.0121722
10106	Clearwater Power	0.0034689	0.0034344
10109	Columbia Basin Elec Coop	0.0017605	0.0017430
10111	Columbia Power Coop	0.0004356	0.0004293
10112	Columbia River PUD	0.0082726	0.0082065
10113	Columbia REA	0.0054756	0.0054213
10116	Consolidated Irrigation District #19	0.0000331	0.0000328
10118	Consumers Power	0.0066350	0.0065691
10121	Coos Curry Elec Coop	0.0057361	0.0056791
10123	Cowlitz County PUD #1	0.0797813	0.0789897
10136	Douglas Electric Cooperative	0.0026743	0.0026543
10142	East End Mutual Electric	0.0003903	0.0003865
10144	Eatonville, City of	0.0004817	0.0004778
10156	Elmhurst Mutual P & L	0.0046687	0.0046368
10157	Emerald PUD	0.0072573	0.0071853
10158	Energy Northwest	0.0003893	0.0003855
10170	Eugene Water & Electric Board	0.0350025	0.0347263
10172	U.S. Airforce Base, Fairchild	0.0008154	0.0008114
10173	Fall River Elec Coop	0.0048127	0.0047649
10174	Farmers Elec Coop	0.0000737	0.0000730
10177	Ferry County PUD #1	0.0014586	0.0013905
10179	Flathead Elec Coop	0.0242340	0.0239935
10183	Franklin County PUD #1	0.0170474	0.0168783
10186	Glacier Elec Coop	0.0027057	0.0026947
10190	Grant County PUD #2	0.0007541	0.0007466
10191	Grays Harbor PUD #1	0.0188860	0.0186941
10197	Harney Elec Coop	0.0033051	0.0032723
10202	Hood River Elec Coop	0.0019028	0.0018839
10203	Idaho County L & P	0.0009027	0.0008937
10204	Idaho Falls Power	0.0096998	0.0096243
10209	Inland P & L	0.0152373	0.0150861
10230	Kittitas County PUD #1	0.0014095	0.0013955
10231	Klickitat County PUD #1	0.0053254	0.0052726
10234	Kootenai Electric Coop	0.0074086	0.0073351
10235	Lakeview L & P (WA)	0.0045911	0.0045682
10236	Lane County Elec Coop	0.0040477	0.0040075
10237	Lewis County PUD #1	0.0160252	0.0159072
10239	Lincoln Elec Coop (MT)	0.0020092	0.0019893
10242	Lost River Elec Coop	0.0013636	0.0013609
10244	Lower Valley Energy	0.0124986	0.0123745
10246	Mason County PUD #1	0.0013055	0.0012926

BPA Customer ID	Customer Name	Modified TOCAs	
		FY 2018	FY 2019
10247	Mason County PUD #3	0.0116111	0.0114959
10256	Midstate Elec Coop	0.0066009	0.0065378
10258	Mission Valley	0.0055133	0.0054586
10259	Missoula Elec Coop	0.0039201	0.0038812
10260	Modern Elec Coop	0.0038184	0.0037805
10273	Nespelem Valley Elec Coop	0.0008544	0.0008459
10278	Northern Lights	0.0049072	0.0048815
10279	Northern Wasco County PUD	0.0094082	0.0093149
10284	Ohop Mutual Light Company	0.0014437	0.0014321
10285	Okanogan County Elec Coop	0.0009484	0.0009390
10286	Okanogan County PUD #1	0.0066694	0.0066032
10288	Orcas P & L	0.0035930	0.0035574
10291	Oregon Trail Coop	0.0114283	0.0113884
10294	Pacific County PUD #2	0.0050625	0.0050290
10304	Parkland L & W	0.0020076	0.0019932
10306	Pend Oreille County PUD #1	0.0000000	0.0000000
10307	Peninsula Light Company	0.0099302	0.0098437
10326	U.S. Naval Base, Bremerton	0.0042306	0.0041886
10331	Raft River Elec Coop	0.0053172	0.0052645
10333	Ravalli County Elec Coop	0.0026896	0.0026629
10338	Riverside Elec Coop	0.0003447	0.0003413
10342	Salem Elec Coop	0.0055201	0.0054792
10343	Salmon River Elec Coop	0.0016779	0.0016613
10349	Seattle City Light	0.0754206	0.0753012
10352	Skamania County PUD #1	0.0022512	0.0022332
10354	Snohomish County PUD #1	0.1142959	0.1145352
10360	Southside Elec Lines	0.0009829	0.0009731
10363	Springfield Utility Board	0.0139352	0.0138315
10369	Surprise Valley Elec Coop	0.0023871	0.0023634
10370	Tacoma Public Utilities	0.0554876	0.0565413
10371	Tanner Elec Coop	0.0016026	0.0015867
10376	Tillamook PUD #1	0.0080086	0.0079489
10378	Coulee Dam, City of	0.0002780	0.0002773
10379	Steilacoom, Town of	0.0006940	0.0006907
10388	Umatilla Elec Coop	0.0164477	0.0162845
10391	United Electric Coop	0.0043547	0.0043115
10406	U.S. DOE Albany Research Center	0.0000665	0.0000659
10408	U.S. Naval Station, Everett (Jim Creek)	0.0002131	0.0002109
10409	U.S. Naval Submarine Base, Bangor	0.0028731	0.0028485
10426	U.S. DOE Richland Operations Office	0.0026740	0.0045013
10434	Vera Irrigation District	0.0039450	0.0039059

BPA Customer ID	Customer Name	Modified TOCAs	
		FY 2018	FY 2019
10436	Vigilante Elec Coop	0.0027822	0.0027546
10440	Wahkiakum County PUD #1	0.0007249	0.0007177
10442	Wasco Elec Coop	0.0019267	0.0019140
10446	Wells Rural Elec Coop	0.0139125	0.0137744
10448	West Oregon Elec Coop	0.0012035	0.0011916
10451	Whatcom County PUD #1	0.0038659	0.0038275
10482	Umpqua Indian Utility Cooperative	0.0004003	0.0003963
10502	Yakama Power	0.0024515	0.0025383
13927	Kalispel Tribe Utility	0.0005917	0.0005858
10597	Hermiston, City of	0.0018365	0.0018182
10706	Port of Seattle - SETAC In'tl. Airport	0.0025100	0.0024851
11680	Weiser, City of	0.0009193	0.0009102
12026	Jefferson County PUD #1	0.0064695	0.0064240
10007	Alcoa	0.0071017	0.0109630
10312	Port Townsend Paper	0.0018614	0.0018430
10298	PNGC Aggregate	0.0762502	0.0755231

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SECTION III. DEFINITIONS

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1. Ancillary Services

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

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

Ancillary Services are available under the ACS rate schedule.

2. Balancing Authority Area

See definition in Control Area.

3. Billing Factor

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

4. Control Area

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

- a. match at all times the power output of the generators within the electric power system(s) and the import of energy from entities outside the electric power system(s) with the load within the electric power system(s) and the export of energy to entities outside the electric power system(s);
- b. maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
- c. maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and
- d. provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

5. Control Area Services

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

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

6. Daily Service

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

7. Direct Assignment Facilities

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

8. Direct Service Industry (DSI) Delivery

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

9. Dispatchable Energy Resource

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

10. Dispatchable Energy Resource Balancing Service

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

11. Dynamic Schedule

See definition in Dynamic Transfer Operating and Scheduling Business Practice.

12. Dynamic Transfer

See definition in Dynamic Transfer Operating and Scheduling Business Practice.

13. Eastern Intertie

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

14. Energy Imbalance Service

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

15. Federal Columbia River Transmission System

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

16. Federal System

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

- a. from which BPA receives all or a portion of the generating capability (other than station service) for use in meeting BPA's loads to the extent BPA has the right to receive such capability ("BPA's loads" do not include any of the loads of any BPA customer that are served by a non-Federal generating resource purchased or owned directly by such customer that may be scheduled by BPA);
- b. that BPA may use under contract or license; or
- c. to the extent of the rights acquired by BPA pursuant to the 1961 U.S.-Canada Treaty relating to the cooperative development of water resources of the Columbia River Basin.

17. Generation Imbalance

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

18. Generation Imbalance Service

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

19. Heavy Load Hours (HLH)

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

20. Hourly Non-Firm Service

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

21. Integrated Demand

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

22. Light Load Hours (LLH)

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

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

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

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

24. Main Grid

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

25. Main Grid Distance

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

26. Main Grid Interconnection Terminal

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

27. Main Grid Miscellaneous Facilities

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

28. Main Grid Terminal

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

29. Measured Demand

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

30. Metered Demand

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

- a. at each point of delivery (receipt) for which the Metered Demand is the basis for the determination of the Measured Demand;
- b. during each time period specified in the applicable rate schedule; and
- c. during any billing period.

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

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

31. Montana Intertie

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

32. Monthly Services

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

33. Monthly Transmission Peak Load

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

34. Network

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

35. Network Integration Transmission (NT) Service

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

36. Network Load

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

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

37. Network Upgrades

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

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

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

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

39. Operating Reserve – Spinning Reserve Service

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

40. Operating Reserve – Supplemental Reserve Service

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

41. Operating Reserve Requirement

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

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

42. Persistent Deviation

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

a. For Generation Imbalance Service only:

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

- (1) both 15 percent of the schedule and 20 MW in each scheduled period for three consecutive hours or more in the same direction;
- (2) both 7.5 percent of the schedule and 10 MW in each scheduled period for six consecutive hours or more in the same direction;
- (3) both 1.5 percent of the schedule and 5 MW in each scheduled period for twelve consecutive hours or more in the same direction; or
- (4) both 1.5 percent of the schedule and 2 MW in each scheduled period for twenty-four consecutive hours or more in the same direction.

b. For Energy Imbalance Service only:

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

- (1) both 15 percent of the schedule and 20 MW in each scheduled period for three consecutive hours or more in the same direction;
- (2) both 7.5 percent of the schedule and 10 MW in each scheduled period for six consecutive hours or more in the same direction;
- (3) both 1.5 percent of the schedule and 5 MW in each scheduled period for twelve consecutive hours or more in the same direction; or
- (4) both 1.5 percent of the schedule and 2 MW in each scheduled period for twenty-four consecutive hours or more in the same direction.

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

43. Point of Delivery (POD)

A Point of Delivery is a point on the BPA Transmission System, or transfer points on other utility systems pursuant to section 36 of the Open Access Transmission Tariff, where capacity and energy transmitted by BPA will be made available to the Receiving Party under Parts II and III of the Tariff or to the Transmission Customer under other BPA transmission service agreements. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-to-Point Service, Network Integration Transmission Service, and other BPA transmission services.

44. Point of Integration (POI)

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

45. Point of Interconnection (POI)

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

46. Point of Receipt (POR)

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

47. Ratchet Demand

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

48. Reactive Power

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

49. Reactive Supply and Voltage Control from Generation Sources Service

Reactive Supply and Voltage Control from Generation Sources Service is required to maintain voltage levels on BPA's transmission facilities within acceptable limits. In order to maintain transmission voltages on BPA's transmission facilities within acceptable limits, generation facilities (in the Control Area where the BPA transmission facilities are located) are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation Sources Service must be provided for each transaction on BPA's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by BPA. The Transmission Customer must purchase this service from BPA.

50. Regulation and Frequency Response Service

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

51. Reliability Obligations

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

52. Reserved Capacity

Reserved Capacity is the maximum amount of capacity and energy that BPA agrees to transmit for the Transmission Customer over the BPA Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the Open Access Transmission Tariff. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60)-minute interval (commencing on the clock hour) basis. In cases where Dynamic Schedules are involved, the Reserved Capacity must be set at a level to

accommodate (i) a demand equal to the largest ten-minute moving average of the load or generation expected to occur during the contract period for one-way Dynamic Schedules used to transfer generation or load from one Control Area to another Control Area; or (ii) a demand equal to the instantaneous peak demand, for each direction, of the supplemental Control Area service request expected to occur during the contract period for two-way Dynamic Transfers used to provide supplemental Control Area services. The supplemental Control Area service response shall always be the lesser of the Control Area service request or the Reserved Capacity associated with the supplemental Control Area service.

53. Scheduled Demand

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

54. Scheduling, System Control, and Dispatch Service

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

55. Secondary System

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

56. Secondary System Distance

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

57. Secondary System Interconnection Terminal

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

58. Secondary System Intermediate Terminal

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

59. Secondary Transformation

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

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

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

61. Southern Intertie

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

62. Spill Condition

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

63. Spinning Reserve Requirement

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

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

64. Station Control Error

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

65. Super Forecast Methodology

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

66. Supplemental Reserve Requirement

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

67. Total Transmission Demand

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

68. Transmission Customer

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

69. Transmission Demand

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

70. Transmission Provider

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

71. Utility Delivery

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

72. Variable Energy Resource

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

73. Variable Energy Resource Balancing Service

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

74. Weekly Service

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

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