

BP-20 Rate Proceeding

**ADMINISTRATOR'S FINAL
RECORD OF DECISION**

BP-20-A-03

July 2019



ADMINISTRATOR'S PREFACE

The Bonneville Power Administration is committed to providing clean, efficient and reliable power and transmission services within the Pacific Northwest at rates that are competitive and that include smart investments in the region's future. The power and transmission rates for the BP-20 rate period (fiscal years 2020 and 2021) reflect the extensive and disciplined efforts BPA has taken to achieve these objectives in a rapidly changing electricity industry and to deliver on our 2018-2023 Strategic Plan.

I am pleased to announce that there will be no increase in the base power rate for the FY 2020-2021 rate period. Thanks to our steadfast efforts to further reduce capital-related costs and our targeted actions on the trading floor to bring in additional revenues from forward market sales of surplus power, we have averted the 1.4 percent *base* power rate increase that was included in the initial proposal.

The base power rate does not include the impact of the Financial Reserves Policy surcharge, which at this point appears to be needed to strengthen BPA's financial health, consistent with our first strategic goal and the 2018 Financial Plan. Assuming the maximum financial reserves surcharge of \$30 million is needed, the effective power rate increase would be 1.5 percent over the two-year rate period. This is less than the Initial Proposal *effective* power rate increase of 2.9 percent. It is also significantly below the rate of inflation and would support BPA's financial resiliency – two important objectives of our Strategic Plan.

I am proud of the work we have done to implement our strategy, including the outcome of the Integrated Program Review, which resulted in significant program cost reductions. Our final projected agency program costs for fiscal years 2020 and 2021 are \$66 million lower per year compared to the current rate period, mostly due to cost reductions in Power Services. We not only met our cost-management objective to keep program costs at or below the rate of inflation, but also decreased our costs in nominal terms. These results reflect our commitment and progress toward strengthening BPA's financial health so that we continue delivering on Bonneville's mission and providing tremendous value to the Northwest for many years to come.

Just as significantly, earlier this year parties reached almost unanimous agreement over a settlement of the transmission rates and the terms and conditions of BPA's Open Access Transmission Tariff for FY 2020-2021. These efforts reflect exceptional collaboration and compromise among customers and stakeholders with many diverse interests. The settlement supports our efforts to serve transmission customers more efficiently and responsively through a limited rate increase and progress toward a modern transmission tariff. Under the rates settlement, the weighted average transmission rate increase is 3.6 percent over the two-year rate period, which is significantly less than what we had anticipated before the settlement.

The regional collaboration and responsiveness inherent in the settlement will be necessary to support our ongoing efforts to address the effects of changing markets. Investing in system modernization and taking advantage of new markets and technology are vital to BPA's long-term success. Through our grid modernization initiative, we are investing in state awareness tools and

technological advances to preserve and enhance the value of the Federal power and transmission systems. We are particularly focused on emerging opportunities to deploy the surplus capability of the region's clean, flexible hydroelectric resources to support regional reliability and the growing demand for flexible capacity in the Western Interconnection.

I want to express my appreciation to our customers and other stakeholders for engaging with us through both the transmission settlement and the rate proceeding; our Federal partners, Energy Northwest and other regional partners for taking steps to support BPA's cost-management goals; and BPA employees for their collaboration and hard work. This record of decision reflects the extensive efforts of employees from across the agency who found efficiencies and reduced costs to stabilize rates for the benefit of all who rely on the Northwest's Federal power and transmission system. We recognize that our work is not finished, and we remain committed to the disciplined business management that will be necessary to build on the gains we have made over the last two rate periods.

Finally, I would like to thank our customers and stakeholders for their patience as we continue to work through the ongoing process to review and correct any errors in BPA's attribution of financial reserves between the Power and Transmission business lines. BPA is committed to resolving this issue in a transparent and open manner. I understand the uncertainty this process introduces, but the existence of any errors does not change the fundamental importance of the Financial Reserves Policy and the foundational anchor it provides for BPA's financial resiliency. By the end of the fiscal year, the process and actions necessary to resolve any attribution errors will be complete, which will allow BPA to implement the Financial Reserves Policy as planned.

I look forward to working with you in the months ahead as we continue to deliver on BPA's role as an engine of the region's economic prosperity and environmental sustainability.

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Appendix C: 2020 Transmission, Ancillary, and Control Area Service Rate Schedules and General Rate Schedule Provisions (BP-20-A-03-AP03)

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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
CWIP	Construction Work in Progress
CY	calendar year (January through December)
DD	Dividend Distribution
DDC	Dividend Distribution Clause
dec	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
FRP	Financial Reserves Policy
F&W	Fish & Wildlife
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
inc	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
LTF	Long-term Firm
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
NRU	Northwest Requirements Utilities
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
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
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
RDC	Reserves Distribution Clause
REC	Renewable Energy Certificate
Reclamation	U.S. Bureau of Reclamation
REP	Residential Exchange Program
REPSIA	REP Settlement Implementation Agreement
RevSim	Revenue Simulation Model
RFA	Revenue Forecast Application (database)
RHWM	Rate Period High Water Mark
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RR	Resource Replacement
RRS	Resource Remarketing Service
RSC	Resource Shaping Charge
RSS	Resource Support Services
RT1SC	RHWM Tier 1 System Capability
SCD	Scheduling, System Control, and Dispatch Service
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
VER	Variable Energy Resource
VERBS	Variable Energy Resource 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.
AW	Alliance of Western Energy Consumers
BC	Benton County Public Utility District No. 1
ED	EDP Renewables North America LLC
FR	Franklin County Public Utility District No. 1
ID	Idaho Conservation League, Idaho Rivers United, and Columbia Riverkeeper
IP	Idaho Power Company
JP01	NC, SM, TU
JP02	PPC, SE, SN, TA, Eugene Water & Electric Board
JP03	PC, PG
JP04	PP, PX
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
PO	Pend Oreille Public Utility
PP	Public Power Council
PR	Port of Seattle
PS	Puget Sound Energy, Inc.
PX	Powerex Corporation
RN	Renewable Northwest
SE	City of Seattle
SH	Shell Energy
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 *

* The Western Public Agencies Group (“WPAG”) petition for leave to intervene states that each of the utilities that comprise WPAG individually file the petition requesting leave to intervene. These utilities are Eugene Water & Electric Board; Benton Rural Electric Association; the Cities of Port Angeles, Ellensburg and Milton, Washington; the Towns of Eatonville and Steilacoom, Washington; Alder Mutual Light Company; Elmhurst Mutual Power and Light Company; Ohop Mutual Light Company; Parkland Light and Water Company; Public Utility Districts No. 1 of Clallam, Clark, Cowlitz, Grays Harbor, Kittitas, Lewis, Mason, and Skamania Counties, Washington; Public Utility District No. 3 of Mason County, Washington; and Public Utility District No. 2 of Pacific County, Washington.

Joint Party Designation Codes

Party Code	Joint Party	Joint Party Members
JP01	Joint Party 1	Transmission Agency of Northern California (NC) Sacramento Municipal Utility District (SM) Turlock Irrigation District (TU)
JP02	Joint Party 2	Public Power Council (PP) City of Seattle (SE) Snohomish County Public Utility District No. 1 (SN) City of Tacoma (TA) Eugene Water and Electric Board (part of WPAG)
JP03	Joint Party 3	PacifiCorp (PC) Portland General Electric Company (PG)
JP04	Joint Party 4	Public Power Council (PP) Powerex Corporation (PX)

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1.0 GENERAL TOPICS

1.1 Introduction

The BP-20 Rate Proceeding established 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, 2019.

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, 2019, through September 30, 2021 (fiscal years (FY) 2020–2021). The proceeding included an evidentiary hearing, parties' initial briefs and briefs on exceptions, oral argument before the BPA Administrator, and publication of a 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 March 1, 2019.

1.1.1 Procedural History of this Rate Proceeding

1.1.1.1 Issue Workshops and Settlement Discussions

1.1.1.1.1 BP-20 Workshops

Beginning in the spring of 2018, prior to the start of the BP-20 Proceeding, BPA sponsored a series of workshops and other meetings to discuss certain topics related to power and transmission rates before the release of BPA's Initial Proposal. BPA designed the workshops to allow its Staff and interested parties to develop a common understanding of specific topics, generate ideas, and discuss alternative proposals. BPA also held separate workshops regarding the development of a new open access transmission tariff. *See* Section 1.1.1.1.2 below.

On April 24, 2018, BPA held a workshop addressing power, transmission, and generation inputs issues. BPA held a workshop on May 30, 2018, on transmission rates and generation inputs. BPA held workshops on June 14, 2018, and July 18, 2018, on transmission rates. On July 25, 2018, BPA held a workshop that included preliminary power and transmission rate estimates, power rates issues, revenue requirement issues, repayment modeling, and a presentation by Northern California Utilities on the Southern Intertie hourly rate. BPA held a workshop on August 8, 2018, regarding transmission and power rates. On August 22, 2018, BPA held a workshop regarding revenue requirements, generation inputs, and transmission rates. BPA held a workshop on September 12, 2018, on generation inputs. Finally, BPA held a workshop on September 26, 2018, on transmission rates.

1.1.1.1.2 BP-20 Partial Rates Settlement Agreement

In October 2018, BPA entered into settlement discussions with long-term transmission service customers regarding the terms and conditions of the new open access transmission tariff that BPA would propose to adopt in a proceeding pursuant to Section 212(i)(2)(A) of the Federal Power Act (the TC-20 proceeding). The TC-20 proceeding was a separate hearing process that BPA conducted concurrently with the initial stages of the BP-20 proceeding and concluded earlier this year. During the course of those discussions, the parties addressed a potential settlement of proposed transmission rates for FY 2020–2021 in addition to a settlement of the terms and conditions of service. BPA and all but two long-term transmission service customers ultimately reached agreement on a settlement “package” that addressed all issues in the TC-20 proceeding as well as the rates for transmission, ancillary, and control area services that BPA would propose in its BP-20 Initial Proposal. The BP-20 Partial Rates Settlement Agreement (the Settlement) specifies the proposed rates for all of these services and certain terms related to generation inputs. The Settlement provides for a weighted average transmission rate increase of 3.6 percent for the FY 2020–2021 rate period. The Settlement excludes power rates and the proposed Transmission Cost Recovery Adjustment Clause (CRAC), the Transmission Reserves Distribution Clause (RDC), and the Transmission Financial Reserves Policy (FRP) Surcharge. The Settlement is included as Appendix A to this Final ROD.

BPA offered the Settlement to customers on October 31, 2018, updated the tendered agreement on November 8, 2018, and signed the Settlement on November 30, 2018. Approximately 70 long-term transmission customers signed the Settlement. The signatories represent a broad cross-section of BPA’s transmission customers, including public utilities, investor-owned utilities, power marketers, and independent power producers, including renewable energy developers. Appendix A includes a list of signatories to the Settlement.

On December 12, 2018, BPA filed a motion requesting that the Hearing Officer establish a deadline for any party in this proceeding to object to the Settlement. Motion of Bonneville Power Administration to Establish Deadline for Objection to BP-20 Partial Rates Settlement Agreement and Request for Expedited Consideration, BP-20-M-BPA-01. The Hearing Officer established a deadline of December 18, 2018, for any party to formally object to the agreement. Order Establishing Deadline and Process for Objections to BP-20 Partial Rates Settlement Agreement, BP-20-HOO-04. Any party that did not file a formal objection would waive the right to object in BP-20. *Id.* Of the approximately 30 parties in the BP-20 rate proceeding, only Sacramento Municipal Utility District (SMUD), Turlock Irrigation District (TID), and the Transmission Agency of Northern California (TANC) (collectively, Joint Party 1 or JP01) filed objections. SMUD and TID had informally notified BPA about their objections before the start of the proceeding, and BPA and these customers entered into a letter agreement that, among other things, limited the scope of the objection to the Settlement of the proposed rate for hourly transmission service on the Southern Intertie. Fredrickson *et al.*, BP-20-E-BPA-19, Appendix B. Because of the limited number of parties objecting and the limited scope of the objections to the Settlement, BPA Staff recommended adoption of the Settlement despite the objections. The rates agreed to in the Settlement were part of the Initial Proposal in the BP-20 proceeding.

1.1.1.2 BP-20 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 of Procedure, which were published in the *Federal Register*, 83 Fed. Reg. 39,993 (Aug. 13, 2018), and posted on BPA's website at <https://www.bpa.gov/Finance/RateCases/RulesProcedure/Pages/default.aspx> (hereinafter *Procedures*). The *Procedures* implement the Section 7(i) requirements.

The BP-20 rate proceeding includes power and transmission rates in a single docket. On December 3, 2018, BPA held a scheduling conference to discuss a procedural schedule and procedural orders with prospective parties in the case. On December 6, 2018, BPA published a Federal Register notice, "Fiscal Year (FY) 2020–2021 Proposed Power and Transmission Rate Adjustments[,] Public Hearing and Opportunities for Public Review and Comment," 83 Fed. Reg. 62,849 (Dec. 6, 2018). The formal rate proceeding began with a prehearing conference on December 7, 2018. After the prehearing conference, the Hearing Officer issued orders establishing the schedule for the rate proceeding, special rules of practice, and granted petitions to intervene.

BPA's Initial Proposal was supported by Staff's initial studies and written testimony issued on January 14, 2019. Clarification of the Initial Proposal took place on January 22, 2019. BPA Staff filed supplemental testimony on February 6, 2019; no party requested clarification regarding this additional testimony. The parties filed direct testimony on February 21, 2019. Clarification of parties' direct testimonies took place on February 28, 2019. BPA Staff and the parties filed rebuttal testimony on March 28, 2019. Clarification of BPA's rebuttal testimony took place on April 4, 2019.

Cross-examination of BPA Staff and the parties' witnesses took place on April 23, 2019.

On May 3, 2019, the Hearing Officer for the proceeding resigned after the BPA Office of General Counsel expressed concern about the appearance of bias associated with an undisclosed request by the Hearing Officer for a professional reference from the Administrator during the proceeding. BPA appointed a new Hearing Officer on May 8, 2019, and instructed the new Hearing Officer to review all orders and rulings rendered by the former Hearing Officer on or after February 4, 2019, and determine whether each of "those orders and rulings were reasonable in light of the applicable legal standards and the facts and circumstances at hand." Notice of Appointment of Hearing Officer and Order on JP01's Motion Requesting Suspension of Proceedings and Other Measures, BP-20-A-01. The new Hearing Officer issued an order regarding his review on May 20, 2019, finding that "each of the decisions and rulings by Hearing Officer Dennison-Leonard on or after February 4, 2019[,] was reasonable both under the applicable law and the facts and circumstances of the case extant at the time, and shows no evidence of bias." Order on Review of Prior Hearing Officer Decisions, BP-20-HOO-19.

Further, the Hearing Officer found no need for additional proceedings or the introduction of additional evidence. *Id.*

The parties filed initial briefs on May 6, 2019. Oral argument before the Administrator took place on May 13, 2019. A Draft ROD was issued on June 13, 2019. One party filed a brief on exceptions on June 28, 2019.

At times, certain parties to this proceeding consolidated for the purpose of filing joint testimony or briefs on one or more issues. *See Procedures*, § 1010.7. 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-20-HOO-03.

BPA received one written comment during the participant¹ comment period, which began with the publication of the Federal Register notice on December 6, 2018, and ended March 1, 2019. Participant comments are part of the record upon which the Administrator bases his decisions; they are summarized and addressed separately in Final ROD Chapter 5. Participant comments may be viewed at BPA's website under "Involvement & Outreach," "Public Comments."

1.1.1.3 Waiver of Issues by Failure to Raise in Briefs

Pursuant to Section 1010.17(f) of the *Procedures*, arguments not raised in parties' briefs are deemed to be waived. Under this provision, a party's brief must specifically address the legal or factual dispute at issue. Blanket statements that seek to preserve every issue raised in testimony will not preserve any matter at issue.

Sections 1010.17(b) and (c) of the *Procedures* set forth the requirements applicable to initial briefs and briefs on exceptions. Pursuant to Section 1010.17(c) of the *Procedures*, a party that raises 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.

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,

¹ For interested persons who are not eligible or do not wish to become parties to the formal evidentiary hearings, BPA's *Procedures* provide opportunities to participate in the ratemaking process through submission of comments as "participants." *See Procedures*, § 1010.8. No party may submit comments as a participant, and comments so submitted will not be included in the record. *Id.* at § 1010.8(d).

conservation, and transmission of electric power, including the amortization of the Federal investment in the Federal Columbia River Power System (FCRPS) (including irrigation costs required to be paid by power revenues) over a reasonable period of years. *Id.* Section 7 of the Northwest Power Act also contains rate directives describing how rates for individual customer groups are established.

Section 7(a)(1) of the Northwest Power Act reaffirms the applicability of Section 5 of the Flood Control Act of 1944 (Flood Control Act), which directs that the Secretary of Energy shall transmit and dispose of electric power and energy in such manner as to encourage the most widespread use of power at the lowest possible rates to consumers consistent with sound business principles. 16 U.S.C. § 839e(a)(1); *see also* 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. 16 U.S.C. § 825s.

Section 7(a)(1) of the Northwest Power Act also reaffirms the applicability of Sections 9 and 10 of the Federal Columbia River Transmission System Act of 1974 (Transmission System Act), 16 U.S.C. §§ 838g-838h, which contain 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 N.C. v. Se. 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 Am. 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. Dep’t of Energy—Bonneville Power Admin.*, 13 FERC ¶ 61,157, at 61,339 (1980). The Commission may not modify rates proposed by the Administrator but may only confirm, reject, or remand them. *U.S. Dep’t of Energy—Bonneville Power Admin.*, 23 FERC ¶ 61,378, at 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’s rates. 18 C.F.R. Part 300 (1997).

1.1.3.1 Standard of Commission Review

The Commission reviews BPA’s 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. *See* 16 U.S.C. §§ 839e(a)(2)(A)-(B). 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. *See* 16 U.S.C. § 839e(a)(2)(C); *see also U.S. Dep’t of Energy—Bonneville Power Admin.*, 39 FERC ¶ 61,078, at 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 a discussion of topics and processes separate and distinct from this rate proceeding that provide information and policy context to the proceeding, including program cost estimates developed in the Integrated Program Review (IPR), the 2012 Residential Exchange Program Settlement Agreement (2012 REP Settlement), and the Rate Period High Water Mark (RHWM) Process. Issues related to those processes are outside the scope of the BP-20 proceeding. *See* 83 Fed. Reg. 62,850-62,853 (Dec. 6, 2018).

1.2.1 Spending Review

Since 1986, in a process separate from its rate proceedings, BPA has conducted a public review of planned expense and capital spending levels used in the development of rates, now known as the IPR. This process provides interested parties the opportunity to review and provide comment on all of BPA's program expense and capital spending level estimates prior to the use of those estimates in setting rates.

In June 2018, BPA held a series of public workshops to review the proposed program expense and capital spending to be the basis for power and transmission rates in the BP-20 rate proceeding. This combined process provided opportunities for the public to review and comment on power, transmission, and agency service expense programs, and included detailed review of asset strategies and associated capital spending levels.

BPA issued the Final Close-Out Report for the IPR, in which BPA responded to public comments, in October 2018. In the report, BPA established the program expense and capital spending level estimates that were used in the Initial Proposal to establish the proposed power and transmission rates.

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, 16 U.S.C. § 839c(c), through 2028. The Administrator's findings regarding the legal, factual, and policy challenges to the 2012 REP Settlement are thoroughly explained in the REP-12 Record of Decision (REP-12 ROD). The 2012 REP Settlement and the Administrator's decision in the REP-12 ROD to sign the settlement were upheld by 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 2020–2021 RHWMs for customers with Contract High Water Mark (CHWM) contracts. In the RHW Process, which preceded the BP-20 rate proceeding and concluded in August 2018, 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 RHW Process provided customers an opportunity to review, comment, and challenge BPA's RHW determinations. The RHWs and related outputs of the RHW 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 Revenue Requirement

The Power and Transmission Revenue Requirement Studies, BP-20-FS-BPA-02 and BP-20-FS-BPA-09, respectively, 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 mitigation, and conservation;
- Federal agencies' operations and maintenance expenses allocated to power;
- capitalized contract expenses associated with acquisitions of non-Federal resources such as Columbia Generating Station;
- 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. Dep't 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 mitigation, conservation, and associated assets. Repayment studies are conducted for each year of the two-year rate test period and extend over a repayment period of 50 years for power and 35 years for transmission.

2. For each year of the rate test period, operating expenses and the Minimum Required Net Revenues (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, if any, based on the risks identified and quantified, the Treasury Payment Probability 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.

The Power Revenue Requirement Study includes modifications related to changing the accounting for the Columbia Generating Station asset retirement obligation. The modifications include new costs and credits. These changes are also reflected in the cost table and the Slice true-up tables of the Power Rate Study, BP-20-FS-BPA-01. Parties were offered the opportunity to object to the inclusion of these changes in the Final Proposal. No party objected.

Issue 2.1.1

Whether BPA should accelerate amortization of the Conservation Acquisition regulatory asset to the extent permitted by available MRNR.

Parties' Positions

AWEC proposes that BPA adopt a policy to accelerate amortization of the Conservation Acquisition regulatory asset, to the extent such acceleration does not exceed MRNR. AWEC Br., BP-20-B-AW-01, at 2; AWEC Br. Ex., BP-20-R-AW-01.

BPA Staff's Position

In rebuttal testimony, Staff indicated an openness to AWEC's proposal, with certain caveats. Lennox & Hendricks, BP-20-E-BPA-23, at 1-6.

Evaluation of Positions

AWEC recommends that BPA accelerate amortization of the Conservation Acquisition regulatory asset because doing so (1) will not raise BP-20 costs, because accelerated amortization would be offset by a reduction to MRNR; and (2) will put downward pressure on rates in future years. AWEC Br., BP-20-B-AW-01, at 2-3. AWEC proposes that BPA create a customized amortization schedule and develop necessary mechanisms to limit the acceleration to available MRNR. *Id.* at 3. AWEC believes it is important for BPA not to delay implementation of this proposal, even if this will require additional work to develop amortization schedules, because “replacing MRNR with accelerated amortization will . . . reduce future obligations.” AWEC Br. Ex., BP-20-R-AW-01, at 4.

In rebuttal testimony, Staff agreed with AWEC that accelerating amortization of regulatory assets would reduce MRNR and could reduce amortization expense currently expected in FY 2022 through the remainder of the Regional Dialogue contract period. Lennox & Hendricks, BP-20-E-BPA-23, at 3. However, Staff noted that doing so may not lower future revenue requirements because, if MRNR remains positive, then a reduction in future amortization expense would simply be offset dollar-for-dollar by higher MRNR. *Id.* Staff concluded, “[w]e are open to accelerating amortization of the Conservation Acquisition regulatory asset. The amount of acceleration will depend on expectations about MRNR and the ability to create an accelerated schedule that fits within the available MRNR.” *Id.* at 6.

AWEC’s proposal continues to have potential. However, after considering the proposal more closely, BPA has decided to not adopt it at this time. To implement AWEC’s proposal, BPA would need to create a customized amortization schedule – something BPA has not done before. Analyzing the potential ramifications of different approaches to accelerating amortization, and then implementing those changes before the end of the BP-20 rate case, would be very difficult. Given that this change would not affect the BP-20 rates, BPA believes it prudent to take time to more fully understand the ramifications of AWEC’s proposal. While BPA will not adopt AWEC’s recommendation in this rate case, BPA agrees this idea deserves additional consideration. BPA will continue to look at this proposal internally to see how it may align with more holistic goals in the Strategic Plan.

Decision

BPA will not accelerate amortization of the Conservation Acquisition regulatory asset at this time.

2.2 Power and Transmission Risk

The Power and Transmission Risk Study, BP-20-FS-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. The Study presents BPA’s analysis of quantitative and qualitative risks facing each business line’s net revenues, and also

presents tools for mitigating risk and establishes the adequacy of those tools for meeting BPA's TPP standard.

In the 1993 Wholesale Power and Transmission rate proceeding (WP-93), BPA adopted and implemented its 10-Year Financial Plan, which included a policy requiring BPA to set rates to achieve a high probability of meeting its payment obligations to the U.S. Department of Treasury (Treasury). *See* Wholesale Power Rate and Transmission Rate Adjustment Proceeding, Administrator's Final Record of Decision, July 1993, WP-93-A-02, at 68–73. 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 in 2008 and 2018, both of which reiterate the TPP standard. The most recent financial plan is 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 the TPP standard.
- 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).
- Implement BPA's Financial Reserves Policy in order to maintain prudent financial reserves levels and support BPA's financial objectives.
- Include in the risk mitigation package only those elements that can be relied upon.
- 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 in order to maintain long-term availability.

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.

Issue 2.2.1

Whether BPA should assume for risk-modeling purposes that the revenue financing in the Transmission Revenue Requirement is available to pay the U.S. Treasury.

Parties' Positions

No party raised this issue.

BPA Staff's Position

Staff has not taken a position on this issue.

Evaluation of Positions

BPA adopted a Leverage Policy in September 2018 to provide guidance on managing one aspect of the accumulation and repayment of debt. *See Lennox et al.*, BP-20-E-BPA-17, at 15. In general terms, the Leverage Policy calls for the forecasting of business unit debt-to-asset ratios, also referred to as the leverage ratio, and sets near-term, mid-term, and long-term targets for the ratio. *Id.* If a forecast ratio is above a relevant target, the policy contemplates that the Administrator will take action to limit the accumulation of additional debt that would cause the ratio to increase. *Id.* Those actions include, among other actions, revenue financing (*i.e.*, paying capital projects with current rates).

Staff explained that the Leverage Policy includes a “phase-in” for Transmission Services for FY 2020–2021 that allows “the Transmission ratio to increase by an amount determined by the Administrator.” *Id.* at 16. Consistent with this phase-in, the calculation of the Transmission revenue requirement under the BP-20 Partial Rates Settlement Agreement in the Initial Proposal includes revenue financing to help limit the increase in Transmission Services’ leverage ratio to 0.6 percent by the end of the rate period. *Id.*; Transmission Revenue Requirement Study Documentation, BP-20-E-BPA-09A, Table 3-8.

At the time of the Initial Proposal, BPA calculated Transmission Services’ Treasury Payment Probability (TPP) to be above 95 percent. Subsequent to these calculations, however, BPA identified certain potential errors in the attribution of financial reserves between the business lines. The process for identifying and correcting these potential errors is outside of the rate case and is still ongoing. Consistent with prior practice, Staff has assumed for rate case purposes the latest financial reserves forecast, which in this case reflects a proposal to correct the financial reserves potential error. *See Lennox & Hendricks*, BP-20-E-BPA-23-CC01, at 12-13.

Using the latest financial reserves forecast, Transmission Services’ TPP would fall below 95 percent. To maintain a 95 percent TPP for Transmission Services, BPA will assume in its final Power and Transmission Risk Study that the revenue financing of capital projects for the phase-in of the Leverage Policy could be borrowed against in the event the funds are needed to make payment to the U.S. Treasury. This modeling assumption increases Transmission Services’ TPP above 95 percent without affecting the Transmission revenue requirement. BPA is making this assumption based on the provisions of the Leverage Policy providing for a

phase-in for Transmission Services in FY 2020–2021 and in recognition that transmission rates have been settled in the BP-20 Partial Rates Settlement Agreement. *See* Section 1.1.1.1.2. This assumption establishes no precedent for BPA’s risk modeling, use of revenue financing, or implementation of the Leverage Policy in the future.

Decision

BPA will assume for risk-modeling purposes that the revenue financing in the Transmission Revenue Requirement is available to pay the U.S. Treasury.

Issue 2.2.2

Whether BPA should adopt three proposed risk adjustment mechanism features: implementing the Financial Reserves Policy (FRP) through the FRP Surcharge, retaining Accumulated Calibrated Net Revenue (ACNR) as the triggering metric, and changing the timing for triggering risk adjustment mechanisms to actual, rather than forecast, financial data.

Parties’ Positions

NRU supports BPA’s proposals to use a surcharge mechanism, retain the ACNR triggering metric, and change the timing for triggering BPA’s three risk adjustment mechanisms. NRU Br., BP-20-B-NR-01, at 4-6.

BPA Staff’s Position

Staff proposes three risk adjustment features: (1) implement the FRP’s below-lower-threshold rate action through a surcharge mechanism rather than Planned Net Revenues for Risk (PNRR); (2) retain the ACNR triggering metric; and (3) change the timing for triggering risk adjustment mechanisms to make determinations based on actual, rather than forecast, financial data. Mandell *et al.*, BP-20-E-BPA-18, at 7-10, 13-14; Mandell *et al.*, BP-20-E-BPA-20, at 2.

Evaluation of Positions

Staff proposes three risk adjustment mechanisms for each business line: the Cost Recovery Adjustment Clause (CRAC), the FRP Surcharge, and the Reserves Distribution Clause (RDC). Mandell *et al.*, BP-20-E-BPA-18, at 5. The CRAC and FRP Surcharge are designed to increase a business line’s rates and financial reserves under certain circumstances. *Id.* The RDC is designed to allow business line financial reserves to be repurposed under certain circumstances. *Id.* The FRP Surcharge implements the FRP’s below-lower-threshold rate action through a surcharge mechanism, rather than PNRR. *Id.* at 7-10. As the triggering metric for the risk adjustment mechanisms, Staff proposes to continue using ACNR. Mandell *et al.*, BP-20-E-BPA-20, at 1. Staff also proposes to change the timing for triggering risk adjustment mechanisms, basing determinations on end-of-year actual ACNR rather than on forecast values. *Id.* at 2; Mandell *et al.*, BP-20-E-BPA-18, at 13-14.

Although NRU argues that BPA should delay implementation of the FRP Surcharge and RDC during the BP-20 rate period (discussed in Issue 2.2.3), NRU supports the three risk adjustment mechanism features proposed by Staff. NRU Br., BP-20-B-NR-01, at 4-10.

First, NRU supports implementing the FRP's below-lower-threshold rate action through the FRP Surcharge, rather than through PNRR. *Id.* at 5. The FRP Surcharge implements Section 4.2.2 of the FRP, which directs that BPA should take rate action to increase financial reserves when a business line is below its lower financial reserves threshold. Mandell *et al.*, BP-20-E-BPA-18, at 8. In considering *how* to implement Section 4.2.2 of the FRP, Staff considered two rate mechanisms: PNRR and the FRP Surcharge. *Id.* at 9. PNRR is included in the revenue requirement at the time rates are set and, therefore, must be based on forecast values. *Id.* The FRP Surcharge, in contrast, triggers *after* rates are set and can be implemented using actual values. *Id.* at 9-10. Staff explained that since forecast values are inherently less accurate than actual values, it is appropriate in this case to adopt the FRP Surcharge as the mechanism for implementing Section 4.2.2 of the FRP. *Id.* at 10. As noted above, NRU supports Staff's proposal to use the FRP Surcharge instead of PNRR. NRU Br., BP-20-B-NR-01, at 5.

Second, NRU supports Staff's proposal to retain ACNR as the triggering metric for the risk adjustment mechanisms. *Id.* at 6; *see* Mandell *et al.*, BP-20-E-BPA-20, at 1-5. ACNR is the metric that BPA used during the BP-16 rate period and is using during the current BP-18 rate period. Mandell *et al.*, BP-20-E-BPA-20, at 1; NRU Br., BP-20-B-NR-01, at 6. ACNR applies a "calibration" component to account for divergences between net revenue (an accrual-based metric) and financial reserves (a cash-based metric). Mandell *et al.*, BP-20-E-BPA-20, at 2. Without the calibration component, the potential exists that accounting and other financial events could cause accrual-based changes that would not have a commensurate impact on BPA's financial reserves, or vice versa. *Id.* at 3.

Third, NRU supports Staff's proposal to change the timing for triggering BPA's risk adjustment mechanisms. NRU Br., BP-20-B-NR-01, at 5-6; Mandell *et al.*, BP-20-E-BPA-18, at 13-14. In BP-18, BPA's determination whether any risk adjustment mechanisms had triggered for an upcoming fiscal year occurred prior to the start of that fiscal year and was therefore based on forecast data. Mandell *et al.*, BP-20-E-BPA-20, at 13-14. Staff now proposes to use actual end-of-year financial data to trigger the risk adjustment mechanisms. *Id.* In its Initial Brief, NRU agrees that using actual data will reduce the risk of BPA either unnecessarily triggering the FRP Surcharge or CRAC, thereby collecting unneeded monies from its customers, or inappropriately triggering an RDC, thereby "undermin[ing] BPA's efforts to improve its financial health." NRU Br., BP-20-B-NR-01, at 5-6.

Given the above support, and lack of any opposition, concerning all three of these risk adjustment mechanism features, BPA will adopt Staff's proposals.

Decision

BPA will adopt Staff's proposed risk adjustment mechanism features.

Issue 2.2.3

Whether BPA should revisit prior determinations regarding the FRP and FRP Phase-In Implementation that are outside the scope of the BP-20 proceeding in order to delay implementation of the FRP Surcharge or the Reserves Distribution Clause (RDC).

Parties' Positions

WPAG argues that BPA should suspend application of the FRP Surcharge during the BP-20 rate period. WPAG Br., BP-20-B-WG-01, at 15-16. NRU argues that BPA should delay implementation of the FRP Surcharge and the RDC during the BP-20 rate period. NRU Br., BP-20-B-NR-01, at 7-10.

BPA Staff's Position

BPA's determinations regarding the FRP and FRP Phase-In Record of Decision are outside the scope of the BP-20 proceeding. Fredrickson & Fisher, BP-20-E-BPA-24, at 6; Bonneville Power Administration, Fiscal Year (FY) 2020–2021 Proposed Power and Transmission Rate Adjustments Public Hearing and Opportunity for Public Review and Comment, 83 Fed. Reg. 62,849, 62,851 (Dec. 6, 2018). The FRP Surcharge and the RDC should be implemented in accordance with the FRP and the FRP Phase-In Implementation Records of Decision. Fredrickson and Fisher, BP-20-E-BPA-24, at 6; BP-18 Administrator's Final Record of Decision, July 2017, BP-18-A-04; FRP Phase-In Implementation Record of Decision, September 2018, at A-1–A-5, available at <https://www.bpa.gov/Finance/FinancialPublicProcesses/Financial-Reserves-Leverage/Pages/Financial-Reserves-Leverage-Policies.aspx>.

Evaluation of Positions

WPAG and NRU both acknowledge that the Federal Register Notice initiating the BP-20 rate case (FRN) expressly excludes from the scope of the rate proceeding BPA's FRP and FRP Phase-In determinations. WPAG Br., BP-20-B-WG-01, at 15 n.44; NRU Br., BP-20-B-NR-01, at 7. The FRN states that “the Administrator directs the Hearing Officer to exclude from the record all argument, testimony, or other evidence that seeks in any way to visit or revisit Bonneville's determinations in the BP-18 ROD regarding the Financial Reserves Policy or the FRP Phase-In ROD in this rate proceeding.” Bonneville Power Administration, Fiscal Year (FY) 2020–2021 Proposed Power and Transmission Rate Adjustments Public Hearing and Opportunity for Public Review and Comment, 83 Fed. Reg. 62,849, 62,851 (Dec. 6, 2018).

NRU and WPAG argue that BPA “muddle[d] the waters” regarding the BP-20 rate proceeding's scope by designating certain letters received from external sources as *ex parte* communications. NRU Br., BP-20-B-NR-01, at 7-8; WPAG Br., BP-20-B-WG-01, at 15 n.44. BPA disagrees. The cited letters concerned a BPA financial reserves error and included advocacy for suspension of the FRP Surcharge. *Id.* In an abundance of caution, BPA designated these letters as *ex parte* communications because they requested the Administrator to not adopt rate mechanisms that were pending in the BP-20 rate proceeding. As part of BPA's analysis on this issue, BPA considered whether the requests made in the parties' communications could be adopted without implicating the *ex parte* rule. That is, if BPA were to agree with the request made in the

communications, would the resulting action have been “relevant to the merits of any issue in the pending proceeding?” *Procedures*, §1010.2(j). In this instance, BPA determined that responding to the communications would have required changes to the FRP Surcharge and RDC, which are rate mechanisms pending in the proceeding. Thus, BPA’s designation of these communications as *ex parte* was appropriate.

By identifying these letters as *ex parte*, BPA was not modifying the scope of the BP-20 rate proceeding or signaling that the BP-20 rate proceeding was an appropriate forum to revisit the FRP or FRP Phase-In Implementation decisions. The fact that BPA classified as *ex parte* letters requesting changes to the rate implementation aspects of those decisions indicates that BPA takes seriously its duty to guard against any allegation of an *ex parte* violation in the rate case. *See Cent. Lincoln Peoples’ Util. Dist. v. Johnson*, 735 F.2d 1101, 1119 (9th. Cir. 1984).

WPAG and NRU argue that, because of changed circumstances, BPA should revisit its prior decisions to adopt the FRP, and should suspend the FRP Surcharge and RDC. WPAG Br., BP-20-B-WG-01, at 16; NRU Br., BP-20-B-NR-01, at 8-10. WPAG argues that BPA should suspend application of the FRP Surcharge during the BP-20 rate period because of a recently discovered potential error in the calculation of business line financial reserves. WPAG contends that, had this error been discovered earlier, it would have put both business lines in fundamentally different reserves positions than when the FRP was adopted and when the BP-20 Partial Rate Settlement and TC-20 Settlement were executed. WPAG Br., BP-20-B-WG-01, at 15-16. Similarly, NRU argues that BPA customers should be given an opportunity to revisit the near-term implementation of the FRP because Power Services is in a vastly different position regarding financial reserves. NRU Br., BP-20-B-NR-01, at 9.

WPAG’s and NRU’s request to suspend the FRP is outside of the scope of this proceeding. Fredrickson & Fisher, BP-20-E-BPA-24, at 5-6. BPA has already determined, based on the full record at the time the decision was made, that it is appropriate to take rate action to recover financial reserves when financial reserves are below a business line’s lower threshold, and has determined the appropriate parameters for doing so. *See* FRP Phase-In Implementation Record of Decision, September 2018, at 9-10, A-4, *available at* <https://www.bpa.gov/Finance/FinancialPublicProcesses/Financial-Reserves-Leverage/Pages/Financial-Reserves-Leverage-Policies.aspx>; *see also* BP-18 Administrator’s Final Record of Decision, July 2017, BP-18-A-04, § 6 and Appendix A (July 26, 2017). No party challenged those decisions, and they are now final. BPA will not revisit those decisions here.

Within the scope of this proceeding is the choice of rate mechanisms to implement the Administrator’s prior decisions. *See* FRP Phase-In Implementation Record of Decision, September 2018, at 41. No party objected to Staff’s recommendation. *See* Section 2.2.2.

Moreover, the proposed design of the FRP Surcharge ensures that it triggers based on actual ACNR values. Fredrickson & Fisher, BP-20-E-BPA-24, at 6. Thus, the FRP Surcharge will trigger based on the best available information regarding BPA’s financial reserves. *See* Mandell *et al.*, BP-20-E-BPA-18, at 9; Fredrickson & Fisher, BP-20-E-BPA-24, at 6. The outcome of the financial reserve review process will not affect the appropriateness of having an FRP Surcharge

mechanism to recover financial reserves below each business line's lower threshold. Fredrickson & Fisher, BP-20-E-BPA-24, at 6. BPA will continue to review and address questions and concerns with BPA's financial reserve proposals through the public process established to address those issues. *Id.* at 5. A decision on the financial reserve issues will be released in the fall of 2019, before the FRP Surcharge and RDC are calculated. *See* <https://www.bpa.gov/Finance/FinancialPublicProcesses/Reserves-Review/Pages/default.aspx>.

Decision

BPA will not revisit prior determinations regarding the FRP or FRP Phase-In Implementation, which are outside the scope of the BP-20 proceeding; BPA will not delay implementation of the FRP Surcharge or the RDC.

3.0 POWER RATES AND POLICIES

3.1 Competitiveness and the Proposed Power Rate Increase

Although not an issue that can be addressed solely in a BPA rate case, the need for BPA to remain a competitive supplier of wholesale power was addressed by a number of parties. AWEC notes that in the BP-16 rate case, AWEC's predecessor organization argued that BPA's trend of biennial and significant rate increases was damaging to the ability of companies in the Northwest to prosper in competitive global markets, harmful to the economy of the region, and a threat to the long-term competitiveness and viability of the agency itself. AWEC Br., BP-20-B-AW-01, at 1. However, AWEC is encouraged that, in the four years since that proceeding, BPA has demonstrated a commitment to bending its cost curves and driving down the trajectory of its rates. *Id.* AWEC states that while there is still work to be done, BPA's achieved cost reductions and development of the 2018–2023 Strategic Plan are important steps. *Id.*

NRU appreciates the efforts BPA has recently made to mitigate the upward pressure on rates that its customers have experienced over the past eight years. NRU Br., BP-20-B-NR-01, at 1. NRU encourages BPA to continue its exploration of opportunities to decrease costs and increase revenues while maintaining an appropriate budget that allows the Agency to meet the evolving needs of its preference customers. *Id.* However, NRU states that BPA needs to maintain an appropriate balance between keeping its rates low and preserving its ability to reliably and responsively deliver power to its preference customers. *Id.* at 2. NRU notes that maintaining low rates is an important aspect of being competitive, but it is only one aspect, because NRU believes that the package of products and services that BPA provides to NRU members is essential for maintaining their own economic competitiveness in their service territories. *Id.* Therefore, NRU urges BPA to focus its efforts not only on responsibly reducing its costs but also on increasing its revenues as well. *Id.*

NRU states that while BPA has made a substantial effort to reduce its costs, it is important for BPA to consider that a primary driver of increasing rates in the past several rate cases is diminishing revenues from sales of firm and non-firm surplus power. *Id.* at 3. NRU encourages BPA to look for ways to increase its revenues by both increasing its power sales and the value it gets for its surplus sales. *Id.* NRU believes that as the energy industry evolves and moves towards decarbonization, the value of carbon-free, highly flexible hydropower should grow and create opportunities for BPA to increase its revenue from the sale of firm and non-firm surplus power. *Id.*

WPAG states that it is apparent from the BP-20 Initial Proposal that BPA is beginning to implement a plan to address the concerns of its preference customers regarding its competitive position, and understands that this is and has been a difficult task, and it commends BPA and BPA Staff for the hard work needed to achieve this result. WPAG Br., BP-20-B-WG-01, at 2-3. However, WPAG believes there is a risk that BPA's power rates will be above market as we approach the 2028 power contract renewal, notwithstanding the gains made in the 2018 IPR process and the BP-20 initial proposal. *Id.* at 3. WPAG believes the risk to BPA under such a circumstance is that it can result in price-induced reductions in demand for BPA power that will

undermine BPA's capacity to balance its costs and revenues, and that this, in turn, can threaten BPA's ability to meet its statutory objectives, including BPA's obligations to repay the Federal Treasury, recover its costs, and mitigate, protect, and enhance fish and wildlife. *Id.* WPAG states that the ultimate risk is that the potential failure by BPA to meet these obligations will prompt political action in Washington, D.C. *Id.*

WPAG recommends that BPA not depend on the chance of favorable outcomes with respect to factors it cannot control to determine its long-term competitive fate, but instead focus in this rate case on those factors over which it can exercise control to steer itself to a more secure competitive footing in advance of 2028. *Id.* at 4. WPAG suggests that BPA can use three interdependent factors to change its competitive position: (i) its costs, (ii) its marketing decisions, and (iii) the level of its rates. *Id.* In summary, WPAG believes BPA should implement a zero percent rate increase for the BP-20 rate period. *Id.* at 5.

In response to the foregoing comments, first, BPA would like to thank the parties for their acknowledgement of BPA's accomplishments in the IPR leading up to the BP-20 rate case. As demonstrated through those spending level actions, BPA is committed to changing the trajectory of its historical rate increases. Fisher *et al.*, BP-20-E-BPA-21, at 2. BPA is also mindful of the impact its rates have on the economic health of the Pacific Northwest and the additional work that lies ahead to continue to "bend the cost curve" to avoid the competitive pitfalls that WPAG identified in its direct case and initial brief. *Id.* In addition, BPA is aligned with the recommendations to continue to evaluate its costs and to explore new revenue opportunities. *Id.* However, BPA believes that the parties recognize that cost levels, product design, and potential marketing opportunities are outside the scope of the rate case. *See* Bonneville Power Administration, Fiscal Year (FY) 2020–2021 Proposed Power and Transmission Rate Adjustments Public Hearing and Opportunities for Public Review and Comment, 83 Fed. Reg. 62,849, 62,850-51 (Dec. 6, 2018).

While BPA is mindful of the impact its rates have 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. BPA has varied and often competing responsibilities, which include, but are not limited to, implementing the Northwest Power Act and BPA's other statutory obligations to encourage conservation, energy efficiency and the development of renewable resources within the region; mitigating for fish and wildlife affected by construction and operation of the FCRPS; and ensuring that BPA has an adequate, efficient, economical, and reliable power supply to meet its supply obligations. 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 Final Proposal strikes that appropriate balance.

Thus, as noted above, BPA is in agreement with WPAG on changing BPA's power rate trajectory for many of the reasons that WPAG states. WPAG advocates for a zero percent rate

increase and suggests a number of ways in which it believes BPA can get closer to a zero rate impact. Some of WPAG's suggestions have been adopted and further contribute to what BPA believes are BP-20 rates that demonstrate a significant change in the power rate trajectory. For example, consistent with WPAG's and other parties' recommendations, BPA's forecast for surplus power sales better reflects BPA's ongoing marketing efforts to bring in additional revenue. These issues are addressed individually in this Final ROD.

BPA remains committed to collaborating with its stakeholders to sustain competitiveness through its implementation of the 2018-2023 Strategic Plan. Stakeholders and BPA worked together in the 2018 Integrated Program Review to reduce program costs and BPA plans to ensure the curve stays bent in the future. Implementing the plan's objectives will require the free exchange of ideas and strategic choices. Those choices and collaboration will be imperative as BPA moves forward with opportunities for new revenues, strategic investments, and business changes that maximize the value of the system for its customers and the region.

3.2 Power Loads and Resources

The Power Loads and Resources Study (Study), BP-20-FS-BPA-03, contains the load and resource data used to develop BPA's wholesale power rates for FY 2020–2021. Documentation supporting the results of the Study is presented in the Power Loads and Resources Study Documentation, BP-20-FS-BPA-03A. The Study is also described in the direct testimony of Bellcoff *et al.*, BP-20-E-BPA-12.

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 forecasted load obligations for the rate period, FY 2020–2021. 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 Northwest Power Act 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 spill operation modeled in the Study remains the same as was modeled in the Initial Proposal because “that operation [is] the best representation of the financial impact BPA expects to experience under the 2019–2021 Spill Operation Agreement” Fredrickson *et al.*, BP-20-E-BPA-19, at 19. The Study includes spring spill assumptions that are based on the actual operations implemented in 2018, which involved spilling to applicable water quality

standards for total dissolved gas (TDG), or “gas cap” spill. Spill cap limits have been updated to the latest available information from the Corps Water Quality Team (November 2018). Summer spill assumptions used are informed by the results of biological performances standard testing conducted over the last decade to measure dam passage survival for out-migrating juvenile fish. Summer spill assumptions do not include early August spill curtailment.

The Study provides inputs to various other studies and calculations in the ratemaking process: (1) the Power Rates Study, BP-20-FS-BPA-01; (2) the Power Market Price Study, BP-20-FS-BPA-04; and (3) the Power and Transmission Risk Study, BP-20-FS-BPA-05.

No party raised issues related to BPA’s forecast of loads and resources for the BP-20 rate period.

3.3 Power Market Price Study

The Power Market Price Study, BP-20-FS-BPA-04, contains BPA’s natural gas price and electricity market price forecasts for the BP-20 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, Planned Net Revenues for Risk (PNRR), and other components outlined in the Power Rates Study, BP-20-FS-BPA-01. The direct testimony of Graessley *et al.*, BP-20-E-BPA-13, 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-20 rate period.

3.4 Power Rate Development

This section addresses issues related to the Power Rates Study, BP-20-FS-BPA-01, and the power rate schedules, including the General Rate Schedule Provisions (GRSPs), Appendix B to this Final ROD, BP-20-A-03-AP02. 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-20-FS-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. No. 96-976, Part I, 96th Cong., 2d Sess. 69 (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, RAM2020, for purposes of calculating power rates. BPA makes the RAM2020 spreadsheet model available to the public on its website. The Study describes how the tiered Priority Firm (PF) Public rate is designed following the cost of service and rate directives ratemaking steps. The rate design for the PF Public rate was established in the Tiered Rate Methodology (TRM). TRM, BP-12-A-03. The TRM restricts BPA and customers with Contract High Water Mark contracts from proposing changes to the TRM except in a Section 7(i) rate proceeding, and only after certain procedures specified in the TRM have been followed. *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 (REP) 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, as outlined below. The parties’ initial briefs contained no objections to these changes, and some parties supported the adoption of the changes. For a more complete explanation and description of each of the changes, see the Power Rates Study, BP-20-FS-BPA-01; the Power Rate Schedules and GRSPs, Appendix B to this Final ROD, BP-20-A-03-AP02; Stiffler *et al.*, BP-20-E-BPA-15; Traetow *et al.*, BP-20-E-BPA-16; Mandell *et al.*, BP-20-E-BPA-18 and BP-20-E-BPA-20; Fredrickson *et al.*, BP-20-E-BPA-19; and Yokota *et al.*, BP-20-E-BPA-14.

1. **Priority Firm (PF) Power Rate Schedule.** The Tier 2 Load Growth, VR1-2014, and VR1-2016 charges have been removed from Section 2.2 of the PF rate schedule. BPA does not forecast any sales at the Load Growth rate in FY 2020 and FY 2021, and the two Tier 2 vintage rates (VR1-2014 and VR1-2016) expire at the end of FY 2019.
2. **New Resource (NR) Firm Power Rate Schedule.** Language has been added to the Availability section of the NR rate schedule to clarify that NR Firm Power is available to serve *planned* new large single loads.
3. **Firm Power and Surplus Products and Services (FPS) Rate Schedule.** Language has been added to the Availability section of the FPS rate schedule to clarify that BPA’s non-firm power sales made outside of the region are not sold under this rate schedule. Also the word “interruptible” was removed from the description of the products sold under the category of “Other Capacity, Energy, and Scheduling Products and Services” in Section 6.

4. **TOCA Adjustment (GRSP II.G).** Language was added that allows BPA to modify a Load Following customer's TOCA if its Existing Resource amounts in Exhibit A are modified within the rate period. This language already exists in the TOCA Adjustment section for Slice/Block and Block customers.
5. **Transmission Scheduling Service (TSS) Charge and Transmission Curtailment Management Service (TCMS) Charge (GRSP II.I.5).** In response to customer requests, BPA has expanded the types of TSS that will be available in BP-20. There will be two levels of service: Full Service (TSS-Full) and Partial Service (TSS-Partial). TSS-Full is the current TSS in which Power Services schedules all Federal power deliveries and non-Federal resource deliveries to a customer's load. TSS-Partial has been developed to allow a customer to schedule all of its own non-Federal resources to its load.
6. **Transfer Service Charges (GRSP II.L).** The Transfer Service Regulation and Frequency Response Charge has been moved from the FPS rate schedule to GRSP II.L, Transfer Service Charges. Additionally, the Transfer Service WECC Charge has been renamed the Transfer Service Regional Compliance Enforcement Charge.
7. **Risk Adjustments (GRSP II.O-Q).** The risk adjustment sections in the GRSPs have been updated to implement the Financial Reserves Policy, including adding the Power Financial Reserves Policy (FRP) Surcharge. All three risk adjustment sections (Power CRAC, Power RDC, and Power FRP Surcharge) include the same notification procedures and similar billing provisions.
8. **Slice True-Up Adjustment (GRSP II.R).** Several lines were added and removed from the Composite Cost Pool True-Up table to reflect changes to: (1) the accounting treatment of non-Federal debt, and (2) the treatment of Regional Cooperation Debt (RCD) refinancing in the revenue requirement. Additionally, under "Revenue Credits," the line for Large Project Revenues (for the Large Project Program in conservation) was removed and a line for PF Load Forecast Deviation Liquidated Damages was added. Several lines in the True-Up table were revised to better reflect their nature.
9. **Remarketing Value (GRSP III.B.24).** The definition has been updated to reflect the new methodology for establishing Remarketing Values in BP-20, including replacing Aurora[®] Mid-C market prices with Intercontinental Exchange (ICE) Mid-C settlement prices in the calculation.
10. **Super Peak Period (GRSP III.B.30).** The definition of the Super Peak Period has been changed *from* (1) October through May during hour ending (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, *to* (1) October through May during HE 8 through HE 10 and HE 19 through HE 21; and (2) June through September during HE 16 through HE 21, in BP-20.
11. **Residential Exchange Program (REP) Settlement Customer Refund Amounts.** The GRSP appendix containing Customer REP Refund Amounts was removed because it was no longer needed to implement part of the 2012 REP Settlement Agreement, BPA Contract No. 11PB-12322. The 2012 REP settlement required BPA to make a stream of payments, known as refund amounts, to certain preference customers as credits on their power bills. The final payment for these credits will be made in FY 2019.

12. **Product Conversion Charge.** The GRSP appendix containing Product Conversion Charges for Seattle City Light and Klickitat PUD was removed as both customers have repaid the benefits from the Regional Cooperation Debt management actions in FY 2014 and FY 2015 that the customers received twice due to switching products at the start of the BP-18 rate period.
13. **Spill Surcharge.** The GRSP appendix for the Spill Surcharge was removed as BPA is not implementing a Spill Surcharge in BP-20.
14. **Supplemental Information.** BPA has added Appendix A, Supplemental Information, to the GRSPs. The appendix will include a summary of any adjustments to rates and GRSPs made during the rate period in accordance with the rate schedules and GRSPs, including adjustments made due to the Power CRAC, Power RDC, and the Power FRP Surcharge.

BPA Staff also proposed that the Administrator decide in this BP-20 proceeding whether to replace the 4 aMW reduction in Tier 1 System resources associated with the termination of the Foote Creek 1 Power Purchase Agreement. Fredrickson *et al.*, BP-20-E-BPA-19, at 11-15. The Foote Creek 1 Power Purchase Agreement was expected to be terminated in early 2019. *Id.* at 10-11. However, the agreement has not been terminated at this time, and therefore the costs and generation of Foote Creek 1 are included for purposes of setting final BP-20 rates. If the contract is later terminated, the resource will not be replaced for purposes of calculating future Rate Period High Water Marks (RHWs).

3.4.2 Valuing Surplus Power

Issue 3.4.2.1

Whether BPA should change how it models the firm surplus portion of the net secondary revenue forecast.

Parties' Positions

Although PPC proposed in its testimony that BPA value firm surplus and committed purchases energy in the net secondary revenue forecast using the output of the “critical water price” run of AURORA[®], PPC supports BPA Staff’s proposal to value this energy at the same price assumed for firm surplus serving loads at PF Tier 2 rates. PPC Br., BP-20-B-PP-01, at 5. PPC urges the Administrator to adopt this approach for purposes of the net secondary revenue forecast because it would more accurately reflect the value of BPA’s firm surplus energy. *Id.*

WPAG suggests that to the extent BPA does not make any additional forward sales of firm surplus energy prior to setting final rates, the Administrator should adopt the alternative proposal put forward by Staff in rebuttal to use the same treatment as Tier 2 for valuing firm surplus energy using a forward market price index while modeling such energy as a flat block of power. WPAG Br., BP-20-B-WG-01, at 10. WPAG believes this proposal is largely consistent with the proposal made by WPAG in its direct case, and adopting it would ensure that the real value firm surplus energy has above and beyond a short-term market price is captured in BPA’s ratemaking and, all other things being equal, would lower the PF Tier 1 rate. *Id.*

BPA Staff's Position

BPA Staff proposes that only the amount of firm power used to meet load at Tier 2 rates would be priced based on a forward market price index. Any remaining firm power (forecast to be available under critical water) would be sold at the average monthly market prices forecast in the AURORA[®] market price run. Power and Transmission Risk Study, BP-20-E-BPA-05-CC01, at 33. Although Staff did not believe it was necessary to adjust the value of firm surplus power as proposed by PPC and WPAG, it described the method it would use to model such a proposal if adopted by the Administrator. Fisher *et al.*, BP-20-E-BPA-21, at 13-14. In short, Staff would value such power using the same approach as proposed for pricing service at Tier 2 rates – as a flat block of power valued at forward market prices, which would appear as a flat block obligation to its RevSim model. *Id.* at 14. It would then have the RevSim model balance that obligation with increased purchases and decreased sales at the AURORA[®] forecast market prices. *Id.*

Evaluation of Positions

In the Initial Proposal, BPA forecast firm surplus energy sales in the amounts of 193 aMW in FY 2020 and 53.4 aMW in FY 2021. Bellcoff *et al.*, BP-20-E-BPA-12, at 12. Firm surplus energy is power that BPA has determined for planning purposes will be available on a firm basis during the rate period under critical water conditions and would be used to serve Tier 1 load during the rate period if there was sufficient Tier 1 load to serve. Andersen *et al.*, BP-20-E-WG-01, at 11. This is in contrast to BPA's forecast of secondary energy, which is based on better than critical water conditions and, for planning purposes, is normally not assumed to be available to serve firm load. *Id.* at 11-12. For ratemaking purposes, BPA proposed that only the amount of firm surplus power used to serve load at Tier 2 rates be priced based on a forward market price index, and that any remaining firm energy be priced at the average monthly market prices forecast in its market price run in AURORA[®]. Power and Transmission Risk Study, BP-20-E-BPA-05-CC01, at 33.

In addition to the surplus firm power that is forecast to be available under critical water conditions, another source of surplus firm energy has been identified. BPA has made two resource acquisitions in the form of power purchases of 100 aMW in FY 2020 and 77 aMW in FY 2021 to serve firm power loads for Southeast Idaho Load Service (SILS) following termination of the BPA-PacifiCorp Southeast Idaho Exchange Agreement. Power and Transmission Risk Study, BP-20-E-BPA-05-CC01, at 34; Andersen *et al.*, BP-20-E-WG-01, at 14-15. These purchases increase the amount of BPA's firm surplus power. *Id.*; Deen & Bush, BP-20-E-PP-01, at 6. BPA's Initial Proposal assumes that this energy will increase the amount of surplus power marketable at Mid-C and assigns it a value based on BPA's monthly average AURORA[®] market price forecast. Power and Transmission Risk Study, BP-20-E-BPA-05-CC01, at 34. PPC's and WPAG's proposals regarding the value of surplus firm power include this Federal power made available due to SILS power purchases.

Firm surplus energy has real value above and beyond a spot or short-term market price. Fisher *et al.*, BP-20-E-BPA-21, at 7. This additional value is due to the availability of firm surplus energy across all water conditions, which makes it available for forward market sales. Andersen

et al., BP-20-E-WG-01, at 11. Forward market prices are often higher than short-term market prices because they “tend to include a risk premium when compared with the expectation of the price in the spot market . . .” Fisher *et al.*, BP-20-E-BPA-21, at 7. Based upon these facts, PPC and WPAG made recommendations to better ensure that rates would benefit from this added value. PPC suggested the agency should value firm surplus energy not serving Tier 2 loads and “committed purchases” at the “critical water price,” and not at the spot or short-term market price. PPC Br., BP-20-B-PP-01, at 2. PPC suggested this would better reflect the value of that surplus power as firm across all water conditions and would increase the net secondary revenue forecast by approximately \$7.4 million per year and \$14.9 million during the rate period. *Id.* WPAG recommended that BPA assume that all of its firm surplus energy will be sold on a forward basis as flat blocks of power and assigned a value based on either (i) the weighted average price of any such forward sales actually made; or, (ii) if no such sales are actually made, the same methodology (using prices based on a forward market price index) BPA proposes to use to fix the price of firm surplus energy sold to customers under the Tier 2 Short-Term rate. WPAG Br., BP-20-B-WG-01, at 6-7.

PPC supports its proposal by noting that when BPA must purchase power to make up a deficit in its firm capability, it uses the forecast generated using the “critical water price” run of AURORA[®], and not the spot or short-term market price forecast. Deen & Bush, BP-20-E-PP-01, at 7. PPC argues that if BPA uses the “critical water price” to value *purchases* of firm energy in case of a deficit, it is only logical that the agency would use the same value for *sales* of firm energy in case of a surplus. PPC Br., BP-20-B-PP-01, at 3. PPC suggests that given the firmness and favorable environmental attributes of BPA’s firm power, Power Services would certainly be expected to market that energy on a forward basis and achieve at least this value. Deen & Bush, BP-20-E-PP-01, at 8.

In rebuttal, BPA Staff noted that there were a number of reasonable ways to value firm surplus power available under critical water conditions. WPAG and PPC pointed to one such way – looking at the current forward market prices for energy and using those prices to value BPA’s firm surplus power. Fisher *et al.*, BP-20-E-BPA-21, at 5. Staff had identified another reasonable method for valuing firm surplus—using the AURORA[®] market price forecast the same as it does for all unsold BPA inventory. *Id.* Staff noted that the main difference between these methodologies was risk. *Id.* The methodology proposed by WPAG and PPC would place greater financial risk on BPA. *Id.* Forward market prices tend to be higher than the AURORA[®] market prices (which BPA uses as an approximation of the spot market price) because forward transactions lock in a price and reduce the uncertainty that comes with relying on transactions made at variable spot market prices, and because of differences in market participant expectations of future spot prices. *Id.* If Staff assumed BPA would receive the current forward market price for its firm surplus power, it would increase BPA’s financial risk in two ways: (1) by locking a credit into rates based on a price premium for a forward power sale before it actually happens (*i.e.*, counting chickens before they hatch), and (2) by calculating that premium based on a snapshot in time that would invariably change as market risk preferences and expectations change (*i.e.*, there is no guarantee that BPA would receive yesterday’s premium today). *Id.*

In considering these methodologies, which vary in the level of forecast secondary revenues and risk, Staff stated that it is important to recall the Administrator's statement in the preface to the BP-18 ROD:

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.

Id. at 6, *citing* BP-18 Administrator's Final Record of Decision, BP-18-A-04, at P-5.

Staff noted that the Administrator's concerns are illustrated by the past decade of secondary sales and revenue performance relative to rate case estimates. Fisher *et al.*, BP-20-E-BPA-21, at 6. During the past decade, flattening load growth and below-expected secondary sales performance have contributed to a significant decline in Power Services' financial reserves for risk. *Id.* At the very least, history has shown that meeting the secondary revenue forecasts used for setting rates has not been easy. *Id.* Relying on high probabilities of triggering a CRAC, or other risk adjustment provisions like the proposed Financial Reserves Policy Surcharge, adds uncertainty to BPA's rates and runs counter to the ratemaking principle of rate stability. *Id.*

Staff noted that in the seminal text *Principles of Public Utility Rates*, Bonbright articulated two important principles, among many others, which are relevant here: revenue stability and predictability, with a minimum of unexpected changes seriously adverse to utility companies; and stability and predictability of the rates themselves, with a minimum of unexpected changes seriously adverse to ratepayers and with a sense of historical continuity. *Id.* Therefore, Staff recommended that BPA stay with the direction stated in the BP-18 ROD and remember its importance now rather than recognizing its significance only during the rate period after rates have been established. *Id.*

As noted above, Staff did not believe it was necessary to adjust the value of firm surplus power available under critical water conditions. *Id.* at 11. However, if the Administrator were to decide to set rates based on a different value for firm surplus power available under critical water conditions as compared to above-critical water surplus, Staff saw no reason why the firm surplus created by the SILS purchases should be treated differently than the firm surplus produced by the rest of the Federal system. *Id.* Although Staff did not believe it was necessary to adjust the value of firm surplus power available under critical water conditions, it described the method it would use to model such a proposal. *Id.* at 12. In short, Staff would value the firm surplus as a flat block of power, and do so by adding a flat block obligation to its RevSim model. *Id.* It would then have the RevSim model balance that obligation with increased purchases and decreased sales at the AURORA[®] forecast market prices. *Id.* Staff noted that this is mostly a matter of timing; the consequence of a higher or lower net secondary revenue forecast in base rates would ultimately be borne by the same customer group. *Id.* Customers that are subject to BPA's risk adjustment provisions would be impacted equally—either through higher base rates and a lower probability of a risk adjustment triggering, or lower base rates and higher probability

of a risk adjustment triggering. *Id.* Further, if BPA sells firm surplus power available under critical water conditions (or any surplus for that matter) prior to setting the final rates, the actual revenue that will be received for that sale would be included as a revenue credit in base rates. *Id.* Therefore, under Staff's Initial Proposal, it was not precluding the benefit of forward sales from being included in the base rates; rather, it was proposing not to count on it until it happens. *Id.*

Lastly, Staff stated that using the forward market price was a reasonable proxy for the actual market transaction cost when small amounts of firm surplus power must be valued, but as the amount of firm power sales increases, it would expect the actual market clearing price to respond by decreasing under the fundamental principles of supply and demand. *Id.* The inverse is true under large amounts of purchases—increased purchases in the forward market would tend to increase the price of those purchases. *Id.* at 12-13. Given this market fundamental, it is reasonable to assume a different price for forward sales as compared to forward purchases because the actual cost of purchases in the forward market would tend to increase the forward market price (for example, purchases made by utilities to serve above-RHWM load), and the actual value of sales in the forward market would tend to decrease the forward market price (for example, the sale of surplus energy). *Id.* at 13. Staff believes the quantities in question are small enough at this point that it would not expect a significant forward market response. *Id.* Therefore, for simplicity it may be reasonable to use the same treatment for Tier 2 pricing as for valuing firm surplus power available under critical water conditions. *Id.* Also, BPA tries to avoid having its rates dictate operations, including trading floor operations. *Id.* Valuing unsold firm surplus at the forward market price for rate-setting purposes would remove the incentive to rush an actual sale for the sole purpose of making the sale in time to be included in final rates. *Id.*

Staff provided a recommended modeling approach to the Administrator if PPC's and WPAG's proposal were to be adopted. This approach would use the same pricing treatment for power sold at Tier 2 rates and for surplus firm power (including the firm surplus created by the SILS power purchases), and not use the augmentation price. *Id.* The augmentation price represents the expected spot price for power sold, or purchased, under 1937 water conditions. *Id.* If BPA tied the firm surplus price to the augmentation price, it would credit unsold firm surplus inventory at an expected price that is relevant only under the most extreme water conditions—when water is scarce and market prices are relatively high. *Id.* In all other water conditions, the unsold inventory of firm surplus energy would be valued at this augmentation price, even if expected spot market prices under that particular water condition were lower. *Id.* Such an approach could be inconsistent with BPA's statutory mandate to set rates to recover its costs, particularly if the augmentation price was significantly higher than the forward market available to BPA. *Id.* at 13-14.

Staff had previously proposed to use the augmentation price as a proxy for a forward market price, but that was before the rate case included a forward market price index used for the purpose of pricing Tier 2. *Id.* at 14. With the availability of this forward market index, it recommends using the Tier 2 method so as to avoid any potential large deviations between the augmentation price and the price used for Tier 2. *Id.* As it happens, however, in the Initial Proposal these two values were rather close. *Id.*

Also, if PPC's and WPAG's proposal were to be adopted, Staff recommends continuing to model firm surplus as a flat block of power, and including it in RevSim as a firm obligation equal to the amount of firm surplus in each year after all other obligations are met. *Id.* It would then run RevSim the same as described in the Initial Proposal and let the added obligation reduce balancing sales or increase balancing purchases in each of the 3,200 modeled scenarios. *Id.*

After reviewing Staff's modeling approach for their proposals if the Administrator were to adopt them, PPC and WPAG supported its adoption. Although PPC proposed in its testimony that BPA value firm surplus and committed purchases energy in the net secondary revenue forecast using the output of the "critical water price" run of AURORA[®], it supports BPA Staff's recommendation to value this energy at the same price assumed for firm surplus serving Tier 2. PPC Br., BP-20-B-PP-01, at 5. PPC urges the Administrator to adopt this approach for purposes of the net secondary revenue forecast because it would more accurately reflect the value of BPA's firm surplus energy. *Id.* Similarly, WPAG suggests that to the extent BPA does not make any additional forward sales of firm surplus energy prior to setting final rates, the Administrator should adopt the proposed modeling of its proposal put forward by Staff in rebuttal to use the same treatment as Tier 2 for valuing firm surplus energy using a forward market price index while modeling such energy as a flat block of power. WPAG Br., BP-20-B-WG-01, at 10. WPAG believes Staff's recommendation is largely consistent with the proposal made by WPAG in its direct case, and adopting it would ensure that the real value firm surplus energy has above and beyond a short-term market price is captured in BPA's ratemaking and, all other things being equal, would lower the PF Tier 1 rate. *Id.*

There is merit in the method proposed for valuing firm surplus power (available under critical water) in the Initial Proposal as well as in the method proposed by PPC and WPAG. However, given the relatively small size of the firm surplus, it is reasonable to assume BPA will realize a premium above its AURORA[®] market prices for its firm surplus power and not significantly impact BPA's rate stability.

Decision

In the net secondary revenue forecast, BPA will value all firm surplus power available under critical water (including firm surplus created by the SILS power purchases) using the same treatment as Tier 2 pricing and model it as recommended by Staff.

Issue 3.4.2.2

Whether BPA should adopt a sur-credit mechanism to refund incremental surplus firm power sales revenue.

Parties' Positions

AWEC supports adoption of any of the mechanisms for valuing surplus firm power proposed by Staff, PPC, or WPAG, but requests that if BPA Staff's initial proposal were adopted, Staff and other stakeholders should be directed to develop an appropriate sur-credit mechanism to provide

certainty regarding when customers will receive the value of such sales. AWEC Br., BP-20-B-AW-01, at 6.

BPA Staff's Position

Although the sur-credit is an interesting proposal, such proposals have previously failed to gain customer support, and would need to be designed in concert with BPA's other risk and rate provisions and not as an *ad hoc* addition to the overall framework on which BPA manages the inherent variability of its financial performance. Fisher *et al.*, BP-20-E-BPA-21, at 4.

Evaluation of Positions

AWEC states that BPA's Initial Proposal recognizes there is additional value to firm products by assuming a sales price equal to the Tier 2 rate and the "Firm Surplus Price," both of which are appropriately higher than the average price for net secondary sales. AWEC Br., BP-20-B-AW-01, at 4. AWEC, however, believes the average price for net secondary does not sufficiently value BPA's firm surplus power. *Id.* In order to most accurately track the benefit of firm surplus sales, AWEC recommends that BPA institute a sur-credit, which would pass incremental benefit back to customers when it is realized, or sufficiently known. *Id.* AWEC believes this would incentivize both BPA and its customers to go into the market to find the highest possible value for this resource, while preventing excessive risk if favorable deals are not available. *Id.* at 4-5.

AWEC notes that PPC and WPAG proposed more aggressive solutions to correct the under-valuation of BPA surplus firm, including using forward market prices or the critical water forecast. *Id.* at 5. AWEC also notes that Staff recognized these were "reasonable ways" to value surplus firm power, but Staff argued that the AURORA[®] forecast is a superior method because it reduces BPA's risk. *Id.* AWEC notes that regardless of the method used to value surplus firm power, it is unclear when, absent AWEC's sur-credit, the benefit of actual firm sales would actually accrue to customers. *Id.*

However, AWEC states that because a number of "reasonable" proposals have been made by the parties in this proceeding, the question of how to value surplus firm power may be reduced to a balancing of the critical duties to provide electric power at the lowest possible rates to consumers with the need to prudently manage risk. AWEC Br., BP-20-B-AW-01, at 6. AWEC supports adoption of any of the mechanisms for valuing surplus firm power proposed by Staff, PPC, or WPAG, but requests that if BPA Staff's initial proposal were adopted, Staff and other stakeholders should be directed to develop an appropriate sur-credit mechanism to provide certainty regarding when customers will receive the value of such sales. *Id.*

As noted above, AWEC's sur-credit proposal is a rebate-type mechanism that would credit power rates if the value of BPA's surplus capacity exceeded rate case forecasts. Fisher *et al.*, BP-20-E-BPA-21, at 3-4. AWEC's suggestion of a sur-credit is similar to other rate designs that BPA and stakeholders have discussed on and off for more than a decade. *Id.* at 4. BPA Staff presented a number of concerns with AWEC's sur-credit proposal which would make it imprudent to adopt at this time without further analysis and adequate consideration of the

impacts of such a proposal on BPA's existing rate mechanisms and financial policies. *Id.* Also, AWEC's proposal would require considerable work to determine the details of how it would be implemented. *Id.* Such important details would include issues such as the definition of "incremental revenue" and how BPA would measure such revenue as actual loads, inventory, and costs change through time. *Id.* As noted above, however, AWEC states that its request for a sur-credit would apply only if the initial Staff proposal for valuing surplus firm power were adopted, but the final decision (see Issue 3.4.2.1) adopts PPC's and WPAG's proposals to value surplus firm power, not Staff's proposal. Therefore, AWEC's request for a sur-credit is no longer applicable.

Decision

BPA will not adopt a sur-credit mechanism for surplus firm power sales at this time.

Issue 3.4.2.3

Whether BPA should assume a forward sale of 75 aMW of secondary energy using a forward market price.

Parties' Positions

WPAG recommends that BPA assume for ratemaking purposes that the 75 aMW from the terminated sale to Alcoa will be sold as a flat block on the forward market for the BP-20 rate period and to then value that assumption based on the same methodology used to value firm surplus energy as proposed by WPAG. WPAG Br., BP-20-B-WG-01, at 12.

BPA Staff's Position

Staff believes that WPAG's proposed assumption is overly aggressive, unprecedented, and would significantly increase the risk of BPA not being able to meet its rate case forecast of secondary revenue. Fisher *et al.*, BP-20-E-BPA-21, at 15.

Evaluation of Positions

WPAG notes that Alcoa exercised its option to terminate its power contract with BPA effective August 31, 2019, and accordingly there will be no Alcoa load during the BP-20 time period. WPAG Br., BP-20-B-WG-01, at 11. WPAG states that the terminated contract included a sale of 75 aMW of secondary energy to Alcoa as a firm flat block through September 30, 2022. *Id.* at 11-12. WPAG recommends that BPA assume for ratemaking purposes that the 75 aMW from the terminated sale to Alcoa will be sold as a flat block on the forward market for the BP-20 rate period and should be valued at a forward market price. *Id.* at 12. WPAG argues that Alcoa's termination of its contract with BPA should not, in and of itself, change BPA's previous determination, *i.e.*, that BPA can isolate the 75 aMW of its secondary inventory with the highest certainty of being realized for purposes of assuming a forward sale of such energy in setting rates for the BP-20 rate period. *Id.*

In response to WPAG's argument, Staff did not support this proposal for the same reasons it was generally not supportive of proposals to change how BPA values firm surplus energy (inventory available under critical water conditions). Fisher *et al.*, BP-20-E-BPA-21, at 14. WPAG's proposal is particularly problematic because it assumes a price premium for a sale of inventory BPA does not have under 1937 water (critical water conditions) and has not yet made. *Id.* at 14-15. This aggressive assumption regarding BPA's secondary sales would be unprecedented and would significantly increase the risk of BPA not being able to meet its rate case forecast of secondary revenue. *Id.* at 15.

Also, WPAG's comparison of the Alcoa power sale agreement to its proposal is misplaced. *Id.* Specifically, in its evaluation of the risk its proposal places on BPA, WPAG fails to recognize the difference between the Industrial Firm Power (IP) rate and the forward market price forecast. *Id.* For comparison, the IP rate is \$41.84/MWh in the BP-20 Initial Proposal, which is significantly higher than forward market prices that average \$25.16/MWh for the rate period. *Id.* This rate delta provides BPA revenue above the forward market prices and spot market prices, which played a significant role in BPA's conclusion that the sale did not create undue risk for BPA. *Id.* In other words, a different conclusion might have been reached if the agreement had been evaluated at the forward market price instead of the IP rate because the risk profile changes significantly when selling above critical water inventory at \$41.84/MWh compared to selling that inventory at \$25.16/MWh. *Id.*

However, WPAG is correct that there are gradations of certainty within BPA's secondary sales inventory, specifically because in many water conditions BPA has more inventory than what is available under 1937 water conditions. *Id.* Even so, Staff is not comfortable changing decades of ratemaking precedent to speculate how the trading floor would manage a subset of the inventory BPA has above 1937 water conditions. *Id.* Rather, Staff believes BPA should continue its longstanding practice of valuing all inventory above 1937 water conditions in the same manner (at the forecast market price as produced with AURORA[®]) until BPA has an actual committed sale evaluated with the specific facts of the transaction at that time—exactly the same as the Alcoa transaction mentioned by WPAG. *Id.*

WPAG argues that much of the risk BPA ascribes to its proposal could be alleviated by an actual forward sale of some secondary inventory under the right market circumstances. WPAG Br., BP-20-B-WG-01, at 13. WPAG also asserts that for that portion of BPA's secondary inventory with the highest degree of certainty of being realized, BPA assumes a market price risk/lost opportunity risk when it does not make a forward sale at a premium but instead withholds such high-certainty secondary energy to be sold into the short-term market. *Id.* WPAG believes that given the differential between current forward market prices and BPA's market price forecast for the BP-20 rate period, BPA should be looking for buyers for a portion of its high-certainty secondary energy in the forward wholesale market. *Id.* WPAG identifies an operational scenario that BPA is currently evaluating as the agency balances its inventory uncertainty with current market conditions. In other words, BPA has made transactions for firm surplus power available under critical water that are providing rate benefits, but has not completed the type of forward market transactions that WPAG believes BPA should assume for purposes of setting rates. Given this, Staff is correct in its conclusion that until the trading floor finds, evaluates, and

makes such a sale, it would be speculative and overly aggressive to assume that such a sale will be made for purposes of setting rates.

WPAG believes its proposal to value the 75 aMW using the Tier 2 methodology is reasonable even though it produces a value that is less than the IP rate. *Id.* WPAG does not dispute that use of the IP rate was an important part of BPA's risk analysis when it originally decided to enter into the power sales contract with Alcoa. *Id.* WPAG believes an important difference between that situation and WPAG's proposal is that whereas the Alcoa contract was for a term spanning multiple rate periods, WPAG's proposal is limited to the upcoming two-year rate period. *Id.* WPAG asserts that BPA was assuming considerably more long-term risk when it entered into the Alcoa contract than the risk it would assume if it were to adopt WPAG's proposal. *Id.* at 13-14. WPAG states that BPA offset the added risk arising from the long duration of its contract with Alcoa by requiring the sale to be made under the IP rate. *Id.* at 14. WPAG believes it does not follow that BPA must receive the same risk premium it received in the long-term Alcoa transaction before it will consider using a forward sales assumption for a portion of its highest-certainty secondary energy to set rates (or to make an actual forward sale of such energy) for the much shorter two-year rate period. *Id.*

WPAG, however, misses Staff's point. Staff was not stating that the same risk premium received at the IP rate must be achieved to determine that a forward sale of its highest-certainty secondary energy should be made. Rather, Staff was pointing out that the higher the premium, the more likely BPA would make a forward sale. Said differently, it is less risky to sell high-certainty secondary at a \$15/MWh premium above the forecast market price than a \$5/MWh premium. Therefore, one cannot conclude, as WPAG does, that the historical existence of the 75 aMW Alcoa decision to sell power at the IP rate justifies the ratemaking assumption that BPA would or should make a similar deal at a much lower premium price.

Finally, WPAG argues that there are a number of factors that would stem the market price risk concerns expressed by BPA Staff; for example, the risk that the subject 75 aMW of secondary energy would be unavailable during the rate period is lower than for BPA's remaining balance of secondary inventory since it has the highest degree of certainty of being realized. *Id.* WPAG also states that the quantity in question is small enough that using a forward market price to value it is a reasonable proxy for an actual market sale. *Id.* Further, WPAG believes using the same method to value this energy as BPA proposes to use to value firm surplus energy sold to Tier 2 loads would reduce the overall risk that BPA would not be able to receive the assumed premium tomorrow because it appears that the assumed premium will be less than current forward market prices. *Id.*

It is indisputable that WPAG's proposal would increase BPA's risk of revenue underrecovery. The argument that the proposal would create only a small amount of additional risk is not a compelling reason to adopt WPAG's proposal. This is particularly true in light of the past decade of difficulty that BPA has observed in meeting its secondary revenue projections. BPA is actively working to find additional sources of revenue and the benefits of that activity would provide rate relief. When, or if, BPA makes more of these transactions, the revenue associated with those transactions will be included when setting rates. However, until that time, it would be

speculative and would improperly second-guess BPA's operational actions to assume additional transactions for ratemaking purposes when the transactions have not actually occurred.

Decision

BPA will not assume a forward sale of 75 aMW of secondary energy using a forward market price.

3.4.3 Super Peak Credit

Issue 3.4.3.1

Whether BPA should impose a forfeiture of the Super Peak Credit for a month should a customer fail to schedule its contractually committed-to Super Peak amounts during one hour of a month.

Parties' Positions

WPAG argues that BPA should change its proposal to amend the Super Peak Credit program by imposing a forfeiture of the Super Peak Credit for an entire month should such customers fail to schedule as little as one megawatt during one hour of a month. WPAG Br., BP-20-B-WG-01, at 16. WPAG proposed that BPA adopt a stepped process to address instances of non-performance under the Super Peak Program. *Id.*

BPA Staff's Position

Staff initially proposed to revise the PF rate schedule language to provide that if a customer did not supply the Super Peak amount listed in its CHWM Contract for any hour of the Super Peak Period, then it would not receive a Super Peak Credit for that month. *See* 2020 Power Rate Schedules and GRSPs, BP-20-E-BPA-10-CC01, at 8. Additionally, Staff proposed to revise the GRSP language for the demand UAI to state that Super Peak amounts were not included in the calculation of excess demand entitlement, and thus a customer would not be subject to a demand UAI if it failed to provide its Super Peak amounts at the time of the customer's system peak. *Id.* at 71. After reviewing WPAG's direct case, Staff revised its proposal to provide that Super Peak Credit program participants would not receive a Super Peak Credit for a month if the participating customer failed to schedule the proper amount of power during at least two hours of a Super Peak Period. Fisher *et al.*, BP-20-E-BPA-21, at 21.

Evaluation of Positions

The Super Peak Credit program allows a Load Following customer to reshape its Dedicated Resource amounts into the Super Peak Period to reduce its Customer System Peak (CSP) and its Priority Firm (PF) demand charge on its power bill. *Id.* at 16. The Super Peak Credit is equal to the amount of additional capacity provided by a non-Federal resource over the amount of capacity provided by an equivalent amount of energy delivered flat across the monthly heavy load hour (HLH) period. *Id.* This credit is applied to a customer's demand charge billing determinant regardless of when the customer's actual CSP occurs. *Id.*

Under the program, a customer must elect by October 31 prior to a rate period to contractually commit defined amounts of energy into the Super Peak Period for either year or both years of the upcoming rate period. *Id.* The Super Peak Credit was proposed at the time BPA adopted the Tiered Rate Methodology (TRM) and has been available to preference customers since 2012. *Id.* The Super Peak Period, which may vary by month, is made up of either two three-hour periods each day or a single six-hour period each day, as determined prior to each rate case and documented in the GRSPs. *Id.*

In BPA's Initial Proposal, Staff revised the PF rate schedule language to provide that if a customer did not supply the Super Peak amount listed in its CHWM Contract for any hour of the Super Peak Period, then it would not receive a Super Peak Credit for that month. *See* 2020 Power Rate Schedules and GRSPs, BP-20-E-BPA-10-CC01, at 8. WPAG argued in its direct case that BPA should change its proposal to amend the Super Peak Credit program by imposing a forfeiture of the Super Peak Credit for an entire month should such customers fail to schedule as little as one megawatt during one hour of a month. WPAG Br., BP-20-B-WG-01, at 16. WPAG alleged that BPA's proposed amendment was not made in response to any identified problem, was harsher than similar provisions in other commercial capacity transactions, did not bear a reasonable relationship to the harm BPA appeared to be attempting to address, and would serve as a disincentive for preference customers to participate in the program. *Id.* In the alternative, WPAG proposed that BPA adopt a stepped process to address instances of non-performance under the Super Peak Program. *Id.*

In response to WPAG's direct case, Staff recognized that BPA and WPAG agreed that there should be consequences if a preference customer participating in the program does not supply the amount of capacity it has committed to make available to BPA during Super Peak periods, but such consequences should be congruent with BPA's treatment of such failures in analogous circumstances. Fisher *et al.*, BP-20-E-BPA-21, at 21. Staff proposed to revise its Initial Proposal for this reason. *Id.* Staff proposed that program participants would not receive a Super Peak Credit for a month if the participating customer failed to schedule the proper amount of power during at least two hours of a Super Peak Period. *Id.* Staff proposed to change the PF demand billing determinant language to implement this approach. *Id.*

WPAG also expressed a concern that in the event that non-performance occurred on a customer's system peak, BPA could impose a demand UAI charge on the customer in addition to the Super Peak Credit forfeiture. Andersen *et al.*, BP-20-E-WG-01, at 27. Staff noted that it was not BPA's intent to impose a demand UAI on a customer, in addition to not providing a Super Peak Credit, if a customer failed to provide the contractually committed Super Peak amount at the time of the customer's system peak. Fisher *et al.*, BP-20-E-BPA-21, at 20. The Initial Proposal contained language revising the UAI Charge to reflect this intent, but to further clarify that the demand UAI language will not apply if a customer fails to provide its Super Peak amounts, Staff proposed to revise the UAI Charge language. *Id.*

WPAG appreciates that BPA listened to its concerns and supports, and recommends that the Administrator adopt BPA Staff's (i) proposed revisions to the Super Peak Credit forfeiture, and (ii) clarifications regarding the UAI. WPAG Br., BP-20-B-WG-01, at 17.

Decision

BPA will revise the 2020 Power Rate Schedules and GRSPs to provide that Super Peak Credit program participants will not receive a Super Peak Credit for a month if the participating customer fails to schedule the proper amount of power during at least two hours of a Super Peak Period. In addition, BPA will clarify that the demand UAI language will not apply if a customer fails to provide its Super Peak amounts.

3.5 Other Issues

3.5.1 Self-Funding Assumption for Energy Efficiency

Issue 3.5.1.1

Whether BPA should lower the PF Tier 1 rate by increasing the self-funding assumption for energy efficiency.

Parties' Positions

WPAG notes that five large preference customers that perform the vast majority of self-funding will continue to do so to meet policy and/or regulatory goals independent of BPA's programmatic savings goals and self-fund more than their share of BPA's utility self-funding assumption. WPAG Br., BP-20-B-WG-01, at 17. WPAG believes BPA should increase the self-funding assumption for the BP-20 rate period from 30 to 35 percent. *Id.* at 18.

BPA Staff's Position

BPA Staff believes that although WPAG states that it is not arguing for a lower programmatic savings goal than established in the IPR process, its proposal would create a conflict between BPA's determination of the cost of reaching its programmatic goal and the cost reflected in BPA's rates. Fisher *et al.*, BP-20-E-BPA-21, at 28. To revisit those cost decisions here is outside of the scope of the rate case and would undermine the separate and more focused review and determination of BPA's costs through the IPR process. *Id.*

Evaluation of Positions

WPAG notes that BPA currently assumes utilities will self-fund 30 percent of the programmatic savings goal set for the rate period. WPAG Br., BP-20-B-WG-01, at 17. WPAG also notes that BPA's power customers self-funded nearly 36 percent of the original programmatic savings goal of 116 aMW for the BP-16 rate period, and for the BP-20 rate period, BPA has reduced the programmatic goals identified in the Action Plan for FY 2020 and FY 2021 from 59 aMW and 58 aMW, respectively, to 51 aMW for both years. *Id.* WPAG states that the vast majority of self-funding of energy efficiency by BPA's preference customers is done by five large utilities located in Washington state in order to meet policy and/or regulatory obligations that are independent of BPA's programmatic savings goals and BPA's self-funding assumption ("Independent EE Obligations"). *Id.* WPAG notes that these Independent EE Obligations have caused and will continue to cause those utilities that are subject to them to conduct energy

efficiency independent of BPA's goals, and to self-fund much more than their pro-rata share of BPA's utility self-funding assumption. *Id.* Accordingly, WPAG believes it is reasonable to assume that, because BPA's reduction of the programmatic goals for FY 2020 and FY 2021 will not itself result in a reduction to the self-funding performed by utilities to meet their Independent EE Obligations, the percentage share of self-funding of BPA's goals compared to the lower overall targets should go up, all other things being equal. *Id.* at 18. Thus, WPAG argues that BPA's initial proposal likely sets power rates higher than needed in order to meet the rate period's programmatic goal, and BPA should increase the self-funding assumption for the BP-20 rate period from 30 to 35 percent. *Id.*

In response to WPAG's argument, BPA Staff points out that WPAG's proposal touches on two issues: BPA's 2016–2021 Energy Efficiency Action Plan and the budgeted funding needed to support that Action Plan. Fisher *et al.*, BP-20-E-BPA-21, at 28. Both are outside the scope of this rate case. *Id.*; Bonneville Power Administration, Fiscal Year (FY) 2020–2021 Proposed Power and Transmission Rate Adjustments Public Hearing and Opportunities for Public Review and Comment, 83 Fed. Reg. 62850-51 (Dec. 6, 2018). The IPR process began in June 2018 and concluded on October 11, 2018. Fisher *et al.*, BP-20-E-BPA-21, at 27. The IPR Process is designed to allow the public an opportunity to review and comment on BPA's proposed expense and capital spending level estimates before the spending levels are used to set rates. *Id.* This process included the review and comments on the budgeted conservation spending levels that WPAG challenges. *Id.*

Although WPAG states that it is not arguing for a lower programmatic savings goal than established in the IPR process, its proposal would create a conflict between BPA's determination of the cost of reaching its programmatic goal and the cost reflected in BPA's rates. *Id.* The time to make these points was during the IPR process, which is the process BPA uses to set its programmatic spending levels for its conservation program. *Id.* BPA determined the costs needed to reach its programmatic savings goals outside the rate case, and the proposed rates were set based on these costs. *Id.* To revisit those cost decisions here is not only outside of the scope of the rate case, but would also undermine the separate and more focused review and determination of BPA's costs through the IPR process. *Id.*

WPAG responded that it did recommend that BPA increase the self-funding assumption in its IPR comments, but BPA never acknowledged or responded to that recommendation in its IPR materials or close-out report. WPAG Br., BP-20-B-WG-01, at 18. WPAG argues that it is a little disingenuous for BPA to now say that the IPR was the correct forum for raising this issue. *Id.* In addition, WPAG alleges that the line between what is properly an IPR issue versus what is a rate case issue is frequently drawn at BPA's convenience to remove issues from the heightened scrutiny of the rate case setting. *Id.* However, WPAG's own IPR statements demonstrate that WPAG addressed self-funding energy efficiency issues in the IPR process. Further, the Integrated Program Review Close-Out Report, October 2018, stated:

Energy Efficiency

Energy Efficiency is holding program spending levels at initial IPR levels by maintaining conservation infrastructure costs flat relative to BP-18 while

adjusting the conservation acquisition portion of funding. This adjustment reflects the accelerated early achievements in 2016 and 2017 toward the Northwest Power and Conservation Council's Seventh Power Plan goals, as well as insights gained from BPA's recently completed Resource Program. Overall, Energy Efficiency is reducing its FY 2020 and 2021 spending by \$4.6 million per year relative to the BP-18 average, which is a 3.9 percent reduction. BPA expects that this funding level will enable it to acquire cost-effective conservation sufficient to meet BPA's forecast needs and meet the goals established in the 2016 EE Action Plan.

Integrated Program Review Close-out Report, October 2018, at 11, available at <https://www.bpa.gov/Finance/FinancialPublicProcesses/IPR/2018IPR/2018-IPR-Close-Out-Report.pdf>. Thus, the IPR was and is the correct forum to address such energy efficiency issues. Indeed, potentially changing the share of utility-funded conservation spending was not only addressed in WPAG's IPR comments, it was also addressed during an IPR workshop at <https://www.bpa.gov/Finance/FinancialPublicProcesses/IPR/2018IPR/IPR%202018%20EE%20Workshop.pdf>.

The current rate period, BP-18, is the first rate period for an official 70 percent/30 percent split of savings by funding source (energy efficiency versus utility-funded). In order to change its self-funding assumption in the IPR, BPA would have had to evaluate performance under the 70 percent/30 percent split. However, an entire rate period under this 70/30 split would be needed to perform a comprehensive evaluation and, therefore, BPA will evaluate the self-funding assumption after the two-year BP-18 rate period concludes on September 30, 2019. Despite the challenges BPA faced in obtaining sufficient data to make any self-funding decisions in the IPR, BPA remains committed to tracking and monitoring program performance and making prudent adjustments that meet BPA's needs and the needs of its customers, and reviewing such matters in the IPR.

While WPAG's comment in the IPR on self-funding was inadvertently not addressed in the Close-Out Report, this does not change the fact that BPA's proposed program funding level assumptions were reviewed in the IPR process. Importantly, BPA did not decide to change the amount of conservation savings it expects to acquire over the rate period. BPA encourages WPAG to continue to express its opinions on the level of self-funded energy efficiency in the IPR and other non-rate case forums.

WPAG argues that rate case parties have a statutory right to submit oral and written comments to present any views, data, questions, and argument related to BPA's proposed rates. WPAG Br., BP-20-B-WG-01, at 18-19. WPAG argues that, if adopted, WPAG's arguments regarding the self-funding assumption would impact the PF Tier 1 rate and, for this reason, are fully within the scope of WPAG's statutory rights. *Id.* at 19. BPA respects WPAG's statutory rights to participate in the establishment of BPA's rates. *See* 16 U.S.C. § 839e(i). However, arguably every BPA expenditure, even the most trivial, has an impact on rates because it must be included in BPA's revenue requirement and recovered through rates. This, however, does not mean that the determination of program costs occurs in BPA's rate cases. BPA does not incur costs because of rate cases. Rather, costs are incurred by BPA through its implementation and

administration of its multiple statutory and contractual obligations. Ratemaking establishes the revenue needed to pay those costs. This issue has been addressed by BPA in previous rate cases, and the analysis is incorporated by reference here. *See* Administrator's Record of Decision, 1993 Final Rate Proposal, WP-93-A-02, at 319-340. In addition, BPA has established a separate public forum, the IPR process, to receive public input on its proposed program cost levels, where a practical and effective dialogue can occur between all parties without the constraints of a formal hearing process.

Decision

The establishment of BPA's self-funding assumption for energy efficiency is outside the scope of BPA's rate cases.

3.5.2 New Large Single Loads (NLSL)

Issue 3.5.2.1

Whether BPA should pursue new avenues to increase its power sales to NLSLs.

Parties' Positions

NRU suggests that BPA should hold workshops after the conclusion of the BP-20 rate proceeding to explore alternatives to the current NR rate and service to NLSLs. NRU Br., BP-21-B-NR-01, at 3-4.

BPA Staff's Position

Staff noted that policy decisions regarding the manner in which BPA may sell power to serve NLSLs is outside the scope of the BP-20 rate proceeding, but noted that work had already started on this effort outside of the rate case. Fisher *et al.*, BP-20-E-BPA-21, at 26.

Evaluation of Positions

In its direct case, NRU made a suggestion for capturing an opportunity to increase power sales, which would be to revise the New Resources (NR) rate to make it more attractive for BPA to serve NLSLs. NRU Br., BP-20-B-NR-01, at 3-4. NRU recognizes that BPA must work within the confines of the Northwest Power Act restrictions on serving NLSLs but believes there is an opportunity to work within those limitations that would allow BPA to increase its surplus power sales and meet a substantial need of its preference customers who may have NLSLs locating in their service territories. *Id.* at 3-4. NRU recognizes that working within the statutory limitations and evaluating potential risks, such as increased carbon obligations associated with balancing purchases or load defaulting on payments, will be complex and take time. *Id.* at 4. Therefore, NRU suggested that BPA hold workshops after the conclusion of the BP-20 rate proceeding to explore alternatives to the current NR rate and service to NLSLs. *Id.*

In response to NRU's testimony, both BPA Staff and AWEC filed rebuttal testimony supporting NRU's proposal to hold workshops outside of the rate proceeding to explore service to NLSLs.

Id., citing Fisher *et al.*, BP-20-E-BPA-21 at 26; Mullins & Hellman, BP-20-E-AW-02, at 1. Indeed, although Staff noted that policy decisions regarding the manner in which BPA may sell power to serve NLSLs is outside the scope of the BP-20 rate proceeding, Staff also noted that work had already started on this effort outside of the rate case. Fisher *et al.*, BP-20-E-BPA-21, at 26. BPA looks forward to working with stakeholders on ways of increasing its sales to NLSLs outside of BPA's rate cases.

Although NRU notes that AWEC recommended that BPA adopt language in the BP-20 power rate schedules that would allow for the outcome of the future process to become effective immediately, AWEC did not raise this issue in its initial brief. Also, as Staff noted, no specific proposals were made to amend the NR-20 rate in the BP-20 proceeding. *Id.* Staff, however, is willing to potentially redesign the NR rate in a future rate proceeding. *Id.*

Decision

Policy decisions regarding the manner in which BPA may sell power to serve NLSLs are outside the scope of the BP-20 rate proceeding, but BPA will continue to work with stakeholders outside of BPA's rate cases on ways of increasing its sales to NLSLs.

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4.0 TRANSMISSION RATES

4.1 BP-20 Partial Rates Settlement Agreement

The BP-20 Partial Rates Settlement Agreement (the “Settlement”) includes the proposed rates for BPA’s transmission, ancillary, and control area services for FY 2020–2021 and specifies certain terms for generation inputs during that period. The weighted average transmission rate increase under the Settlement is 3.6 percent for the rate period. Almost all of BPA’s long-term transmission service customers have agreed to and support the Settlement. The members of JP01 are the only parties in BP-20 that oppose the Settlement, and JP01’s opposition is limited to the portion of the Settlement related to the rate for hourly transmission service on the Southern Intertie (the “hourly rate”).

JP01’s objection to BPA’s treatment of the hourly rate started in the BP-18 proceeding, where JP01 opposed BPA’s decision to change the hourly rate design. Because many of JP01’s current arguments go to the heart of BPA’s decision in the BP-18 proceeding, a short background is provided below. Staff’s rebuttal testimony contains an excerpt of the BP-18 ROD, which fully explains the extensive history of this issue and BPA’s reasons for changing the hourly rate design in the BP-18 proceeding. Fredrickson & Linn, BP-20-E-BPA-22-AT01, at 36-42 (excerpt of the BP-18 ROD). The members of JP01 were designated “JP03” in the BP-18 proceeding. For simplicity, BPA refers to these parties as “JP01” throughout this Final ROD.

Shortly after BPA issued the Draft ROD in this proceeding, the United States Court of Appeals for the Ninth Circuit issued an opinion upholding BPA’s decision to change the hourly rate design in the BP-18 proceeding. *SMUD v. BPA*, No. 18-71753, 2019 WL 2499687 (9th Cir. June 17, 2019). Although the Ninth Circuit’s opinion was issued after the evidentiary phase in this BP-20 proceeding, the decision is relevant to the issues here, and BPA has taken it into account in this Final ROD.

Background

The Southern Intertie is a system of transmission lines and substations that transmit power between the Pacific Northwest and California. In the Initial Proposal in the BP-16 proceeding, Staff proposed to use its longstanding 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. *Id.* at 36. These 80 “peak” hours per week represented the hours of highest demand for power in California. *Id.* Powerex and PPC proposed to change the rate design to address “seams issues” between the Pacific Northwest and California. *Id.* at 36-42 (describing the seams issues). They claimed the seams issues led to a disincentive to purchase and renew long-term firm service on the Southern Intertie, which could jeopardize recovery of the Southern Intertie costs. *Id.* at 37. Although BPA did not adopt the customers’ proposal in the BP-16 proceeding, the Administrator recognized the concerns about protecting the investments in the Southern Intertie and directed Staff to examine the issues following the rate case. *Id.*

After the BP-16 proceeding concluded, Staff conducted an extensive public process to better understand the issues. The public process was publicly noticed, and the members of JP01 were welcome to participate, but they chose not to do so. *Id.* at 45. At the end of the process, Staff and most stakeholders agreed about the risk associated with the seams issues and supported addressing the issues. Staff prepared a white paper that summarized the issues and described alternatives. *See* Fredrickson & Linn, BP-20-E-BPA-22-AT02. Although the process had evaluated both ratemaking and non-rates alternatives, at the end of the process Staff committed to proposing to change the hourly rate design in the BP-18 proceeding. Fredrickson & Linn, BP-20-E-BPA-22-AT01, at 37. During the pre-rate case workshops, Staff and customers collaborated on hourly rate design options and determined that Staff should propose a change to the rate design to reflect changes in California’s resource mix.

Staff’s Initial Proposal in the BP-18 proceeding proposed the same basic rate design that had been used in the past but with one significant change—an updated assumption about the number of peak hours in California. *Id.* The evidence showed that significant increases in the amount of solar generation in California had reduced the state’s net load (total load minus in-state wind and solar generation) during the middle of the day. *Id.* The decrease in net load during daytime hours is known as the “duck curve” (because of the shape of the curve on a graph). *Id.* Because the daytime hours traditionally had been included in the assumption of 16 “peak hours” per weekday, the decrease in net load had effectively reduced the number of peak hours to between four and six hours. Staff used five hours in the rate design in the Initial Proposal. As a result, a customer reserving hourly transmission service for five hours a day, five days per week (25 hours in total) would pay the same amount as a customer reserving long-term firm transmission service. The change significantly increased the hourly rate.

BPA ultimately adopted Staff’s proposal in the BP-18 proceeding based on the evidence of the impact of the seams issues in combination with the increase in the amount of solar generation capacity in California. Fredrickson & Linn, BP-20-E-BPA-22-AT01, at 84-85. BPA identified two main reasons for making the change: (1) concern about cost recovery risk if customers with contracts for long-term firm service on the Southern Intertie do not renew their agreements, and (2) to ensure that customers taking hourly service pay their “fair share” of the Southern Intertie costs. *Id.* at 85.

As stated above, the members of JP01 opposed Staff’s proposal to change the hourly rate design in the BP-18 proceeding. After BPA adopted Staff’s proposal in BP-18, JP01 protested BPA’s filing with FERC for confirmation and approval of the BP-18 rates and appealed BPA’s decision to the Ninth Circuit. Both FERC and, most recently, the Ninth Circuit upheld BPA’s decision. *See Bonneville Power Admin.*, 162 FERC ¶ 61,248, at P 29 (2018); *SMUD v. BPA*, No. 18-71753, 2019 WL 2499687 (9th Cir. June 17, 2019) (“[s]ubstantial evidence supports the BPA’s decision to raise the hourly rate . . .”).

The Settlement

BPA appreciates the time and effort that all parties, including the members of JP01, devoted to the discussions that led to the Settlement of transmission rates for FY 2020–2021. The rates Settlement is one part of a larger settlement “package” that also addresses BPA’s new Open

Access Transmission Tariff. Some of the tariff issues addressed by the settlement package have loomed large for many years. The settlement package truly is a product of regional collaboration that will provide benefits for customers and BPA for the foreseeable future. BPA is pleased to adopt the Settlement for the reasons fully explained in this section.

Adopting the Settlement's hourly rate should not harm JP01. The members of JP01 purchase almost no Southern Intertie hourly transmission service ("hourly service") from BPA. TANC does not purchase any transmission service from BPA. SMUD purchases no hourly service. TID purchases a little hourly service from BPA, but the amount is so limited that JP01 has not even considered the direct costs associated with paying the BP-18 hourly rate as part of TID's alleged harm. *See* Peters, BP-20-E-BPA-JP01-CC01, at 20-21. In addition, as explained below, the record in this proceeding shows that adoption of the BP-18 hourly rate did not reduce exports of power from the Pacific Northwest to California and had no discernible effect on California power prices. Parker & Peters, BP-20-E-JP01-02, at 14.

The BP-18 ROD explained that changing the hourly rate design enjoyed broad support from a wide variety of BPA customers, including the largest hourly customers. Fredrickson & Linn, BP-20-E-BPA-22-AT01, at 45-46. The support for the Settlement includes all long-term transmission customers except SMUD and TID (TANC is not a transmission customer). BPA takes JP01's arguments seriously and has addressed them below, but BPA places great weight on the fact that customers that purchase significant amounts of hourly service have supported both the BP-18 hourly rate and the Settlement. Considering the widespread support for the Settlement, and the Ninth Circuit's recent opinion upholding the BP-18 hourly rate, the Settlement provides a reasonable result for transmission rates for the FY 2020-2021 rate period.

Issue 4.1.1

Whether the proposed rates in the Settlement satisfy the applicable statutory ratemaking directives.

Parties' Positions

JP01 argues that the hourly rate does not satisfy the statutory directive to establish the "lowest possible rates consistent with sound business principles." JP01 Br., BP-20-B-JP01-01, at 10-14.

JP04 states that the proposed rates in the Settlement meet BPA's statutory ratemaking requirements. JP04 Br., BP-20-B-JP04-01, at 27-32.

BPA Staff's Position

The proposed rates in the Settlement meet the applicable statutory ratemaking requirements. Fredrickson *et al.*, BP-20-E-BPA-19, at 7-8.

Evaluation of Positions

Staff, JP04, and JP01 agree that the proposed rates under the Settlement, including the hourly rate, satisfy the ratemaking standards for cost recovery and “equitable allocation” in Section 7(a)(2) of the Northwest Power Act. Fredrickson *et al.*, BP-20-E-BPA-19, at 7-8; JP04 Br., BP-20-B-JP04-01, at 27-32; JP01 Br., BP-20-B-JP01-01, at 7-8 (conceding that the Settlement rates satisfy the Section 7(a)(2) standards but incorrectly stating that Staff “never discusses the statutory standards the proposal is claimed to satisfy”). As Staff testified, the proposed rates recover BPA’s costs, are based on total system costs, and equitably allocate the Federal transmission system costs between Federal and non-Federal power. Fredrickson *et al.*, BP-20-E-BPA-19, at 7-8.

JP01 takes issue, however, with whether the hourly rate complies with the directive in multiple Bonneville statutes to establish “the lowest possible rates to consumers consistent with sound business principles.” JP01 Br., BP-20-B-JP01-01, at 4-5; 16 U.S.C. §§ 838g, 825s, 839e(a)(1). JP01 emphasizes the language requiring the “lowest possible” rates, arguing that the black box Settlement provides no basis to conclude the hourly rate is as low as possible. JP01 Br., BP-20-B-JP01-01, at 11.

JP01 misconstrues the statutory directive. The standard applies to BPA’s rates overall and not to particular rates in isolation. *See* 16 U.S.C. §§ 825s, 838g. The reasons for this are simple. BPA’s paramount objective in setting rates is to recover its total system costs, and the revenue requirement used to set rates is based on those overall costs. Administrator’s Record of Decision, 1996 Final Rate Proposal, WP-96-A-02, at 393 (June 1996). In the rate development process, decreasing the rate for one product or service to some nominal level would require increasing one or more rates for other products or services to ensure full recovery of the revenue requirement. For example, in the context of the transmission services offered on the Southern Intertie, discounting the rate for hourly service, as JP01 suggests, would require increasing the rates for the other services to fully recover the Southern Intertie costs. Applying the standard as JP01 suggests would lead to absurd results and endless arguments about whether any one rate is “as low as possible.” *See* JP01 Br., BP-20-B-JP01-01, at 5; *see also Cal. Energy Comm’n v. Bonneville Power Admin.*, 909 F.2d 1298, 1308 (9th Cir. 1990) (“If the strict interpretation of the ‘lowest possible rates’ standard . . . were accepted, the discretion that Congress vested in the Administrator would be eliminated.”).

JP01 argues that the standard prohibits including “non-necessary expenses” in rates, and that BPA cannot satisfy this requirement without considering non-rate alternatives before increasing rates. JP01 Br., BP-20-B-JP01-01, at 5, 11. But JP01 does not identify the “non-necessary expenses” it claims that BPA has included in the proposed rates. JP01’s recommendations to discount or otherwise reduce the proposed hourly rate would not reduce the overall costs in the transmission revenue requirement. Instead JP01’s recommendations would, as explained above, result in the reallocation of costs to rates for other transmission services. For issues of cost allocation, the courts have found that the statutory language requiring the lowest possible rates consistent with sound business principles standard is so broad that it provides no law to apply. *Cal. Energy Comm’n*, 909 F.2d at 1307.

JP01 claims that BPA must consider such non-rate alternatives to ensure the exclusion of “non-necessary expenses” (and set rates as low as possible), but the broad statutory language does not suggest such a requirement, and no court has ever made such a finding. Even if such a requirement did exist, however, the record shows that BPA reviewed non-rate alternatives before changing the hourly rate design in the BP-18 rate proceeding. Staff’s white paper from the public process that preceded the BP-18 rate proceeding discussed non-rate alternatives at length. Fredrickson & Linn, BP-20-E-BPA-22-AT02, at 41-71, 80-81. The white paper shows that JP01’s recommendation to adopt certain non-rate measures would actually increase the overall cost of transmission service by millions of dollars. Fredrickson & Linn, BP-20-E-BPA-22, at 30; BP-20-E-BPA-22-AT02, at 59.

JP01 points out that the Record of Decision in the BP-16 rate proceeding called for an examination of non-rates alternatives to address the seams issues, and it argues Staff has offered shifting explanations of the plans for such an examination ever since that time. JP01 Br., BP-20-B-JP01-01, at 11-12. To help clear up any confusion on this point, Staff’s examination of non-rates alternatives to address the seams issues has been sufficient to address the direction in the BP-16 Record of Decision. *See* Fredrickson & Linn, BP-20-E-BPA-22-AT01, at 48-50; *see also SMUD v. BPA*, No. 18-71753, 2019 WL 2499687 (9th Cir. June 17, 2019) (holding that BPA did not act arbitrarily and capriciously in adopting the hourly rate after examining non-rate alternatives). As for any change in Staff’s perspective since the end of the BP-16 rate proceeding, the discussions in Issues 4.1.2 and 4.1.3 describe the evidence showing that the increase in the hourly rate in the BP-18 rate proceeding did not negatively affect wholesale power markets. Unless circumstances change, no further examination of non-rates alternatives to address seams issues is necessary.

JP01 is incorrect that circumstances regarding non-rates alternatives have “radically changed” since the BP-18 rate proceeding because of “restrictions” on the amount of hourly firm service available for purchase on the Southern Intertie that will take effect later this year. JP01 Br., BP-20-B-JP01-01, at 12. The “restrictions” that JP01 refers to relate to provisions of the TC-20 settlement agreement that may limit the amount of hourly firm service that BPA will make available in the future. *See* Section 1 (explaining the TC-20 proceeding); Administrator’s Final Record of Decision, TC-20-A-03, Appendix 1 at 10-14. Although these restrictions apply on every segment of BPA’s transmission system, including the Southern Intertie, they will have little to no practical effect on Southern Intertie customers because only 0.1 percent of service that BPA sells on the Southern Intertie is hourly firm. Fredrickson & Linn, BP-20-E-BPA-22-AT05, at 1. The discussion of the seams issues in the BP-18 ROD also makes clear that BPA was concerned about the use of hourly non-firm service on the Southern Intertie. Fredrickson & Linn, BP-20-E-BPA-22-AT01, at 38. The restrictions on hourly firm service in the TC-20 settlement do not address the seams issues.

As for the level of the proposed rates overall, BPA undertook a thorough review of its program level costs in the IPR process before the BP-18 rate proceeding began. The IPR results show that the overall FY 2020–2021 projected costs that went into the Initial Proposal were 4 percent lower than FY 2018–2019 levels. Stratman, BP-20-E-NR-01, Attachment 1 at 3. In addition, as explained in Section 2.2 of this Final ROD, BPA has employed a risk mitigation package that is

intended, in part, to result in the lowest possible rates consistent with sound business principles. *See also* Power and Transmission Risk Study, BP-20-FS-BPA-05, at 3. Given BPA’s review of its forecast spending levels in the IPR, the widespread support for the rate levels in the Settlement, and the goals behind BPA’s risk mitigation package, the record supports that the proposed FY 2020–2021 rates both recover BPA’s costs and are the “lowest possible rates to consumers consistent with sound business principles.” 16 U.S.C. §§ 838g, 825s, 839e(a)(1).

Decision

The proposed rates in the BP-20 Partial Rates Settlement Agreement satisfy the applicable statutory ratemaking directives.

Issue 4.1.2

Whether the evidence in the record is sufficient to support adoption of the Settlement.

Parties’ Positions

JP01 maintains that BPA has not met its burden of proof to justify the proposed hourly rate based on substantial evidence in the record. JP01 Br., BP-20-B-JP01-01, at 2, 6.

JP04 states that BPA has substantial evidence to adopt the Settlement. JP04 Br., BP-20-B-JP04-01, at 4.

BPA Staff’s Position

The record supports adoption of the Settlement, including the proposed hourly rate. Fredrickson *et al.*, BP-20-E-BPA-19, at 8-9; *see* Fredrickson & Linn, BP-20-E-BPA-22, at 1-2, 5-6.

Evaluation of Positions

JP01 argues that Section 7(c) of the Administrative Procedure Act assigns Staff and other proponents of the Settlement the “burden of proof” to support the recommendation to adopt the Settlement. JP01 Br., BP-20-B-JP01-01, at 2-3, *citing* 5 U.S.C. § 556(d) and *Director, Office of Workers’ Comp. Programs v. Greenwich Collieries*, 512 U.S. 267, 275-81 (1994). JP01 adds that, because Section 9(e)(2) of the Northwest Power Act requires BPA’s rate decisions to be supported by substantial evidence, the proponents must provide substantial evidence to meet the burden. *Id.*, *citing* 16 U.S.C. § 839f(e)(2). Although JP01 is correct that Section 9(e)(2) requires BPA’s rate determinations to “be supported by substantial evidence in the rulemaking record . . . as a whole,” that section also explicitly states that nothing in it “shall be construed to require a hearing” under Section 7 of the Administrative Procedure Act. 16 U.S.C. § 839f(e)(2) (also specifying that no hearing is required under Sections 5 and 8 of the Administrative Procedure Act). In other words, the burden of proof that JP01 claims is applicable to hearings under Section 7 of the Administrative Procedure Act does not apply to BPA rate proceedings.

JP01 seems to misunderstand the process for BPA rate proceedings under Section 7(i) of the Northwest Power Act. Section 7(i) requires a hearing to develop a record for a final decision, but the hearing is a formal rulemaking. It is not an adjudication. JP01 argues that Staff and the other proponents of the contested Settlement failed to meet the burden of proof because Staff's Initial Proposal contained no evidence or rationale for adopting the Settlement other than the Settlement itself. JP01 Br., BP-20-B-JP01-01, at 6-9. As explained below, BPA disagrees that the Settlement and other evidence in the Initial Proposal provides insufficient evidence and rationale to support the decision in this Final ROD. Notwithstanding that disagreement, JP01's argument that Staff's Initial Proposal must have provided all the evidence to justify adoption of the Settlement effectively disregards the development of the record throughout the rest of the proceeding. Indeed, JP01 itself has added a substantial amount of evidence to the record that helps support the decision to adopt the Settlement. BPA must consider that evidence and make its decision based on the evidence in the record considered as a whole. *See* 16 U.S.C. § 839f(e)(2).

The parties frame their arguments about the evidence in terms of whether the record includes "substantial evidence" to adopt the Settlement. JP01 Br., BP-20-B-JP01-01, at 2, 6; JP04 Br., BP-20-B-JP04-01, at 4. The substantial evidence standard applies to the Ninth Circuit's review of BPA's rate decisions. *See* 16 U.S.C. § 839f(e)(2). The Ninth Circuit has said that the evidence required to satisfy the standard "is simply more than a mere scintilla. It means such relevant evidence as a reasonable mind might accept as adequate to support a conclusion." *Pub. Power Council v. Bonneville Power Admin.*, 442 F.3d 1204, 1209 (9th Cir. 2006) (internal quotations and citations omitted). With this standard in mind, BPA's rate decisions necessarily, and explicitly, involve weighing the evidence in the record considered as a whole and concluding that it supports the decision. In doing so, BPA finds that the record includes substantial evidence for the decision.

Evidence Regarding the Settlement, Regional Collaboration, Lack of Objection in BP-20, and Satisfaction of Statutory Ratemaking Directives

BPA disagrees with JP01 that the Settlement itself and other evidence provided in the Initial Proposal provide insufficient evidence and rationale to support Staff's recommendation. *See* JP01 Br., BP-20-B-JP01-01, at 6-9. JP01 focuses on Staff's testimony that the Settlement is a "black box" that specifies the rates and revenues "without linking them to particular assumptions." *Id.* at 7, quoting Fredrickson *et al.*, BP-20-E-BPA-19, at 2. JP01 reasons that without evidence of specific ratemaking principles, assumptions, or rate design in the Settlement, BPA cannot demonstrate that adopting the Settlement is not arbitrary and capricious or satisfies "the APA's basic requirement of reasoned decisionmaking." *Id.* at 3, quoting *Exxon Co., USA v. FERC*, 182 F.3d 30, 38, 40 (D.C. Cir. 1999) and *Tejas Power Corp. v FERC*, 908 F.2d 998, 1003 (D.C. Cir. 1990). JP01 adds that even an uncontested settlement would not relieve BPA from determining that the Settlement satisfies the applicable statutory standards. *Id.*

BPA's rationale for adopting the Settlement starts with consideration of the Administrator's authority and compliance with the applicable statutory standards. The Administrator plainly has authority to adopt a settlement, even a contested one, as the basis for rates established in a proceeding under Section 7(i) of the Northwest Power Act. *Ass'n of Pub. Agency Customers v.*

Bonneville Power Admin., 733 F.3d 939, 967 (9th Cir. 2013) (“So long as the Settlement complies with the relevant statutory authority—as we have concluded that it does—BPA does not need its customers to unanimously agree to the rates it sets in accordance with the Settlement.”). BPA explained in the discussion of the preceding issue that the testimony and studies in the Initial Proposal addressing the Settlement rates, the Transmission Revenue Requirement, and BPA’s risk policies demonstrate the Settlement satisfies the applicable statutory standards. *See* Issue 4.1.1; Fredrickson *et al.*, BP-20-E-BPA-19, at 7-8; Lennox *et al.*, BP-20-E-BPA-17, at 11-12; Transmission Revenue Requirement Study, BP-20-E-BPA-09; Power and Transmission Risk Study, BP-20-E-BPA-05-CC01, at 3.

The evidence of the Settlement itself and how the rates satisfy the applicable statutory standards shows that adopting the Settlement is not arbitrary and capricious. The rates are not based on a random choice or whim. They are the result of serious negotiation among BPA and knowledgeable and capable transmission customers.

As for BPA’s specific reasons for adopting the Settlement, it “hardly seems necessary to point out that there is an overriding public interest in settling and quieting litigation.” *Van Bronkhorst v. Safeco Corp.*, 529 F.2d 943, 950 (9th Cir. 1976). Although the hearing process under Section 7(i) is not “litigation,” the complexity and extent of the process and issues have the potential to cause great burden, expense, and uncertainty for parties. In BPA’s rate proceedings, the ability to settle on the rate levels without agreeing to specific principles or methodologies can be an important component of settlement discussions. Fredrickson & Linn, BP-20-E-BPA-22, at 6. Adopting the Settlement here furthers the sound public policy behind the voluntary resolution of the issues and limits disagreement in BPA proceedings.

Staff’s testimony pointed out the importance of the Settlement in terms of the “consensus among the parties,” the “benefits of collaboratively resolving both the terms and conditions of transmission service and transmission rates,” and the lack of objection from any party other than JP01 in the BP-20 rate proceeding. Fredrickson & Linn, BP-20-E-BPA-22, at 4; *see also* BP-20-M-JP01-05, Attachment A, at 98-99 (Data Response JP01-BPA-28-123). JP01 reduces these points to just “one fact”—that there is a Settlement—but BPA views the issues quite differently. *See* JP01 Br., BP-20-B-JP01-01, at 7-8.

BPA places great weight on the Settlement itself and its significance in the broader “settlement package” that includes the new Open Access Transmission Tariff adopted in the TC-20 proceeding. *See* Section 1 (explaining the TC-20 proceeding). As the Final ROD in the TC-20 proceeding explained, the settlement package represents BPA and transmission customers “com[ing] together to provide a path forward” on a new transmission tariff “after many years of stagnation” on some very contentious issues. Administrator’s Final Record of Decision, TC-20-A-03, at P-1. The TC-20 ROD specifically identified elimination of “the complexity, uncertainty, and potential gridlock associated with filing tariff changes with [FERC]” as one of the most important issues in the TC-20 settlement. *Id.* Securing the agreement of almost all transmission customers not to contest all transmission rate and generation input issues in the BP-20 proceeding was an important consideration for BPA in supporting the overall settlement package. *See* Fredrickson *et al.*, BP-20-E-BPA-19, at 9.

BPA places separate value on the benefits of the regional collaboration that went into the development of the Settlement. *See* Fredrickson & Linn, BP-20-E-BPA-22, at 4. JP01’s brief dismisses the benefits of regional collaboration as indistinct from the Settlement itself, but in oral argument JP01 emphasized how much it had valued collaboration with BPA in the past and how important such an approach will be in the future during this period of rapid change. JP01 Br., BP-20-B-JP01-01, at 8; Oral Tr. at 6-8. JP01’s remarks were very similar to one of BPA’s stated purposes for the settlement package: to facilitate being a “responsive and dependable business partner in a rapidly changing energy industry.” Fredrickson *et al.*, BP-20-E-BPA-19, at 9, *quoting* Dibble *et al.*, TC-20-E-BPA-02, at 11. Reinforcing the goodwill and trust reflected in and developed through the negotiation of the settlement package has distinct benefits and value to BPA that help support the decision to adopt the Settlement.

BPA also disagrees with JP01’s dismissal of the lack of objection by any party in this proceeding that was not involved in the Settlement negotiations. The Settlement negotiations involved only BPA transmission customers or organizations representing those customers. *See id.* at 2. A broader set of stakeholders often participates in BPA rate proceedings, which sometimes results in opposition to BPA’s proposals based on more diverse interests. For example, in the BP-18 rate proceeding, the Sierra Club and the Montana Energy Information Center, which are not BPA transmission customers, objected to BPA’s Montana Intertie rate proposal based on their interests in “the development of clean energy solutions to [the] climate problem.” Petition to Intervene of Sierra Club and Montana Environmental Information Center, BP-18-S-SC-01, at 3 (Nov. 18, 2016); *see also* Petition to Intervene by Idaho Rivers United, BP-18-PR-BPA-02-AT01 (Apr. 27, 2017) (intervening because of interest in litigation separate from BPA rates). All stakeholders had the opportunity to intervene in the BP-20 proceeding, and all intervenors had the opportunity to object to the Settlement. *See* Order Establishing Deadline and Process for Objections to BP-20 Partial Rates Settlement Agreement, BP-20-HOO-04. There is no objection from any party other than JP01. The lack of objection to the Settlement is an important and relevant fact for Bonneville to consider with respect to its decision to adopt the Settlement.

Evidence Regarding the Hourly Rate

JP01’s claims about the lack of evidence and rationale specific to the hourly rate are contrary to the evidentiary record developed in this proceeding. Much of JP01’s case appears intended to connect the hourly rate in the Settlement with the extensive record regarding JP01’s opposition to the change in the rate design in the BP-18 proceeding. JP01 made clear at the start of this proceeding that its objection to the hourly rate in the Settlement is based on its opposition to the hourly rate increase in the BP-18 proceeding: “JP01 continues to be significantly harmed by the BP-18 Southern Intertie rate decision to nearly triple the hourly rate for firm and non-firm service, and wish to preserve their rights with respect to this issue in BP-20.” Objection of JP01 to BP-20 Partial Rates Settlement Agreement, BP-20-M-JP01-01, at 1. To that end, JP01’s direct testimony included more than 800 pages of evidence from the BP-18 record about the hourly rate, including all of Staff’s and JP01’s testimony, the entire cross-examination transcript, the transmission rates study, responses to numerous data requests, and excerpts from various presentations on the seams issues. Peters, BP-20-E-JP01-01-AT04. JP01 also included the

report that Staff assembled after the BP-18 rate proceeding to assess whether the BP-18 hourly rate increase had unintended consequences. Peters, BP-20-E-JP01-01-AT03, at 14-62.

The Hearing Officer found that JP01’s direct testimony contained “extensive discussion of the BP-18 proceeding and the rationales for and consequences of the rate increase” Order Denying JP01 Motion for Surrebuttal and to Strike, BP-20-HOO-14, at 6. PPC put it more bluntly: “JP01 painstakingly analyzed and attacked BPA’s BP-18 justifications to conclude that the BP-18 rate design is not working as BPA intended and should not be carried forward to the BP-20 rates for hourly service on BPA’s Southern Intertie.” Answer of PPC to JP01’s Motion to Strike Portions of PPC’s Rebuttal Testimony, BP-20-M-PP-01, at 2. In other words, JP01 has provided a substantial amount of evidence about the BP-18 hourly rate in this proceeding.

Staff, PPC, and Powerex responded to JP01’s testimony with more evidence and discussion of the decision in the BP-18 proceeding and additional testimony to address JP01’s claims about the alleged impacts of the hourly rate increase in that proceeding. Fredrickson & Linn, BP-20-E-BPA-22, at 3-7, AT01–AT03; Deen, BP-20-E-PP-02, at 8-14; Wellenius, BP-20-E-PX-01, at 28-31. The record also includes the transcript of JP01’s cross-examination of the BPA, PPC, and Powerex witnesses about the hourly rate, hundreds of pages of JP01’s cross-examination exhibits, and the responses to data requests admitted by a variety of parties.

Against this backdrop, JP01 essentially claims that the “black box” nature of the Settlement somehow nullifies all of the evidence of the background and rationale for BPA’s previous decision to change the hourly rate design simply because the Settlement does not specify that particular design. JP01 Br., BP-20-B-JP01-01, at 7-10; Fredrickson *et al.*, BP-20-E-BPA-19, Attachment A at 3. This simply is not a credible view of the evidence, the background on this issue, or the requirement that BPA consider the record as a whole. *See* 16 U.S.C. § 839f(e)(2). JP01 has put forth much of the argument and evidence regarding the decision adopting the BP-18 hourly rate and the connection to the issues in this proceeding, and it is unreasonable to suggest that evidence and the record developed in response to it is somehow off limits for BPA to consider because of the “black box” Settlement or the fact that the evidence was not part of the Initial Proposal.

Take, for example, JP01’s claim that there is no underlying rate design for the hourly rate in the Settlement. JP01 Br., BP-20-B-JP01-01, at 7-10. After Staff published its Initial Proposal, JP01 filed a motion requesting to send certain data requests about the proposal to Powerex, PGE, PacifiCorp, PPC, and certain PPC members. Motion of SMUD and TID to Permit the Submission of Data Requests to Certain Parties, BP-20-M-SM-04, at 1; *see Procedures*, § 1010.12(b)(2)(iii) (requiring a motion to submit such requests and setting a high bar for granting the motion). Contrary to its current claims, JP01 stated that Staff’s “BP-20 proposal retains the Southern Intertie Hourly Firm and Non-Firm rate structure adopted in the BP-18 Record of Decision” and that since “Staff proposes maintaining the hourly Intertie rate design in the BP-20 proceeding, it is relevant to ask whether the BP-18 rate hike accomplished one of its stated purposes: to increase the value of LTF service.” Motion of SMUD and TID to Permit the Submission of Data Requests to Certain Parties, BP-20-M-SM-04, at 3, 7. Powerex responded to JP01’s motion with essentially the same conclusion about the hourly rate design, stating that “the

‘black box’ settlement implicitly proposes to carry forward the BP-18 rate design.” Opposition of Powerex Corp. to Motion of SMUD and TID to Permit the Submission of Data Requests to Certain Parties, BP-20-M-PX-01, at 10-11. Given the extensive debate about changing the hourly rate design in the BP-18 proceeding and the fact that the hourly rate in the Settlement is 4 percent higher than the BP-18 rate, the parties’ conclusion that the hourly rate in the Settlement effectively maintains the BP-18 hourly rate design is easy to understand.

Staff weighed in on this issue after JP01 switched its position in direct testimony. Fredrickson & Linn, BP-20-E-BPA-22, at 4-6; *see* Peters, BP-20-E-JP01-01-CC01, at 3, 8. JP01 argued in direct testimony that the proposed hourly rate was not based on any principles or rate design and not supported by any “evidence or rationale” because the parties had agreed to the rate in a “black box” Settlement. Peters, BP-20-E-JP01-01-CC01, at 3, 8. Staff explained that JP01’s argument appeared to be based on Staff’s objections to approximately 50 data requests that JP01 had submitted about a sentence in Staff’s testimony that described the Settlement as a “black box.” Fredrickson & Linn, BP-20-E-BPA-22, at 5, *citing* Peters, BP-20-E-JP01-01-AT01, at 1-9, 46-50, 59-72, 76-94, 100-110. Staff objected to the requests as outside the scope of the testimony, repeated the statement from the testimony, and provided responses without waiving the objections. *Id.*

In responding to JP01’s claims that there was no evidentiary support, principles, or rate design underlying the Settlement, Staff stated that “from BPA’s perspective . . . the calculation of the hourly rate under the proposed settlement relies on the same rate design that was adopted in the BP-18 rate proceeding, and the principles and assumptions underlying the current hourly rate are implicit in the hourly rate under the proposed settlement.” *Id.* at 5-6. Staff added that, as “a practical matter, a customer that reserves 25 hours of hourly transmission service a week would pay the same amount as a long-term firm transmission customer under either the hourly rate in the proposed settlement or the BP-18 hourly rate.” *Id.* at 6.

JP01 maintains that Staff’s testimony is “plainly false” and contrary to the terms of the Settlement, because the Settlement parties “expressly agreed that there is no underlying rate design” JP01 Br., BP-20-B-JP01-01, at 16 (emphasis omitted). Staff made clear, however, that it was providing its perspective only, and doing so in response to JP01’s claims, and that no Settlement party necessarily agrees with that perspective. Fredrickson & Linn, BP-20-E-BPA-22, at 6. That is consistent with the terms of the Settlement, which prohibits arguing that parties *have agreed* to any particular principle or rate design. Fredrickson *et al.*, BP-20-E-BPA-19, Attachment A at A-3. It does not prohibit stating that the parties *have not* agreed to a rate design. Notably, no parties to the Settlement have expressed concern with Staff’s statements, and at least one party appears to agree with Staff. *See* Opposition of Powerex Corp. to the Motion of SMUD and TID to Permit the Submission of Data Requests to Certain Parties, BP-20-M-PX-01, at 10-11.

Staff’s testimony also is consistent with JP01’s previous argument to the Hearing Officer that the Settlement “retains” the BP-18 hourly rate design. Motion of SMUD and TID to Permit the Submission of Data Requests to Certain Parties, BP-20-M-SM-04, at 1. JP01 argued one position to justify its motion to the Hearing Officer and then switched its position without

explanation in its direct testimony and Initial Brief. Setting aside the impact of this unexplained change on the credibility of JP01's argument, the point is that JP01 first raised the issues of the hourly rate design, and it led to the development of an extensive record regarding the specifics of the hourly rate in the Settlement. BPA is considering that record as a whole in reaching a reasoned decision.

In the end, although no Settlement party is agreeing to any particular hourly rate design, and BPA is not adopting any specific hourly rate design in this proceeding, the level of the hourly rate in the Settlement results in a customer that reserves hourly transmission for 25 hours a week paying the same amount for service as a long-term firm transmission customer. Fredrickson & Linn, BP-20-E-BPA-22, at 6. This is basic math. Regardless of the fact that the parties chose not to agree to any particular hourly rate design in the Settlement, the evidence, much of which was either entered into the record by JP01 or in response to JP01's data requests and testimony, shows that the level of the hourly rate agreed to by the parties provides the incentive to purchase and renew long-term firm service that BPA described in the BP-18 ROD. As explained below, the evidence also shows that the underlying circumstances contributing to the seams issues have not changed since the BP-18 proceeding and that the amount of solar generation in California continues to increase. Peters, BP-20-E-JP01-01-CC01, at 28-30; Peters, BP-20-E-JP01-01-AT03, at 36-38, 59. In light of this evidence, adopting the hourly rate in the Settlement has the added benefit of helping to achieve the objectives that BPA explained in the BP-18 ROD.

JP01 argues that the Settlement rates are arbitrary because Staff has failed to show that they are cost-based and otherwise explain why the hourly rates on the Southern Intertie are higher than rates for hourly service on other parts of BPA's system. JP01 Br., BP-20-B-JP01-01, at 4, 9. These are the same arguments that JP01 raised in the BP-18 proceeding. In denying JP01's petition to review the BP-18 hourly rate, the Ninth Circuit found that "BPA did not arbitrarily and capriciously depart from any relevant non-discrimination or cost-based rate setting principles." *SMUD v. BPA*, No. 18-71753, 2019 WL 2499687 (9th Cir. June 17, 2019). Like the BP-18 rates, the rates under the Settlement are based on BPA's costs. Fredrickson *et al.*, BP-20-E-BPA-19, at 8; *see also* Lennox *et al.*, BP-20-E-BPA-17, at 11-12; Transmission Revenue Requirement Study, BP-20-FS-BPA-09.

As for JP01's argument about differences in the level of the rates for hourly service on other parts of BPA's system, the record provides ample support for the differences. Much of JP01's evidence from the BP-18 proceeding shows why the Southern Intertie hourly rates in the Settlement are higher than the hourly rates on other parts of the system. The Southern Intertie hourly rates in the Settlement are approximately 4 percent higher than the current hourly rates. Fredrickson & Linn, BP-20-E-BPA-22, at 2. As described above, BPA changed the rate design for the Southern Intertie hourly rates in the BP-18 proceeding because of concerns about (1) cost recovery risk if customers did not renew long-term service, and (2) hourly customers paying a "fair share" of the Southern Intertie costs. Fredrickson & Linn, BP-20-E-BPA-22-AT01, at 84-85. There was no change to the rate design for the hourly rates on other parts of the system in the BP-18 proceeding, because neither Staff nor any party raised concerns these were issues on other parts of the system. Changing the rate design led to a significant increase in the

Southern Intertie hourly rates, making them much higher than the hourly rates on other parts of the system. BP-18 Final Transmission Rates Study and Documentation, BP-20-E-JP01-10, at 24.

Finally, JP01 argues that the record provides no rationale or explanation why “yet another [rate] increase is necessary for hourly service” or why the hourly rate is increasing over 4 percent when the overall rate increase is 3.6 percent. JP01 Br., BP-20-B-JP01-01, at 10. As the Transmission Revenue Requirement Study states, the current revenue tests show that current transmission rates would be insufficient to demonstrate cost recovery. Transmission Revenue Requirement Study, BP-20-FS-BPA-09, at 22. In addition, the forecast program level costs and capital expense that make up the Transmission revenue requirement have changed since the BP-18 rate proceeding. Lennox *et al.*, BP-20-E-BPA-17, at 11-12; Transmission Revenue Requirement Study, BP-20-E-BPA-09. The transmission rates in the Settlement are based on that revenue requirement, and they reflect the changes in the forecast program level costs and capital expense.

Evidence Regarding the Fair Allocation of Costs

JP01 also claims that the record lacks evidence to show that the hourly rate meets the objective stated in the BP-18 ROD that hourly customers pay their “fair share” of the Southern Intertie costs. JP01 Br., BP-20-B-JP01-01, at 15. Staff defined “fair share” in terms of the principle stated in the BP-18 ROD 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.” Fredrickson & Linn, BP-20-E-BPA-22, at 7, quoting BP-20-E-BPA-22-AT01, at 85. Staff’s testimony shows that the hourly rate in the Settlement achieves this result. *Id.* at 7-8. In addition, as described above, the switch to 25 peak hours was the key principle underlying the change in the hourly rate design in the BP-18 proceeding. See Fredrickson & Linn, BP-20-E-BPA-22-AT01, at 85. Staff’s analysis in this case shows that there continue to be 25 peak hours in California. Peters, BP-20-E-JP01-01-AT01, at 9-45 (Data Response JP01-BPA-28-6). Given this finding, the evidence and explanation from the record in the BP-18 rate proceeding support why the hourly rate in the Settlement will result in hourly customers paying their fair share of costs.

JP01 also claims that Staff provided no analysis to show how much hourly customers paid before and after the BP-18 rate proceeding or to analyze how much those amounts contribute to recovery of the Southern Intertie costs. JP01 Br., BP-20-B-JP01-01, at 15. Although there is no reason that this specific comparison would be necessary to have sufficient evidence to adopt the Settlement, the record shows that Staff did provide the data for that comparison, and JP01 moved it into the record. Peters, BP-20-E-JP01-01-AT01, at 89-91. JP01 also included evidence showing the overall Southern Intertie costs used to set FY 2018–2019 rates and the revenues that BPA forecast for sales of hourly service after the rate increase. BP-18 Final Transmission Rates Study and Documentation, BP-20-E-JP01-10, at 22, 25. All of this provides the data for the comparison that JP01 claims is necessary, but such a comparison is of little significance. Hourly customers are paying their fair share, because, as explained above, BPA’s longstanding policy is that a customer that purchases hourly service for only the peak number of hours should make the same contribution to cost recovery as a customer that purchases long-term firm service. The record shows that this is the case under the hourly rate in the Settlement. Fredrickson & Linn, BP-20-E-BPA-22, at 7-8. Nothing in the Settlement altered this longstanding policy.

Evidence Regarding the Seams Issues and Solar Generation in California

As described above, BPA’s primary reason for changing the hourly rate design in the BP-18 proceeding was to address the impact of “seams” issues between the Pacific Northwest and California in combination with the increase in the amount of solar generation capacity in California. Fredrickson & Linn, BP-20-E-BPA-22-AT01, at 38-42 (describing the seams issues and the “duck curve”), 84-85. JP01 questions in its Initial Brief whether the evidence regarding the relationship between the seams issues, the duck curve, and the risk of renewals in the BP-18 proceeding ever justified the decision in that proceeding. JP01 Br., BP-20-B-JP01-01, at 13, 16, 18. The Ninth Circuit found that BPA’s decisions in the BP-18 ROD were reasonable, and BPA will not repeat the rationale for those decisions here. *SMUD v. BPA*, No. 18-71753, 2019 WL 2499687 (9th Cir. June 17, 2019); Fredrickson & Linn, BP-20-E-BPA-22-AT01, at 38-42, 84-85.

JP01 likewise claims that the record in *this* proceeding is deficient because Staff has not provided evidence to demonstrate the significance of the seams issues today as opposed to in the BP-18 proceeding. JP01 Br., BP-20-B-JP01-01, at 13. However, the record contains overwhelming evidence, much of it from the BP-18 proceeding, that seams issues exist and must be mitigated. Fredrickson & Linn, BP-20-E-BPA-22-AT01, at 38-41 (describing the seams issues and the evidence demonstrating those issues). Indeed, JP01 agreed in the BP-18 proceeding that the seams issues exist and needed to be addressed. *Id.* at 36, 39. JP01 suggests that the undisputed fact that seams issues are a problem is insufficient to justify the hourly rate in the Settlement, and that Staff must provide new evidence to demonstrate how significant the seams issues are *today*. JP01 Br., BP-20-B-JP01-01, at 13. That argument is unsupported by the record in this proceeding. The record contains all the evidence relied on for the conclusions about seams issues in the BP-18 proceeding but no evidence to show that the underlying factors that contribute to the seams issues have changed. Fredrickson & Linn, BP-20-E-BPA-22-AT01, at 38-41. In fact, JP01 unequivocally testified that the factors that contribute to the seams issues have *not* changed. Peters, BP-20-E-JP01-01-CC01, at 28-30. This does not mean, as JP01 claimed, that the change in the hourly rate design was ineffective. *See id.* at 30. It simply means that the evidence in the record provides no basis for BPA to change its conclusions about seams issues.

JP01’s other new argument in this proceeding is that Staff admitted in cross-examination that “there were *never* any material seams issue[s] apart from the duck curve” and seams issues were “*never* a valid justification for changing the design of the Southern Intertie hourly rates.” *Id.* at 13, 16-17. JP01 bases its allegation on Staff’s statement that “[p]rior to the emergence of the duck curve . . . , it seems that the denominator of the previous hourly rate was effective.” *Id.* at 17, *quoting* Cross-Ex. Tr. at 40. Staff’s statement, however, was not the sweeping admission that JP01 suggests. JP01 leaves out Staff’s response to the very next question, which reaffirmed the contribution of the CAISO market rules to the seams issues:

- Q. Okay. So when the renewal rates were 100 percent or in that range in the—in the 2012 case, the 2014 case, was the lower hourly rate the—causing an incentive for people to renew long-term firm service?

- A. (Michael Linn) So in the—in the process that led to the BP-18 rate change, we described both the California ISO seams and the emergence of the California duck curve. So prior to the emergence of the duck curve, it seems that the denominator of the previous hourly rate was effective.
- Q. *Okay. So it was the duck curve that you're saying caused the—the disincentive to renew?*
- A. (Michael Linn) *The duck curve in combination with the ISO market rules.*

Cross-Ex. Tr. at 40 (emphasis added). The effect of the duck curve in combination with the CAISO market rules was what BPA described in the BP-18 ROD.

JP01 incorrectly portrays the duck curve itself as a seams issue, arguing that Staff and PPC have not studied or explained how the duck curve affects the likelihood that non-firm hourly service would flow ahead of long-term firm service. JP01 Br., BP-20-B-JP01-01 at 17. The duck curve is not a seams issue, and Staff has never claimed differently. The duck curve has heightened the effect of the seams issues because it has contributed to the reduction in the number of peak hours in California for which customers would have to purchase hourly service. *See Fredrickson & Linn, BP-20-E-BPA-22-AT01, at 39.* As the BP-18 ROD states, “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.” *Id.* The evidence of conditions since the BP-18 proceeding shows that the amount of solar generation in California continues to increase and “the duck curve has gotten more pronounced.” Peters, BP-20-E-JP01-01-AT03, at 36-38, 59; Cross-Ex. Tr. at 54. As Staff testified, “the reasons for changing the rate have only intensified.” Cross-Ex. Tr. at 54.

Evidence Regarding Renewal Rates

JP01 also focuses on rates of renewal for long-term service, which it notes have always been high. JP01 Br., BP-20-B-JP01-01, at 18. According to JP01, the high renewal rates show that there was no basis for changing the hourly rate design in the BP-18 rate proceeding and that there is no basis for increasing the hourly rate in this proceeding. *Id.* JP01 made its arguments about renewal rates in the BP-18 proceeding, and those arguments were fully addressed in the BP-18 ROD and by the Ninth Circuit. Fredrickson & Linn, BP-20-E-BPA-22-AT01, at 51-55; *SMUD v. BPA*, No. 18-71753, 2019 WL 2499687 (9th Cir. June 17, 2019) (BPA “reasonably determined that in the absence of an increase in the hourly rate, its customers were less likely to renew LTF [long-term firm] service.”).

JP01’s new argument is that BPA’s methodology for assessing the risk that customers will not renew long-term firm service on the Southern Intertie shows that the risk is “vanishingly low,” and the fact that BPA has used the same methodology since the BP-16 proceeding demonstrates that the risk has always been that low. JP01 Br., BP-20-B-JP01-01, at 20. JP01 alleges that BPA’s methodology for assessing renewal risk on the Southern Intertie does not take into account the level of hourly transmission rates. *Id.* JP01 misconstrues the purpose of BPA’s risk

study for transmission rates. The study helps ensure that BPA's transmission rates overall are set high enough to satisfy BPA's TPP standard. Power and Transmission Risk Study, BP-20-E-BPA-05-CC01, at 1. The assumptions in and results of the study are not an input in the design of the long-term rate or the hourly rates on the Southern Intertie. If the study were to show that transmission rates were insufficient for purposes of the TPP standard, the result would be to increase transmission rates overall or rely on some risk mitigation mechanism. The study would not identify that any one rate is too high or too low.

As for BPA's use of the same methodology to assess renewal risk for Southern Intertie service since before the change to the hourly rate design, JP01 raised a similar point in the BP-18 proceeding. *See* Fredrickson & Linn, BP-20-E-BPA-22-AT01, at 54. JP01 argued that the sales forecast in the BP-18 Initial Proposal assumed that all long-term firm Southern Intertie service would be renewed, while at the same time Staff was claiming that renewal risk justified changing the hourly rate design. *Id.* BPA explained in the BP-18 ROD that the sales forecast assumption was consistent with the proposal to change the hourly rate design. *Id.* Staff expected the proposed hourly rate design to provide an effective incentive to renew long-term firm service. *Id.*

The rationale from the BP-18 ROD applies to JP01's argument about the assumptions in the BP-20 risk study as well. Staff acknowledges that it has used the same methodology for the past three proceedings, but the assumption of low renewal risk in the BP-18 proceeding and this proceeding are consistent with the expectation that the BP-18 hourly rate increase will be effective at providing an incentive to renew long-term firm service. Similarly, the BP-16 risk study assumed a low renewal risk, but that study was completed *before* the extensive public process ordered by the Administrator to thoroughly understand the issues. The BP-16 record did not include the evidence—found in the subsequent public process—that solar generation, in combination with seams issues, was making hourly service more economical than long-term firm transmission service. Fredrickson & Linn, BP-20-E-BPA-22-AT01, at 65-66.

Since the BP-18 hourly rate has been in effect, all of the long-term firm megawatts up for renewal have been renewed, no customer has rejected an offer of long-term firm service, and customers have not complained to BPA about the seams issues. Fredrickson & Linn, BP-20-E-BPA-22, at 9; Peters, BP-20-E-JP01-01-AT03, at 32; Wellenius, BP-20-E-PX-01, at 28.

Conclusion

After fully developing the record through the evidentiary hearing process required under Section 7(i) of the Northwest Power Act and considering the record taken as whole, the evidence shows that adopting the Settlement is a reasonable result. Although a primary basis for adopting the Settlement rates, including the hourly rate, is the agreement of the settling parties, the record contains sufficient evidence to demonstrate that the change to hourly rate design in the BP-18 proceeding has been effective and has had no adverse market impacts. The record also shows that the level of the hourly rate in the Settlement furthers the objectives that BPA explained in the BP-18 ROD in terms of providing an incentive to renew long-term firm service on the Southern Intertie and helping to ensure hourly customers pay a fair share of the Southern Intertie costs.

Decision

The evidence in the record supports adoption of the Settlement.

Issue 4.1.3

Whether Staff adequately studied the effect of the hourly rate adopted in the BP-18 proceeding.

Parties' Positions

JP01 argues that Staff's report regarding the impacts of the BP-18 hourly rate increase contained no specific conclusions and did not address what caused the revenues, prices, and long-term firm renewal rates that occurred in FY 2017 and 2018. JP01 Br., BP-20-B-JP01-01, at 22. JP01 claims that the report is "a collection of data" that simply compares certain market indicators in FY 2018 (the year the higher BP-18 hourly rate took effect) with the preceding seven years. *Id.* at 23. JP01 believes that BPA should have conducted a regression analysis to isolate the effect of the hourly rate on wholesale power markets, but chose not to do so. *Id.* at 36-37.

JP04 concurs with Staff's methodology and its conclusions. JP04 Br., BP-20-B-JP04-01, at 16-17.

BPA Staff's Position

Staff compiled and reviewed information from a variety of sources on a monthly basis after the BP-18 hourly rate took effect to assess whether the change in the rate design had the type of effects that JP01 had alleged in the BP-18 rate proceeding. Fredrickson & Linn, BP-20-E-BPA-22, at 6. Staff had monitored the effects for about 10 months when discussions about a potential rates settlement started, and nothing suggested any discernible impacts that would cause the need for BPA to reduce the hourly rate in the BP-20 proceeding. *Id.*

Evaluation of Positions

According to Staff, its Southern Intertie report was intended to: (1) assess whether the BP-18 hourly rate had unintended consequences, such as lowering exports from the Pacific Northwest to California; and (2) determine if the hourly rate was effective in creating an incentive to renew long-term firm service on the Southern Intertie. *Id.* at 12-13. Staff concluded that it "has not observed any changes to the wholesale power markets" due to the hourly rate increase and, that since the hourly rate went into effect, all customers renewed their long-term firm service. Peters, BP-20-E-JP01-01-AT01, at 104 (JP01-BPA-28-68); Fredrickson & Linn, BP-20-E-BPA-22, at 9, 15. JP01 levies a variety of criticisms against Staff's report, but JP01's primary point is that the report did not serve Staff's purposes. JP01 Br., BP-20-B-JP01-01, at 22. The discussion below addresses JP01's specific criticisms.

For deciding whether to adopt the Settlement, the primary concern is the first aspect of Staff's report—whether the BP-18 hourly rate has had unintended or adverse consequences. Although BPA is certainly concerned about the BP-18 hourly rate's effectiveness in terms of the incentive

to renew, all customers have renewed their long-term service since the BP-18 hourly rate took effect. Fredrickson & Linn, BP-20-E-BPA-22, at 9. Whether the hourly rate was the sole factor that caused customers to renew is not as significant as whether the hourly rate had unintended or adverse consequences on wholesale power markets. In the absence of such consequences, BPA sees no reason to lower the hourly rate and unnecessarily risk customers either not renewing long-term firm service or not accepting new offers of long-term firm service. JP01 calls this risk “vanishingly low,” but even if JP01 were correct, there is no reason to accept even this amount of incremental risk unless the hourly rate adversely affected wholesale power markets. JP01 Br., BP-20-B-JP01-01, at 20.

JP01 faults Staff’s report for not identifying “what an ‘adverse impact’ might be or how an ‘adverse impact’ would be recognized and measured.” *Id.* at 22. Yet there was no need for the report itself to define an adverse impact or describe how to measure it. As JP01 states in its Initial Brief, the purpose of the report was to “see if there were adverse consequences that . . . JP01 described in previous rate periods.” *Id.* (quoting Cross-Ex. Tr. at 76). In other words, the report focused on the types of adverse impacts and consequences that JP01 had previously predicted, and JP01 had already defined and identified how to measure those impacts and consequences in the BP-18 proceeding. JP01 had alleged that a higher hourly rate would greatly reduce, or even eliminate, all exports of hourly energy between the Pacific Northwest and California and, if such exports still occurred, the price would increase by \$8/MWh. Peters, BP-20-E-JP01-01-AT04, at 208, 211, 361. This reduction in exports would lead to an increase in Pacific Northwest power supply, which would depress Pacific Northwest wholesale power prices. *Id.* at 219. Although the BP-18 ROD concluded that such impacts were highly unlikely, Staff began to monitor data from West Coast power markets on a monthly basis after the rate increase took effect to assess whether JP01’s predictions were correct. Fredrickson & Linn, BP-20-E-BPA-22-AT01, at 75-76; Fredrickson & Linn, BP-20-E-BPA-22, at 12; *see also* Cross-Ex. Tr. at 76. Staff then compiled these monthly reports into an annual report for FY 2018. Fredrickson & Linn, BP-20-E-BPA-22, at 12.

Staff’s report examined prices and liquidity for day-ahead and real-time markets at Mid-Columbia (Mid-C), the California-Oregon border (COB), and the Nevada-Oregon border (NOB), and NP-15 and SP-15 power prices, from FY 2011 to FY 2018. *Id.* at 13. Mid-C is the main power trading hub in the Pacific Northwest, and COB and NOB “are the points on the transmission system where Pacific Northwest power is sold to California utilities.” *Id.* “NP-15 and SP-15 are average power prices of northern and southern California, respectively, calculated by the California ISO.” *Id.* Staff also examined the differences in prices between all of these trading hubs (“price spreads”) and data about factors that affect power prices at the hubs, including natural gas prices, market heat rates, exports from the Pacific Northwest to California, the growth of the western Energy Imbalance Market (EIM), and the increase in California solar generation. *Id.* at 13, 17. The price of natural gas is “one of the most important factors in how power prices are set because the marginal resource (*i.e.*, the generator that sets the price in wholesale energy markets) typically generates power using natural gas.” *Id.* at 14. “Market heat rates are calculated by dividing the energy price by the price of natural gas.” *Id.* Market heat rates and the price of natural gas “provide useful context for understanding whether power prices and price spreads are the result of supply and demand dynamics or fuel costs or both.” *Id.* Staff

implicitly controlled for other factors, such as streamflow and transmission de-rates, by looking at data over a period of eight years. *Id.* at 17.

JP01 criticizes Staff for using price data published by the Intercontinental Exchange (ICE), Powerdex, and the California ISO rather than FERC Electronic Quarterly Report (EQR) data. EQR data is information that FERC requires certain entities to provide on a quarterly basis to show all transactions at market-based rates in the quarter. Peters, BP-20-E-JP01-01-CC01, at 37. JP01 claims that FERC EQR data includes all transactions. JP01 Br., BP-20-B-JP01-01, at 34. Staff did not use FERC EQR data because such data is not limited to the Mid-C, NOB, and COB day-ahead and real-time energy markets, which was the focus of Staff's report. Fredrickson & Linn, BP-20-E-BPA-22, at 20-21. Similarly, some EQR transactions that appear to be real-time market transactions are, in fact, day-ahead market transactions. *Id.* at 20. This makes it very difficult to compile pricing data for any single market, such as the Mid-C day-ahead market. *Id.* Although JP01 appears to fault ICE and Powerdex data for not containing "millions" of transactions, Staff used data containing the weighted average of the relevant transactions occurring at Mid-C, COB, and NOB in only the day-ahead and real-time energy markets. JP01 Br., BP-20-B-JP01-01, at 35-36; Fredrickson & Linn, BP-20-E-BPA-22, at 13. Therefore, using ICE and Powerdex data for Staff's report is reasonable.

JP01 also faults Staff for not conducting a regression analysis to assess the impacts of the BP-18 hourly rate increase. JP01 Br., BP-20-B-JP01-01, at 36. A regression analysis "studies the relationship between one variable, called a dependent variable, and one or more other variables, which are called independent or explanatory variables." Fredrickson & Linn, BP-20-E-BPA-22, at 22. In this case, the dependent variable would be market prices or trading volumes, and the explanatory variables would be other factors that affect power prices in the western United States including the hourly transmission rate. *Id.* at 16-17. Studying the relationship between the dependent variable and the explanatory variables would, in theory, allow one to isolate the effect of the hourly rate on wholesale power markets. Staff states that it could not perform a "meaningful" regression analysis because it lacked data for major factors that affected power prices in the western United States. *Id.* at 20-21. If Staff had performed a regression analysis, it would have been unable to determine if any differences in market prices or trading volumes were due to the hourly rate or to factors where it lacked data, such as generation outside BPA's balancing authority area. In response, JP01 states that BPA had access to ICE and EQR data. JP01 Br., BP-20-B-JP01-01, at 36. But these are wholesale transaction prices, not information about generation and other factors outside of BPA's balancing authority area. This sort of data would help to explain how the wholesale power prices reflected in ICE, Powerdex, and EQR data were set.

Staff did not need to conduct a regression analysis to determine if JP01's predictions from the BP-18 proceeding were accurate. Staff's report demonstrated that the BP-18 hourly rate did not reduce or eliminate all exports of hourly energy between the Pacific Northwest and California. Staff found that "[e]xports were at the highest level since at least 2011." Fredrickson & Linn, BP-20-E-BPA-22, at 15; Peters, BP-20-E-JP01-01-AT03, at 38. JP01 argues that Staff's report is deficient because Staff did not determine what caused this level of exports, but that was not

Staff's goal. JP01 Br., BP-20-B-JP01-01, at 22. Staff's goal was to determine whether the hourly rate eliminated or reduced exports.

Despite JP01's criticism of Staff's report, Staff's conclusions about the level of exports are consistent with the results of analysis performed by JP01. As described in Issue 4.1.5, JP01 performed a regression analysis to attempt to assess the impacts of the BP-18 hourly rate. Like Staff's report, JP01's analysis does not show a decrease in power exports from the Pacific Northwest to California after the BP-18 hourly rate took effect. In fact, JP01's results suggest a statistically significant increase in the volume of exports due to the BP-18 hourly rate. Parker & Peters, BP-20-E-JP01-02-AT04, at 22, 24; Parker & Peters, BP-20-E-JP01-02-AT04-E01-CC01, at 16. Although JP01's analysis is flawed and the testimony describing the results appears incorrect for reasons explained in Issue 4.1.5, Staff and Powerex independently confirmed that the results show a statistically significant increase in volume at COB. Fredrickson & Linn, BP-20-E-BPA-22, at 27; Wellenius, BP-20-E-PX-01, at 21-22.

Aside from the data about export volumes, Staff's report includes power price data for the past eight years. Based on review of that data, Staff found that the BP-18 hourly rate had no discernible impact on prices at COB and NOB. *Id.* at 17. JP01's analysis contains similar findings. At COB, JP01 found that "day-ahead prices fell about \$5.40/MWh and real-time prices rose about \$0.35/MWh [due to the hourly rate], but neither change was statistically significant." Parker & Peters, BP-20-E-JP01-02, at 14. Similarly, at NOB, JP01 found "day-ahead prices fell about \$4.80/MWh and real-time prices fell about \$2.00/MWh [due to the hourly rate], but again neither change was statistically significant." *Id.* Given all of this evidence, there is no basis to conclude that the BP-18 hourly rate raised power prices in California by any amount, let alone \$8/MWh. *See* Fredrickson & Linn, BP-20-E-BPA-22, at 17-18; *see also* Peters, BP-20-E-JP01-01-AT04, at 208, 211, 361.

Similarly, Staff's report shows that the hourly rate had no discernible impact on Mid-C power prices. Fredrickson & Linn, BP-20-E-BPA-22, at 16; Peters, BP-20-E-JP01-01-AT03, at 40-54. In its testimony in the BP-18 and BP-20 proceedings, JP01 argues that increasing the hourly rate would reduce the amount of exports from the Pacific Northwest to California. Peters, BP-20-E-JP01-01-AT04, at 219. This reduction would lead to increased power supplies in the Pacific Northwest, which would depress power prices at Mid-C. *Id.* But, as explained above, there was no such reduction in exports in FY 2018. Staff's report shows they were at the highest level since 2011. Fredrickson & Linn, BP-20-E-BPA-22, at 15; Peters, BP-20-E-JP01-01-AT03, at 38.

JP01's Initial Brief offers a different theory about the impacts on Mid-C prices. JP01 argues that demand at market hubs is "inelastic," so no reduction in exports is necessary to reduce Mid-C prices. JP01 Br., BP-20-B-JP01-01, at 49. As stated above, however, JP01's analysis shows that the hourly rate led to a statistically significant *increase* in the volume of exports from the Pacific Northwest to California. *See* Parker & Peters, BP-20-E-JP01-02-AT04, at 22, 24; Parker & Peters, BP-20-E-JP01-02-AT04-E01-CC01, at 16. JP01 does not explain how a higher hourly rate could increase the volume of exports from the Pacific Northwest to California and decrease

Mid-C prices. As explained in Issue 4.1.5, BPA believes that JP01's finding that the hourly rate reduced Mid-C power prices is severely flawed and unreliable.

JP01 claims that Staff did not adequately study whether the BP-18 hourly rate was an "effective incentive" to renew long-term firm service, and that "BPA admits that [it] does not know whether, absent the hourly rate increase, customers would have renewed anyway" JP01 Br., BP-20-B-JP01-01, at 23 (citing Cross-Ex. Tr. at 30). Given the amount of study and attention this issue has received over the past several years and the overwhelming consensus that has developed around it, Staff did not need to establish how many customers would renew long-term firm transmission service absent the increase in the hourly rate. As Staff stated during cross-examination, "we've had three years of process on this very issue, and we've heard from customers about this issue. . . . I don't think we're making a big leap that, when we had this public process, as a region formulated an alternative, and the results were what we expected, that it's just a mere correlation." Cross-Ex. Tr. at 39-40. Nonetheless, Staff's report shows that, in FY 2015, the year before BPA had committed to address issues related to the Southern Intertie, customers failed to renew 31 percent of the megawatts that were eligible for renewal. Peters, BP-20-E-JP01-01-AT03, at 32. Moreover, "during the BP-16 rate period up until the Administrator issued the BP-18 ROD, five different customers declined LTF [long-term firm transmission] service." JP04 Br., BP-20-B-JP04-01, at 21. Since BPA raised the hourly rate, no customer has rejected an offer of long-term firm service, whether it be a renewal or an offer of new service. Peters, BP-20-E-JP01-01-AT03, at 32; JP04 Br., BP-20-B-JP04-01, at 22.

Although JP01 claims that the risk of long-term firm transmission customers not renewing their service is "vanishingly low," the record from the BP-18 proceeding showed that it would be more economical for customers to replace long-term firm transmission with hourly transmission service without an increase in the hourly rate. JP01 Br., BP-20-B-JP01-01, at 18. As JP01 notes, customers hold long-term firm transmission rights on the Southern Intertie "almost exclusively for short-term arbitrage" *Id.* at 26. For these types of short-term power sales, however, a customer does not have to use long-term firm transmission service to deliver its power to California. Fredrickson & Linn, BP-20-E-BPA-22, at 18-19. Instead, it can replace its long-term firm transmission service with hourly non-firm transmission service, which, due to the seams issues, is widely available and does not have priority over long-term firm transmission service. *Id.*

JP01 disputes this by relying on data from the BP-18 proceeding that it claims shows that requests for hourly service were denied between 11 percent and 17 percent of the time during hours of highest demand in FY 2016. JP01 Br., BP-20-B-JP01-01, at 25. The BP-18 ROD addressed this issue, finding "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." Fredrickson & Linn, BP-20-E-BPA-22-AT01, at 62. For example, "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.* As in the BP-18 proceeding, JP01 fails to take this into account.

In addition, Staff concluded that if there were unmet demand for hourly transmission service “long-term firm customers could resell their capacity to other customers for at least the amount of the hourly rate and perhaps more than that rate.” Fredrickson & Linn, BP-20-E-BPA-22, at 19. Staff’s report, however “shows that the prices at which long-term firm customers have resold their transmission service is in line with the preceding eight years,” even though “the hourly rate increas[ed] by approximately 170 percent in FY 2018” *Id.* Also, resale volumes remain low, even though exports were at their highest in at least eight years. *Id.* All of this indicates there is “not much, if any, unmet demand for hourly service on the Southern Intertie.” *Id.*

Staff’s report also shows that, although overall exports from the Pacific Northwest to California increased from FY 2017 to FY 2018, exports are declining in daytime hours at the same time that California solar generation is increasing. Peters, BP-20-E-JP01-01-AT03, at 36-38, 59. In addition, most of the year-over-year increase in exports is reflected in greater amounts of power being exported in the early evening or “peak” hours. *Id.* at 36-38. If BPA had not increased its hourly rate, it would be more economical to serve this 25-hour peak with hourly transmission service. JP01 argues that customers’ returns on long-term firm transmission service must have been “sufficient to support renewal” because customers, in fact, did renew in most instances. JP01 Br., BP-20-B-JP01-01, at 26. Prior to the BP-18 hourly rate increase, however, even JP01 acknowledged that Powerex, BPA’s largest Southern Intertie transmission customer, was canceling long-term firm transmission service and buying more hourly transmission service than any other customer. Peters, BP-20-E-JP01-01-AT04, at 243-44. Staff’s report shows that the hourly rate increase mitigated these cost-recovery concerns without any adverse effects on wholesale power markets.

Decision

After adequately studying the effect of the hourly rate adopted in the BP-18 proceeding, Staff reasonably concluded that the hourly rate had no unintended consequences and that it was effective in providing an incentive to renew long-term firm service on the Southern Intertie.

Issue 4.1.4

Whether BPA’s hourly rate is a barrier to trade between the Pacific Northwest and California.

Parties’ Positions

JP01 argues that the hourly rate is an export tax that constitutes a barrier to trade between the Pacific Northwest and California. JP01 Br., BP-20-B-JP01-01, at 32. It states that “[e]nergy sold by those subject to the hourly rate will find their products less attractive for buyers in California to purchase.” *Id.* at 33.

JP04 argues that the hourly rate is not an export tax or barrier to trade, and that exports from the Pacific Northwest to California after the BP-18 hourly rate increase were at their highest level

since at least 2011. JP04 Br., BP-20-B-JP04-01, at 23. AWEC claims “there is no evidence that the Southern Intertie rates had any impact on market prices,” and that the hourly rate applies to only a “de minimis portion of total volume.” AWEC Br., BP-20-B-AW-01, at 7.

Staff’s Position

Staff argues that the hourly rate is not a barrier to trade because other transmission services are available to move power from the Pacific Northwest to California. Graessley *et al.*, BP-20-E-BPA-25, at 19. Also, the hourly rate applies to only approximately 1 percent of transactions on the Southern Intertie. *Id.*

Evaluation of Positions

In the BP-18 proceeding, JP01 defined an “export tax” as “a levy, not based on any defined cost, that is imposed on each unit exported (in this case, each megawatt-hour).” Peters, BP-20-E-JP01-01-AT04, at 209. In this proceeding, JP01 concedes that the hourly rate does not apply “to each unit exported” or to “each megawatt-hour,” but it nonetheless argues that the rate is an export tax and a barrier to trade. *Id.*; JP01 Br., BP-20-B-JP01-01, at 33-34. Approximately 1 percent of Southern Intertie transactions are subject to the hourly rate. Fredrickson & Linn, BP-20-E-BPA-AT05, at 1. In terms of megawatts, “the amount of exports facing the hourly rate averaged 57 MW in each hour of FY 2018” out of BPA’s 5,825 MW share of the Southern Intertie. JP04 Br., BP-20-B-JP04-01, at 6. Because almost 99 percent of exports from the Pacific Northwest to California are unaffected by the hourly rate, it “is simply incorrect to characterize the Hourly IS rate as an ‘export tax’” Wellenius, BP-20-E-PX-01, at 4.

In addition to the limited applicability of the hourly rate, the rate is based on the cost of the Southern Intertie, which is a defined cost. *See* Fredrickson & Linn, BP-20-E-BPA-22-AT01, at 35 (stating that a reduction in Southern Intertie costs resulted in a corresponding reduction in the hourly rate). Therefore, the hourly rate does not meet any element of JP01’s definition of “export tax.”

JP01’s BP-18 testimony discussed the impact that an export tax would have. It stated that the export tax will cause “the cost of delivered energy at COB and NOB [to] increase, and utilities [to] take actions to avoid the higher cost of imported power.” Peters, BP-20-E-JP01-01-AT04, at 209. In this proceeding, there is no evidence of price increases at COB and NOB or of utilities taking actions to avoid the higher cost of imported power. *See* Fredrickson & Linn, BP-20-E-BPA-22, at 15-16; Parker & Peters, BP-20-E-JP01-02, at 14. In fact, JP01’s Initial Brief does not allege that the BP-18 hourly rate harmed any member of JP01 or any other California utility. Moreover, as stated above, no party in this proceeding has alleged that the hourly rate caused prices at COB and NOB to increase or that the hourly rate caused a decline in power exports from the Pacific Northwest to California. Parker & Peters, BP-20-E-JP01-02, at 14; Fredrickson & Linn, BP-20-E-BPA-22, at 15-16; Deen, BP-20-E-PP-02, at 3; Wellenius, BP-20-E-PX-01, at 4. This “directly undermine[s] the core premise of [JP01’s] ‘barrier to trade’ theory,” and, shows that the hourly rate did not, in fact, create a barrier to trade. JP04 Br., BP-20-B-JP04-01, at 14.

Finally, JP01 argues that the current (BP-18) rate for long-term firm service is “not less expensive than the pre-BP-18 rates but less expensive than the increased [hourly] rate.” JP01 Br., BP-20-B-JP01-01, at 31 (emphasis omitted). This is incorrect. The BP-18 rate for long-term firm service decreased by approximately 15.6 percent relative to the BP-16 rate. BP-18 Final Rates Study and Documentation, BP-20-E-JP01-10, at 24.

Decision

BPA’s hourly rate is not a barrier to trade between the Pacific Northwest and California.

Issue 4.1.5

Whether the increase in the hourly rate in the BP-18 proceeding is harming BPA’s preference customers in the Pacific Northwest by depressing Mid-C power prices.

Parties’ Positions

JP01 believes that the BP-18 hourly rate increase has depressed prices at Mid-C, which it claims reduced BPA’s revenues by \$40 million per year, harming BPA and its Pacific Northwest preference power customers. JP01 Br., BP-20-B-JP01-01, at 26.

JP04 and AWEC argue that the hourly rate did not depress power prices at Mid-C, and that JP01’s analysis showing such harm contains numerous errors. JP04 Br., BP-20-B-JP04-01, at 5; AWEC Br., BP-20-B-AW-01, at 6-8.

Staff’s Position

Staff states that JP01’s analysis showing harm to Pacific Northwest preference customers is “fundamentally flawed” and “suffers from numerous statistical errors.” Grassley *et al.*, BP-20-E-BPA-25, at 5-6. As a result, JP01’s analysis fails to support its claims. *Id.* at 6.

Evaluation of Positions

JP01’s Theories

In its testimony, JP01 theorizes that “the quantity of hourly energy exported to California should fall” due to BPA increasing its hourly rate in the BP-18 rate proceeding. Parker & Peters, BP-20-E-JP01-02, at 3. This “fall in exports has a secondary and complementary effect because the amount of energy *not* exported [to California] causes a shift to the right in the supply curve at Mid-C, depressing spot prices in that market.” *Id.* at 3-4. In other words, JP01’s theory is that the BP-18 hourly rate will lower exports from the Pacific Northwest to California. This lower amount of exports will increase the supply of power in the Pacific Northwest, thereby depressing the price of power at Mid-C. JP01 testified that it was concerned about lower Mid-C power prices because of the potential harm to Pacific Northwest entities, and making those entities aware of the harm might cause them to reconsider the Settlement. Peters, BP-20-E-JP01-01-

CC01, at 6-7, 43-44. According to JP01, it conducted a regression analysis to assess the “actual effects of the 2017 increase” during FY 2018 because Staff had presented no analysis of the actual effects. *Id.* at 43. JP01’s witnesses testified that the regression analysis “confirmed [JP01’s] predictions” about the harm to Pacific Northwest entities. *Id.* at 6.

In responding to JP01’s testimony, Staff, Powerex, and PPC pointed out that the results of JP01’s analysis did not support JP01’s theory. Fredrickson & Linn, BP-20-E-BPA-22, at 27; Graessley *et al.*, BP-20-E-BPA-25; Deen, BP-20-E-PP-02, Wellenius, BP-20-E-PX-01; McCrary, BP-20-E-PX-02. Far from showing a decrease in the quantity of hourly energy exported to California, JP01’s regression analysis shows that the hourly rate led to a statistically significant increase in day-ahead transaction quantities at COB and NOB and in real-time quantities sold at COB. Parker and Peters, BP-20-E-JP01-02-AT04, at 22, 24; Parker & Peters, BP-20-E-JP01-02-AT04-E01-CC01, at 16. The only export market that did not have a statistically significant increase in volume was the NOB real-time market. Parker & Peters, BP-20-E-JP01-02, at 14.

JP01 confuses this point in its testimony by incorrectly asserting that its analysis shows that changes in volumes at COB and NOB “were either statistically insignificant (*i.e.*, indistinguishable from zero) or economically insignificant (*i.e.*, MWhs).” Parker & Peters, BP-20-E-JP01-02, at 14. This is contrary to the actual results of JP01’s analysis, which show changes in volume at COB, for example, labeled in red as “Significant.” Parker & Peters, BP-20-E-JP01-02-AT04, at 22, 24. Staff confirmed the results, finding that JP01’s analysis concluded that the BP-18 hourly rate led to a “statistically significant increase in COB volume of 21 percent to 28 percent of daily average volume.” Fredrickson & Linn, BP-20-E-BPA-22, at 27. Moreover, given that JP01’s analysis shows that the BP-18 hourly rate increase is responsible for about a quarter of the daily average volume at COB, it is incorrect to suggest that is “economically insignificant.” Parker & Peters, BP-20-E-JP01-02, at 14. These findings alone should have led JP01 to conclude that its underlying theory regarding the hourly rate’s impact on Mid-C prices was incorrect. Since JP01’s analysis showed an increase in exports, there could be no secondary and complementary effect of a price decrease at Mid-C. Fredrickson & Linn, BP-20-E-BPA-22, at 27; Wellenius, BP-20-E-PX-01, at 22.

In its Initial Brief, JP01 appears to replace its original theory with a new one. JP01 now argues that, despite the increase in exports, the hourly rate reduced Mid-C prices because demand in spot power markets is “inelastic.” JP01 Br., BP-20-B-JP01-01, at 30, 49. Although the alleged inelasticity of spot market demand is central to this theory, JP01 did not define or otherwise discuss this concept in its direct testimony in this proceeding.

“Elasticity of demand is the percent change in demand given a percent change in price.” Cross-Ex. Tr. at 93. Generally speaking, demand is inelastic when the percent change in demand for a good or service is less than the percent change in price. Demand would be “perfectly inelastic” if demand for a good or service is not affected by price.

JP01’s Initial Brief theorizes that, as a result of “inelastic” demand for power at Mid-C, COB, and NOB, prices at Mid-C fell, even though exports from the Pacific Northwest to California did

not decrease. JP01 Br., BP-20-B-JP01-01, at 49-50. As described above, JP01's direct testimony is silent on the inelasticity of demand, so the record includes no evidence supporting JP01's assumption. JP01 did testify about it in the BP-18 proceeding, but there it stated that "perfectly inelastic demand is an unreasonable assumption." Peters, BP-20-E-JP01-01-AT04, at 216. That testimony seems contrary to the theory that JP01 offers now.

In response to a question from JP01 during cross-examination, Powerex's witness stated that "the general assumption that the demand for electrical usage by end users is not particularly sensitive to real time prices but that's not what we're talking about here." Cross-Ex. Tr. at 231. Instead, for spot market transactions, which are the only ones that JP01 claims are at issue in this proceeding, "the sensitivity to price would be relatively high," and therefore elastic. *Id.* This is because utilities typically face a decision to purchase power from the spot market or generate power from their own resources, and utilities make this decision based on the price of spot market power versus the cost of generating power from their own resources. *Id.*

The evidence in the record indicates that this is, in fact, the case. In the BP-18 proceeding, JP01 alleged that the hourly rate would increase prices at COB by \$8/MWh. Peters, BP-20-E-JP01-01-AT04, at 211. At that time, JP01 did not argue that its demand for spot market energy was "inelastic" and that it had no other option but to pay the extra \$8/MWh. Rather, JP01 stated that if prices increased at COB by \$8/MWh, it could "use SMUD's own internal thermal generation" to meet its demand, and that "SMUD expects that this kind of response by California purchasers would be typical . . ." *Id.* at 163. Conversely, if prices at COB decreased by \$8/MWh, SMUD would presumably make more purchases at COB and reduce its thermal generation. All of this indicates that demand for power in wholesale spot markets is elastic, which is contrary to JP01's theory.

Even assuming for the sake of argument that demand for power at Mid-C, COB, and NOB were inelastic, JP01's theory that the BP-18 hourly rate increase reduced Mid-C prices is still severely flawed. JP01 argues that the BP-18 hourly rate increase would cause transmission customers that previously used hourly transmission service to no longer sell power to California. JP01 Br., BP-20-B-JP01-01, at 30-31. Instead, these customers would now sell that power at Mid-C to Southern Intertie long-term firm transmission customers. *Id.* The long-term firm transmission customers would then sell that power to California. *Id.* JP01 claims that this series of events would reduce prices at Mid-C because supply would increase, but "energy exports in spot markets would not fall" and volume at Mid-C would not increase. *Id.* at 30, 49.

However, under JP01's theory, demand for power at Mid-C would not stay the same because Southern Intertie long-term firm transmission customers would purchase more power at Mid-C than they did prior to the BP-18 hourly rate increase. In other words, any hypothetical increase in supply at Mid-C would be counterbalanced by Southern Intertie long-term firm transmission customers buying more power at Mid-C and selling it to California. Cross-Ex. Tr. at 125. As a result, the only way that the hourly rate could potentially affect Mid-C prices is if Pacific Northwest exports to California dropped, increasing power supply at Mid-C without an offsetting increase in demand. *Id.* at 98. This drop in exports would increase power supplies in the Pacific Northwest, which could theoretically reduce Mid-C prices. But, as JP01 concedes, this did not

occur. JP01 Br., BP-20-B-JP01-01, at 49. All of this indicates that JP01 cannot adequately explain why its analysis shows that the hourly rate reduced Mid-C prices by \$7.87/MWh in the day-ahead market and \$5.18/MWh in the real time market. Parker & Peters, BP-20-E-JP01-02, at 13.

Flaws and Errors in JP01's Regression Analysis

Equally as troubling as JP01's failure to adequately explain why the hourly rate would depress prices at Mid-C is the extensive and sometimes pointed testimony regarding serious flaws and errors in JP01's regression analysis. These flaws and errors render JP01's analysis to be of no practical value in determining the effect of the hourly rate on Mid-C prices.

As described above, a regression analysis studies relationships between variables. Fredrickson & Linn, BP-20-E-BPA-22, at 22. The goal of JP01's regression analysis was to quantify the extent to which energy prices at the Mid-C hub were impacted by the BP-18 hourly rate increase. McCrary, BP-20-E-PX-02, at 4-5. Since the BP-18 hourly rate took effect on the first day of FY 2018 (October 1, 2017), JP01 used one full year of data before the BP-18 hourly rate took effect (FY 2017) and compared it to one full year of data after the BP-18 hourly rate was in effect (FY 2018). *Id.* Powerex's witness testified that this was basically a before-after analysis that controls for some variables, and using one full year of data before and after the BP-18 hourly rate took effect for such an analysis could result in an "apples-to-apples comparison if appropriately implemented." *Id.* at 5; Cross-Ex. Tr. at 244.

JP01, however, did not make an "apples-to-apples comparison." *Id.* Instead, it added a variable to its regression analysis that resulted in JP01 not comparing prices from all of FY 2017 to prices from all of FY 2018. McCrary, BP-20-E-PX-02, at 5-6. The variable was intended to account for the impact of Powerex and Idaho Power joining the western Energy Imbalance Market (EIM), which is a real-time energy market operated by the California ISO, on April 4, 2018. By adding this variable, JP01 effectively compared the prices from all of FY 2017 to prices from only the first half of FY 2018. *Id.* The problem with that approach is that Mid-C "prices in the second half of each fiscal year—which includes the summer months—were higher than in the first half of each fiscal year, consistent with typical seasonal patterns." Wellenius, BP-20-E-PX-01, at 6. By comparing prices from all of FY 2017 with prices from only the first half of FY 2018, JP01 wrongly concluded that the hourly rate reduced Mid-C prices.

The addition of the Powerex and Idaho Power EIM variable effectively separated FY 2018 into two parts for purposes of JP01's analysis. From October 1, 2017, to April 3, 2018, JP01's analysis, after purporting to control for other factors that influence power prices, attributed changes in Mid-C price to the hourly rate. *Id.* at 12. From April 4, 2018, to September 30, 2018, changes in Mid-C prices are attributed to Powerex and Idaho Power joining the EIM. *Id.* at 11. Given the increase in Mid-C prices during the second half of FY 2018, JP01's analysis shows that Powerex and Idaho Power joining the EIM caused the Mid-C price to more than double. JP04 Br., BP-20-B-JP04-01, at 10.

The evidence does not support the finding that Powerex and Idaho Power's entry into the EIM caused Mid-C prices to more than double. During the second half of FY 2018, for example,

Powerex exported an average of 70 MW out of the EIM, yet “the volume of day-ahead on-peak energy at Mid-Columbia traded on ICE over the same period was approximately 1,600 MW, on average.” Wellenius, BP-20-E-PX-01, at 17. Powerex’s limited participation in the EIM, which, on average, represents about 4 percent of day-ahead on-peak energy average volume at Mid-C, was extremely unlikely to cause Mid-C prices to more than double. *Id.* Similarly, there is no evidence in the record that indicates Idaho Power’s participation in the EIM would have a major effect on Mid-C prices. In its Initial Brief, JP01 argues that it should take into account Powerex’s and Idaho Power’s entry into the EIM. JP01 Br., BP-20-B-JP01-01, at 51-53. But the issue is not whether JP01 should have taken into account Powerex and Idaho Power’s entry into the EIM. Rather the issue is whether Powerex and Idaho Power’s entry into the EIM caused Mid-C prices to more than double. There is no basis in the record for such a conclusion. In response to the criticisms about the impact of including this variable, JP01 responded that there is “no rule in economics or econometrics that econometric analysis must incorporate equal durations of periods before and after a market shift.” *Id.* at 55. JP01 questioned Powerex’s witness McCrary on this point in cross-examination, but the response did not help JP01’s case. Professor McCrary concluded that the “windows of time would either be defined in a symmetric way” or some aspect of the regression methodology “would try to make sure that the nature of the comparisons was apples to apples.” Cross-Ex. Tr. at 246. JP01’s approach, according to the witness, “fundamentally distorts the nature of the comparison that’s being drawn.” *Id.* at 244.

Powerex took JP01’s regression analysis and corrected this flaw to compare prices for all of FY 2017 with prices for all of FY 2018. Wellenius, BP-20-E-PX-01, at 12. After making that correction, the analysis showed that the hourly rate had no statistically significant effect on Mid-C prices. *Id.* Similarly, Staff took JP01’s regression analysis and added variables created by JP01 to control for seasonal differences in power prices not explained by JP01’s model. Graessley *et al.*, BP-20-E-BPA-25, at 13. The results of that analysis showed that the hourly rate had no statistically significant effect on prices at Mid-C. *Id.*

JP01 argues that Staff’s approach to testing JP01’s flawed methods would somehow lead to “measurement error.” JP01 Br., BP-20-B-JP01-01, at 39-40. By better taking into account seasonal differences in prices at Mid-C, however, Staff is compensating for JP01’s distorted comparison. JP01 also argues that Staff did not actually control for seasonality, and its Initial Brief misleadingly cuts off a quote from Staff’s cross-examination testimony in mid-sentence in an effort to support its point. *Id.* at 40. Staff goes on to say that including seasonality “demonstrate[s] the fact that on an annual basis there is no statistically significant impact of the transmission rate after accounting for that seasonality.” Cross-Ex. Tr. at 144-45. JP01’s criticisms are without merit.

Equally troubling is that JP01’s regression analysis does not isolate the effect of the hourly rate on wholesale spot markets—which was its stated purpose. All of BPA’s BP-18 transmission and power rates, including the hourly rate, took effect on October 1, 2017. Wellenius, BP-20-E-PX-01, at 19. Portland General Electric (PGE) joined the EIM on this date as well. *Id.* at 19-20. Because JP01’s regression model failed to isolate the impact of the hourly rate increase, JP01’s finding of reduced power prices at Mid-C “could be pinned on *any* of these other causes, and doing so would be just as baseless as [JP01’s] attempt to pin their result on the Hourly IS rate

change” *Id.* at 20. JP01 argues that no party has put forward a theory that explains how transmission rates, other than the hourly rate, affect Mid-C prices. JP01 Br., BP-20-B-JP01-01, at 42. But JP01 overlooks PGE joining the EIM. To draw the conclusion that the hourly rate reduced Mid-C prices, one must believe that Powerex and Idaho Power joining the EIM caused Mid-C prices to more than double, and PGE’s entry into the EIM had no effect on Mid-C prices. Neither JP01 nor any other party has explained how both of those things can be true. If Mid-C prices did somehow double as a result of Powerex and Idaho Power joining the EIM, it is difficult to see how PGE joining the same market would have no effect on Mid-C prices.

The evidence demonstrates that JP01 failed to adequately control for variables that may be influencing Mid-C prices. The variables that JP01 included in its model could not explain 57 percent of the variation in Mid-C hour-ahead prices, and 81.1 percent of the variation in Mid-C day-ahead prices. Graessley *et al.*, BP-20-E-BPA-25, at 12. This led Staff to conclude that whenever JP01 finds that the hourly rate caused a reduction in Mid-C prices, its real conclusion is Mid-C prices decreased due to “the intertwined, cumulative, and joint impacts of BPA’s transmission rate increase, PGE joining the EIM, and the influence of everything that happened in FY 2018 that was not explicitly included in one of the other input variables.” *Id.* at 11.

Staff, Powerex, and PPC pointed out numerous other flaws and errors in JP01’s regression analysis. JP01’s analysis suggests “that increases in [Pacific Northwest] loads of *any* magnitude will have *no* significant impact on prices.” *Id.* at 19 (emphasis in original). JP01 does not explain why an increase in demand for power would have no impact on price.

JP01’s analysis also relied only on generation within BPA’s balancing authority area. *Id.* at 12. This does not represent all generation in the Pacific Northwest. During FY 2018, after the BP-18 hourly rate increase went into effect, 2,000 MW of wind generation and the Centralia coal plant left the BPA balancing authority area and joined other balancing authority areas. *Id.* Although this did not impact these plants’ ability to generate power and “the actual impact of the plants continued to affect the Mid-C price,” these generators simply disappeared from JP01’s analysis. *Id.* In its Initial Brief, JP01 concedes that it made this error, but argues that Staff did not show that this error was enough to invalidate JP01’s analysis. JP01 Br., BP-20-B-JP01-01, at 40-41. That is beside the point. This error, combined with the evidence of all the other flaws in JP01’s analysis of Mid-C prices, cumulatively makes that analysis unreliable.

JP01’s regression analysis also did not include the price of natural gas in the Pacific Northwest. See Graessley *et al.*, BP-20-E-BPA-25, at 13-14. JP01 has not addressed this point. Staff explains that the price of natural gas “is the primary driver of the marginal cost of generation from natural gas power plants.” *Id.* Since “natural gas power plants are frequently the marginal resource in the [Pacific Northwest] . . . they frequently set the marginal cost of electricity.” *Id.* at 14. JP01 agrees that the price of natural gas is relevant, but did not include the price of Pacific Northwest natural gas in its analysis. Parker & Peters, BP-20-E-JP01-02, at 8. However, “the prices of acquiring or selling natural gas at trading hubs in close physical proximity to a natural gas power plant should tend to be the gas prices with the most influence over the cost of the power plant’s electricity.” Graessley *et al.*, BP-20-E-BPA-25, at 14. This omission

“fundamentally compromises both JP01’s model and its results.” *Id.* at 15. To its credit, JP01 did include variables representing natural gas prices at Henry Hub (the national benchmark), northern California, and southern California. *Id.* But even here JP01’s results are “particularly troublesome” because they show that power prices would fall as natural gas prices at Henry Hub increased. This “consistently backward interpretation of the link between Henry Hub prices and Mid-C prices is another indication that JP01’s models are performing poorly, and this should cast doubt on the models’ results” *Id.* at 16.

JP01’s use of FERC EQR data in its regression analysis to determine spot market power prices raises questions as well. Contrary to assertions in its Initial Brief, JP01 did not rely on “all transactions reported to FERC.” JP01 Br., BP-20-B-JP01-01, at 34. Instead, JP01 examined only transactions by customers that held long-term firm rights on the Southern Intertie. It ignored any transactions by entities that do not hold those rights. Peters, BP-20-E-JP01-01-CC01, at 39. Like JP01’s omission of generation that is not in BPA’s balancing authority area, it is as if these transactions do not exist. Further, FERC EQR data includes transactions outside of the “well-defined spot markets” for energy that JP01 claims is the sole focus of its analysis. *See* JP01 Br., BP-20-B-JP01-01, at 28; Fredrickson & Linn, BP-20-E-BPA-22, at 20-21. Using FERC EQR data also makes it difficult to distinguish between various spot markets, such as the Mid-C day-ahead market and the Mid-C real-time market. Fredrickson & Linn, BP-20-E-BPA-22, at 20-21.

The results of JP01’s analysis in this proceeding also are inconsistent with the analysis of the alleged impacts of the BP-18 hourly rate that JP01 presented in a pre-BP-20 rate case workshop. In that workshop, JP01 concluded that the hourly rate caused “export volume on the Southern Intertie to decrease by about 33%,” yet this would cause Mid-C prices to decline by only \$1.05/MWh. Fredrickson & Linn, BP-20-E-BPA-22-AT03, at 12-14. In other words, JP01 found that a major decrease in Southern Intertie flows would only impact Mid-C prices by little more than a dollar per megawatt-hour. In this proceeding, however, JP01 found that a statistically significant *increase* in volume at COB and in the day-ahead market at NOB corresponds to a \$7.87/MWh decline in prices in the Mid-C day-ahead market and \$5.18/MWh in the Mid-C real-time market. Parker & Peters, BP-20-E-JP01-02, at 13. In other words, JP01 concluded that the level of harm to BPA’s preference customers was 500 to 700 percent greater than its previous analysis despite an increase in exports from the Pacific Northwest to California. The discrepancies between JP01’s previous analysis and its current analysis should have indicated to JP01 the need to explain its results.

The evidence shows that the hourly rate had no effect on Mid-C prices. Staff states that the hourly rate had “no discernible impact on Mid-C power prices” because the hourly rate did not affect Pacific Northwest exports to California. Fredrickson & Linn, BP-20-E-BPA-22, at 16. Powerex testifies that FY 2018 Mid-C prices were 22 percent higher than in FY 2017, despite the BP-18 hourly rate. Wellenius, BP-20-E-PX-01, at 6. BPA also attaches meaningful significance to the fact that PPC finds that the hourly rate is not negatively affecting BPA’s preference customers. JP04 Br., BP-20-B-JP04-01, at 4-5. Nearly all of BPA’s preference customers are members of PPC, and PPC is in a much better position to determine harm to BPA’s preference customers than JP01. Similarly, AWEC’s support of the hourly rate indicates that the hourly rate

is not negatively affecting large consumers of power in the Pacific Northwest. AWEC Br., BP-20-B-AW-01, at 6-8.

JP01's theory that the BP-18 hourly rate reduced Mid-C prices, despite an increase in exports from the Pacific Northwest to California, is unsound and not supported by the evidence. In addition, JP01's regression analysis purporting to show that the hourly rate decreased Mid-C prices contains numerous flaws and errors and, as a result, JP01's finding of harm to Pacific Northwest preference customers, is not credible.

Decision

BPA's hourly rate is not harming BPA's preference customers in the Pacific Northwest.

Issue 4.1.6

Whether to adopt JP01's recommendations to use the pre-BP-18 rate design for FY 2020–2021 hourly rates, discount current hourly rates from north to south on the Southern Intertie, and adopt rules regarding contested settlements.

Parties' Positions

JP01 makes three separate recommendations. It states that BPA should: (1) revert to the pre-BP-18 hourly rate design for the FY 2020–2021 hourly rates, (2) discount the current hourly rate from north to south on the Southern Intertie, and (3) adopt rules to govern contested settlements. JP01 Br., BP-20-B-JP01-01, at 20, 56-57.

JP04 supports adopting the hourly rate in the Settlement and opposes JP01's recommendation to discount the current hourly rate from north to south. JP04 Br., BP-20-B-JP04-01, at 32-33.

BPA Staff's Position

Staff recommends adopting the hourly rate in the Settlement and rejecting JP01's proposal to discount the current hourly rate from north to south. Fredrickson & Linn, BP-20-E-BPA-22, at 29-30. JP01's Initial Brief was the first time that JP01 has proposed the adoption of new rules, so Staff has not taken a position on that issue.

Evaluation of Positions

As described in Issue 4.1.2, JP01 maintains that the record contains insufficient evidence to demonstrate that the circumstances that led to the decision to change the hourly rate design in the BP-18 proceeding are still present at this time. JP01 Br., BP-20-B-JP01-01, at 14-20. JP01 adds that it doubts that those circumstances ever existed. *Id.* To address this alleged deficiency, JP01 recommends that BPA "revert its rate design for hourly service on the Southern Intertie to the pre-BP-18 methodology." *Id.* at 20.

The discussion in Issue 4.1.2 describes the evidence demonstrating that the circumstances that led to changing the hourly rate design in the BP-18 proceeding are still present today. BPA

disagrees with JP01's view of the record on that point. JP01's Initial Brief is the first time JP01 has suggested to "revert" to the "pre-BP-18" rate design in this proceeding, so the record includes no specific discussion of that option. The evidence from the BP-18 proceeding, which JP01 added to the record, is probably the most relevant evidence on that proposal, and BPA already decided that the weight of that evidence supports changing the pre-BP-18 rate design. BPA has no evidence or rationale to adopt JP01's recommendation under these circumstances.

JP01's other two recommendations are outside the scope of this proceeding. JP01 suggests discounting current (BP-18) hourly rates from north to south on the Southern Intertie to incentivize customers reserving hourly transmission prior to the operating hour and to address the alleged adverse impacts of the BP-18 rate increase. Peters, BP-20-E-JP01-01-CCO1, at 47; JP01 Br., BP-20-B-JP01-01, at 57-58. The proposal to discount current rates is not within the scope of this proceeding. Fredrickson & Linn, BP-20-E-BPA-22, at 29-30. Also, contrary to JP01's testimony, BPA does not need to discount the hourly rate for customers that reserve hourly service 80 minutes to 200 minutes before the operating hour. Peters, BP-20-E-JP01-01-CCO1, at 47-48. BPA sells almost no hourly firm service on the Southern Intertie, and the majority of hourly non-firm service is reserved well before the operating hour. Fredrickson & Linn, BP-20-E-BPA-25, at 29-30. In addition, as described in Issues 4.1.3 and 4.1.5, BPA does not agree that the evidence shows that the BP-18 hourly rate has had unintended consequences or adverse impacts. BPA is not adopting JP01's recommendation for a discount for those reasons.

JP01 also suggests adopting rules for contested settlements that would "not lock BPA itself into supporting a particular position" and would not prevent Staff from examining evidence that might change Staff's position. JP01 Br., BP-20-B-JP01-01, at 56-57. JP01 maintains that Staff "disabled" itself in this proceeding by agreeing to support the Settlement. *Id.* at 2. JP01 raised this proposal for the first time in its Initial Brief, and Staff and parties have not taken a position on the issue.

JP01's proposal to adopt a new rule is outside the scope of this proceeding. Nevertheless, BPA was not "locked in" to a particular result by Staff's agreement to submit an Initial Proposal for transmission rates based on the Settlement. Staff's Initial Proposal is the start of the hearing process required under the Northwest Power Act, but the purpose of that process is to develop a record to decide whether to adopt Staff's proposal or some alternative. JP01 has been afforded all the process that the Northwest Power Act requires to develop the record in this proceeding. Indeed, for a proceeding that started with a narrow objection to the non-precedential settlement of an hourly rate that JP01 does not pay and that applies to only a small number of transactions on one part of BPA's system, the record now contains a huge volume of material encompassing virtually the entire discussion of the issue over the past four years. The issue is not that Staff and other parties somehow disabled themselves from thoroughly evaluating the evidence JP01 submitted in opposition to the Settlement. The record shows that Staff and the parties thoroughly evaluated that evidence and found it lacking. *See* Issues 4.1.2 to 4.1.5.

Decision

JP01's recommendations are outside the scope of this proceeding, unsupported by the evidence and otherwise unjustified.

5.0 PARTICIPANT COMMENTS

This chapter summarizes and evaluates the comments of participants in the rate case. As defined in BPA’s procedures for conducting rate proceedings, “participants” are persons who 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 December 6, 2018, BPA published in the Federal Register a Notice of “Fiscal Year (FY) 2020–2021 Proposed Power and Transmission Rate Adjustments Public Hearing and Opportunities for Public Review and Comment.” 83 Fed. Reg. 62,849 (2018). The Federal Register notice may be viewed at the link: <https://www.govinfo.gov/app/details/FR-2018-12-06/2018-26422/context>. The Federal Register notice set a deadline of March 1, 2019 for participant comments. *Id.* at 62,850.

BPA received one comment through the participant comment process. A summary of the participant comment, and BPA’s response, is provided below.

Comment RHWMP20180002. Participant Pace suggests that the March 1, 2019, deadline for participant comments is contrary to the Northwest Power Act. The Act provides the public an opportunity to submit comments related to the proposed rates. 16 U.S.C. § 839e(i). The March 1 date was established to allow participants to submit comments after all issues had been identified by the litigants in the formal hearing; that is, after BPA filed its Initial Proposal and the parties filed their direct cases (the direct cases respond to BPA’s proposal and include any additional affirmative arguments). BPA did not receive any requests to extend the March 1 deadline.

Mr. Pace also suggests that the PNW Power and Conservation Council’s (Council) “cost” is in excess of that allowed by statute, and the costs of the fish and wildlife program support “a money laundering mechanism . . . for . . . bribes to tribes to remain silent” regarding “inadequacies in the biological opinion for operation of the FCRPS and upper Snake reservoirs.” The cost of the Council, however, while included in BPA’s revenue requirement, is established outside of BPA’s rate cases. Before BPA begins a rate case, it conducts a process called the Integrated Program Review (IPR) where the costs of BPA’s programs are reviewed by BPA and interested parties. At the conclusion of the IPR, BPA identifies the costs of its programs that will be included in BPA’s revenue requirement for the upcoming rate case. The “cost” of the Council is outside the scope of the rate case. *See* Fiscal Year (FY) 2020–2021 Proposed Power and Transmission Rate Adjustments Public Hearing and Opportunities for Public Review and Comment, 83 Fed. Reg. at 62,850.

With regard to the claim that the fish and wildlife program expenditures involve a “money laundering scheme” or “bribes,” no evidence has been presented to support such allegations. BPA assumes that Mr. Pace’s comments refer to the Columbia Basin Fish Accords that BPA

signed in 2008, and extended in 2018, 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 biological objectives for fish that address specific statutory responsibilities. 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 and extending the Accords are set forth in records of decision: https://www.bpa.gov/news/pubs/PastRecordsofDecision/2008/MOA_ROD.pdf and <https://www.bpa.gov/news/pubs/RecordsofDecision/rod-20180928-Extensions-of-the-Columbia-Basin-Fish-Accords.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 recovered from customers paying those rates.

Finally, Mr. Pace suggests that BPA intends to spend over two billion dollars for “smartening up the grid,” which would be financed through loans “taken out by what remains of the failed hydro-thermal program.” No documentation or further information was provided to help BPA understand this comment. As noted previously, however, BPA’s program costs are not established in BPA’s rate cases, and this comment is outside the scope of the rate case. *See* Fiscal Year (FY) 2020–2021 Proposed Power and Transmission Rate Adjustments Public Hearing and Opportunities for Public Review and Comment, 83 Fed. Reg. at 62,850.

6.0 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 2020-2021 proposed power and transmission rate adjustments (BP-20). The NEPA analysis was conducted separately from the formal ratemaking process.

In the Federal Register notice for the BP-20 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. 83 Fed.Reg. 62,849, 62,853 (2018). No comments concerning NEPA compliance and potential environmental effects of the proposal were received before the comment deadline of March 1, 2019.

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 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-20 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 the BPA website: <https://www.bpa.gov/efw/Analysis/CategoricalExclusions/Pages/2019.aspx>.

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7.0 CONCLUSION

As required by law, the rates established and adopted in this Final Record of Decision have been set to recover the costs associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the FCRPS (including irrigation costs required to be repaid out of power revenues) over a reasonable period of years and the other costs and expenses incurred by the Administrator in carrying out the requirements of the Northwest Power Act and other provisions of law. In addition, these rates have been designed to be 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 2020–2021 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 establish the accompanying 2020 Power Rate Schedules and General Rate Schedule Provisions and the 2020 Transmission, Ancillary, and Control Area Service Rate Schedules and General Rate Schedule Provisions as 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 25th day of July, 2019.

/s/ Elliot E. Mainzer

Elliot E. Mainzer

Administrator and Chief Executive Officer

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Appendix A

BP-20 Partial Rates Settlement Agreement

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BP-20 PARTIAL RATES SETTLEMENT AGREEMENT

Bonneville Power Administration BP-20 Rate Case Transmission, Ancillary, and Control Area Services Rates

THIS PARTIAL RATES SETTLEMENT AGREEMENT (“Agreement” or “BP-20 Partial Rates Settlement Agreement”) is among the Bonneville Power Administration (“Bonneville”) and parties to the BP-20 rate proceeding as provided for in section 3 of this Agreement (such parties in the singular, “Party,” in the plural, “Parties”).

RECITALS

- A. Bonneville and the Parties have been engaged in settlement discussions with respect to Transmission, Ancillary, and Control Area Services Rates and General Rate Schedule Provisions (“Transmission Rates”) for the FY 2020–2021 Rate Period (“Rate Period”);
- B. In addition to discussion of Transmission Rates for the Rate Period, the settlement discussions have addressed issues related to Bonneville’s proposal to conduct a proceeding pursuant to Section 212(i)(2)(A) of the Federal Power Act (the “TC-20 proceeding”) to establish a new open access transmission tariff for transmission service across the Federal Columbia River Transmission System;
- C. As part of the settlement discussions, Bonneville and the Parties have agreed to the terms of settlement for Transmission Rates for the Rate Period and for all issues in the TC-20 proceeding;
- D. Bonneville and its Transmission Customers have agreed to the TC-20 Settlement Agreement;
- E. The terms of this Agreement are intended to be a part of a settlement package that includes the settlement in the TC-20 proceeding; and
- F. The purpose of this Agreement is to document the terms of settlement for Transmission Rates for the Rate Period, without precedent for subsequent rate periods.

AGREEMENT

Bonneville and the Parties agree to the following:

1. In the BP-20 rate proceeding, Bonneville staff will file and recommend that the Administrator adopt a proposal (“Settlement Proposal”) to establish Transmission Rates for the Rate Period as shown in Attachment 1, Proposed 2020 Transmission, Ancillary, and Control Area Services Rate Schedules and General Rate Schedule Provisions (FY 2020–2021). The Settlement Proposal will include only the terms specified in this Agreement and in Attachments 1–3.

2. This Agreement settles, in accordance with its terms, all issues within the scope of the Settlement Proposal for purposes of Transmission Rates in the BP-20 rate proceeding and the Rate Period.
3. Bonneville will notify the Hearing Officer for the BP-20 rate proceeding of this Agreement and move the Hearing Officer to (1) require any party in the BP-20 rate proceeding that does not sign the Agreement to state any objection to the Settlement Proposal and to identify each issue included in the Settlement Proposal that such party chooses to preserve in the BP-20 proceeding by a date established by the Hearing Officer; and (2) specify that any party in the BP-20 rate proceeding that does not state an objection to the Settlement Proposal by such date will waive its rights to preserve any objections to the Settlement Proposal and will be deemed a Party to this Agreement.
4. If, in response to the Hearing Officer's order made pursuant to section 3, any party to the BP-20 rate proceeding states an objection to the Settlement Proposal, Bonneville and any Party to this Agreement will have three business days from the date of the objection to withdraw its assent to the Settlement Proposal. If Bonneville or any Party to this Agreement withdraws its assent to the Settlement Proposal, Bonneville shall promptly schedule a meeting with the Parties to this Agreement to discuss how to proceed and will provide notice and the opportunity to participate to parties to the BP-20 rate proceeding.
5. If the TC-20 proceeding does not result in the adoption of the TC-20 Settlement Agreement, this Agreement will be void *ab initio*.
6. This Agreement will become effective on the date for objections to the Settlement Proposal in the Hearing Officer's order made pursuant to section 3, and will terminate on September 30, 2021; except that, if the Administrator does not adopt the Settlement Proposal in the BP-20 rate proceeding, this Agreement will be void *ab initio*.
7. Preservation of BP-20 Transmission Rates and Settlement Proposal
 - a. If the Administrator adopts the Settlement Proposal, the Parties agree not to contest this Agreement or its implementation pursuant to its terms, from the effective date of this Agreement through the end of the Rate Period.
 - b. The Parties agree to waive their rights to submit data requests and conduct cross-examination in the BP-20 rate proceeding with respect to any issue within the scope of the Settlement Proposal, except in response to issues raised by any party in the BP-20 rate proceeding that objects to this Agreement in response to the Hearing Officer's order made pursuant to section 3.
 - c. Bonneville and the Parties agree that this is a "black box" settlement. Bonneville and the Parties understand, and will not argue otherwise, that this Agreement does not constitute consent or agreement in any future rate proceedings to the Transmission Rates, and that they retain all of their rights to take and argue whatever position they believe appropriate as to such matters.

- d. Bonneville and the Parties acknowledge that this Agreement reflects a compromise in their positions with respect to Transmission Rates for the Rate Period, and that acceptance of the settlement does not create or imply any agreement with any position of any other Party. Bonneville and the Parties agree not to assert in any forum that anything in the Settlement Proposal, or that any action taken or not taken with regard to this Agreement by Bonneville or any Party, the Hearing Officer, the Administrator, the Commission, or a court, creates or implies: (1) agreement to any particular or individual treatment of costs, expenses, or revenues; (2) agreement to any particular interpretation of Bonneville's statutes; (3) any precedent under any contract or otherwise between Bonneville and any Party; or (4) any basis for supporting any Bonneville rate or general rate schedule provision for any period after the Rate Period.
8. Conduct, statements, and documents disclosed in the negotiation of this Agreement will not be admissible as evidence in the BP-20 rate proceeding, any other proceeding, or any other judicial or administrative forum, nor will the fact that the Parties entered into this settlement be cited or used in any future proceedings or Administrator decisions as support for any matters, other than application or enforcement of this Agreement.
9. Reservation of rights
 - a. Except as provided in section 7 above, no Party waives any of its rights, under Bonneville's enabling statutes, the Federal Power Act, or other applicable law, 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. By signing this Agreement, no Party agrees or admits that the level of financial reserves resulting from the Transmission Rates, if any, are acceptable or otherwise appropriate, and nothing in this Agreement shall limit, waive, or otherwise alter a Party's right to challenge in future rate proceedings the level of Bonneville's financial reserves.
 - c. Except as provided in section 7 above, no Party waives any rights to challenge the Financial Reserves Policy, Leverage Policy, Access to Capital policies or initiatives, all of which are outside of the scope of this Agreement. In particular, nothing in this Agreement limits, waives, or alters the Parties' rights: (1) to challenge the Leverage Policy Record of Decision under and subject to applicable law; and (2) to challenge, in future rate proceedings, the application of the Leverage Policy or the application of depreciation to assets funded by revenue financing. Furthermore, the Parties are not conceding any application of any such policies by agreeing to this Agreement.
 - d. Nothing in this Agreement limits, waives, or alters Bonneville's right to propose, or a Party's right to contest, the adoption of a Transmission General Rate Schedule Provision in the BP-20 rate proceeding to provide for a Financial Reserves Policy Surcharge, as described in the Financial Reserves Policy Phase-In Implementation Record of Decision, dated September 25, 2018.

- e. Bonneville and the Parties reserve the right to respond during the Rate Period to any filings, protests, or claims, by Bonneville, any Party, or others; however, the Parties will not support a challenge to any rates, terms and conditions, or other matters described in this Agreement.
10. All Transmission, Ancillary, and Control Area Service Rates and General Rate Schedule Provisions, as reflected in Attachment 1, are part of this Agreement, and cannot be contested in the BP-20 rate proceeding. For purposes of clarity, Power rates and the terms of the Transmission Cost Recovery Adjustment Clause and the Transmission Reserves Distribution Clause, sections II.H and II.I of the General Rate Schedule Provisions, respectively, are not within the scope of this Agreement or the Settlement Proposal.
 11. If, because of a ruling issued in response to a legal challenge, Bonneville is required to materially modify or discontinue any of the rates, terms and conditions, or other matters provided in this Agreement, Bonneville may seek, and the other Parties agree to support, or not contest, a stay of enforcement of that ruling until after the Rate Period.
 12. Attachment 1, Proposed 2020 Transmission, Ancillary, and Control Area Service Rate Schedules and General Rate Schedule Provisions (FY 2020–2021), Attachment 2, Rate Period Terms for Generation Inputs, and Attachment 3, Inter-business Line Allocations, are made part of this Agreement.
 13. 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 Parties’ rights to challenge such revisions.
 14. Notwithstanding section 6 of this Agreement, sections 7, 8, and 9 will survive termination or expiration of this Agreement.
 15. This Agreement may be executed in counterparts each of which is an original and all of which, taken together, constitute one and the same instrument.

Customer Name: _____

Bonneville Power Administration

Signature: _____

Signature: RICHARD SHAHEEN
Digitally signed by RICHARD SHAHEEN
Date: 2018.11.30 11:27:30 -08'00'

Signatory: _____

Richard L. Shaheen, P.E.

Title: _____

Senior Vice President, Transmission Services

Date: _____

Date: **11-30-18**

ATTACHMENTS

Attachment 1 – Proposed 2020 Transmission, Ancillary, and Control Area Services Rate Schedules and General Rate Schedule Provisions (FY 2020–2021)

Attachment 2 – Rate Period Terms for Generation Inputs

Attachment 3 – Inter-business Line Allocations

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Attachment 1 – BP-20 PARTIAL RATES SETTLEMENT AGREEMENT

**BONNEVILLE POWER ADMINISTRATION
PROPOSED 2020 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-20.1
FORMULA POWER TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes the FPT-18.1 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:

$$\left(1 + \frac{GSR_q}{\$1.726\text{kW/mo}} \right) * \text{FPT Base Charges}$$

Where:

GSR_q = The ACS-20 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	\$0.0729 per mile
2. Main Grid Interconnection Terminal	\$0.76kW
3. Main Grid Terminal	\$0.84/kW
4. Main Grid Miscellaneous Facilities	\$4.16/kW

SECONDARY SYSTEM CHARGES

1. Secondary System Distance	\$0.7173 per mile
2. Secondary System Transformation	\$7.84/kW
3. Secondary System Intermediate Terminal	\$3.03/kW
4. Secondary System Interconnection Terminal	\$2.14/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.G.

D. TRANSMISSION RESERVES DISTRIBUTION CLAUSE

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause, specified in GRSP II.H.

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FPT-20.3 FORMULA POWER TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes the FPT-18.3 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:

$$\left(1 + \frac{\text{GSR}_q}{\$1.726\text{kW/mo}} \right) * \text{FPT Base Charges}$$

Where:

- GSR_q = The ACS-20 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	\$0.0728 per mile
2.	Main Grid Interconnection Terminal	\$0.76/kW
3.	Main Grid Terminal	\$0.84/kW
4.	Main Grid Miscellaneous Facilities	\$4.15/kW
SECONDARY SYSTEM CHARGES		
1.	Secondary System Distance	\$0.7160 per mile
2.	Secondary System Transformation	\$7.83/kW
3.	Secondary System Intermediate Terminal	\$3.03/kW
4.	Secondary System Interconnection Terminal	\$2.14/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.

NT-20 NETWORK INTEGRATION RATE

SECTION I. AVAILABILITY

This schedule supersedes the NT-18 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

\$1.771 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.

Except as provided below, 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 = \$1.771 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.

Notwithstanding the formula above, the amount of the credit given for a particular DNR SD will be limited to the amount of the monthly charges for NT Service for that DNR SD.

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.G.

I. TRANSMISSION RESERVES DISTRIBUTION CLAUSE

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause, specified in GRSP II.H.

PTP-20 POINT-TO-POINT RATE

SECTION I. AVAILABILITY

This schedule supersedes the PTP-18 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. 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

\$1.533 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** \$0.070 per kilowatt per day
- b. Day 6 and beyond** \$0.050 per kilowatt per day

2. Hourly Firm and Non-Firm Service

4.41 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.G.

L. TRANSMISSION RESERVES DISTRIBUTION CLAUSE

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause, specified in GRSP II.H

IS-20
SOUTHERN INTERTIE RATE

SECTION I. AVAILABILITY

This schedule supersedes the IS-18 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

\$1.084 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** \$0.050 per kilowatt per day
- b. Day 6 and beyond** \$0.036 per kilowatt per day

2. Hourly Firm and Non-Firm Service

9.98 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.G.

J. TRANSMISSION RESERVES DISTRIBUTION CLAUSE

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause, specified in GRSP II.H.

IM-20
MONTANA INTERTIE RATE

SECTION I. AVAILABILITY

This schedule supersedes the IM-18 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

\$0.506 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 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.G.

J. TRANSMISSION RESERVES DISTRIBUTION CLAUSE

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause, specified in GRSP II.H.

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UFT-20

USE-OF-FACILITIES TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes the UFT-18 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-20
ADVANCE FUNDING RATE

SECTION I. AVAILABILITY

This schedule supersedes the AF-18 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-20
TOWNSEND-GARRISON TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes the TGT-18 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.

RC-20
REGIONAL COMPLIANCE ENFORCEMENT AND REGIONAL
COORDINATOR RATES

SECTION I. AVAILABILITY

This schedule supersedes the PW-18 rate schedule. The rates in this schedule recover the costs billed to BPA by the “regional entity” and the “reliability coordinator” for reliability compliance monitoring and enforcement and reliability coordination services. The rates apply to all loads in the BPA Control Area except for loads of customers billed directly by the regional entity and the reliability coordinator. 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. REGIONAL COMPLIANCE ENFORCEMENT RATE

0.05 mills per kilowatthour

B. REGIONAL COORDINATOR RATE

0.04 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-20 OVERSUPPLY RATE

SECTION I. AVAILABILITY

This schedule supersedes the OS-18 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, 2019, through September 30, 2021. The Oversupply Charge shall remain in effect until all costs incurred pursuant to OATT Attachment P during the FY 2020-2021 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 *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-20
EASTERN INTERTIE RATE

SECTION I. AVAILABILITY

This schedule supersedes the IE-18 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-20
ANCILLARY AND CONTROL AREA SERVICE RATES

SECTION I. AVAILABILITY

This schedule supersedes the ACS-18 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 and on the Southern Intertie are each charged separately for Scheduling, System Control, and Dispatch Service.

1. RATES

a. NT Service

The rate shall not exceed \$0.365 per kilowatt per month.

b. Long-Term Firm PTP Transmission Service

The rate shall not exceed \$0.317 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 \$0.010 per kilowatt per day

(2) Hourly Firm and Non-Firm Service

The rate shall not exceed 0.91 mills per kilowatthour.

2. BILLING FACTORS

a. Point-To-Point Transmission Service

For Transmission Customers taking Point-to-Point Transmission Service (PTP and IS), 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-20).

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 2020 and FY 2020 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, 2019, 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, 2019 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-20).

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 is the continuous balancing of resources with load by providing 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 0.49 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-20 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 9.53 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 10.96 mills per kilowatthour.

For energy delivered, the generator shall purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence.

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 Current Transmission Rates website 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 8.32 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 9.57 mills per kilowatthour.

For energy delivered, the Transmission Customer (for interruptible imports only) or the generator shall purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence.

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 Current Transmission Rates website 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 is the continuous balancing of resources with load by providing 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 0.49 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 Dispatchable Energy Resources operating in the BPA Balancing Authority Area.

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-20 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-20 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 9.53 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 10.96 mills per kilowatthour.

For energy delivered, the customer shall purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence.

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 Current Transmission Rates website 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

- . For customers that elect to purchase Operating Reserve – Supplemental Reserve Service from BPA, the rate shall not exceed 8.32 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 9.57 mills per kilowatthour.

For energy delivered, the customer shall purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence.

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 Current Transmission Rates website 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

The total charge for Balancing Service is the applicable rate in section 2.a. or 2.b, below, plus Direct Assignment Charges under section 3 and Intentional Deviation Penalty Charges under section 4.

a. BALANCING SERVICE RATES FOR WIND RESOURCES

(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 \$0.10 per kilowatt per month
- (b) Following Reserves \$0.40 per kilowatt per month
- (c) Imbalance Reserves \$0.43 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 \$0.10 per kilowatt per month
- (b) Following Reserves \$0.38 per kilowatt per month
- (c) Imbalance Reserves \$0.15 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 \$0.10 per kilowatt per month
- (b) Following Reserves \$0.37 per kilowatt per month
- (c) Imbalance Reserves \$0.62 per kilowatt per month

b. BALANCING SERVICE RATES FOR SOLAR RESOURCES

(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 \$0.14 per kilowatt per month
- (b) Following Reserves \$0.26 per kilowatt per month
- (c) Imbalance Reserves \$0.29 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.

\$0.37 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 \$0.14 per kilowatt per month
- (b) Following Reserves \$0.26 per kilowatt per month
- (c) Imbalance Reserves \$0.51 per kilowatt per month

c. BILLING FACTOR

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

- (1) For each plant, or phase of a 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 plant, or phase of a 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 plant, or phase of a 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 and 2.b 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 sections 2.a and 2.b 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. 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 2021, but chooses to interconnect during the FY 2020–2021 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 \$0.280 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.

4. 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 15.11 mills per kW maximum hourly deviation
- b. Decremental Reserves 1.59 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 2021 but chooses to interconnect during the FY 2020-2021 rate period;
- c. a customer operating in another Balancing Authority Area chooses to dynamically transfer into the BPA Balancing Authority Area during the FY 2020-2021 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 \$0.280 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.

G. NEW GENERATION TECHNOLOGY PILOT PROGRAM

A customer and BPA may jointly develop a pilot program at the individual generation project level in order to integrate new uses of technology, such as a solar project coupled with a co-located battery. The goal of the pilot is to reduce the project’s balancing reserve capacity burden placed on the Bonneville balancing authority area. In place of any normally applicable Regulation and Frequency Response, VERBS or DERBS rates, Bonneville will instead directly assign the cost of balancing reserve capacity to the pilot project customer in accordance with the following capacity rate components:

- (a) Regulation Reserve INC \$0.264 per kilowatt-day
- (b) Following Reserve INC \$0.256 per kilowatt-day
- (c) Imbalance Reserve INC \$0.250 per kilowatt-day
- (d) DEC Balancing Reserves \$0.022 per kilowatt-day

These rates are applied to the balancing reserve capacity BPA determines is needed for the pilot (not the installed nameplate of the project), and shall not exceed the total cost of the normally applicable Regulation and Frequency Response, VERBS, or DERBS rates. On a monthly basis, BPA shall revisit the amount of balancing reserves required for the project based on actual operational data for that project. All other rates required for the project shall apply.

A customer participating in a pilot program may still be subject to any applicable Intentional Deviation or Persistent Deviation penalties if operation of the project is not consistent with the pilot program expectations, resulting in the pilot adding to rather than reducing the Station Control Error of the project.

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 FOR TRANSMISSION COST RECOVERY ADJUSTMENT CLAUSE, TRANSMISSION RESERVES DISTRIBUTION CLAUSE, AND TRANSMISSION FINANCIAL RESERVES POLICY SURCHARGE

Customers taking Scheduling, System Control, and Dispatch Service under this rate schedule are subject to the Transmission Cost Recovery Adjustment Clause, the Transmission Reserves Distribution Clause, and the Transmission Financial Reserves Policy Surcharge, specified in GRSPs II.G, II.H, and II.I.

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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, 2019. All rate schedules shall remain in effect until they are replaced or expire on their own terms.

B. General Provisions

These BP-20 rate schedules and the GRSPs associated with these schedules supersede BPA's BP-18 rate schedules (which became effective October 1, 2017) 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-20 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-20) Rate, section III

b. Utility Delivery

\$1.324 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.G.

b. Transmission Reserves Distribution Clause

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause, specified in GRSP II.H.

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 Transmission Rates website the name of the index to be used. BPA will not change the index more often than once per year unless BPA determines that the existing index is no longer a reliable price index.

2. BILLING FACTOR

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

- a. Failure to shed load when directed to do so by BPA in accordance with the Load Shedding provisions of the Open Access Transmission Tariff or any other applicable agreement between the parties. This includes failure to shed load pursuant to such orders within the time period specified by the North American Electric Reliability Council (NERC), Western Electricity Coordinating Council (WECC), or Northwest Power Pool (NWPP) criteria.
- b. Failure of a generator in the BPA Control Area or which directly interconnects to the FCRTS to change or limit generation levels when directed to do so by BPA in accordance with Good Utility Practice as defined in the OATT. This includes failure to change generation levels pursuant to such orders within the time period specified by NERC, WECC, or NWPP criteria.

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

3. WAIVER OR REDUCTION OF A FAILURE TO COMPLY PENALTY CHARGE

BPA may, in its sole discretion, waive or reduce a Failure to Comply Penalty Charge if requested by a customer for good cause shown. In order to qualify for a waiver or reduction in a Failure to Comply Penalty Charge, a customer must submit a request demonstrating that the events resulting in a Failure to Comply Penalty Charge were:

- a. Due to a technical error or malfunction that could not have been avoided through the exercise of reasonable care; and
- b. Were immediately corrected upon discovery of the technical error or malfunction.

BPA will also consider the customer's history of incurring Failure to Comply Penalty Charges in deciding whether to waive or reduce a Failure to Comply Penalty Charge.

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. Transmission Cost Recovery Adjustment Clause (Transmission CRAC)

[intentionally omitted – not within scope of partial settlement agreement]

H. Transmission Reserves Distribution Clause (Transmission RDC)

[intentionally omitted – not within scope of partial settlement agreement]

I. [Reserved for Proposed Transmission Financial Reserves Policy Surcharge (Transmission FRP Surcharge)]

[intentionally omitted – not within scope of partial settlement agreement]

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-20 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.

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.

5. WAIVER OR REDUCTION OF INTENTIONAL DEVIATION PENALTY CHARGE

BPA may, in its sole discretion, waive or reduce an Intentional Deviation Penalty Charge if requested by a customer for good cause shown. In order to qualify for a waiver or reduction of an Intentional Deviation Penalty Charge, a customer must submit a request demonstrating that the events resulting in an Intentional Deviation Penalty Charge were:

- a. Due to a technical error or malfunction that could not have been avoided through the exercise of reasonable care; and
- b. Were immediately corrected upon discovery of the technical error or malfunction.

BPA will also consider the customer's history of incurring Intentional Deviation Penalty Charge in deciding whether to waive or reduce an Intentional Deviation Penalty Charge.

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

BPA Customer ID	Customer Name	Modified TOCAs	
		FY 2020	FY 2021
10005	Alder Mutual	0.0000818	0.0000816
10015	Asotin County PUD #1	0.0000857	0.0000853
10024	Benton County PUD #1	0.0301320	0.0299757
10025	Benton REA	0.0089311	0.0088847
10027	Big Bend Elec Coop	0.0091609	0.0091134
10029	Blachly Lane Elec Coop	0.0026371	0.0026235
10044	Canby, City of	0.0030403	0.0030246
10046	Central Electric Coop	0.0122534	0.0121898
10047	Central Lincoln PUD	0.0232070	0.0231368
10055	Albion, City of	0.0000579	0.0000576
10057	Ashland, City of	0.0030086	0.0029920
10059	Bandon, City of	0.0011234	0.0011197
10061	Blaine, City of	0.0013093	0.0013025
10062	Bonners Ferry, City of	0.0007963	0.0007921
10064	Burley, City of	0.0020924	0.0020851
10065	Cascade Locks, City of	0.0003560	0.0003541
10066	Centralia, City of	0.0036484	0.0036295
10067	Cheney, City of	0.0023678	0.0023555
10068	Chewelah, City of	0.0003845	0.0003830
10070	Declo, City of	0.0000537	0.0000534
10071	Drain, City of	0.0002803	0.0002791
10072	Ellensburg, City of	0.0035902	0.0035716
10074	Forest Grove, City of	0.0039943	0.0039736
10076	Heyburn, City of	0.0007212	0.0007175
10078	McCleary, City of	0.0005565	0.0005536
10079	McMinnville, City of	0.0130347	0.0131321
10080	Milton, Town of	0.0010368	0.0010329
10081	Milton-Freewater, City of	0.0015652	0.0015570
10082	Minidoka, City of	0.0000142	0.0000141
10083	Monmouth, City of	0.0012520	0.0012455
10086	Plummer, City of	0.0005829	0.0005812
10087	Port Angeles, City of	0.0046157	0.0045934
10089	Richland, City of	0.0155475	0.0154669

BPA Customer ID	Customer Name	Modified TOCAs	
		FY 2020	FY 2021
10091	Rupert, City of	0.0014106	0.0014033
10094	Soda Springs, City of	0.0004547	0.0004523
10095	Sumas, Town of	0.0005453	0.0005425
10097	Troy, City of	0.0003027	0.0003026
10101	Clallam County PUD #1	0.0113815	0.0113225
10103	Clark County PUD #1	0.0457296	0.0459166
10105	Clatskanie PUD	0.0131423	0.0138260
10106	Clearwater Power	0.0035639	0.0035561
10109	Columbia Basin Elec Coop	0.0018141	0.0018047
10111	Columbia Power Coop	0.0004584	0.0004568
10112	Columbia River PUD	0.0081991	0.0081680
10113	Columbia REA	0.0056427	0.0056134
10116	Consolidated Irrigation District #19	0.0000340	0.0000339
10118	Consumers Power	0.0068374	0.0068020
10121	Coos Curry Elec Coop	0.0058584	0.0058252
10123	Cowlitz County PUD #1	0.0629891	0.0653668
10136	Douglas Electric Cooperative	0.0027266	0.0027177
10142	East End Mutual Electric	0.0004023	0.0004002
10144	Eatonville, City of	0.0005042	0.0005016
10156	Elmhurst Mutual P & L	0.0048260	0.0048010
10157	Emerald PUD	0.0074787	0.0074399
10158	Energy Northwest	0.0003636	0.0003615
10170	Eugene Water & Electric Board	0.0358338	0.0357020
10172	U.S. Airforce Base, Fairchild	0.0008127	0.0008126
10173	Fall River Elec Coop	0.0049596	0.0049338
10174	Farmers Elec Coop	0.0000748	0.0000742
10177	Ferry County PUD #1	0.0013838	0.0013837
10179	Flathead Elec Coop	0.0249736	0.0248440
10183	Franklin County PUD #1	0.0175677	0.0174766
10186	Glacier Elec Coop	0.0026801	0.0030634
10190	Grant County PUD #2	0.0007771	0.0007731
10191	Grays Harbor PUD #1	0.0194571	0.0193396
10197	Harney Elec Coop	0.0034061	0.0033885
10202	Hood River Elec Coop	0.0019609	0.0019507
10203	Idaho County L & P	0.0009301	0.0009253
10204	Idaho Falls Power	0.0094343	0.0093733

BPA Customer ID	Customer Name	Modified TOCAs	
		FY 2020	FY 2021
10209	Inland P & L	0.0157023	0.0156209
10230	Kittitas County PUD #1	0.0014525	0.0014449
10231	Klickitat County PUD #1	0.0054879	0.0054595
10234	Kootenai Electric Coop	0.0076346	0.0075950
10235	Lakeview L & P (WA)	0.0047304	0.0047260
10236	Lane County Elec Coop	0.0041293	0.0041039
10237	Lewis County PUD #1	0.0164179	0.0163622
10239	Lincoln Elec Coop (MT)	0.0020959	0.0020846
10242	Lost River Elec Coop	0.0014259	0.0014185
10244	Lower Valley Energy	0.0128799	0.0128131
10246	Mason County PUD #1	0.0013221	0.0013250
10247	Mason County PUD #3	0.0119230	0.0118484
10256	Midstate Elec Coop	0.0069724	0.0069616
10258	Mission Valley	0.0056815	0.0056520
10259	Missoula Elec Coop	0.0040398	0.0040189
10260	Modern Elec Coop	0.0039349	0.0039145
10273	Nespelem Valley Elec Coop	0.0008804	0.0008759
10278	Northern Lights	0.0053656	0.0053506
10279	Northern Wasco County PUD	0.0096954	0.0096451
10284	Ohop Mutual Light Company	0.0014788	0.0014726
10285	Okanogan County Elec Coop	0.0009774	0.0009723
10286	Okanogan County PUD #1	0.0068729	0.0068373
10288	Orcas P & L	0.0036435	0.0036338
10291	Oregon Trail Coop	0.0118537	0.0117347
10294	Pacific County PUD #2	0.0052773	0.0052421
10304	Parkland L & W	0.0020576	0.0020524
10306	Pend Oreille County PUD #1	0.0038575	0.0038375
10307	Peninsula Light Company	0.0101507	0.0101059
10326	U.S. Naval Base, Bremerton	0.0044429	0.0044222
10331	Raft River Elec Coop	0.0054082	0.0053874
10333	Ravalli County Elec Coop	0.0027515	0.0027573
10338	Riverside Elec Coop	0.0003552	0.0003534
10342	Salem Elec Coop	0.0057104	0.0056957
10343	Salmon River Elec Coop	0.0018174	0.0018077
10349	Seattle City Light	0.0777693	0.0777998
10352	Skamania County PUD #1	0.0023055	0.0022965

BPA Customer ID	Customer Name	Modified TOCAs	
		FY 2020	FY 2021
10354	Snohomish County PUD #1	0.1091522	0.1084460
10360	Southside Elec Lines	0.0010127	0.0010074
10363	Springfield Utility Board	0.0142705	0.0142215
10369	Surprise Valley Elec Coop	0.0024600	0.0024472
10370	Tacoma Public Utilities	0.0577326	0.0572991
10371	Tanner Elec Coop	0.0016515	0.0016430
10376	Tillamook PUD #1	0.0082032	0.0081778
10378	Coulee Dam, City of	0.0002864	0.0002877
10379	Steilacoom, Town of	0.0007142	0.0007139
10388	Umatilla Elec Coop	0.0169498	0.0168619
10391	United Electric Coop	0.0044875	0.0044642
10406	U.S. DOE Albany Research Center	0.0000686	0.0000683
10408	U.S. Naval Station, Everett (Jim Creek)	0.0002236	0.0002223
10409	U.S. Naval Submarine Base, Bangor	0.0029366	0.0029213
10426	U.S. DOE Richland Operations Office	0.0046022	0.0052230
10434	Vera Irrigation District	0.0040654	0.0040443
10436	Vigilante Elec Coop	0.0028672	0.0028523
10440	Wahkiakum County PUD #1	0.0007412	0.0007367
10442	Wasco Elec Coop	0.0018920	0.0018910
10446	Wells Rural Elec Coop	0.0140089	0.0139502
10448	West Oregon Elec Coop	0.0012244	0.0012173
10451	Whatcom County PUD #1	0.0039649	0.0035230
10482	Umpqua Indian Utility Cooperative	0.0004062	0.0004040
10502	Yakama Power	0.0028005	0.0027859
13927	Kalispel Tribe Utility	0.0004544	0.0005044
10597	Hermiston, City of	0.0018508	0.0018422
10706	Port of Seattle - SETAC In'tl. Airport	0.0025866	0.0025732
11680	Weiser, City of	0.0009473	0.0009424
12026	Jefferson County PUD #1	0.0066949	0.0066890
10007	Alcoa	0.0000000	0.0000000
10312	Port Townsend Paper	0.0018062	0.0017964
10298	PNGC Aggregate	0.0786303	0.0782600

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.

Attachment 2 – BP-20 PARTIAL RATES SETTLEMENT AGREEMENT

Rate Period Terms for Generation Inputs

- a. **Inter-Business Line Allocations.** Bonneville and the Parties agree for the purposes of this Agreement to the Inter-Business Line Allocations described in Attachment 3.
- b. **Solar Technical Work.** As part of the workshop phase of the BP-22 rate case, and starting no later than January, 2020, Bonneville will:
 - i. Present to customers and stakeholders the costs and impacts of holding reserves in a non-flat shape, such as planned shaped diurnal reserve amounts. This presentation(s) will use the BP-18 Solar Integration Study with Solar modeling updates identified and implemented during BP-20 workshops to provide:
 - (a) Up to two shaped balancing reserve forecasts for all Generation Input customer classes (Wind, Solar, DERBS and Load).
 - (b) Forecasts for the different thresholds of installed solar generation in order to identify any meaningful thresholds where a shaped diurnal balancing reserve forecast or other form of planned shaped reserve operation becomes impactful and cost-effective.
 - ii. Analyze and present to customers any Generation Inputs variable and embedded cost allocation differences associated with a shaped balancing reserve operation, including the associated impact on Ancillary and Control Area Service rates. This analysis and presentation will:
 - (a) Assume that shaped balancing reserve held on Bonneville’s system is physically possible.
 - (b) Use a variation of the Generation And Reserves Dispatch (GARD) model or other balancing reserve variable cost estimation method to estimate any material change in Bonneville’s cost of providing balancing reserves associated with a planned shaped balancing reserves operation.

If, following these deliverables, Bonneville staff, customers and stakeholders agree that a shaped balancing reserve operation provides material value, Bonneville will provide customers a list highlighting the workload necessary with approximate completion timelines that would need to occur for Bonneville to be able to implement such an operation.

**Attachment 3 - BP-20 PARTIAL RATES SETTLEMENT AGREEMENT
Used for BPA Transmission and Ancillary Services Rates**

Inter-Business Line Allocations			
	A	B	C
	Generation Inputs	Annual Average for FY 2020-2021 Forecast Quantity (MW)	Annual Average for FY 2020-2021 Revenue Forecast
1	Regulating Reserve	5,881	\$ 24,833,500
2	Balancing Reserve Capacity for VERBS wind, VERBS solar and DERBS		\$ 31,587,700
3	Operating Reserve - Spinning	233.0	\$ 18,675,000
4	Operating Reserve - Supplemental	233.0	\$ 16,297,000
5	Operating Reserve Total	466.0	\$ 34,972,000
6	Synchronous Condensing		\$ 831,360
7	Generation Dropping		\$ 497,838
8	Redispatch		\$ 250,000
9	Segmentation of COE/Reclamation Network and Delivery Facilities		\$ 8,806,000
10	Station Service		\$ 1,660,037
11	Generation Inputs Total		\$ 103,438,435

** Numbers based on a settled weighted average cost of \$7.65 kW/mo (\$8.54/kW/mo for Balancing Reserves and \$6.52/kW/mo for Operating Reserves).

[The inter-business line allocations shown on this table were updated for the balancing service elections and the operating reserve elections in spring 2019. The amounts used in the Final Proposal are shown in the Power Rates Study Documentation, BP-20-FS-BPA-01A, Table 9.3.]

**LIST OF SIGNATORIES TO THE
BP-20 PARTIAL RATES SETTLEMENT AGREEMENT**

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Signatories to the BP-20 Partial Rates Settlement Agreement

The following is a list of parties that signed the BP-20 Partial Rates Settlement Agreement. A copy of the BP-20 Partial Rates Settlement Agreement with original signatory pages is included in Attachment 1 to Motion of Bonneville Power Administration to Establish Deadline for Objection to BP-20 Partial Rates Settlement Agreement and Request for Expedited Consideration, BP-20-M-BPA-01. The City of Centralia and Energy Northwest did not sign the BP-20 Partial Rates Settlement Agreement until after the Motion was filed and are therefore not included in Attachment 1.

Arlington Wind Power Project LLC
Avangrid Renewables, LLC
Avista Corporation
Benton Rural Electric Association
Biogreen Sustainable Energy Company, LLC
Bonneville Power Administration Transmission Services
Canby Utility Board
Central Lincoln People's Utility District
City of Burley
City of Centralia
City of Cheney
City of Chewelah
City of Ellensburg
City of Forest Grove
City of Heyburn
City of Idaho Falls
City of McCleary
City of McMinnville
City of Milton-Freewater
City of Plummer
City of Richland, Washington
City of Rupert
City of Seattle, City Light Department
City of Troy
City of Weiser
Consolidated Irrigation District No. 19
EDP Renewables North America LLC
Energy Northwest (CGS)
Equilon Enterprises LLC dba Shell Oil Products US
Exelon Generation Company, LLC

Flathead Electric Cooperative, Inc.
Hermiston Power, LLC
Hood River Electric Cooperative
Idaho Power Company
Kalispel Tribal Utilities
Missoula Electric Cooperative, Inc.
Modern Electric Water Company
Morgan Stanley Capital Group, Inc.
Nespelem Valley Electric Cooperative, Inc.
New Sun Energy Transmission Company LLC
Northern Wasco County People's Utility District
Ohop Mutual Light Company
Okanogan County People's Utility District No. 1
Oregon Trail Electric Consumers Cooperative, Inc.
Outback Solar, LLC
Pacific Northwest Generating Cooperative
PacifiCorp
Pend Oreille County PUD No. 1
Port of Seattle - Seattle-Tacoma International Airport
Powerex Corporation
Public Utility District No. 1 of Clallum County
Public Utility District No. 1 of Cowlitz County
Public Utility District No. 1 of Ferry County
Public Utility District No. 1 of Franklin County
Public Utility District No. 1 of Grays Harbor County
Public Utility District No. 1 of Klickitat County
Public Utility District No. 1 of Lewis County
Public Utility District No. 1 of Snohomish County
Public Utility District No. 1 of Whatcom County
Public Utility District No. 2 of Pacific County
Public Utility District No. 3 of Mason County
Renewable Northwest
Sagebrush Power Partners, LLC
Salem Electric
Salmon River Electric Cooperative, Inc.
Shell Energy North America (US), LP
South Side Electric, Inc.
Springfield Utility Board
Tacoma Power
Town of Coulee Dam

United Electric Co-op, Inc.
Utah Associated Municipal Power Systems
Vera Water & Power
Vigilante Electric Cooperative, Inc.
Wheat Field Wind Power Project LLC
Yakama Power

BP-20 Rate Proceeding

**ADMINISTRATOR'S FINAL
RECORD OF DECISION**

Appendix B: 2020 Power Rate
Schedules and General Rate Schedule
Provisions

BP-20-A-03-AP02

July 2019

BONNEVILLE POWER ADMINISTRATION
2020 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-20 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, 2019, this rate schedule supersedes the PF-18 rate schedule. Sales under the PF-20 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	1,980,553	(200,365)	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	11.42
November	12.07
December	13.45
January	12.10
February	11.66
March	9.19
April	8.61
May	5.60
June	5.04
July	10.27
August	12.10
September	11.91

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.

If a customer does not supply the Super Peak amount listed in its CHWM Contract, Exhibit A, Section 9 for at least two hours of the Super Peak Period, then the customer does not receive a Super Peak Credit for that month.

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	23.84	18.88
November	25.19	21.84
December	28.09	23.56
January	25.24	19.21
February	24.36	19.28
March	19.19	16.11
April	17.98	14.40
May	11.71	6.55
June	10.52	1.68
July	21.45	15.31
August	25.24	20.21
September	24.86	19.98

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:

Customer’s Actual Monthly/Diurnal Tier 1 Load,
in kilowatthours
minus
Customer’s System Shaped Load for the relevant
diurnal period, in kilowatthours.

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 = RHWM Tier 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 Risk Adjustments

The Power CRAC (GRSP II.O); the Power RDC (GRSP II.P); and the Power FRP Surcharge (GRSP II.Q) are adjustments to certain Tier 1 rates that apply to the following products under the PF-20 rate schedule: Load Following, Block, and the Block portion of Slice/Block. Any adjustments to rates and GRSPs during the Rate Period due to such risk adjustments are summarized in GRSP Appendix A.

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 customers' CHWM Contracts, Exhibit C, Section 2.5.

2.2.2.1 Short-Term Rate

<i>Fiscal Year</i>	<i>Rate in mills/kWh</i>
2020	30.32
2021	33.00

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.

3. Priority Firm Merged Rate

The PF Merged rate is applicable to the sale of Firm Requirements Power under contracts other than CHWM Contracts.

Rates under contracts that contain charges that escalate based on BPA's PF rate shall be based on the rates listed in this section in addition to any applicable transmission and ancillary service charges.

The PF Merged 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	38.68	33.72
November	40.03	36.68
December	42.93	38.40
January	40.08	34.05
February	39.20	34.12
March	34.03	30.95
April	32.82	29.24
May	26.55	21.39
June	25.36	16.52
July	36.29	30.15
August	40.08	35.05
September	39.70	34.82

The PF Melded energy rates in the table above are subject to risk adjustments during the Rate Period pursuant to the Power CRAC (GRSP II.O); the Power RDC (GRSP II.P); and the Power FRP Surcharge (GRSP II.Q). Any adjustments to rates and GRSPs during the Rate Period due to such risk adjustments are summarized in GRSP Appendix A.

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	11.42
November	12.07
December	13.45
January	12.10
February	11.66
March	9.19
April	8.61
May	5.60
June	5.04
July	10.27
August	12.10
September	11.91

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-20 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	52.03	11.87	63.89580
Idaho Power	52.03	9.09	61.11240
NorthWestern	52.03	22.15	74.17480
PacifiCorp	52.03	20.46	72.48300
Portland General	52.03	18.29	70.31570
Puget Sound Energy	52.03	16.99	69.01780
<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	52.13	2.22	54.35
Snohomish County PUD No 1	52.13	1.86	53.99

6.2 Energy Billing Determinant

The billing determinant for the PF Exchange Power charge is the customer's Residential Load specified in GRSP ILS, 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.

<i>GRSP II.</i>	<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>Applicable to:</i>			
		<i>Load Following</i>	<i>Firm Requirements</i>		<i>REP</i>
			<i>Block only and Block Portion of Slice/Block</i>	<i>Slice Portion of Slice/Block</i>	
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	

<i>GRSP II.</i>	<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>Applicable to:</i>				<i>REP</i>
		<i>Firm Requirements</i>				
		<i>Load Following</i>	<i>Block only and Block Portion of Slice/Block</i>	<i>Slice Portion of Slice/Block</i>		
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	Power Financial Reserves Policy (Power FRP) Surcharge	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	
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	

<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	Supplemental Information	X	X	X

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SCHEDULE NR-20 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, including planned NLSLs, as defined in Exhibit D of a customer's CHWM Contract. This schedule also 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, 2019, this rate schedule supersedes the NR-18 rate schedule. Sales under the NR-20 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	84.43	79.47
November	85.78	82.43
December	88.68	84.15
January	85.83	79.80
February	84.95	79.87
March	79.78	76.70
April	78.57	74.99
May	72.30	67.14
June	71.11	62.27
July	82.04	75.90
August	85.83	80.80
September	85.45	80.57

2.1.1.1 REP Surcharge

Each energy rate in the table above reflects an REP Surcharge of 6.93 mills/kWh.

2.1.1.2 Risk Adjustments

The NR energy rates in Section 2.1.1 are subject to risk adjustments during the Rate Period pursuant to the Power CRAC (GRSP II.O); the Power RDC (GRSP II.P); and the Power FRP Surcharge (GRSP II.Q). Any adjustments to rates and GRSPs during the Rate Period due to such risk adjustments are summarized in GRSP Appendix A.

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	11.42
November	12.07
December	13.45
January	12.10
February	11.66
March	9.19
April	8.61
May	5.60
June	5.04
July	10.27
August	12.10
September	11.91

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-20 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 tables.

<i>GRSP II.</i>	<i>Adjustments, Charges, and Special Rate Provisions</i>
B	Low Density Discount (LDD)
D	Demand Rate Billing Determinant Adjustments
J.1	Energy Shaping Service for NLSLs Charge
J.2	NR Resource Flattening Service Charge
M	Unanticipated Load Service
N	Unauthorized Increase (UAI) Charge
O	Power Cost Recovery Adjustment Clause (Power CRAC)
P	Power Reserves Distribution Clause (Power RDC)
Q	Power Financial Reserves Policy (Power FRP) Surcharge
U	Conservation Surcharge
Y	Flexible New Resource Firm Power (NR) Rate Option
Z	Cost Contributions

<i>GRSP Appendix</i>	<i>Adjustments and Charges</i>
A	Supplemental Information

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**SCHEDULE IP-20
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, 2019, this rate schedule supersedes the IP-18 rate schedule. Sales under the IP-20 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-20 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	45.43	40.47
November	46.78	43.43
December	49.68	45.15
January	46.83	40.80
February	45.95	40.87
March	40.78	37.70
April	39.57	35.99
May	33.30	28.14
June	32.11	23.27
July	43.04	36.90
August	46.83	41.80
September	46.45	41.57

2.1.1.1 REP Surcharge

Each energy rate in the table above reflects an REP Surcharge of 6.93 mills/kWh.

2.1.1.2 Value of Reserves Credit

Each energy rate in the table above reflects a 0.967 mills/kWh credit for the value of the Minimum DSI Operating Reserve – Supplemental.

2.1.1.3 Risk Adjustments

The IP energy rates in Section 2.1.1 are subject to risk adjustments during the Rate Period pursuant to the Power CRAC (GRSP II.O); the Power RDC (GRSP II.P); and the Power FRP Surcharge (GRSP II.Q). Any adjustments to rates and GRSPs during the Rate Period due to such risk adjustments are summarized in GRSP Appendix A.

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	11.42
November	12.07
December	13.45
January	12.10
February	11.66
March	9.19
April	8.61
May	5.60
June	5.04
July	10.27
August	12.10
September	11.91

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 through a contract action, then the Industrial Demand Adjuster value in the above table will be reduced proportionately and reflected in GRSP Appendix A.

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 tables.

<i>GRSP II.</i>	<i>Adjustments, Charges, and Special Rate Provisions</i>
D	Demand Rate Billing Determinant Adjustments
H	DSI Reserves
N	Unauthorized Increase (UAI) Charge
O	Power Cost Recovery Adjustment Clause (Power CRAC)
P	Power Reserves Distribution Clause (Power RDC)
Q	Power Financial Reserves Policy (Power FRP) Surcharge
U	Conservation Surcharge
Z	Cost Contributions

<i>GRSP Appendix</i>	<i>Adjustments and Charges</i>
A	Supplemental Information

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SCHEDULE FPS-20

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. This rate schedule is not available for sales of non-firm power outside of the region.

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, 2019, this rate schedule supersedes the FPS-18 rate schedule. Sales under the FPS-20 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) firm energy with negotiated curtailment rights; (2) resource support and scheduling services for non-Federal resources not eligible for services under Section 7 of this FPS rate schedule; (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); and (4) non-firm energy within the region.

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-20 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>GRSP II.</i>	<i>Adjustments, Charges, and Special Rate Provisions</i>
I.4	Forced Outage Reserve Service (FORS)
I.5	Transmission Scheduling Service/Transmission Curtailment Management Service (TSS/TCMS)
I.7	Resource Remarketing Service (RRS)
M.4	Unanticipated Load Service
N	Unauthorized Increase (UAI) Charge
Z	Cost Contributions

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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 approve these rate schedules and GRSPs effective October 1, 2019. 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 2018 Power rate schedules, which became effective October 1, 2017, 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-20 rate schedule. RT1SC is the Tier 1 System Firm Critical Output plus RHWL Augmentation. The RT1SC values for the FY 2020–2021 rate period are shown in Table A below.

Table A
FY 2020-2021 RHWL Tier 1 System Capability

<i>Month</i>	<i>RT1SC in kWh</i>	
	<i>HLH</i>	<i>LLH</i>
October	3,009,065,388	1,608,251,808
November	3,677,367,528	2,188,065,711
December	3,598,456,672	2,196,143,524
January	3,035,580,672	1,794,571,524
February 2020	2,760,597,124	1,615,019,676
February 2021	2,648,204,932	1,558,823,580
March	3,094,593,816	1,772,482,121
April	2,493,584,744	1,469,193,736
May	3,468,087,100	1,876,310,596
June	4,425,608,244	2,393,479,736
July	3,680,313,244	1,666,067,952
August	3,567,762,744	1,638,547,952
September	2,993,385,600	1,680,773,880

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-20 Composite Customer charge, PF-20 Non-Slice Customer charge, PF-20 Load Shaping charge, PF-20 Load Shaping Charge True-Up Adjustment, PF-20 Demand charge, the Power CRAC (GRSP II.O); the Power RDC (GRSP II.P); and the Power FRP Surcharge (GRSP II.Q). The LDD also applies to eligible customers under the PF-20 Melded rate schedule and the NR-20 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, Demand charge, and risk adjustments). The applicable discount percentage will be adjusted for Above-RHWL Load, as described in Section 6 below.

An LDD dollar benefit will be calculated by BPA for Slice/Block purchases as though it were 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. The applicable discount percentage will also be applied to the customer's monthly billed risk adjustments, if any. 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 46.30 mills/kWh for FY 2020 and FY 2021.
- (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 11.11 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>Fiscal Year</i>	<i>Rate in mills/kWh</i>
2020	-15.19
2021	-15.19

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); and the Power FRP Surcharge (GRSP II.Q). See GRSP Appendix A, Supplemental Information, for adjusted Load Shaping Charge True-Up rates.

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(c) and (d). 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-20 7(i) process and will be made available to the customer prior to October 1, 2019. 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-20 7(i) process by at least 20 percent, this Adjusted TOCA will be used in place of the TOCA calculated in the BP-20 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. Additionally, if the customer's Existing Resource amounts in Exhibit A have changed in accordance with its CHWM Contract, then the customer's TOCA may be updated 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-20 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-20 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 \$7.08 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

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 2.3.6.2(2) of Exhibit D (Exhibit D planned amounts); or (3) planned amounts listed in monthly/diurnal megawatt-per-hour amounts in Section 2.3.6.2(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 RAM2020 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-20 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 RAM2020 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-20 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 (UAIs) 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-20 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	11.42
November	12.07
December	13.45
January	12.10
February	11.66
March	9.19
April	8.61
May	5.60
June	5.04
July	10.27
August	12.10
September	11.91

(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 Charges 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. There are two available service levels of TSS: full service (TSS-Full) and partial service (TSS-Partial).

Transmission Curtailment Management Service (TCMS) is a feature of TSS (both TSS-Full and TSS-Partial) 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) Transmission Scheduling Service Full Service (TSS-Full) Charge

(1) TSS-Full Rate

<i>Fiscal Year</i>	<i>Rate in mills/kWh</i>
2020	0.11
2021	0.11

(2) TSS-Full Billing Determinant

The TSS-Full billing determinants are the annual Exhibit A amounts in kilowatthours. When TSS-Full is provided to a resource to which RRS also applies, the TSS-Full 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-Full Charge

For each eligible resource, the TSS-Full Charge is calculated by multiplying the TSS-Full rate and the TSS-Full 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 \$896/month, then the monthly charge is capped at \$896/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 \$2,688/month, then the monthly charge is capped at \$2,688/month.

For each TSS-Full customer, BPA will determine the number of resources receiving TSS-Full. 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) Transmission Scheduling Service Partial Service (TSS-Partial) Charge

(1) TSS-Partial Rate

<i>Fiscal Year</i>	<i>\$ per TSS-Partial Event</i>
2020	\$185
2021	\$185

(2) TSS-Partial Billing Determinant

The TSS-Partial billing determinant is the total number of TSS-Partial events that occur within a month. Each of the following is considered a single TSS-Partial event:

- (1) a customer, or its scheduling agent, fails to carbon copy (CC) Power Services on a schedule; or
- (2) a day that a customer has a TCMS charge.

(3) Calculation of TSS-Partial Charge

The TSS-Partial charge is calculated by multiplying the TSS-Partial rate by the TSS-Partial billing determinant for each month of the rate period.

(c) 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. If a customer with TSS-Partial fails to CC Power Services on a schedule during a transmission event for a resource supported by TCMS, then the customer will be charged Unauthorized Increase in Energy (GRSP II.N.2) for the amount of energy that was curtailed in place of the TCMS rate. Additionally, the customer may be subject to Unauthorized Increase in Demand if the customer's HLH demand is in excess of its demand entitlement in accordance with GRSP II.N.1.

(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

(d) 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-20 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-20 energy rates in Section 2.1.1 of the NR-20 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 2020–2021 rate period prior to February 1, 2019. 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-20 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 2020–2021.

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 2020–2021.

3. Remarketing Value

For each fiscal year, the Remarketing Value rate shall be:

<i>Fiscal Year</i>	<i>Rate in mills/kWh</i>
2020	28.27
2021	30.84

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 reserves for the customer's load served by transfer.

(a) Transfer Service Operating Reserve Rate

- (1) The rate for the Transfer Service Spinning Operating Reserve Charge shall be equal to the ACS-20 Operating Reserve – Spinning Reserve Service rate.
- (2) The rate for the Transfer Service Supplemental Operating Reserve Charge shall be equal to the ACS-20 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-20 Operating Reserve – Spinning Reserve Service rate, except that the load used to calculate the billing determinant for Power Services' charge shall be the amount of the customer's metered load 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-20 Operating Reserve – Supplemental Reserve Service rate, except that the load used to calculate the billing determinant for Power Services' charge shall be the amount of the customer's metered load served by transfer (non-BPA Balancing Authority Area load) or a portion thereof (if applicable).

3. Transfer Service Regulation and Frequency Response Charge

The Transfer Service Regulation and Frequency Response 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 Regulation and Frequency Response for the customer's load served by transfer.

(a) Transfer Service Regulation and Frequency Response Rate

The rate for the Transfer Service Regulation and Frequency Response Charge shall be equal to the ACS-20 Regulation and Frequency Response rate.

(b) Transfer Service Regulation and Frequency Response Billing Determinant

The monthly billing determinant for the Transfer Service Regulation and Frequency Response Charge shall be the same as that used for the applicable ACS-20 Regulation

and Frequency Response rate, except that the load used to calculate the billing determinant for Power Services' charge shall be the amount of the customer's total load served by transfer (non-BPA Balancing Authority Area load) or a portion thereof (if applicable).

4. Transfer Service Regional Compliance Enforcement Charge

The Transfer Service Regional Compliance Enforcement Rate shall apply to Public customers with load outside the BPA Balancing Authority Area.

(a) Transfer Service Regional Compliance Enforcement Rate

	<i>Rate in mills/kWh</i>
All months	0.03

(b) Transfer Service Regional Compliance Enforcement Billing Determinant

The monthly billing determinant for the Transfer Service Regional Compliance Enforcement Charge shall be the public customer's metered load at points of delivery 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, 2019, that results in an unanticipated increase in a customer's load placed on BPA during the FY 2020–2021 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 2020–2021 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-20, 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-20, Unanticipated Load is:

- New Large Single Loads
- Requirements service requested by investor-owned utilities

Under FPS-20, 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, 2021, 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-20 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-20 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 applicable diurnal period PF Tier 1 Equivalent energy rate (GRSP II.AA);
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.

(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-20 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-20 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 applicable diurnal period energy rate in Section 2.1.1 of the NR-20 rate schedule; 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.

(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-20 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-20 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 applicable diurnal period Resource Replacement rate that equals the PF Tier 1 Equivalent energy rate (GRSP II.AA) from the same diurnal period; 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.

(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	11.42
November	12.07
December	13.45
January	12.10
February	11.66
March	9.19
April	8.61
May	5.60
June	5.04
July	10.27
August	12.10
September	11.91

(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 amounts, not including Super Peak amounts in section 9 of Exhibit A if any, or Exhibit D amounts, 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, 2019, and September 30, 2021.

O. Power Cost Recovery Adjustment Clause (Power CRAC)

The Power CRAC is an upward adjustment to certain rates that apply to the following products under the PF-20 rate schedule: Load Following, Block, and the Block portion of Slice/Block. The Power CRAC also applies to power purchased at the PF Melded rate (PF-20), Industrial Firm Power rate (IP-20), and New Resource Firm Power rate (NR-20).

1. Power CRAC Amount

At the beginning of each fiscal year of the rate period (that is, each “applicable year”), BPA will calculate Accumulated Calibrated Net Revenue for Power (Power ACNR) for the fiscal year preceding the applicable year. If 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 for the period of December 1 through September 30 of the applicable year.

(a) Calculating Power Calibrated Net Revenue (Power CNR) and Accumulated Calibrated Net Revenue (Power ACNR)

Power CNR is Power Net Revenue (Power NR) plus 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).

Power NR Calibration is the sum of the amounts of each Power NR Calibration Event. A Power NR Calibration Event is a financial event not forecast in the BP-20 rate case that (1) impacts Power NR differently than it impacts financial reserves available for risk attributed to Power, and (2) results in a difference between the amounts of such impacts that is greater than \$5 million (positive or negative). Such events may include, but are not limited to, debt management transactions, contract settlements, and changes in non-cash expenses. The amount of a Power NR Calibration Event will be calculated as (1) the impact of the event on financial reserves available for risk attributed to Power, minus (2) the impact of the event on Power NR.

Power ACNR is Power CNR accumulated since the end of FY 2018. Actual 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 Power ACNR for use in determining the Power CRAC that will apply to FY 2020 rates will be the actual Power CNR for FY 2019. The Power ACNR for use in determining the Power CRAC that will apply to FY 2021 rates will be the sum of the actual Power CNR for FY 2019 plus the actual Power CNR for FY 2020.

(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 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.

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 from CNR for Fiscal Year(s)</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>
2019	2020	(\$89)	\$0	\$300
2019 + 2020	2021	(\$44)	\$0	\$300

2. Power CRAC Surcharge Rate

(a) Calculating the Power CRAC Surcharge Rate

The Power CRAC Surcharge rate in mills per kilowatthour shall be:

$$\frac{\text{Power CRAC Amount}}{\sum BD}$$

Where:

$\sum BD$ (*Sum of Billing Determinants*) is the sum of the following December through September forecasts, made on or about the beginning of each applicable year, in kilowatthours:

- service under the PF Melded, IP, and NR rates, and
- PF System Shaped Loads.

(b) Billing

For customers taking service at the PF Melded, IP, and NR rates, the Power CRAC Surcharge rate will be added to the December through September monthly/diurnal PF Melded, IP and NR energy rates for the applicable year.

For PF customers with a System Shaped Load, the Power CRAC Surcharge rate will be applied to the sum of each customer's HLH and LLH PF System Shaped Load for December through September of the applicable year. A customer's Low Density Discount shall be applied to the Power CRAC.

(c) Adjustment to the PF Tier 1 Equivalent Energy Rates

The Power CRAC Surcharge rate will be added to each of the monthly/diurnal PF Tier 1 Equivalent energy rates (GRSP II.AA) for December through September of the applicable year.

(d) Annual Power CRAC Surcharge Rate

An Annual Power CRAC 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 Power CRAC Surcharge rate is calculated by dividing the Power CRAC Amount by the annual forecast, made around the beginning of each Fiscal Year, of service under the PF Melded, IP, and NR rates and the sum of PF System Shaped Loads for the applicable year, in kilowatthours. The Annual Power CRAC Surcharge rate will be:

- (1) Subtracted from the Load Shaping Charge True-Up rate (GRSP II.E, Section 1)
- (2) Subtracted from the PF Melded Equivalent Energy Scalar rate (GRSP II.R, Section 1(c)).

3. 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.

For the Second and Third Quarter Reviews, BPA shall post to its external website (www.bpa.gov) a preliminary forecast of the Power CRAC Amount.

(b) Notification of Power CRAC

By November 30, 2019, BPA will complete the calculation of Power ACNR through the end of FY 2019, for use in calculating the Power CRAC applicable to rates for December through September of FY 2020. By November 30, 2020, BPA will complete the calculation of Power ACNR through the end of FY 2020, for use in calculating the Power CRAC applicable to rates for December through September of FY 2021.

If the Power CRAC triggers, BPA will notify customers of the preliminary Power CRAC Amount to be recovered by the Power CRAC Surcharge rate for the applicable year. Such notice will be provided as soon as practicable, but in no case later than November 30 of each applicable year. BPA will make available to customers the preliminary data relied upon to calculate the surcharge, including the calculation of Power ACNR.

BPA will hold at least one public meeting to discuss the calculations of Power ACNR, the Power CRAC Amount, the Power CRAC Surcharge rate, and the Annual Power CRAC Surcharge rate. BPA will provide customers an opportunity for comment on the preliminary data. BPA will issue the final Power CRAC Amount, Power CRAC Surcharge rate, and the Annual Power CRAC Surcharge rate as soon as practicable, but in no case later than December 15 of each applicable year.

P. Power Reserves Distribution Clause (Power RDC)

The Power RDC is a process for determining the distribution of financial reserves to purposes determined by the Administrator. The Power RDC is calculated each fiscal year.

If the Power RDC quantitative criteria (below) are met, the Administrator will calculate the Power RDC Amount, and determine what part, if any, will be applied to debt reduction, incremental capital investment, rate reduction through a Power Dividend Distribution (Power DD), distribution to customers, or any other Power-specific purposes determined by the Administrator.

A Power DD is a downward adjustment to certain rates that apply to the following products under the PF-20 rate schedule: Load Following, Block, and the Block portion of Slice/Block. The Power DD also applies to power purchased at the PF Melded rate (PF-20), Industrial Firm Power rate (IP-20), and New Resource Firm Power rate (NR-20).

1. Power RDC Amount

At the beginning of each fiscal year of the rate period (that is, each “applicable year”), BPA will calculate Power Accumulated Calibrated Net Revenue (Power ACNR) and BPA Accumulated Calibrated Net Revenue (BPA ACNR) for the fiscal year preceding the applicable year. If Power ACNR is greater than the Power RDC Threshold for that

applicable year by at least \$5 million, and BPA ACNR is greater than the BPA RDC Threshold for that applicable year by at least \$5 million, the Administrator will determine a Power RDC Amount. If the Administrator determines that part of the Power RDC Amount will be applied to a Power DD, the resulting rate decrease will go into effect for the period of December 1 through September 30 of the applicable year.

(a) Calculating the Power ACNR and BPA ACNR

The Power ACNR calculation is described in GRSP II.O.1(a). The BPA ACNR is the sum of the Transmission ACNR and the Power ACNR. See Transmission GRSP II.G.1(a) and Power GRSP II.O.1(a).

(b) Calculating the Power RDC Amount

The Power RDC can trigger only 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 amount of financial reserves for risk attributed to Power that the Administrator will consider applying to reduce debt, incrementally fund capital projects, decrease rates through a Power DD, distribute to customers, or any other Power-specific purposes determined by the Administrator. The Power RDC Amount will be the smallest of Power ACNR minus the Power RDC Threshold, BPA ACNR minus the BPA RDC Threshold, or the Power RDC Cap.

**Table D.1
Power RDC Annual Thresholds and Caps
(dollars in millions)**

<i>ACNR Calculated from CNR for Fiscal Year(s)</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>
2019	2020	\$513	\$601	\$500
2019 + 2020	2021	\$558	\$601	\$500

Table D.2
BPA RDC Annual Thresholds
(dollars in millions)

<i>ACNR Calculated from CNR for Fiscal Year(s)</i>	<i>RDC Applied to Fiscal Year</i>	<i>Threshold Measured in BPA ACNR</i>	<i>Threshold Measured in BPA Reserves for Risk</i>
2019	2020	\$294	\$597
2019 + 2020	2021	\$424	\$597

2. Power DD Credit Rate

If the Administrator elects to apply all or a portion of a Power RDC Amount to reduce Power rates, then the following Power DD Credit rate shall apply:

(a) Calculating the Power DD Credit Rate

The Power DD Credit rate in mills per kilowatthour shall be:

$$\frac{\text{Power RDC Amount being used for a Power DD}}{\sum BD}$$

Where:

$\sum BD$ (*Sum of Billing Determinants*) is the sum of the following December through September forecasts, made on or about the beginning of each applicable year, in kilowatthours:

- service under the PF Melded, IP, and NR rates, and
- PF System Shaped Loads.

(b) Billing

For customers taking service at the PF Melded, IP, and NR rates, the Power DD Credit rate will be subtracted from the December through September monthly/diurnal PF Melded, IP and NR energy rates for the applicable year.

For PF customers with a System Shaped Load, the Power DD Credit rate will be applied to the sum of each customer’s HLH and LLH PF System Shaped Load, multiplied by -1, for December through September of the applicable year. A customer’s Low Density Discount shall be applied to the Power DD, which will be a charge.

(c) Adjustment to the PF Tier 1 Equivalent Energy Rates

The Power DD Credit rate will be subtracted from each of the monthly/diurnal PF Tier 1 Equivalent energy rates (GRSP II.AA) for December through September of the applicable year.

(d) Annual Power DD Credit Rate

An Annual Power DD Credit 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 Power DD Credit rate is calculated by dividing the Power RDC Amount being used for a Power DD by the annual forecast, 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, in kilowatthours. The Annual Power DD Credit rate will be:

- (1) Added to the Load Shaping Charge True-Up rate (GRSP II.E, Section 1); and
- (2) Added to the PF Melded Equivalent Energy Scalar rate (GRSP II.R, Section 1(c)).

3. 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.

For the Second and Third Quarter Reviews, BPA shall post to its external website (www.bpa.gov) a preliminary forecast of the Power RDC Amount.

(b) Notification of Power RDC

By November 30, 2019, BPA shall complete the calculation of Power ACNR and BPA ACNR through the end of FY 2019, for use in calculating the Power RDC applicable to rates for December through September of FY 2020. By November 30, 2020, BPA shall complete the calculation of Power ACNR and BPA ACNR through the end of FY 2020, for use in calculating the Power RDC applicable to rates for December through September of FY 2021.

If the Power RDC triggers, BPA will notify customers of the preliminary Power RDC Amount and whether the amount will be used to reduce debt, incrementally fund capital projects or other high-value Power purposes, or reduce rates, as soon as practicable, but in no case later than November 30 of each applicable year. BPA will make available to customers the preliminary data relied upon to calculate the Power RDC Amount, including the calculation of Power ACNR.

BPA will hold at least one public meeting to discuss the calculations of Power ACNR, the Power RDC Amount, and if applicable, the Power DD Credit rate and Annual Power DD Credit rate. BPA will provide customers an opportunity for comment on the preliminary data. BPA will issue the final Power RDC Amount as soon as practicable, but in no case later than December 15 of each applicable year.

Q. Power Financial Reserves Policy (Power FRP) Surcharge

The Power FRP Surcharge is an upward adjustment to certain rates that apply to the following products under the PF-20 rate schedule: Load Following, Block, and the Block portion of Slice/Block. The Power FRP Surcharge also applies to power purchased at the PF Melded rate (PF-20), Industrial Firm Power rate (IP-20), and New Resource Firm Power rate (NR-20).

1. Power FRP Surcharge Amount

At the beginning of each fiscal year of the rate period (that is, each “applicable year”), BPA will calculate Accumulated Calibrated Net Revenue for Power (Power ACNR) for the fiscal year preceding the applicable year. If Power ACNR is less than the Power FRP Surcharge Threshold for that applicable year by at least \$5 million, the Power FRP Surcharge will trigger, and a rate increase will go into effect for the period of December 1 through September 30 of the applicable year.

(a) Calculating the Power Accumulated Calibrated Net Revenue (Power ACNR)

The Power ACNR calculation is described in GRSP II.O.1(a).

(b) Calculating the Power FRP Surcharge Amount

The Power FRP Surcharge Threshold is an amount of Power ACNR, below which Power is considered to have experienced an underrun. The underrun amount is equal to the Power FRP Surcharge Threshold minus Power ACNR.

The Power FRP Surcharge Amount is based on the underrun, limited by the Base Surcharge. There are three possibilities:

- (1) If the underrun is less than \$5 million, there is no Power FRP Surcharge.
- (2) If the underrun is greater than or equal to \$5 million and less than or equal to the Base Surcharge, the Power FRP Surcharge Amount is equal to the underrun.
- (3) If the underrun is greater than or equal to the Base Surcharge, the Power FRP Surcharge Amount is equal to the Base Surcharge.

The Power FRP Surcharge Thresholds and Base Surcharges are shown in Table C.

Table E
Power FRP Surcharge Annual Thresholds and Caps
(dollars in millions)

<i>ACNR Calculated from CNR for Fiscal Year(s)</i>	<i>FRP Surcharge Applied to Fiscal Year</i>	<i>Threshold Measured in ACNR</i>	<i>Threshold Measured in Reserves for Risk</i>	<i>Base Surcharge</i>
2019	2020	\$212	\$301	\$30
2019 + 2020	2021	\$257	\$301	\$30

2. Power FRP Surcharge Rate

(a) Calculating the Power FRP Surcharge Rate

The Power FRP Surcharge rate in mills per kilowatthour shall be:

$$\frac{\text{Power FRP Surcharge Amount}}{\sum BD}$$

Where:

$\sum BD$ (*Sum of Billing Determinants*) is the sum of the following December through September forecasts, made on or about the beginning of each applicable year, in kilowatthours:

- service under the PF Melded, IP, and NR rates, and
- PF System Shaped Loads.

(b) Billing

For customers taking service at the PF Melded, IP, and NR rates, the Power FRP Surcharge rate will be added to the December through September monthly/diurnal PF Melded, IP and NR energy rates for the applicable year.

For PF customers with a System Shaped Load, the Power FRP Surcharge rate will be applied to the sum of each customer’s HLH and LLH PF System Shaped Load for December through September of the applicable year. A customer’s Low Density Discount shall be applied to the Power FRP Surcharge.

(c) Adjustment to the PF Tier 1 Equivalent Energy Rates

The Power FRP Surcharge rate will be added to each of the monthly/diurnal PF Tier 1 Equivalent energy rates (GRSP II.AA) for December through September of the applicable year.

(d) Annual Power FRP Surcharge Rate

An Annual Power FRP 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 Power FRP Surcharge rate is calculated by dividing the Power FRP Surcharge Amount by the annual forecast, 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, in kilowatthours. The Annual Power FRP Surcharge rate will be:

- (1) Subtracted from the Load Shaping Charge True-Up rate (GRSP II.E, Section 1)
- (2) Subtracted from the PF Melded Equivalent Energy Scalar rate (GRSP II.R, Section 1(c)).

3. Power FRP Surcharge 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.

For the Second and Third Quarter Reviews, BPA shall post to its external website (www.bpa.gov) a preliminary forecast of the Power FRP Surcharge Amount.

(b) Notification of Power FRP Surcharge

By November 30, 2019, BPA shall complete the calculation of Power ACNR through the end of FY 2019, for use in calculating the Power FRP Surcharge applicable to rates for December through September of FY 2020. By November 30, 2020, BPA shall complete the calculation of Power ACNR through the end of FY 2020, for use in calculating the Power FRP Surcharge applicable to rates for December through September of FY 2021.

If the Power FRP Surcharge triggers, BPA will notify customers of the preliminary Power FRP Surcharge Amount to be recovered by the Power FRP Surcharge for the applicable year. Such notice will be provided as soon as practicable, but in no case later than November 30 of each applicable year. BPA will make available to customers the preliminary data relied upon to calculate the surcharge including the calculation of Power ACNR.

BPA will hold at least one public meeting to discuss the calculations of Power ACNR, the Power FRP Surcharge Amount, the Power FRP Surcharge rate, and the Annual Power FRP Surcharge rate. BPA will provide customers an opportunity for comment on the preliminary data. BPA will issue the final Power FRP Surcharge

Amount, Power FRP Surcharge rate, and the Annual Power FRP Surcharge rate as soon as practicable, but in no case later than December 15 of each applicable 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-20 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-20 Composite Customer rate; and

- (3) the Change in Unused RHW Revenue for the applicable fiscal year (change can be positive or negative).

Where:

Change in Unused RHW Revenue = (Actual Unused RHW – Forecast Unused RHW) × 24.17 mills/kWh.

Actual Unused RHW = (1.00 – sum of actual TOCAs, expressed as a decimal) × RHW Tier 1 System Capability for the applicable fiscal year (expressed in aMW) × 8,760 hours (8,784 hours if a leap year).

Forecast Unused RHW = (1.00 – sum of forecast TOCAs, expressed as a decimal) × RHW Tier 1 System Capability for the applicable 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-20 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 -22.56 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.

-22.56 mills/kWh is calculated by the equation:

$$\text{PFMEES} - 7.72 \text{ mills/kWh}$$

Where:

PFMEES is the PF Melded Equivalent Energy Scalar of -14.84 mills/kWh and is subject to adjustment during the Rate Period by the Power CRAC (GRSP II.O); the Power RDC (GRSP II.P); and the Power FRP Surcharge (GRSP II.Q).

See GRSP Appendix A, Supplemental Information, for adjusted PF Melded Equivalent Energy Scalars.

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 periodfrom
 - (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 Exhibits 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 2020 forecast (\$000)	FY 2021 forecast (\$000)
1	Operating Expenses		
2	Power System Generation Resources		
3	Operating Generation		
4	COLUMBIA GENERATING STATION (WNP-2)	262,471	319,462
5	BUREAU OF RECLAMATION	153,609	151,623
6	CORPS OF ENGINEERS	252,557	252,557
7	LONG-TERM CONTRACT GENERATING PROJECTS	12,709	13,250
8	Sub-Total	681,345	736,892
9	Operating Generation Settlement Payment and Other Payments		
10	COLVILLE GENERATION SETTLEMENT	22,997	22,997
11	SPOKANE LEGISLATION PAYMENT	-	-
12	Sub-Total	22,997	22,997
13	Non-Operating Generation		
14	TROJAN DECOMMISSIONING	1,200	1,200
15	WNP-1&3 DECOMMISSIONING	431	331
16	Sub-Total	1,631	1,531
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)	250,570	250,370
27	OTHER SETTLEMENTS	-	-
28	Sub-Total	250,570	250,370
29	Renewable Generation		
30	RENEWABLES (excludes Kill)	26,475	24,711
31	Sub-Total	26,475	24,711
32	Generation Conservation		
33	CONSERVATION ACQUISITION (Purchases)	67,000	67,000
34	CONSERVATION INFRASTRUCTURE	27,296	27,296
35	LOW INCOME WEATHERIZATION & TRIBAL	5,739	5,853
36	REIMBURSABLE ENERGY EFFICIENCY DEVELOPMENT	8,000	8,000
37	DR & SMART GRID	855	855
38	LEGACY	590	590
39	MARKET TRANSFORMATION	12,050	12,050
40	Sub-Total	121,530	121,644
41	Power System Generation Sub-Total	1,107,648	1,161,245
42	Power Non-Generation Operations		
43	Power Services System Operations		
44	EFFICIENCIES PROGRAM	-	-
45	INFORMATION TECHNOLOGY	6,714	6,775
46	GENERATION PROJECT COORDINATION	6,059	6,205
47	SLICE IMPLEMENTATION	555	575
48	Sub-Total	13,329	13,555
49	Power Services Scheduling		
50	OPERATIONS SCHEDULING	8,806	9,148
51	OPERATIONS PLANNING	5,643	5,839
52	Sub-Total	14,449	14,987
53	Power Services Marketing and Business Support		
54	POWER R&D	2,662	2,666
55	SALES & SUPPORT	23,191	23,954
56	STRATEGY, FINANCE & RISK MGMT	16,103	16,470
57	EXECUTIVE AND ADMINISTRATIVE SERVICES	3,879	3,967
58	CONSERVATION SUPPORT	8,399	8,699
59	Sub-Total	54,235	55,756
60	Power Non-Generation Operations Sub-Total	82,012	84,298
61	Power Services Transmission Acquisition and Ancillary Services		
62	TRANSMISSION and ANCILLARY Services - System Obligations	32,028	32,028
63	3RD PARTY GTA WHEELING	96,200	96,200
64	POWER 3RD PARTY TRANS & ANCILLARY SVCS (Composite Cost)	2,338	2,384
65	TRANS ACQ GENERATION INTEGRATION	13,577	13,671
66	TELEMETERING/EQUIP REPLACEMENT	-	-
67	Power Services Trans Acquisition and Ancillary Serv Sub-Total	144,143	144,283
68	Fish and Wildlife/USF&W/Planning Council/Environmental Req		
69	Fish & Wildlife	249,603	250,031
70	USF&W Lower Snake Hatcheries	30,483	30,483
71	Planning Council	11,725	11,956
72	Environmental Requirements	-	-
73	Fish and Wildlife/USF&W/Planning Council Sub-Total	291,811	292,470

**Table F, continued
Composite Cost Pool True-Up Table**

	Actual Data (\$000)	FY 2020 forecast (\$000)	FY 2021 forecast (\$000)
74			
75			
76	BPA Internal Support		
77	Additional Post-Retirement Contribution	19,577	20,831
78	Agency Services G&A (excludes direct project support)	57,859	57,644
79	BPA Internal Support Sub-Total	77,436	78,475
80	Bad Debt Expense	-	-
81	Other Income, Expenses, Adjustments	-	(20,000)
82	Depreciation	138,968	141,050
83	Amortization	379,327	384,364
84	Total Operating Expenses	2,221,345	2,266,186
85	Other Expenses and (Income)		
86	Net Interest Expense	270,654	202,407
87	LDD	38,505	39,107
88	Irrigation Rate Discount Costs	20,905	20,905
89	Other Expense and (Income)	-	-
90	Sub-Total	330,064	262,418
91	Total Expenses	2,551,409	2,528,604
92	Revenue Credits		
93	Generation Inputs for Ancillary, Control Area, and Other Services Revenues	119,815	119,815
94	Downstream Benefits and Pumping Power revenues	19,364	19,364
95	4(h)(10)(c) credit	86,250	86,852
96	Colville and Spokane Settlements	4,600	4,600
97	Energy Efficiency Revenues	8,000	8,000
98	PF Load Forecast Deviation Liquidated Damages	9,499	9,458
99	Miscellaneous revenues	12,362	12,397
100	Renewable Energy Certificates	-	-
101	Net Revenues from other Designated BPA System Obligations (Upper Baker)	353	347
102	RSS Revenues	2,728	2,813
103	Firm Surplus and Secondary Adjustment (from Unused RHWM)	68,746	61,756
104	Balancing Augmentation Adjustment	1,213	4,273
105	Transmission Loss Adjustment	30,066	30,308
106	Tier 2 Rate Adjustment	510	615
107	NR Revenues	1	1
108	Total Revenue Credits	363,507	360,598
109			
110	Augmentation Costs (not subject to True-Up)		
111	Tier 1 Augmentation Resources (includes Augmentation RSS and Augmentation RSC adders)	12,367	12,477
112	Augmentation Purchases	-	-
113	Total Augmentation Costs	12,367	12,477
114			
115	DSI Revenue Credit		
116	Revenues 12 aMW @ IP rate	4,303	4,291
117	Total DSI revenues	4,303	4,291
118			
119	Minimum Required Net Revenue Calculation		
120	Principal Payment of Fed Debt for Power	173,072	518,065
121	Repayment of Non-Federal Obligations (EN Line of Credit)	227,000	-
122	Repayment of Non-Federal Obligations (CGS, WNP1, WNP3, N. Wasco, Cowlitz Falls)	41,581	22,871
123	Irrigation assistance	24,331	14,747
124	Sub-Total	465,984	555,683
125	Depreciation	138,968	141,050
126	Amortization	379,327	384,364
127	Capitalization Adjustment	(45,937)	(45,937)
128	Non-Cash Expenses	-	-
129	Customer Proceeds	-	-
130	Cash freed up by DSR refinancing	16,590	15,885
131	Prepay Revenue Credits	(30,600)	(30,600)
132	Non-Federal Interest (Prepay)	9,826	8,863
133	Contribution to decommissioning trust fund	(4,100)	(4,300)
134	Gains/losses on decommissioning trust fund	(5,052)	(5,220)
135	Interest earned on decommissioning trust fund	(8,818)	(9,112)
136	Sub-Total	450,204	454,993
137	Principal Payment of Fed Debt and Non-Fed Debt plus Irrigation assistance exceeds non cash expenses	15,780	100,690
138	Minimum Required Net Revenues	15,780	100,690
139			
140	Annual Composite Cost Pool (Amounts for each FY)	2,211,745	2,276,882
141			
142	SLICE TRUE-UP ADJUSTMENT CALCULATION FOR COMPOSITE COST POOL		
143	TRUE-UP AMOUNT (Diff. between actual Comp. Cost Pool and forecast Comp. Cost Pool for applicable FY)		
144	Adjustment of True-Up Amount when actual TOCAs < 100 percent (divide by sum of TOCAs, expressed as a decimal, 100 percent = 1.0)		
	TRUE-UP ADJUSTMENT CHARGE BILLED (22.3627 percent)		

Table G
Slice Cost Pool True-Up Table

	Audited Actual Data (\$000)	FY 2020 forecast (\$000)	FY 2021 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 2020 and FY 2021, 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-20 Rate Period (in kWh)

<i>Month</i>	<i>Avista</i>	<i>Idaho</i>	<i>NorthWestern</i>
October	250,016,994	455,396,562	50,567,544
November	305,575,577	425,971,623	54,946,271
December	401,987,435	526,910,480	66,836,555
January	497,120,436	684,421,016	80,582,405
February	405,183,431	613,207,645	68,644,239
March	374,163,589	537,238,828	65,532,435
April	315,687,321	427,318,024	55,061,547
May	262,906,040	456,028,908	48,967,394
June	245,752,042	533,302,515	46,872,757
July	275,401,209	693,792,859	50,761,107
August	323,491,046	775,280,099	60,860,523
September	278,352,264	631,238,357	52,544,371

<i>Month</i>	<i>PacifiCorp</i>	<i>Portland General</i>	<i>Puget Sound</i>
October	576,332,767	532,635,733	781,401,544
November	692,983,134	581,131,246	966,099,755
December	947,062,234	746,597,931	1,207,552,439
January	1,107,581,861	1,026,819,502	1,447,257,197
February	881,734,848	865,449,531	1,272,447,236
March	816,242,411	808,601,529	1,266,523,700
April	677,011,323	671,918,724	1,013,046,112
May	603,411,392	560,527,214	854,074,176
June	632,962,988	551,487,026	758,339,658
July	739,061,360	591,163,110	742,772,085
August	805,265,615	613,550,137	796,095,611
September	692,334,537	618,208,981	763,849,027

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-20 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-20 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-20 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-20 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-20 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 \$499,513,518 (the total REP benefits adopted for the two-year rate period in the BP-20 7(i) proceeding).
6. Recomputing the IOU adjustments specified in Section 6.2 of the 2012 REP Settlement.
7. 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-20-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-20 (including Slice purchasers), NR-20, and IP-20 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-20 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-20 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-20 rate schedule, unless such power would be charged as an Unauthorized Increase.

Notwithstanding the effective dates of the PF-20 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-20 rate schedule may agree to a PF-20 Tier 1 Customer charge payment schedule for the rate period that differs from the flat monthly charge specified in the PF-20 rate schedule. BPA will, to the maximum extent practicable while ensuring timely BPA cost recovery, accommodate individual customer requests to “shape” certain PF-20 Tier 1 Customer charges within the fiscal year to mitigate adverse cash flow effects on the customer. The shaped payments at PF-20 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, 2019.

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-20 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-20 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-20 rate schedule, unless such power would be charged as an Unauthorized Increase.

Notwithstanding the effective dates of the NR-20 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	38.14%	61.86%	0%
IP	0%	67.42%	32.58%
NR	0%	67.42%	32.58%
FPS	0%	70.27%	29.73%

2. The cost of resources acquired to meet load growth within the region is estimated to be 31.76 mills/kWh, and the forecast average cost of resources available to BPA under average water conditions is 47.50 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	39.03	34.07	11.42
November	40.38	37.03	12.07
December	43.28	38.75	13.45
January	40.43	34.40	12.10
February	39.55	34.47	11.66
March	34.38	31.30	9.19
April	33.17	29.59	8.61
May	26.90	21.74	5.60
June	25.71	16.87	5.04
July	36.64	30.50	10.27
August	40.43	35.40	12.10
September	40.05	35.17	11.91

These rates are subject to adjustment during the Rate Period by the Power CRAC (GRSP II.O); the Power RDC (GRSP II.P); and the Power FRP Surcharge (GRSP II.Q). See GRSP Appendix A, Supplemental Information, for adjusted PF Tier 1 Equivalent rates.

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-20), New Resources Firm Power (NR-20), and Firm Power and Surplus Products and Services (FPS-20) 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. 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.

9. 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.

10. 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.

11. 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.

12. 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.

13. 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.

14. 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.

15. 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.

16. 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.

17. 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.

18. 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 TRM, a unit of measure for sales of a product or service for which a customer is billed by BPA.

4. Charge

A charge is the product of a billing determinant and a rate.

5. Contract Demand

The customer's Contract Demand is the maximum amount of capacity that the customer agrees to purchase and BPA agrees to make available, subject to any limitations included in the applicable contract between BPA and the customer.

6. Contract Demand Quantity (CDQ)

As defined in the TRM, the Contract Demand Quantity is the monthly quantity of demand (expressed in kilowatts) included in each customer's CHWM Contract that is subtracted from the Customer System Peak (CSP) as part of the process of determining the customer's demand charge billing determinant, as calculated in accordance with TRM Section 5.3.5.

7. Contract Energy

Contract Energy is the maximum amount of energy that the customer agrees to purchase and BPA agrees to make available, subject to any limitations included in the applicable contract between BPA and the customer.

8. Contract High Water Mark (CHWM)

As defined in the TRM, the Contract High Water Mark is the amount (expressed in average megawatts) computed for each customer in accordance with TRM Section 4. For each customer with a CHWM Contract, the CHWM is used to calculate each customer's RHWM in the RHWM 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 Remarketing Value is the value BPA returns to customers for remarketed Tier 2 and non-Federal energy. This value is also used to calculate the cost of unpurchased amounts of Tier 2 energy. If BPA makes a transaction for a flat annual block of power (between November 1, 2018 and June 1, 2019) to be delivered in a fiscal year in the upcoming Rate Period, then the Remarketing Value for that fiscal year is based on the price of that transaction. If multiple transactions are made, then the Remarketing Value for that fiscal year is based on the weighted-average price of all transactions for the applicable delivery fiscal year. Otherwise, the Remarketing Value for a fiscal year is based on average ICE MID-C settlement prices from two separate five consecutive-business-day periods (the last full week in September 2018 and the last full week March 2019) for a flat block of annual power in the same fiscal year, plus \$0.50 per megawatthour.

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 2020–2021 are as follows (HE = Hour Ending):

October – May	HE 8 through HE 10 and HE 19 through HE 21
June – September	HE 16 through HE 21

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.

APPENDIX

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Appendix A: Supplemental Information

Adjustments to rates and GRSPs during the Rate Period due to the Power CRAC (GRSP II.O), the Power RDC (GRSP II.P), and the Power FRP Surcharge (GRSP II.Q) are summarized here. Any other adjustments to rates or GRSPs during the Rate Period, made in accordance with these rate schedules and GRSPs, will also be summarized here.

BP-20 Rate Proceeding

**ADMINISTRATOR'S FINAL
RECORD OF DECISION**

Appendix C: 2020 Transmission,
Ancillary, and Control Area Service Rate
Schedules and General Rate Schedule
Provisions

BP-20-A-03-AP03

July 2019



BONNEVILLE POWER ADMINISTRATION

**2020 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-20.1

FORMULA POWER TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes the FPT-18.1 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:

$$\left(1 + \frac{\text{GSR}_q}{\$1.726\text{kW/mo}}\right) * \text{FPT Base Charges}$$

Where:

GSR_q = The ACS-20 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	\$0.0729 per mile
2. Main Grid Interconnection Terminal	\$0.76kW
3. Main Grid Terminal	\$0.84/kW
4. Main Grid Miscellaneous Facilities	\$4.16/kW

SECONDARY SYSTEM CHARGES

1. Secondary System Distance	\$0.7173 per mile
2. Secondary System Transformation	\$7.84/kW
3. Secondary System Intermediate Terminal	\$3.03/kW
4. Secondary System Interconnection Terminal	\$2.14/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.G.

D. TRANSMISSION RESERVES DISTRIBUTION CLAUSE

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause, specified in GRSP II.H.

E. TRANSMISSION FINANCIAL RESERVES POLICY SURCHARGE

Customers taking service under this rate schedule are subject to the Transmission Financial Reserves Policy Surcharge, specified in GRSP II.I.

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FPT-20.3 FORMULA POWER TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes the FPT-18.3 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:

$$\left(1 + \frac{\text{GSR}_q}{\$1.726\text{kW/mo}} \right) * \text{FPT Base Charges}$$

Where:

- GSR_q = The ACS-20 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	\$0.0728 per mile
2.	Main Grid Interconnection Terminal	\$0.76/kW
3.	Main Grid Terminal	\$0.84/kW
4.	Main Grid Miscellaneous Facilities	\$4.15/kW
SECONDARY SYSTEM CHARGES		
1.	Secondary System Distance	\$0.7160 per mile
2.	Secondary System Transformation	\$7.83/kW
3.	Secondary System Intermediate Terminal	\$3.03/kW
4.	Secondary System Interconnection Terminal	\$2.14/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.

NT-20
NETWORK INTEGRATION RATE

SECTION I. AVAILABILITY

This schedule supersedes the NT-18 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

\$1.771 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.

Except as provided below, 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 = \$1.771 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.

Notwithstanding the formula above, the amount of the credit given for a particular DNR SD will be limited to the amount of the monthly charges for NT Service for that DNR SD.

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.G.

I. TRANSMISSION RESERVES DISTRIBUTION CLAUSE

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause, specified in GRSP II.H.

J. TRANSMISSION FINANCIAL RESERVES POLICY SURCHARGE

Customers taking service under this rate schedule are subject to the Transmission Financial Reserves Policy Surcharge, specified in GRSP II.I.

**PTP-20
POINT-TO-POINT RATE**

SECTION I. AVAILABILITY

This schedule supersedes the PTP-18 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. 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

\$1.533 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** \$0.070 per kilowatt per day
- b. Day 6 and beyond** \$0.050 per kilowatt per day

2. Hourly Firm and Non-Firm Service

4.41 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.G.

L. TRANSMISSION RESERVES DISTRIBUTION CLAUSE

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause, specified in GRSP II.H.

M. TRANSMISSION FINANCIAL RESERVES POLICY SURCHARGE

Customers taking service under this rate schedule are subject to the Transmission Financial Reserves Policy Surcharge, specified in GRSP II.I.

IS-20
SOUTHERN INTERTIE RATE

SECTION I. AVAILABILITY

This schedule supersedes the IS-18 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

\$1.084 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** \$0.050 per kilowatt per day
- b. Day 6 and beyond** \$0.036 per kilowatt per day

2. Hourly Firm and Non-Firm Service

9.98 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.G.

J. TRANSMISSION RESERVES DISTRIBUTION CLAUSE

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause, specified in GRSP II.H.

K. TRANSMISSION FINANCIAL RESERVES POLICY SURCHARGE

Customers taking service under this rate schedule are subject to the Transmission Financial Reserves Policy Surcharge, specified in GRSP II.I.

IM-20
MONTANA INTERTIE RATE

SECTION I. AVAILABILITY

This schedule supersedes the IM-18 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

\$0.506 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 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.G.

J. TRANSMISSION RESERVES DISTRIBUTION CLAUSE

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause, specified in GRSP II.H.

K. TRANSMISSION FINANCIAL RESERVES POLICY SURCHARGE

Customers taking service under this rate schedule are subject to the Transmission Financial Reserves Policy Surcharge, specified in GRSP II.I.

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UFT-20

USE-OF-FACILITIES TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes the UFT-18 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-20
ADVANCE FUNDING RATE

SECTION I. AVAILABILITY

This schedule supersedes the AF-18 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-20

TOWNSEND-GARRISON TRANSMISSION RATE

SECTION I. AVAILABILITY

This schedule supersedes the TGT-18 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.

RC-20
REGIONAL COMPLIANCE ENFORCEMENT AND REGIONAL
COORDINATOR RATES

SECTION I. AVAILABILITY

This schedule supersedes the PW-18 rate schedule. The rates in this schedule recover the costs billed to BPA by the “regional entity” and the “reliability coordinator” for reliability compliance monitoring and enforcement and reliability coordination services. The rates apply to all loads in the BPA Control Area except for loads of customers billed directly by the regional entity and the reliability coordinator. 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. REGIONAL COMPLIANCE ENFORCEMENT RATE

0.05 mills per kilowatthour

B. REGIONAL COORDINATOR RATE

0.04 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-20 OVERSUPPLY RATE

SECTION I. AVAILABILITY

This schedule supersedes the OS-18 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, 2019, through September 30, 2021. The Oversupply Charge shall remain in effect until all costs incurred pursuant to OATT Attachment P during the FY 2020-2021 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 *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-20
EASTERN INTERTIE RATE

SECTION I. AVAILABILITY

This schedule supersedes the IE-18 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-20

ANCILLARY AND CONTROL AREA SERVICE RATES

SECTION I. AVAILABILITY

This schedule supersedes the ACS-18 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 and on the Southern Intertie are each charged separately for Scheduling, System Control, and Dispatch Service.

1. RATES

a. NT Service

The rate shall not exceed \$0.365 per kilowatt per month.

b. Long-Term Firm PTP Transmission Service

The rate shall not exceed \$0.317 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 \$0.010 per kilowatt per day

(2) Hourly Firm and Non-Firm Service

The rate shall not exceed 0.91 mills per kilowatthour.

2. BILLING FACTORS

a. Point-To-Point Transmission Service

For Transmission Customers taking Point-to-Point Transmission Service (PTP and IS), 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-20).

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 2020 and FY 2020 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, 2019, 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, 2019 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-20).

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 is the continuous balancing of resources with load by providing 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 0.49 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-20 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 9.53 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 10.96 mills per kilowatthour.

For energy delivered, the generator shall purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence.

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 Current Transmission Rates website 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 8.32 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 9.57 mills per kilowatthour.

For energy delivered, the Transmission Customer (for interruptible imports only) or the generator shall purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence.

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 Current Transmission Rates website 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 is the continuous balancing of resources with load by providing 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 0.49 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 Dispatchable Energy Resources operating in the BPA Balancing Authority Area.

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-20 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-20 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 9.53 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 10.96 mills per kilowatthour.

For energy delivered, the customer shall purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence.

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 Current Transmission Rates website 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 8.32 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 9.57 mills per kilowatthour.

For energy delivered, the customer shall purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence.

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 Current Transmission Rates website 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

The total charge for Balancing Service is the applicable rate in section 2.a. or 2.b, below, plus Direct Assignment Charges under section 3 and Intentional Deviation Penalty Charges under section 4.

a. BALANCING SERVICE RATES FOR WIND RESOURCES

(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 \$0.10 per kilowatt per month
- (b) Following Reserves \$0.40 per kilowatt per month
- (c) Imbalance Reserves \$0.43 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 \$0.10 per kilowatt per month
- (b) Following Reserves \$0.38 per kilowatt per month
- (c) Imbalance Reserves \$0.15 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 \$0.10 per kilowatt per month
- (b) Following Reserves \$0.37 per kilowatt per month
- (c) Imbalance Reserves \$0.62 per kilowatt per month

b. BALANCING SERVICE RATES FOR SOLAR RESOURCES

(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 \$0.14 per kilowatt per month
- (b) Following Reserves \$0.26 per kilowatt per month
- (c) Imbalance Reserves \$0.29 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.

\$0.37 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 \$0.14 per kilowatt per month
- (b) Following Reserves \$0.26 per kilowatt per month
- (c) Imbalance Reserves \$0.51 per kilowatt per month

c. BILLING FACTOR

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

- (1) For each plant, or phase of a 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 plant, or phase of a 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 plant, or phase of a 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.

d. EXCEPTIONS

- (1) The rates under section 2.a and 2.b 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 sections 2.a and 2.b 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. 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 2021, but chooses to interconnect during the FY 2020–2021 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 \$0.280 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.

4. 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 15.11 mills per kW maximum hourly deviation
- b. Decremental Reserves 1.59 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 2021 but chooses to interconnect during the FY 2020-2021 rate period;
- c. a customer operating in another Balancing Authority Area chooses to dynamically transfer into the BPA Balancing Authority Area during the FY 2020-2021 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 \$0.280 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.

G. NEW GENERATION TECHNOLOGY PILOT PROGRAM

A customer and BPA may jointly develop a pilot program at the individual generation project level in order to integrate new uses of technology, such as a solar project coupled with a co-located battery. The goal of the pilot is to reduce the project’s balancing reserve capacity burden placed on the Bonneville balancing authority area. In place of any normally applicable Regulation and Frequency Response, VERBS or DERBS rates, Bonneville will instead directly assign the cost of balancing reserve capacity to the pilot project customer in accordance with the following capacity rate components:

- (a) Regulation Reserve INC \$0.264 per kilowatt-day
- (b) Following Reserve INC \$0.256 per kilowatt-day
- (c) Imbalance Reserve INC \$0.250 per kilowatt-day
- (d) DEC Balancing Reserves \$0.022 per kilowatt-day

These rates are applied to the balancing reserve capacity BPA determines is needed for the pilot (not the installed nameplate of the project), and shall not exceed the total cost of the normally applicable Regulation and Frequency Response, VERBS, or DERBS rates. On a monthly basis, BPA shall revisit the amount of balancing reserves required for the project based on actual operational data for that project. All other rates required for the project shall apply.

A customer participating in a pilot program may still be subject to any applicable Intentional Deviation or Persistent Deviation penalties if operation of the project is not consistent with the pilot program expectations, resulting in the pilot adding to rather than reducing the Station Control Error of the project.

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 FOR TRANSMISSION COST RECOVERY ADJUSTMENT CLAUSE, TRANSMISSION RESERVES DISTRIBUTION CLAUSE, AND TRANSMISSION FINANCIAL RESERVES POLICY SURCHARGE

Customers taking Scheduling, System Control, and Dispatch Service under this rate schedule are subject to the Transmission Cost Recovery Adjustment Clause, the Transmission Reserves Distribution Clause, and the Transmission Financial Reserves Policy Surcharge, specified in GRSPs II.G, II.H, and II.I.

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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, 2019. All rate schedules shall remain in effect until they are replaced or expire on their own terms.

B. General Provisions

These BP-20 rate schedules and the GRSPs associated with these schedules supersede BPA's BP-18 rate schedules (which became effective October 1, 2017) 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-20 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-20) Rate, section III

b. Utility Delivery

\$1.324 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.G.

b. Transmission Reserves Distribution Clause

Customers taking service under this rate schedule are subject to the Transmission Reserves Distribution Clause, specified in GRSP II.H.

c. Transmission Financial Reserves Policy Surcharge

Customers taking service under this rate schedule are subject to the Transmission Financial Reserves Policy Surcharge, 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 Transmission Rates website the name of the index to be used. BPA will not change the index more often than once per year unless BPA determines that the existing index is no longer a reliable price index.

2. BILLING FACTOR

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

- a. Failure to shed load when directed to do so by BPA in accordance with the Load Shedding provisions of the Open Access Transmission Tariff or any other applicable agreement between the parties. This includes failure to shed load pursuant to such orders within the time period specified by the North American Electric Reliability Council (NERC), Western Electricity Coordinating Council (WECC), or Northwest Power Pool (NWPP) criteria.
- b. Failure of a generator in the BPA Control Area or which directly interconnects to the FCRTS to change or limit generation levels when directed to do so by BPA in accordance with Good Utility Practice as defined in the OATT. This includes failure to change generation levels pursuant to such orders within the time period specified by NERC, WECC, or NWPP criteria.

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

3. WAIVER OR REDUCTION OF A FAILURE TO COMPLY PENALTY CHARGE

BPA may, in its sole discretion, waive or reduce a Failure to Comply Penalty Charge if requested by a customer for good cause shown. In order to qualify for a waiver or reduction in a Failure to Comply Penalty Charge, a customer must submit a request demonstrating that the events resulting in a Failure to Comply Penalty Charge were:

- a. Due to a technical error or malfunction that could not have been avoided through the exercise of reasonable care; and
- b. Were immediately corrected upon discovery of the technical error or malfunction.

BPA will also consider the customer's history of incurring Failure to Comply Penalty Charges in deciding whether to waive or reduce a Failure to Comply Penalty Charge.

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. Transmission Cost Recovery Adjustment Clause (Transmission CRAC)

The Transmission CRAC is an upward adjustment to certain rates. It applies to these Transmission rates:

- Network Integration Rate (NT-20)
- Point-to-Point Rate (PTP-20)
- Formula Power Transmission Rate (FPT-20.1)
- Southern Intertie Point-to-Point Rate (IS-20)
- Scheduling, System Control, and Dispatch Rate (ACS-20)
- Utility Delivery Rate (GRSPs Section II.A.1.b.)
- Montana Intertie Rate (IM-20)

1. TRANSMISSION CRAC AMOUNT

At the beginning of each fiscal year of the rate period (that is, each “applicable year”), BPA will calculate Accumulated Calibrated Net Revenue for Transmission (Transmission ACNR) for the fiscal year preceding the applicable year. If 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 for the period of December 1 through September 30 of the applicable year.

a. Calculating Transmission Calibrated Net Revenue (Transmission CNR) and Accumulated Calibrated Net Revenue (Transmission ACNR)

Transmission CNR is Transmission Net Revenue (Transmission NR) plus 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).

Transmission NR Calibration is the sum of the amounts of each Transmission NR Calibration Event. A Transmission NR Calibration Event is a financial event not forecast in the BP-20 rate case that (1) impacts Transmission NR differently than it impacts financial reserves available for risk attributed to Transmission, and (2) results in a difference between the amounts of such impacts that is greater than \$5 million (positive or negative). Such events may include, but are not limited to, debt management transactions, contract settlements, and changes in non-cash expenses. The amount of a Transmission NR Calibration Event will be calculated as (1) the impact of the event on financial reserves available for risk attributed to Transmission, minus (2) the impact of the event on Transmission NR.

Transmission ACNR is Transmission CNR accumulated since the end of FY 2018. Actual 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 Transmission ACNR for use in determining the Transmission CRAC that will apply to FY 2020 rates will be the actual Transmission CNR for FY 2019. The Transmission ACNR for use in determining the Transmission CRAC that will apply to FY 2021 rates will be the sum of the actual Transmission CNR for FY 2019 plus the actual Transmission CNR for FY 2020.

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 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 A.

Table A
Transmission CRAC Annual Thresholds and Caps
(dollars in millions)

<i>ACNR Calculated from CNR for Fiscal Year(s)</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>
2019	2020	(\$214)	\$0	\$100
2019 + 2020	2021	(\$130)	\$0	\$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 10 month period of December through September of 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 website (www.bpa.gov) preliminary, unaudited, year-to-date aggregate financial results for the transmission function.

For the Second and Third Quarter Reviews, BPA shall post to its external website (www.bpa.gov) a preliminary forecast of the Transmission CRAC Amount.

b. Notification of Transmission CRAC Trigger

By November 30, 2019, BPA will complete the calculation of Transmission ACNR through the end of FY 2019, for use in calculating the Transmission CRAC applicable to rates for December through September of FY 2020. By November 30, 2020, BPA will complete the calculation of Transmission ACNR through the end of FY 2020, for use in calculating the Transmission CRAC applicable to rates for December through September of FY 2021.

If the Transmission CRAC triggers, BPA will notify customers of the preliminary Transmission CRAC Amount to be recovered by the Transmission CRAC Percentage for the applicable year. Such notice will be provided as soon as practicable, but in no case later than November 30 of each applicable year. BPA will make available to customers the preliminary data relied upon to calculate the Transmission CRAC Percentage, including the calculation of Transmission ACNR.

BPA will hold at least one public meeting to discuss the calculations of Transmission ACNR, the Transmission CRAC Amount, and the

Transmission CRAC Percentage. BPA will provide customers an opportunity for comment on the preliminary data. BPA will issue the final Transmission CRAC Amount and the Transmission CRAC Percentage as soon as practicable, but in no case later than December 15 of each applicable year.

H. Transmission Reserves Distribution Clause (Transmission RDC)

The Transmission RDC is a process for determining the distribution of financial reserves to purposes determined by the Administrator. The Transmission RDC is calculated each fiscal year.

If the Transmission RDC quantitative criteria (below) are met, the Administrator will calculate the Transmission RDC Amount, and determine what part, if any, will be applied to debt reduction, incremental capital investment, rate reduction through a Transmission Dividend Distribution (Transmission DD), distributions to customers, or any other Transmission-specific purposes determined by the Administrator.

A Transmission DD is a downward adjustment that applies to these Transmission rates:

- Network Integration Rate (NT-20)
- Point-to-Point Rate (PTP-20)
- Formula Power Transmission Rate (FPT-20.1)
- Southern Intertie Point-to-Point Rate (IS-20)
- Scheduling, System Control, and Dispatch Rate (ACS-20)
- Utility Delivery Rate (GRSPs Section II.A.1.b.)
- Montana Intertie Rate (IM-20)

1. TRANSMISSION RDC AMOUNT

At the beginning of each fiscal year of the rate period (that is, each “applicable year”), BPA will calculate Transmission Accumulated Calibrated Net Revenue (Transmission ACNR) and BPA Accumulated Calibrated Net Revenue (BPA ACNR) for the fiscal year preceding the applicable year. If Transmission ACNR is greater than the Transmission RDC Threshold for that applicable year by at least \$5 million, and BPA ACNR is greater than the BPA RDC Threshold for that applicable year by at least \$5 million, the Administrator will determine the Transmission RDC Amount. If the Administrator determines that part of the Transmission RDC Amount will be applied to a Transmission DD, the resulting rate decrease will go into effect for the period of December 1 through September 30 of the applicable year.

a. Calculating the Transmission ACNR and BPA ACNR

The Transmission ACNR calculation is described in GRSP II.G.1(a). The BPA ACNR is the sum of the Transmission ACNR and the Power ACNR. *See* Transmission GRSP II.G.1(a) and Power GRSP II.O.1(a).

b. Calculating the Transmission RDC Amount

The Transmission RDC can trigger only 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 amount of financial reserves for risk attributed to Transmission that the Administrator will consider applying to reduce debt, incrementally fund capital projects, decrease rates through a Transmission DD, distribute to customers, or any other Transmission-specific purposes determined by the Administrator. The Transmission RDC Amount will be the smallest of Transmission ACNR minus the Transmission RDC Threshold, BPA ACNR minus the BPA RDC Threshold, or the Transmission RDC Cap.

**Table B
Transmission RDC Annual Thresholds and Caps
(dollars in millions)**

<i>ACNR Calculated from CNR for Fiscal Year(s)</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>
2019	2020	(\$20)	\$194	\$200
2019 + 2020	2021	\$65	\$194	\$200

**Table C
BPA RDC Annual Thresholds
(dollars in millions)**

<i>ACNR Calculated from CNR for Fiscal Year(s)</i>	<i>RDC Applied to Fiscal Year</i>	<i>Threshold Measured in BPA ACNR</i>	<i>Threshold Measured in BPA Reserves for Risk</i>
2019	2020	\$294	\$597
2019 + 2020	2021	\$424	\$597

c. Converting a Transmission DD to the Transmission DD Percentage and Calculating Revised Rates

The Transmission DD Credit 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 10 month period of December through September of the applicable year.

The Transmission DD Credit percentage is subtracted from 1.0 and 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 website (www.bpa.gov) preliminary, unaudited, year-to-date aggregate financial results for the transmission function.

For the Second and Third Quarter Reviews, BPA shall post to its external website (www.bpa.gov) a preliminary forecast of the Transmission RDC Amount.

b. Notification of Transmission RDC Trigger

By November 30, 2019, BPA shall complete the calculation of Transmission ACNR and BPA ACNR through the end of FY 2019, for use in calculating the Transmission RDC applicable to rates for December through September of FY 2020. By November 30, 2020, BPA shall complete the calculation of Transmission ACNR and BPA ACNR through the end of FY 2020, for use in calculating the Transmission RDC applicable to rates for December through September of FY 2021.

If the Transmission RDC triggers, BPA will notify customers of the preliminary Transmission RDC Amount and whether the amount will be used to reduce debt, incrementally fund capital projects or other high-value Transmission purposes, or reduce rates, as soon as practicable, but in no case later than November 30 of each applicable year. BPA will make available to customers the preliminary data relied upon to calculate the Transmission RDC Amount, including the calculation of Transmission ACNR.

BPA will hold at least one public meeting to discuss the calculations of Transmission ACNR, the Transmission RDC Amount, and if applicable,

the Transmission DD Credit Amount and the Transmission DD Credit percentage. BPA will provide customers an opportunity for comment on the preliminary data. BPA will issue the final Transmission RDC amount as soon as practicable, but in no case later than December 15 of each applicable year.

I. Transmission Financial Reserves Policy Surcharge (Transmission FRP Surcharge)

The Transmission FRP Surcharge is an upward adjustment to certain rates. It applies to these Transmission rates:

- Network Integration Rate (NT-20)
- Point-to-Point Rate (PTP-20)
- Formula Power Transmission Rate (FPT-20.1)
- Southern Intertie Point-to-Point Rate (IS-20)
- Scheduling, System Control, and Dispatch Rate (ACS-20)
- Utility Delivery Rate (GRSPs Section II.A.1.b.)
- Montana Intertie Rate (IM-20)

1. CALCULATIONS FOR THE TRANSMISSION FRP SURCHARGE

At the beginning of each fiscal year of the rate period (that is, each “applicable year”), BPA will calculate Accumulated Calibrated Net Revenue for Transmission (Transmission ACNR) for the fiscal year preceding the applicable year. If Transmission ACNR is less than the Transmission FRP Surcharge Threshold for that applicable year by at least \$5 million, the Transmission FRP Surcharge will trigger, and a rate increase will go into effect for the period of December 1 through September 30 of the applicable year.

a. Calculating the Transmission Accumulated Calibrated Net Revenue (Transmission ACNR)

The Transmission ACNR calculation is described in GRSP II.G.1(a).

b. Calculating the Transmission FRP Surcharge Amount

The Transmission FRP Surcharge Threshold is an amount of Transmission ACNR, below which Transmission is considered to have experienced an underrun. The underrun amount is equal to the Transmission FRP Surcharge Threshold minus Transmission ACNR.

The Transmission FRP Surcharge Amount is based on the underrun, limited by the Base Surcharge. There are three possibilities:

- (1) If the underrun is less than \$5 million, there is no Transmission FRP Surcharge.
- (2) If the underrun is greater than or equal to \$5 million and less than or equal to the Base Surcharge, the Transmission FRP Surcharge Amount is equal to the underrun.

- (3) If the underrun is equal to or greater than the Base Surcharge, the FRP Surcharge Amount is equal to the Base Surcharge.

The Transmission FRP Surcharge Thresholds and Base Surcharge are shown in Table D.

Table D
Transmission FRP Surcharge Annual Thresholds and Caps
(dollars in millions)

<i>ACNR Calculated from CNR for Fiscal Year(s)</i>	<i>FRP Surcharge Applied to Fiscal Year</i>	<i>Threshold Measured in ACNR</i>	<i>Threshold Measured in Reserves for Risk</i>	<i>Base Surcharge</i>
2019	2020	(\$117)	\$97	\$15
2019 + 2020	2021	(\$33)	\$97	\$15

c. Converting the Transmission FRP Surcharge Amount to the Transmission FRP Surcharge Percentage and Calculating Revised Rates

The Transmission FRP Surcharge percentage is calculated by dividing the Transmission FRP Surcharge Amount by the sum of the most recent forecasts of revenues from the applicable rates for the 10 month period of December through September of the applicable year.

The Transmission FRP Surcharge percentage plus 1.0 is then multiplied by each of the applicable rates, which yields revised rates.

2. TRANSMISSION FRP SURCHARGE 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 transmission function.

For the Second and Third Quarter Reviews, BPA shall post to its external website (www.bpa.gov) a preliminary forecast of the Transmission FRP Surcharge Amount.

b. Notification of Transmission FRP Surcharge

By November 30, 2019, BPA shall complete the calculation of Transmission ACNR through the end of FY 2019, for use in calculating the Transmission FRP Surcharge applicable to rates for December through September of FY 2020. By November 30, 2020, BPA shall complete the calculation of Transmission ACNR through the end of FY 2020, for use in calculating the Transmission FRP Surcharge applicable to rates for December through September of FY 2021.

If the Transmission FRP Surcharge triggers, BPA will notify customers of the preliminary Transmission FRP Surcharge Amount to be recovered by the Transmission FRP Surcharge for the applicable year. Such notice will be provided as soon as practicable, but in no case later than November 30 of each applicable year. BPA will make available to customers the preliminary data relied upon to calculate the surcharge including the calculation of Transmission ACNR.

BPA will hold at least one public meeting to discuss the calculations of Transmission ACNR, the Transmission Surcharge Amount, and the Transmission FRP Surcharge percentage. BPA will provide customers an opportunity for comment on the preliminary data. BPA will issue the final Transmission FRP Surcharge Amount and the Transmission FRP Surcharge percentage as soon as practicable, but in no case later than December 15 of each applicable year.

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-20 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.

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:

$\text{ABS}(\text{Intentional Deviation Measurement Value Error})$ = 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.

5. WAIVER OR REDUCTION OF INTENTIONAL DEVIATION PENALTY CHARGE

BPA may, in its sole discretion, waive or reduce an Intentional Deviation Penalty Charge if requested by a customer for good cause shown. In order to qualify for a waiver or reduction of an Intentional Deviation Penalty Charge, a customer must submit a request demonstrating that the events resulting in an Intentional Deviation Penalty Charge were:

- a. Due to a technical error or malfunction that could not have been avoided through the exercise of reasonable care; and
- b. Were immediately corrected upon discovery of the technical error or malfunction.

BPA will also consider the customer's history of incurring Intentional Deviation Penalty Charge in deciding whether to waive or reduce an Intentional Deviation Penalty Charge.

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

BPA Customer ID	Customer Name	Modified TOCAs	
		FY 2020	FY 2021
10005	Alder Mutual	0.0000818	0.0000816
10015	Asotin County PUD #1	0.0000857	0.0000853
10024	Benton County PUD #1	0.0301320	0.0299757
10025	Benton REA	0.0089311	0.0088847
10027	Big Bend Elec Coop	0.0091609	0.0091134
10029	Blachly Lane Elec Coop	0.0026371	0.0026235
10044	Canby, City of	0.0030403	0.0030246
10046	Central Electric Coop	0.0122534	0.0121898
10047	Central Lincoln PUD	0.0232070	0.0231368
10055	Albion, City of	0.0000579	0.0000576
10057	Ashland, City of	0.0030086	0.0029920
10059	Bandon, City of	0.0011234	0.0011197
10061	Blaine, City of	0.0013093	0.0013025
10062	Bonnors Ferry, City of	0.0007963	0.0007921
10064	Burley, City of	0.0020924	0.0020851
10065	Cascade Locks, City of	0.0003560	0.0003541
10066	Centralia, City of	0.0036484	0.0036295
10067	Cheney, City of	0.0023678	0.0023555
10068	Chewelah, City of	0.0003845	0.0003830
10070	Declo, City of	0.0000537	0.0000534
10071	Drain, City of	0.0002803	0.0002791
10072	Ellensburg, City of	0.0035902	0.0035716
10074	Forest Grove, City of	0.0039943	0.0039736
10076	Heyburn, City of	0.0007212	0.0007175
10078	McCleary, City of	0.0005565	0.0005536
10079	McMinnville, City of	0.0130347	0.0131321
10080	Milton, Town of	0.0010368	0.0010329
10081	Milton-Freewater, City of	0.0015652	0.0015570
10082	Minidoka, City of	0.0000142	0.0000141
10083	Monmouth, City of	0.0012520	0.0012455
10086	Plummer, City of	0.0005829	0.0005812
10087	Port Angeles, City of	0.0046157	0.0045934
10089	Richland, City of	0.0155475	0.0154669
10091	Rupert, City of	0.0014106	0.0014033

BPA Customer ID	Customer Name	Modified TOCAs	
		FY 2020	FY 2021
10094	Soda Springs, City of	0.0004547	0.0004523
10095	Sumas, Town of	0.0005453	0.0005425
10097	Troy, City of	0.0003027	0.0003026
10101	Clallam County PUD #1	0.0113815	0.0113225
10103	Clark County PUD #1	0.0457296	0.0459166
10105	Clatskanie PUD	0.0131423	0.0138260
10106	Clearwater Power	0.0035639	0.0035561
10109	Columbia Basin Elec Coop	0.0018141	0.0018047
10111	Columbia Power Coop	0.0004584	0.0004568
10112	Columbia River PUD	0.0081991	0.0081680
10113	Columbia REA	0.0056427	0.0056134
10116	Consolidated Irrigation District #19	0.0000340	0.0000339
10118	Consumers Power	0.0068374	0.0068020
10121	Coos Curry Elec Coop	0.0058584	0.0058252
10123	Cowlitz County PUD #1	0.0629891	0.0653668
10136	Douglas Electric Cooperative	0.0027266	0.0027177
10142	East End Mutual Electric	0.0004023	0.0004002
10144	Eatonville, City of	0.0005042	0.0005016
10156	Elmhurst Mutual P & L	0.0048260	0.0048010
10157	Emerald PUD	0.0074787	0.0074399
10158	Energy Northwest	0.0003636	0.0003615
10170	Eugene Water & Electric Board	0.0358338	0.0357020
10172	U.S. Airforce Base, Fairchild	0.0008127	0.0008126
10173	Fall River Elec Coop	0.0049596	0.0049338
10174	Farmers Elec Coop	0.0000748	0.0000742
10177	Ferry County PUD #1	0.0013838	0.0013837
10179	Flathead Elec Coop	0.0249736	0.0248440
10183	Franklin County PUD #1	0.0175677	0.0174766
10186	Glacier Elec Coop	0.0026801	0.0030634
10190	Grant County PUD #2	0.0007771	0.0007731
10191	Grays Harbor PUD #1	0.0194571	0.0193396
10197	Harney Elec Coop	0.0034061	0.0033885
10202	Hood River Elec Coop	0.0019609	0.0019507
10203	Idaho County L & P	0.0009301	0.0009253
10204	Idaho Falls Power	0.0094343	0.0093733
10209	Inland P & L	0.0157023	0.0156209

BPA Customer ID	Customer Name	Modified TOCAs	
		FY 2020	FY 2021
10230	Kittitas County PUD #1	0.0014525	0.0014449
10231	Klickitat County PUD #1	0.0054879	0.0054595
10234	Kootenai Electric Coop	0.0076346	0.0075950
10235	Lakeview L & P (WA)	0.0047304	0.0047260
10236	Lane County Elec Coop	0.0041293	0.0041039
10237	Lewis County PUD #1	0.0164179	0.0163622
10239	Lincoln Elec Coop (MT)	0.0020959	0.0020846
10242	Lost River Elec Coop	0.0014259	0.0014185
10244	Lower Valley Energy	0.0128799	0.0128131
10246	Mason County PUD #1	0.0013221	0.0013250
10247	Mason County PUD #3	0.0119230	0.0118484
10256	Midstate Elec Coop	0.0069724	0.0069616
10258	Mission Valley	0.0056815	0.0056520
10259	Missoula Elec Coop	0.0040398	0.0040189
10260	Modern Elec Coop	0.0039349	0.0039145
10273	Nespelem Valley Elec Coop	0.0008804	0.0008759
10278	Northern Lights	0.0053656	0.0053506
10279	Northern Wasco County PUD	0.0096954	0.0096451
10284	Ohop Mutual Light Company	0.0014788	0.0014726
10285	Okanogan County Elec Coop	0.0009774	0.0009723
10286	Okanogan County PUD #1	0.0068729	0.0068373
10288	Orcas P & L	0.0036435	0.0036338
10291	Oregon Trail Coop	0.0118537	0.0117347
10294	Pacific County PUD #2	0.0052773	0.0052421
10304	Parkland L & W	0.0020576	0.0020524
10306	Pend Oreille County PUD #1	0.0038575	0.0038375
10307	Peninsula Light Company	0.0101507	0.0101059
10326	U.S. Naval Base, Bremerton	0.0044429	0.0044222
10331	Raft River Elec Coop	0.0054082	0.0053874
10333	Ravalli County Elec Coop	0.0027515	0.0027573
10338	Riverside Elec Coop	0.0003552	0.0003534
10342	Salem Elec Coop	0.0057104	0.0056957
10343	Salmon River Elec Coop	0.0018174	0.0018077
10349	Seattle City Light	0.0777693	0.0777998
10352	Skamania County PUD #1	0.0023055	0.0022965
10354	Snohomish County PUD #1	0.1091522	0.1084460

BPA Customer ID	Customer Name	Modified TOCAs	
		FY 2020	FY 2021
10360	Southside Elec Lines	0.0010127	0.0010074
10363	Springfield Utility Board	0.0142705	0.0142215
10369	Surprise Valley Elec Coop	0.0024600	0.0024472
10370	Tacoma Public Utilities	0.0577326	0.0572991
10371	Tanner Elec Coop	0.0016515	0.0016430
10376	Tillamook PUD #1	0.0082032	0.0081778
10378	Coulee Dam, City of	0.0002864	0.0002877
10379	Steilacoom, Town of	0.0007142	0.0007139
10388	Umatilla Elec Coop	0.0169498	0.0168619
10391	United Electric Coop	0.0044875	0.0044642
10406	U.S. DOE Albany Research Center	0.0000686	0.0000683
10408	U.S. Naval Station, Everett (Jim Creek)	0.0002236	0.0002223
10409	U.S. Naval Submarine Base, Bangor	0.0029366	0.0029213
10426	U.S. DOE Richland Operations Office	0.0046022	0.0052230
10434	Vera Irrigation District	0.0040654	0.0040443
10436	Vigilante Elec Coop	0.0028672	0.0028523
10440	Wahkiakum County PUD #1	0.0007412	0.0007367
10442	Wasco Elec Coop	0.0018920	0.0018910
10446	Wells Rural Elec Coop	0.0140089	0.0139502
10448	West Oregon Elec Coop	0.0012244	0.0012173
10451	Whatcom County PUD #1	0.0039649	0.0035230
10482	Umpqua Indian Utility Cooperative	0.0004062	0.0004040
10502	Yakama Power	0.0028005	0.0027859
13927	Kalispel Tribe Utility	0.0004544	0.0005044
10597	Hermiston, City of	0.0018508	0.0018422
10706	Port of Seattle - SETAC In'tl. Airport	0.0025866	0.0025732
11680	Weiser, City of	0.0009473	0.0009424
12026	Jefferson County PUD #1	0.0066949	0.0066890
10007	Alcoa	0.0000000	0.0000000
10312	Port Townsend Paper	0.0018062	0.0017964
10298	PNGC Aggregate	0.0786303	0.0782600

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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.

