BP-26 Rate Proceeding

Final Proposal

Power Rates Study

BP-26-FS-BPA-01

July 2025

POWER RATES STUDY

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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
AGC	automatic generation control
aMW	average megawatt(s)
ANR	Accumulated Net Revenues
ASC	Average System Cost
BAA	Balancing Authority Area
BiOp	Biological Opinion
BPA	Bonneville Power Administration
BPAP	Bonneville Power Administration Power
BPAT	Bonneville Power Administration Transmission
Bps	basis points
Btu	British thermal unit
CAISO	California Independent System Operator
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
COI	California-Oregon Intertie
Commission	Federal Energy Regulatory Commission (see also "FERC")
Corps	U.S. Army Corps of Engineers
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council	Northwest Power and Conservation Council (see also "NPCC")
COVID-19	coronavirus disease 2019
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CRFM	Columbia River Fish Mitigation
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
EESC	EIM Entity Scheduling Coordinator
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
FMM-IIE	Fifteen Minute Market – Instructed Imbalance Energy
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)
GDP	Gross Domestic Product
GI	generation imbalance
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)
HYDSIM	Hydrosystem Simulator (computer model)
IE	Eastern Intertie
IIE	Instructed Imbalance Energy
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
LAP	Load Aggregation Point
LDD	Low Density Discount
LGIA	Large Generator Interconnection Agreement
LLH	Light Load Hour(s)
LMP	Locational Marginal Price
LPP	Large Project Program
LT	long term
LTF	Long-term Firm
Maf	million acre-feet
Mid-C	Mid-Columbia
MMBtu	million British thermal units
MNR	Modified Net Revenue
MO	market operator
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	**N**ational Marine Fisheries Service (NMFS) **F**ederal Columbia River Power System (FCRPS) **B**iological Opinion (BiOp)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NOB	Nevada-Oregon border
NORM	Non-Operating Risk Model (computer model)
NWPA	Northwest Power Act/Pacific Northwest Electric Power Planning and Conservation Act
NWPP	Northwest Power Pool
NP-15	North of Path 15
NPCC	Northwest Power and Conservation Council (see also “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
OATT	Open Access Transmission Tariff
O&M	operations and maintenance
OATI	Open Access Technology International, Inc.
ODE	Over Delivery Event
OS	oversupply
OY	operating year (August through July)
P10	tenth percentile of a given dataset
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
PPC	Public Power Council
PRSC	Participating Resource Scheduling Coordinator
PS	Power Services
PSC	power sales contract
PSW	Pacific Southwest
PTP	Point-to-Point
PUD	public or people's utility district
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
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
RRHL	Regional Residual Hydro Load
RRS	Resource Remarketing Service

RSC	Resource Shaping Charge
RSS	Resource Support Services
RT1SC	RHWM Tier 1 System Capability
RTD-IIE	Real-Time Dispatch – Instructed Imbalance Energy
RTIEO	Real-Time Imbalance Energy Offset
SCD	Scheduling, System Control, and Dispatch Service
SCADA	Supervisory Control and Data Acquisition
SCS	Secondary Crediting Service
SDD	Short Distance Discount
SILS	Southeast Idaho Load Service
Slice	Slice of the System (product)
SMCR	Settlements, Metering, and Client Relations
SP-15	South of Path 15
T1SFCO	Tier 1 System Firm Critical Output
TC	Tariff Terms and Conditions
TCMS	Transmission Curtailment Management Service
TDG	Total Dissolved Gas
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
UDE	Under Delivery Event
UFE	unaccounted for energy
UFT	Use of Facilities Transmission
UIC	Unauthorized Increase Charge
UIE	Uninstructed Imbalance Energy
ULS	Unanticipated Load Service
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
WPP	Western Power Pool
WRAP	Western Resource Adequacy Program
WSPP	Western Systems Power Pool

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1. INTRODUCTION AND BACKGROUND

1.1 Power Rates Study Overview

This Power Rates Study (PRS or Study) explains the processes and calculations used to develop the power rates and Billing Determinants for Bonneville Power Administration's (BPA) wholesale power products and services. The PRS serves three primary purposes: 1) to demonstrate that 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 BPA policies, and 3) to demonstrate that rates have been set at a level that recovers the allocated power revenue requirement for the upcoming rate period, fiscal years (FY) 2026, 2027 and 2028.

The development of rates in the PRS uses inputs from a variety of sources:

- The Power Revenue Requirement Study, BP-26-FS-BPA-02, and its accompanying Documentation, BP-26-FS-BPA-02A, provides information regarding the power revenue requirement. *See* Power Revenue Requirement Study, § 2.5.
- The Power Loads and Resources Study, BP-26-FS-BPA-03, and its accompanying Documentation, BP-26-FS-BPA-03A, provide load and resource forecasts.
- The Power Market Price Study and Documentation, BP-26-FS-BPA-04, provides electricity market price forecasts. The market price forecasts are used in the development of demand rates, load shaping rates, short-term balancing purchases and expenses, augmentation purchases and expenses, secondary energy sales and revenue, and Planned Net Revenues for Risk (PNRR), if any.
- The Power and Transmission Risk Study, BP-26-FS-BPA-05, and its accompanying Documentation, BP-26-FS-BPA-05A, provide forecast quantities of power expected to be sold and purchased in electric markets and demonstrate that the rates and risk

mitigation tools together meet BPA's standard for financial risk tolerance—the 92.3 percent three-year equivalent of BPA's two-year Treasury Payment Probability (TPP) standard of 95 percent. The Risk Study includes quantitative and qualitative analyses of financial risks and tools for mitigating those risks, including those required by BPA's Financial Reserves Policy (FRP). *See* Administrator's Record of Decision, Financial Reserves Policy Phase-In Implementation, Appendix 1.

Power Services receives revenue from the generation inputs it provides to Transmission Services. The amount of the anticipated revenues from balancing services and other power services provided to Transmission customers is specified in the Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.

The revenues resulting from the rates developed in the PRS are used by the Power Revenue Requirement Study in the Revised Revenue Test to test the adequacy of rates to recover expenses and supply adequate cash to cover non-expense cash outlays. *See* Power Revenue Requirement Study, BP-26-FS-BPA-02, § 3.3.

1.2 Statutory and Legal Overview

The Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. § 839, is the primary statute providing ratemaking directives to BPA. The Northwest Power Act's Section 7(a)(1), 16 U.S.C. § 839e(a)(1), states:

> The Administrator shall establish, and periodically review and revise, rates for the sale and disposition of electric energy and capacity and for the transmission of non-Federal power. Such rates shall be established and, as appropriate, revised to recover, in accordance with sound business principles, the costs associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the Federal Columbia River Power System (including irrigation costs required to be repaid out of power revenues) over a reasonable period of years and the

other costs and expenses incurred by the Administrator pursuant to this chapter and other provisions of law.

The Bonneville Project Act defines "periodically review and revise" as revision of power and transmission rates not less frequently than once in every five years. 16 U.S.C. § 832d(a). Rates also are to be set in accordance with two other statutes: the Federal Columbia River Transmission System Act (Transmission System Act), 16 U.S.C. § 838, and the Flood Control Act of 1944, 16 U.S.C. § 825s.

Section 7 of the Northwest Power Act governs the allocation of BPA's costs, which is performed in a cost of service analysis, as described in Section 2.1 below, and establishes a set of rate directives that provide further guidance on how individual rates are to be derived, as described in Section 2.2 below. *See* 16 U.S.C. § 839e(b).

1.3 Regional Dialogue Policy Overview

In the Long-Term Regional Dialogue Policy, issued in July 2007, BPA defined its power supply and marketing role for the long term. Key components of the policy include 20-year power sales contracts and a tiered Priority Firm Power rate construct that provides each preference customer with a Contract High Water Mark (CHWM). Each customer's CHWM defines the amount of power the customer has a right to buy at a Tier 1 rate. Any power a utility chooses to buy from BPA for its load in excess of its CHWM is priced at a Tier 2 rate that is designed to recover the marginal cost of serving this additional load.

BPA offered CHWM contracts to all of its preference and investor-owned utility (IOU) customers. Currently, these power service contracts are in effect for these customers for FY 2012-2028.

1.3.1 Regional Dialogue Contract Product Descriptions

Below is a brief summary of the products offered under BPA's CHWM contracts. *See* BPA's *Regional Dialogue Guidebook*, available in the Regional Dialogue Policy Implementation section of BPA's website, www.bpa.gov, for full product descriptions and additional details on the interactions of the products, Tier 2 rate service, and Resource Support Services.

Load Following. The Load Following product supplies firm power to meet a preference customer's Total Retail Load (TRL), less any firm power supplied by the customer from any Dedicated Resources, including "behind the meter" non-federal resource amounts. The costs associated with the energy and capacity necessary to provide the Load Following service are recovered through Tier 1 rate charges for energy and demand.

Block. The Block product provides a planned amount of firm power to meet a preference customer's planned annual net requirement load. To buy this product, the customer must have dedicated non-federal resources, and the customer is responsible for using those resources dedicated to its TRL to meet any load in excess of its planned monthly BPA Block purchase. The costs associated with the energy and capacity necessary to provide this service are recovered through Tier 1 rate charges for energy and demand.

Slice/Block. The Slice/Block product provides a combined sale of two distinct power products: 1) firm power for a preference customer's net requirements load and an advance sale of surplus energy based on the generation shape of the federal system; and 2) firm requirements power under a Block product. The costs associated with the energy and capacity necessary to provide this service are recovered through Tier 1 rate charges for energy and demand.

1.4 Tiered Rate Methodology

The CHWM contracts and the Tiered Rate Methodology (TRM) provide long-term certainty to preference customers regarding their access to Tier 1 rate power and to BPA regarding its obligation to serve its preference customers' loads. *See* 2012 Wholesale Power and Transmission Rate Adjustment Proceeding (BP-12), Tiered Rate Methodology, BP-12-A-03.

The TRM provides for a two-tiered Priority Firm Public (PFp) rate design applicable to firm requirements power service for preference customers that signed CHWM contracts. The TRM established a predictable and durable means to calculate BPA's PF tiered rates for power deliveries beginning in FY 2012. The tiered rate design differentiates between the cost of service associated with Tier 1 system resources and the cost associated with additional amounts of power sold by BPA to serve any remaining portion of a customer's net requirement, also referred to as Above-Rate Period High Water Mark (Above-RHWM) load. The tiering of the PFp rate is one of the final steps in the development of rates and does not alter the fundamental manner in which BPA allocates costs to the various rate pools under the Northwest Power Act. Section 3.2 describes the steps taken to tier the PFp rate.

CHWMs, determined according to the TRM, help determine how much of each customer's net requirement purchased from BPA is charged at Tier 1 rates and how much may be charged at Tier 2 rates. The CHWM for each customer was calculated by BPA in FY 2011 based on the expected output of Tier 1 system resources during FY 2012-2013 and customers' actual FY 2010 loads. The individual utility CHWMs set each customer's initial eligibility to purchase power at Tier 1 rates and became part of each utility's CHWM contract.

1.4.1 Rate Period High Water Marks

Related to the CHWM and also defined in the TRM is the Rate Period High Water Mark (RHWM), which is an expression of the CHWM scaled to the expected output of resources identified as comprising the Tier 1 system for the relevant rate period. Each customer's RHWM for FY 2026-2028 defines that customer's maximum eligibility to purchase at Tier 1 rates for the rate period, limited for Slice and Block customers by the purchaser's Annual Net Requirement and for Load Following customers by the purchaser's Actual Net Requirement. The TRM specifies how rates will be developed to ensure, to the maximum extent possible, that customers' purchases of power at Tier 1 rates do not pay any of the costs of serving Above-RHWM Load.

To meet its Above-RHWM Load, a customer may purchase federal power, non-federal power, or a combination of the two. To the extent a customer purchases federal power for its Above-RHWM Load, a PF Tier 2 rate(s) will be applied to this portion of its federal power service. *See* Section 4.1.2 below.

1.4.2 Rate Period High Water Mark Process

The RHWM is determined based on the customer's CHWM and the RHWM Tier 1 System Capability (RT1SC) for each applicable rate period. The determination of a customer's RHWM occurs outside of the rate proceeding in the RHWM Process, as described in TRM § 4.2.1.

The RHWM Process for the FY 2026-2028 rate period was completed in September 2024. BPA engaged customers in a public process from June to September 2024, with two public comment periods and two public workshops. After completion of the review and comment periods, BPA examined the information collected. BPA posted its determination of values for the FY 2026-2028 rate period for RHWM Tier 1 System Capability, including RHWM Augmentation; each customer's RHWM; and each customer's Above-RHWM Load. *See* Rate Period High Water Mark Process, https://www.bpa.gov/energy-and-services/rate-and-tariff-proceedings/rate-period-high-water-mark-process; PRS Table 1.

Once established, RHWMs are, under most circumstances, not changed. Exceptions include certain changes on a customer's system, including annexation that results in a gain or loss of service territory or a later discovery that a load is a New Large Single Load (NLSL).

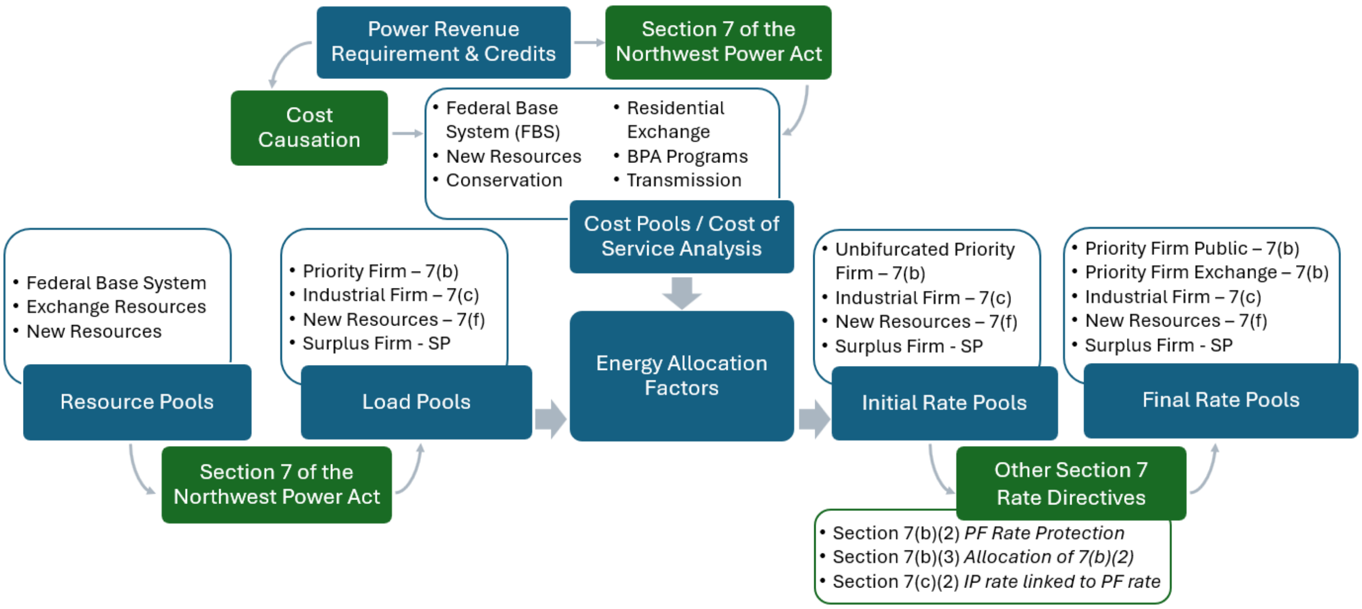
1.5 Overview

The next two sections discuss the ratemaking methodology and process, which result in the rate schedules and General Rate Schedule Provisions (GRSPs) discussed in Sections 4 and 5. At a high level, BPA's ratemaking process for power products and services has three main steps:

1. A Cost of Service Analysis (COSA) Step (Section 2.1), which allocates the various types of costs (categorized into resource or cost pools) to the various classes of customers (categorized into load or rate pools) using energy allocation factors calculated based on loads and resources.
2. A Rate Directives Step (Section 2.2), which reallocates costs between rate pools to ensure that the relationships between the rates for the different classes of customers comport with the rate directives in the Northwest Power Act.
3. A Rate Design Step (Section 3), which produces tiered PFp rates that collect the PFp revenue requirement determined in the Rate Directives Step. This step also implements the rate design for the non-tiered rates.

BPA's ratemaking processing for power products and services is depicted in Figure 1 below.

Figure 1. BPA Ratemaking Process for Power Products and Services



As noted above, Sections 4 and 5 discuss rate schedules and GRSPs resulting from these steps. Section 6 discusses Transfer Service. More than half of BPA's power customers are served by the transmission systems of third parties (entities other than BPA). Under the Regional Dialogue contracts, BPA must acquire transmission services from these third-party transmission providers to deliver federal power to BPA's power customers. This third-party transmission service is commonly referred to as Transfer Service. Transfer Service customers may be subject to one or more separate charges from BPA.

Section 7 discusses the Slice True-Up. Slice customers are subject to an annual Slice True-Up Adjustment for expenses, revenue credits, and adjustments allocated to the Composite cost pool and to the Slice cost pool. BPA calculates the annual Slice True-Up Adjustment for each fiscal year as soon as BPA's audited actual financial data are available.

Section 8 discusses Average System Costs (ASCs). The Residential Exchange Program (REP), established by Section 5(c) of the Northwest Power Act, was designed to provide residential and farm customers of Pacific Northwest utilities a form of access to low-cost federal power. 16 U.S.C. § 839c(c). Under the REP, BPA purchases power from each participating utility at that utility's average system cost (ASC). ASCs—stated in dollars per megawatthour ($/MWh) or mills per kilowatthour (mills/kWh)—are determined by BPA in separate processes occurring outside the BP-26 rate proceeding for each utility participating in the REP.

Section 9 discusses BPA's revenue forecast. The revenue forecast calculates the expected revenue from power rates and other sources for the rate period, FY 2026-2028, and the current year, FY 2025. BPA prepares two revenue forecasts, one using rates from the rate schedules currently in effect (BP-24 rates) and the second using BP-26 rates. The revenue forecasts are used to test whether current rates and revised rates will recover the power revenue requirement.

2. RATEMAKING COST OF SERVICE AND RATE DIRECTIVES STEPS

2.1 Cost of Service Analysis

2.1.1 Statutory Background

Northwest Power Act Sections 7(b), 7(d), 7(f), and 7(g) direct how BPA allocates resource and other costs to load (rate) pools. 16 U.S.C. §§ 839e(b), 839e(d), 839e(f), 839e(g). This allocation is performed in the Rate Analysis Model for the BP-26 rate period (RAM2026).

Section 7(b)(1) states:

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

16 U.S.C. § 839e(b)(1). Section 7(b)(1) thus describes how BPA is to allocate resource costs to meet the general requirements of public body, cooperative, and federal agency customers within the Pacific Northwest and the loads of electric utilities participating in the REP under § 5(c), collectively called the Priority Firm Power (PF) customer class. *Id.* At this initial stage of the ratemaking process, the PF rate pool consists of the loads of public bodies and cooperatives (collectively identified as preference customers in Northwest Power Act Section 5(b)), federal agency loads, and the loads of REP-participating utilities.

Section 7(b)(1) requires that Federal Base System (FBS) resources be used to serve the PF rate pool until the FBS resources are exhausted. *Id.* Thus, a corresponding amount of

FBS costs is allocated to the PF rate pool. After FBS resources are fully used, resources acquired pursuant to the REP (called exchange resources) are used, and then, if needed, new resources are used to serve remaining PF rate load. By allocating resource costs in this order, the appropriate amounts of exchange and new resource costs are allocated to the PF rate pool.

Section 7(d)(1) states:

> In order to avoid adverse impacts on retail rates of the Administrator's customers with low system densities, the Administrator shall, to the extent appropriate, apply discounts to the rate or rates for such customers.

Id. § 839e(d)(1). Section 7(d)(1) thus authorizes BPA to apply a Low Density Discount (LDD) to mitigate the costs of customers with relatively fewer retail consumers spread over relatively larger geographic areas. The LDD is discussed in Sections 2.1.4.3 and 5.4.1 below.

Section 7(f) states:

> Rates for all other firm power sold by the Administrator for use in the Pacific Northwest shall be based upon the cost of the portions of Federal base system resources, purchases of power under Section 5(c) of this title and additional resources which, in the determination of the Administrator, are applicable to such sales.

Id. § 839e(f). Section 7(f) prescribes how costs are allocated to rates for all other firm power after costs are allocated to the PF rate pool and the rates for BPA's direct-service industrial customers (DSIs) are determined. *Id.* Section 7(f) allocates the remaining exchange and new resource costs to the remaining regional load (power sold at the New Resource Firm Power (NR) rate and the Firm Power and Surplus Products and Services (FPS) rate). *Id.*

Section 7(g) states:

> Except to the extent that the allocation of costs and benefits is governed by provisions of law in effect on December 5, 1980, or by other provisions of this section, the Administrator shall equitably allocate to power rates, in accordance with generally accepted ratemaking principles and the provisions of this chapter, all costs and benefits not otherwise allocated under this section, including, but not limited to, conservation, fish and wildlife measures, uncontrollable events, reserves, the excess costs of experimental resources acquired under Section 6 of this title, the cost of credits granted pursuant to Section 6 of this title, operating services, and the sale of or inability to sell excess electric power.

Id. § 839e(g). Section 7(g) thus addresses the allocation of costs that are not covered by the previously cited sections of the Northwest Power Act, such as conservation and fish and wildlife costs.

Consistent with these mandates, the Cost of Service Analysis (COSA) assigns (or "allocates") repayment responsibility for BPA's power revenue requirement (which is grouped into resource pools, or "cost pools") to the various classes of service (which are grouped into load pools, or "rate pools"). These allocations are based upon the resources used to serve those loads, in compliance with the statutory directives governing BPA's ratemaking and in accordance with generally accepted ratemaking principles. The COSA and the other ratemaking steps are programmed into BPA's 2026 Rate Analysis Model (RAM2026) software for purposes of calculating power rates.

2.1.2 COSA Overview

As noted above, the COSA categorizes loads and resources determined in the Loads and Resources Study, BP-26-FS-BPA-03, into "pools." The load pools and resource pools are then used to calculate Energy Allocation Factors (EAFs). The EAFs are calculated based on the priorities of service from resource pools to rate pools specified in Section 7 of the Northwest Power Act, and when Section 7 does not provide guidance, they are based on general principles of cost causation. The COSA then categorizes costs, determined in the Power Revenue Requirement Study, BP-26-FS-BPA-02, and revenue credits, determined in the Power and Transmission Risk Study, BP-26-FS-BPA-05, as well as Section 2.1.6 below, into cost pools. The COSA concludes by using the EAFs to apportion these costs and revenue credits among the rate pools. Sections 2.1.3 through 2.1.7 provide more detail.

2.1.3 Loads and Resources

The COSA uses disaggregated customer load data from the source data used to produce the Power Loads and Resources Study, BP-26-FS-BPA-03. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.1.1. The disaggregated load data are aggregated into the PF rate pool (consisting of two sub-pools, the PF Public (PFp) rate pool and the PF Exchange (PFx) rate pool), the Industrial Firm Power (IP) rate pool, the New Resource Firm Power (NR) rate pool, and the FPS rate pool. *Id.*, Table 2.2.2.1.

The COSA also uses the disaggregated resource data from the source data in the Power Loads and Resources Study. *Id.*, Table 2.1.2. The disaggregated resource data are aggregated into the resource pools specified by Section 7 of the Northwest Power Act. 16 U.S.C. § 839e. These resource pools are the FBS resource pool, the exchange resource pool, and the new resource pool. *Id.*, Table 2.2.2.1. The resources in the FBS and new resource pools are actual or planned resources that are forecast to be able to serve load during the rate period. The ratemaking process requires that the forecast firm resources available to serve load equal BPA's firm load obligations under firm generation. Firm generation conditions assume very low streamflow conditions based on the historical record along with today's generating facilities and constraints to yield an amount of energy output. Firm generation is defined as the monthly 10th percentile (P10) generation of the federal system. See Power Loads and Resources Study, BP-26-FS-BPA-03, § 3.1.2.1.3.

2.1.3.1 Load Pools

Load pools are groupings of forecast sales into customer classes for cost allocation purposes. These load pools are used to create rate pools. The Northwest Power Act establishes three rate pools based on the loads served at particular rates. The 7(b) rate pool includes sales to public body and cooperative customers (consumer-owned utilities or COUs), federal agencies, and utilities participating in the REP. 16 U.S.C. § 839e(b). The 7(c) rate pool includes sales to BPA's DSI customers under contracts authorized by Section 5(d) of the Northwest Power Act. *Id.* § 839e(c). The 7(f) rate pool includes three types of sales: 1) power sold to consumer-owned utilities which is determined to serve NLSLs; 2) Section 5(b) requirements power sold to the region's IOUs; and 3) power sold by BPA pursuant to Section 5(f) of the Northwest Power Act. *Id.* § 839e(f).

The Northwest Power Act states that after July 1, 1985, BPA is not required to allocate any resource costs to the IP rate pool; rather, the IP rate is set using a formula pursuant to Section 7(c). *Id.* § 839e(c). The formula ties the IP rate to the PF rate. However, if DSI loads were excluded from cost allocations, loads and resources would be out of balance, leaving an amount of resource costs not allocated to any loads. Therefore, for ratemaking purposes BPA allocates resource costs to IP loads as it does to all other remaining firm power sold. The result is that BPA has, for all practical purposes, only two rate pools, the 7(b) rate pool and all other loads. The resource cost allocations to the IP rate pool are adjusted later in the Rate Directives Step to conform the IP rate to the statute-based formula.

2.1.3.2 Resource Pools

The three resource pools are FBS resources, exchange resources, and new resources.

The FBS resource pool and associated costs are defined in Section 3(10) of the Northwest Power Act. *Id.* § 839a(10). The FBS consists of the costs of the following resources: 1) the Federal Columbia River Power System (FCRPS) hydroelectric projects; 2) resources acquired by the Administrator under long-term contracts in force on the effective date of the Northwest Power Act; and 3) replacements for reductions in the capability of the resources listed in 1) and 2). Market purchases of system augmentation, balancing purchases, and purchases designated for Tier 2 rates are included as costs of FBS resources. Forecast costs for FBS resources and associated augmentation during the rate period are included in the FBS resource cost pool.

To implement the direction in Northwest Power Act Section 5(c)(1) that BPA is to purchase resources from each eligible REP participant and sell an equivalent amount of electric power to each participant, the exchange resources are sized to be equal to the forecast of the eligible REP exchange load during the rate period. *Id.* § 839c(c)(1). To calculate the eligible REP exchange load, the COSA determines whether the potential exchanging utilities have ASCs that are greater than the applicable base PFx rate for the rate period. Utilities with ASCs higher than the base PFx rate are assumed to participate in the REP during the rate period. In this way, BPA estimates the PFx load, the size of the exchange resource pool, and the costs of the exchange resources (the ASCs multiplied by the eligible exchange loads). *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.1.3. This process is iterative and dependent upon the outcomes of the Rate Directives Step. *See* Section 2.2.2 below.

Exchange resources are set equal to the amount of resulting qualifying exchange load, which implements the direction in Section 5(c)(1) that BPA is to purchase power from each eligible REP participant and sell an equivalent amount of electric power to each participant. 16 U.S.C. § 839c(c)(1).

The new resources pool includes all other resources acquired by BPA unless a resource has been determined to be a replacement for reduced FBS capability.

2.1.3.3 Order of Resource Service to Load Pools

Section 7(b)(1) of the Northwest Power Act specifies how resource costs must be allocated to the PF customer class. *Id.* § 839e(b)(1). FBS resources are used to serve the PF rate pool until FBS resources are exhausted, whereupon exchange resources and then new resources are used and, if required, system augmentation in the form of uncommitted market purchases is forecast to serve any remaining PF loads. After PF loads are met, all remaining resources are used to serve non-PF loads and, if required, Other Augmentation is forecast to serve any remaining non-PF loads. Other Augmentation occurs when BPA's total annual firm energy resources, including any system augmentation to meet PF loads, is less than BPA's total load obligations including non-PF loads. Section 7(f) of the Northwest Power Act specifies what and how costs are allocated to "all other firm power" after costs are allocated to the PF rate pool: the remaining exchange and new resources costs are allocated to remaining load. *Id.* § 839e(f). That remaining load is served under IP, NR, and FPS contracts.

For the BP-26 rates, the PF load (which includes both PFp and PFx loads) exceeds the capability of the FBS resources. Therefore, all FBS costs and benefits are allocated to the PF rate pool. All Exchange Resources are needed to serve PF load; therefore, all costs are allocated to the PF rate pool. PF loads are served by over half of the new resources, which includes Other Augmentation. The costs of new resources are allocated proportionally to the firm PF, IP and NR loads it serves. There is no FPS load forecast for BP-26. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.5.4.

2.1.3.4 Load and Resource Adjustments

The Power Loads and Resources Study includes a forecast of the generating capability of all resources available to BPA to serve its load obligations. Ratemaking uses only the amount of resources available to serve the rate pool loads; thus, some adjustments must be made. BPA has certain system obligations, including the Canadian Entitlement and U.S. Bureau of Reclamation (Reclamation) pumping loads (together called FBS obligations), that have existed since before the passage of the Northwest Power Act. *See* Treaty between Canada and the United States of America relating to the Cooperative Development of the Water Resources of the Columbia River Basin (Columbia River Treaty), Art. VI 4(b), Jan. 17, 1961, 15 U.S.T. 1555, 542 U.N.T.S. 244. FBS resources used to serve these system obligations are taken "off the top," removing both the obligation and a corresponding amount of FBS resource before the ratemaking load-resource balance is calculated.

The ratemaking load-resource balance after adjustments is shown in Power Rates Study Documentation, BP-26-FS-BPA-01A, Tables 2.2.2.1-2.

2.1.3.5 Energy Allocation Factors

The aggregated load and resource data are used to calculate the Energy Allocation Factors (EAFs) that the COSA uses to apportion costs among rate pools. EAFs are calculated for each resource and rate pool combination by dividing the amount of annual energy load in each rate pool by the amount served from each resource pool. The annual EAFs for each resource cost pool and for the rate directive steps are shown in Documentation Tables 2.2.3.1-2. *Id.* The General and Conservation allocation factors assume a pro rata allocation of costs to all firm loads. For example, the General and Conservation EAFs are used to allocate some Section 7(g) costs and rate directive allocation adjustments to all firm energy loads.

2.1.4 Ratemaking Costs

The COSA aggregates costs from the Power Revenue Requirement Study, *id.*, Tables 2.3.1.1-5, into BPA's ratemaking cost pools specified by Section 7 of the Northwest Power Act*, id.*, Table 2.3.2.

Functionalization of costs between the generation and transmission functions (BPA does not have a distribution function normal to most utilities) is reflected in the Power Revenue Requirement Study, BP-26-FS-BPA-02, and the Transmission Revenue Requirement Study, BP-26-FS-BPA-06. The costs functionalized to the generation function are included in the power revenue requirement found in the COSA. An exception is exchange resource costs. *See* Section 2.1.4.2 below. The exchange resource costs are calculated internal to the Rate Analysis Model (RAM2026). The exchange resource costs include transmission function costs. The exchange resource costs are functionalized in the COSA modeling so that only the generation portion of the exchange resource costs is subject to the power cost rate steps, and the transmission cost portion is then added back in after the Rate Directives Step is completed. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.3.4.2. In this way, the statutorily mandated power cost relationships between the various rate pools are maintained without being affected by the transmission function costs of the exchange.

The COSA modeling uses other costs that are internally generated by RAM2026. These include exchange resource costs, some power purchase costs, revenue shortfall costs associated with some rate credits, and revenues from secondary power sales. These are covered in greater detail below.

2.1.4.1 Revenue Requirement

The revenue requirement from the Power Revenue Requirement Study is supplemented in the COSA for costs that are determined in other steps of the ratemaking process (such as projected balancing purchase power costs; system augmentation costs; PNRR, if any; and the functionalized exchange resource costs). Disaggregated costs are listed in a form consistent with the income statement from the Power Revenue Requirement Study and are shown in Table 2.3.1.1-5. *Id.* RAM2026 uses unique identifier key codes to categorize these costs to the COSA cost pools. *Id.*, Table 2.3.2.

In addition to costs associated with operation of the FCRPS, there are three categories of purchased power that are included in the COSA: 1) purchased power under contract; 2) forecast system augmentation; and 3) forecast balancing power purchases.

1. **Purchased Power.** The purchased power subset of purchased power costs includes the costs of acquisition of power through renewable energy, wind, geothermal, and competitive acquisition programs. Costs of purchased power from the Power Revenue Requirement Study are included in the new resources pool.
2. **System Augmentation.** For ratemaking purposes, it may be assumed that BPA acquires resources beyond the inventory represented by the system generating resources and balancing power purchases if loads exceed resources under firm generation assumptions. System augmentation amounts are determined in the Power Loads and Resources Study and are used to meet

annual customer firm power loads in excess of annual firm system resources. System augmentation includes any Tier 1 system augmentation required to meet any annual deficits of the federal system for Tier 1 load service and Tier 2 augmentation to meet Tier 2 load service that is greater than the forecasted available federal system. *See* Power Loads and Resources Study, BP-26-FS-BPA-03, § 4.2. Typically, system augmentation is reflected as an uncommitted market purchase and the cost is based on the remarketing value. *See* Section 3.2.6 below. System augmentation purchases are treated as FBS costs and, as such, the costs are included in and allocated as FBS costs. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Tables 2.3.1.5 and 2.3.2.

3. **Balancing Power Purchases.** The costs of power purchases and storage required to meet firm deficits on a monthly/diurnal basis are included in the category of balancing power purchases. Projected balancing power purchases are generally needed to serve firm loads in months other than the spring fish migration period under some water conditions. Balancing purchase expenses are calculated for each monthly/diurnal period where BPA is energy deficit across all 2,700 iterations in the Revenue Simulation Model (RevSim). The median purchasing price and quantity associated with these purchases for each year of the rate period are passed to RAM2026 to compute balancing purchase costs. *See* Power and Transmission Risk Study, BP-26-FS-BPA-05, § 3.1.2.1. Balancing power purchases are treated as FBS costs and, as such, the costs are included in and allocated as FBS costs. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Tables 2.3.1.5 and 2.3.2.

Other Augmentation also plays a role. Other Augmentation is forecast to occur when BPA's annual firm energy resources including system augmentation are less than

BPA's total load obligations. Typically, Other Augmentation is necessary to serve non-PF loads under IP, NR, and FPS contracts. Other Augmentation amounts are determined in the Power Loads and Resources Study. *See* Power Loads and Resources Study, BP-26-FS-BPA-03, § 4.2. Other Augmentation costs are treated as uncommitted market purchases priced using the Remarketing Value. *See* Section 3.2.6 below. Other Augmentation is classified as a new resource and, as such, the costs are included in the new resource cost pool in the COSA. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.3.2.

2.1.4.2 Functionalization of Exchange Resource Costs

In the COSA, exchange resource costs are based on participating utilities' ASCs and their exchange power sales to BPA. Each utility's ASC includes the cost of power and transmission services associated with serving the utility's TRL. By definition, exchange resource sales to BPA equal the exchange sales by BPA. The rate directive adjustments that occur subsequent to the COSA use the results of the COSA allocations of the generation revenue requirement. Therefore, because the exchange resource costs in the COSA include transmission costs, the PFx rate includes a transmission cost adder, and the exchange resource costs are functionalized between power and transmission.

The exchange resource costs functionalized to power continue through the ratemaking process. The exchange resource costs functionalized to transmission are removed from the generation revenue requirement for the Rate Directives Step and are added back to determine the PFx rate after the Rate Directives Step is completed. In this way, the exchange resource costs functionalized to power are treated the same as other power function costs through the rate development process. The transmission function costs are collected directly from PFx loads through a transmission adder included in the PFx rate.

Because the amount of exchange resource costs functionalized to transmission is equal to the increased revenue due to the PFx rate adder, there is no net cost to other rates due to these transmission costs. The functionalization of exchange resource costs is shown in Table 2.3.4.2. *Id.*

2.1.4.3 Low Density Discount

Section 7(d)(1) of the Northwest Power Act instructs BPA to apply a Low Density Discount (LDD) to mitigate the costs of customers with relatively fewer consumers spread over relatively larger geographic areas. 16 U.S.C. § 839e(d)(1). *See* Power Rate Schedules and General Rate Schedule Provisions (GRSPs), BP-26-A-01-AP01, GRSP II.B.

The cost of providing the discount is computed in RAM2026 using offset quantities and the internally computed TRM rates. Offset quantities are the sum of the applicable LDD percentages applied to the customer-specific billing determinants. *See* TRM, BP-12-A-03, § 10.2. These offsets are computed in the TRM Billing Determinants Model (TRMbd), which is a module of RAM2026.

The estimated cost of the LDD is shown in Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.3.3.1. The entire cost of the discount is allocated to the PF load pool prior to linking the IP rate to the PF rate. *Id.*, Table 2.3.4.1.1

2.1.4.4 Irrigation Rate Discount

A rate discount is available to qualifying irrigation loads pursuant to CHWM contracts and the TRM. The discount is a rate, expressed in mills per kilowatthour that, when applied to qualified irrigation load, produces a dollar credit on eligible customers' power bills. *See* Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.C. The Irrigation Rate

Discount (IRD) rate is calculated in RAM2026, as described in Section 5.4.2 below. The cost of the discount is computed in RAM2026 using contract irrigation loads and the internally calculated rate. The entire cost of the IRD is allocated to the PF load pool prior to linking the IP rate to the PF rate.

2.1.5 Cost Pools

The COSA has six cost pools for the initial allocation of BPA's power costs: FBS resource costs, exchange resource costs, new resource costs, conservation costs, BPA program costs, and power transmission costs. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.3.2. These costs are allocated to the rate pools using direction from Sections 7(b)(1), 7(d), 7(f), and 7(g) of the Northwest Power Act. 16 U.S.C. §§ 839e(b)(1), 839e(f), 839e(g).

2.1.5.1 Section 7(b)(1) and 7(d) Costs

Section 7(b)(1) costs are associated with the resource cost pools necessary to serve PF load, including the PFp load and the PFx load. 16 U.S.C. § 839e(b)(1). For the BP-26 rates, these resources include all of the FBS resources and all of the exchange resources. Therefore, all FBS resource costs and all exchange resource costs are Section 7(b)(1) costs allocated to serve Section 7(b)(1) loads. Costs associated with the LDD under Section 7(d) and the IRD are allocated along with Section 7(b)(1) costs.

2.1.5.2 Section 7(f) Costs

Section 7(f) costs are generally associated with the resource cost pools necessary to serve non-PF load, including IP, NR, and FPS loads. *Id.* § 839e(f). For the BP-26 rates, these resources include the new resources which contains Other Augmentation. Therefore, most new resource costs are Section 7(f) costs allocated to serve all remaining loads; that is, IP, NR, and FPS loads.

2.1.5.3 Section 7(g) Costs

Conservation Costs. The Northwest Power Act requires BPA to treat cost-effective conservation savings as a resource in planning to meet the Administrator's obligations to serve loads. The "conservation" line item, as seen in Power Rates Study Documentation, BP-26-FS-BPA-01A, Tables 2.3.1.1-5, includes 1) amortization of BPA's previous conservation resource acquisition activities; 2) BPA's continuing contributions to the region's market transformation efforts; 3) costs associated with BPA's energy efficiency business; and 4) a share of Net Revenues (Minimum Required Net Revenues (MRNR) plus PNRR, if any). Conservation costs are allocated to all rate pools using the Conservation & General EAF. *Id.*, Table 2.3.4.3.

BPA Program Costs. Some of BPA's program costs are not identified directly with any specific resource pool. An example is the cost of tracking and implementing national energy policies and initiatives. Development of these power program costs occurs in the Integrated Program Review (IPR), as described in Power Revenue Requirement Study, BP-26-FS-BPA-02, Section 2.1. The power portion appears in the COSA as BPA program costs. BPA program costs are allocated to all rate pools using the Conservation & General EAF. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.3.4.3.

BPA Power Transmission Costs. Power transmission expenses include the costs of serving customers under Transfer Service. *See* Section 6 below. They also include the costs Power Services incurs to procure transmission and ancillary services to transmit surplus federal power to purchasers that do not hold transmission contracts, primarily outside the

Pacific Northwest. BPA also has federal generation that exists in third-party service territories; both wheeling costs and financial payments to cover losses are included in this category of costs. Finally, it includes an FCRPS generation-integration cost. Transmission costs are allocated to all rate pools based on the Conservation & General EAF except third Party General Transfer Agreement (GTA) wheeling costs (also referred to as Transfer Costs) are allocated between the PF and NR rate pools based on usage. Under the BP-26 settlement terms NR GTA wheeling costs are forecast to be zero. Administrator's Final Record of Decision, BP-26-A-01, Appendix A § IV.G. In addition, the Transmission and Ancillary Services (Non-Slice) costs supporting non-system obligations uses the FBS EAF. Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.3.4.3.

2.1.5.4 Planned Net Revenues for Risk

PNRR is an amount of net revenues required to be recovered from power rates to ensure that cash flows from such rates are sufficient to meet BPA's TPP Standard. *See* Power and Transmission Risk Study, BP-26-FS-BPA-05, § 2.3. PNRR may also include an amount of additional revenue to build financial reserves under the FRP. Power and Transmission Risk Study, BP-26-FS-BPA-05, Appendix A (FRP), § 4.2.

Under the ratemaking methodology, the amount of PNRR (if any) needed to meet the TPP Standard is the result of an iterative process among several models: RAM2026, RevSim, and ToolKit. *See* Power and Transmission Risk Study, BP-26-FS-BPA-05, § 4. The iteration is initiated with a seed value of $0 for PNRR in the Power Rates Study Documentation, BP-26-FS-BPA-01A, Tables 2.3.1.4 and 2.3.2. The resulting rates are used in RevSim to produce net revenue probability distributions. These net revenue distributions are then used in the ToolKit to test whether TPP is at least 92.6 percent over the three-year rate period. If not, the ToolKit produces a new PNRR value that just meets the TPP standard, rates are recalculated, a new distribution of net revenues is created, and TPP is calculated for the new distribution. The iterations are stopped when the smallest value of PNRR that meets the TPP standard has been determined. *Id.*, Table 2.3.1.4. Because no PNRR was required to meet the TPP Standard in the BP-26 rates, no iterative process was necessary. No PNRR was required in the BP-26 rates for liquidity purposes because any accrual of additional cash reserves required by the FRP is to be collected through the FRP Surcharge. *See* Section 5.2.2 below.

2.1.5.5 New Expenses

BPA will allocate new expenses to the six cost pools using direction from Sections 7(b)(1), 7(f), and 7(g) of the Northwest Power Act. 16 U.S.C. §§ 839e(b)(1), 839e(f), 839e(g). For BP-26, four new costs were added to RAM2026. The new costs have been identified below including the cost pool it is being allocated too.

1. Amortization of P2IP Settlement Payments, a FBS resource costs.
2. Long Term Funding Agreements (Accords), a FBS resource costs.
3. Payments for Litigation of Stay Agreements (P2IP), a FBS resource costs.
4. Other Augmentation, a new resource cost.

Consistent with the Update to BPA's BP-26 Cost Projections, issued on July 14, 2025, cost projections in power rates associated with the Memorandum of Understanding filed on December 14, 2023, in the Columbia River System litigation, *National Wildlife Federation v. National Marine Fisheries Service*, No. 3:01-cv-640-SI (D.Or.), ECF No. 2450-1 (MOU), were removed. Email from Bonneville Power Administration to Tech Forum Subscribers, Update to BPA's BP-26 Cost Projections (July 14, 8:11 PST) (on file with author) ("Update to BPA's BP-26 Cost Projections"); *see* Power Rates Study Documentation, BP-26-FS-BPA-01A, Tables 2.3.1.1-5.

2.1.6 Revenue Credits

In addition to allocating cost data, the COSA allocates various revenue credits that offset costs in each rate pool. Allocation of revenue credits follows the same principles as the allocation of costs, based upon statutory guidance. For example, some revenue credits are associated with the operation of FBS resources and reduce FBS resource costs to be recovered by PF rates. Some revenue credits reduce the new resource and conservation costs. Other revenue credits that are not associated with any particular cost pool are allocated to rate pools pro rata to load using the Conservation & General EAF. *Id.,* Table 2.2.3.2.

2.1.6.1 Downstream Benefits and Pumping Power Revenues

Downstream benefits and pumping power revenues are described in Section 9.2 below. Downstream benefits and pumping power revenues are associated with FBS resources, and these credits are allocated to the same loads to which FBS costs are allocated. *See id.*, Table 2.3.6.

2.1.6.2 Section 4(h)(10)(C) Credits

Section 4(h)(10)(C) credits are described in Section 9.4.1. The forecast credit is calculated as described in the Power and Transmission Risk Study, Section 4.1, and supplied to RAM2026. Section 4(h)(10)(C) credits are associated with FBS resources, and the credits are allocated to the same loads to which FBS costs are allocated. *Id.*

2.1.6.3 FBS Contract Obligations Revenue

BPA has certain FBS obligations that provide revenues. For the BP-26 period, this includes only Upper Baker revenues for energy and capacity purchased by Puget Sound Energy to enable flood control elevation levels at that project. These FBS system obligation revenues are allocated to the same loads to which FBS costs are allocated. *See id.*

2.1.6.4 Colville Credit

The Colville credit is described in Section 9.4.2 below. The Colville credit is associated with FBS resources, and this credit is allocated to the same loads to which FBS costs are allocated. *Id.*

2.1.6.5 Miscellaneous Revenues

Miscellaneous revenues are described in Section 9.2 below. These revenues are allocated to all firm loads through the Conservation & General EAF. *Id.*, Table 2.2.3.1.

2.1.6.6 Renewable Energy Certificates

Revenues result from BPA's sales of Renewable Energy Certificates (RECs). For FY 2026-2028, no revenues are expected, and the forecast is zero. *Id.*

2.1.6.7 General Revenue Credits

In the course of marketing power, Power Services generates transmission-related revenues and credits. The revenues and credits are predominantly revenues associated with providing reserves and energy for ancillary services, control area services, and other reliability needs. *See* Section 9.3 below. In addition to revenues associated with generation inputs, FPS Real Power Losses, NR Energy Shaping Service (NR ESS) products for NLSL service, and Resource Support Services for non-federal resources are allocated using the FBS EAF. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Tables 2.3.7.5 and 2.3.7.6.

2.1.6.7.1 Tiered Rates Adjustment Credit

The Tiered Rates Adjustment revenue credit reflects the value associated with selling energy from the federal system to serve Tier 2 loads within the 7(b) rate pool. The Tiered Rates Adjustment is categorized as a FBS revenue credit and assigned to the Composite cost pool. *See id.*, Table 2.3.7.1.

The Tiered Rates Adjustment credit is calculated internally within RAM2026 by taking the annual average megawatts (aMW) of the federal system serving Tier 2 loads for a specific year of the rate period, multiplying it by the respective annual hours and reported remarketing value. *See* Section 3.2.6 below.

2.1.6.8 Secondary Energy Revenue Credits

The Secondary Energy Revenue Credit adjustment recognizes that BPA collects revenues from certain power sales to which costs are not allocated. BPA credits these revenues to classes of service served with firm federal power.

The ratemaking process ensures that the forecast of firm resources available to serve load is equal to BPA's firm load obligations under firm generation conditions. However, if firm load obligations exceed firm resources, a system augmentation purchase is assumed to achieve load-resource balance. If firm resources exceed firm load obligations, a firm surplus secondary sale is assumed to achieve load-resource balance. System Augmentation expenses are included as FBS costs in the COSA. *See* Section 2.1.4.1 above. Firm Surplus Secondary Sales are included in the secondary revenue credit calculation but allocated in the Surplus Power Sales Revenue Deficiency/Surplus Reallocation. *See* Section 2.1.7 below.

Non-firm secondary sales recognize that better than firm generation conditions will most likely occur. Generation from water in excess of firm conditions is called secondary energy.

The projected secondary energy revenue credits are included so that power rates are set at a level such that revenues from all sources do not recover more than the total Power Services revenue requirement.

The sales of secondary energy in excess of firm obligations on a monthly/diurnal basis under 2,700 iterations of different risk conditions are calculated by RevSim. Power and Transmission Risk Study, BP-26-FS-BPA-05, § 4.1.1; *see also* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.3.8. Mean prices and quantities of these secondary sales, as well as mean market prices, are passed to RAM2026 for the purposes of the secondary revenue credit and the computation of the load shaping rates.

The quantity of secondary sales is valued at expected wholesale market prices in the Northwest at the Mid-Columbia (Mid-C) trading hub. However, BPA makes transactions outside the Northwest. The incremental value of extra-regional sales is computed in RevSim and passed to RAM2026 as an aggregate dollar value to be included in the secondary revenue credit after accounting for both transmission availability and regional price differences. Power and Transmission Risk Study, BP-26-FS-BPA-05, § 4.1.1.2.3; *see also* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.3.8.

For the BP-26 rate period, the value associated with market participation in the Energy Imbalance Market (EIM) is estimated by simulating EIM dispatch using forecast hourly Northwest market prices at Mid-C and projected BPA system flexibility gained by no longer holding Non-Regulating balancing reserves. This value is directly input into RAM2026. Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.3.8.

Per the BP-26 Settlement Agreement, Administrator's Final Record of Decision, BP-26-A-01, Appendix A § IV.C, additional net secondary revenues are included for each year of the rate period. These values are directly input into RAM2026 and captured within the "Adjustments to Secondary Sales" line in Table 2.3.8 of the Power Rates Study Documentation, BP-26-FS-BPA-01A.

The secondary revenues projected in RevSim are for market sales BPA expects to make on behalf of Non-Slice customers. However, RevSim also calculates the value of secondary energy that is expected to be sold by Slice customers. This value for Slice secondary also includes an incremental value for extra-regional sales. The ratemaking process does not consider product choice by preference customers until the Rate Design Step; therefore, the revenues from RevSim used at this stage of ratemaking include all secondary energy expected to be produced by federal generation. *Id.*, Table 2.3.8. Secondary energy revenues are allocated to rate pools based on the FBS EAF to credit the revenues against the costs of the resources producing the secondary energy.

2.1.7 Surplus Power Sales Revenue Deficiency/Surplus Reallocation

BPA sells surplus firm power under the FPS rate schedule. If BPA anticipates firm generation to exceed firm load obligations on an annual average basis, Firm Surplus Secondary Sales are included as a revenue credit. The COSA includes the quantity of these sales in the FPS rate pool and allocates costs to these sales. Sales of such firm power are not necessarily made at rates that recover the exact costs allocated in the COSA to these sales. Therefore, either a revenue surplus or a revenue deficiency will result when the costs allocated to the sales of this firm power are compared with the revenues received under the applicable contract. The expected revenue forecast from the sale of firm power and settlements, the allocated costs, and the resulting FPS revenue deficiency are shown in

Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.3.9. This revenue deficiency is allocated to all other firm power (PF, IP, and NR) rates.

This is the final step of the COSA. At this point, all of BPA's costs have been allocated to the PF, IP, NR, and FPS rate pools, as have all revenues derived from sources other than these rate pools. After completion of the COSA, certain statutory reallocations of these COSA-allocated costs are performed in the Rate Directives Step.

2.2 Rate Directives Step

2.2.1 Statutory Background

Northwest Power Act Sections 7(c), 7(b)(2), and 7(b)(3) provide guidance for the Rate Directives Step. 16 U.S.C. §§ 839e(c), 839e(b)(2), 839e(b)(3). After the COSA allocation of costs and credits to rate pools, the Rate Directives Step reallocates costs among rate pools to ensure that the relationships between the rates for the different classes of customers comport with the rate directives in the Northwest Power Act.

Section 7(c), in pertinent part, states:

> The rate or rates applicable to direct service industrial customers shall be established for the period beginning July 1, 1985, at a level which the Administrator determines to be equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers in the region.

16 U.S.C. § 839e(c). Section 7(c) describes how BPA is to set the rate it charges DSI customers. *Id.* It provides that the DSI rate will be set to be equitable in relation to retail industrial rates of consumer-owned utility (COU) customers. Section 7(c) provides guidance on how to establish and modify this equitable relationship:

> The [DSI rate] shall be based upon the Administrator's applicable wholesale rates to such public body and cooperative customers and the typical margins

> included by such public body and cooperative customers in their retail industrial rates but shall take into account the comparative size and character of the loads served, the relative costs of electric capacity, energy, transmission, and related delivery facilities provided and other service provisions, and direct and indirect overhead costs, all as related to the delivery of power to industrial customers, except that the Administrator's rates during such period shall in no event be less than the rates in effect for the contract year ending on June 30, 1985.

Id. Section 7(c) speaks of the "applicable wholesale rates" to COUs plus the "typical margins" included by those customers in their retail industrial rates. *Id.* The computation of these elements of the DSI rate is discussed below in Section 2.2.2.5.1-2, Section 4.3.1.1.2, and Appendix A. Section 7(c) also requires a comparison of the DSI rate to the DSI rate in effect in 1985, as discussed in Section 2.2.2.5.4 below. *Id.*

Finally, Section 7(c)(3) provides:

> The Administrator shall adjust such rates to take into account the value of power system reserves made available to the Administrator through his rights to interrupt or curtail service to such direct service industrial customers.

Id. § 839e(c)(3). Section 7(c)(3) thus directs that the DSI rate is to be adjusted to account for the value of power system reserves provided through contractual rights that allow BPA to restrict portions of the DSI load. This adjustment is typically made through a Value of Reserves (VOR) Credit. The VOR analysis is discussed in Sections 2.2.2.5.2 and 4.3.1.1.1 below.

In summary, the result of Section 7(c) requirements is that the DSI rate is set equal to the applicable wholesale rate, plus the typical margin, minus the VOR Credit, subject to the DSI floor rate test. Because the DSI rate interacts with the PF rate and the NR rate, the three rates are determined simultaneously through a solution called the 7(c)(2) delta. The determination and application of the 7(c)(2) delta are discussed below in Sections 2.2.2.1-4 and 2.2.2.5.1-4 and applied to the IP rate in Section 4.3.1.1.

Section 7(b)(2) states:

> After July 1, 1985, the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative and Federal agency customers, exclusive of amounts charged such customers under subsection (g) of this section for the costs of conservation, resource and conservation credits, experimental resources and uncontrollable events, may not exceed in total, as determined by the Administrator, during any year after July 1, 1985, plus the ensuing four years, an amount equal to the power costs for general requirements of such customers if the Administrator assumes [five specified assumptions].

Id. § 839e(b)(2). Section 7(b)(2) describes a rate test designed to ensure that preference customers' firm power rates are no higher than rates calculated using five assumptions that remove specified effects of the Northwest Power Act. *Id.* The rate test is now implemented through provisions of the 2012 Residential Exchange Program Settlement Agreement, which resolved challenges to BPA's previous implementation of Sections 7(b)(2) and 7(b)(3). *See* 2012 Residential Exchange Program Settlement Agreement, Contract No. 11PB-12322, REP-12-A-02A (2012 REP Settlement). The 2012 REP Settlement provides the manner by which BPA computes the amount of rate protection for preference customers, and the amount of REP benefits to the IOUs, in lieu of performing the rate test every rate period.

Section 7(b)(3), in pertinent part, states:

> Any amounts not charged to public body, cooperative, and Federal agency customers by reason of [section 7(b)(2)] shall be recovered through supplemental rate charges for all other power sold by the Administrator to all customers.

16 U.S.C. § 839e(b)(3). Section 7(b)(3) directs that the cost of any rate protection afforded to preference customers arising from implementation of Section 7(b)(2) be borne by all other BPA power sales. *Id*. The rate protection does not extend to all PF customers: the public body, cooperative, and federal agency customers receive the rate protection, but REP participants do not. Thus, to allow the cost reallocations due to the rate protection, the

PF rate is bifurcated. The two resulting rates are the PF Public (PFp) rate, which receives the rate protection, and the PFx rate, which does not receive rate protection and bears its allocated share of the rate protection reallocation. The rate protection amount is collected through additional charges included in rates for all non-PF Public sales. The reallocation of rate protection costs is discussed in Section 2.2.2.3 below. The 2012 REP Settlement retains the allocation of rate protection costs to all other rates through mechanisms specified therein. *See* 2012 REP Settlement, REP-12-A-02A.

2.2.2 Rate Directives Step Modeling

The Rate Directives Step modeling takes as input the costs allocated to the four rate pools (PF, IP, NR, and FPS) from the COSA modeling. The Rate Directives Step adjusts these initial allocations among the PF, IP, and NR rate pools with reallocations of costs that conform to Section 7 of the Northwest Power Act. 16 U.S.C. § 839e. At this point in the modeling, the allocation of costs to the FPS rate pool is equal to the expected revenues from FPS sales and will not be altered throughout the remaining ratemaking steps.

2.2.2.1 First IP-PF Rate Link

The IP rate for sales of power to BPA's DSI customers is a formula rate tied to the unbifurcated PF rate (*i.e.*, the PF rate at this point in the modeling includes costs to be allocated between the PFp and PFx rate sub-pools later in the process). Also, at this point in the modeling, the costs allocated to the IP and NR rate pools are equal on a per-megawatthour basis. An adjustment is needed to set the IP rate to its proper relationship with the PF rate. That adjustment, the IP-PF Link 7(c)(2) rate adjustment, will result in the 7(c)(2) delta, thereby reducing the allocated costs to the IP rate pool and increasing the costs allocated to the PF and NR rate pools.

The IP-PF Link adjustment sets the IP rate equal to the monthly/diurnal PFp energy rates applied to DSI Billing Determinants, plus the net industrial margin. To determine the IP rate, the model first calculates the net industrial margin by subtracting the VOR provided by sales to the DSIs from the typical industrial margin calculated in the 7(c)(2) Margin Study, Power Rates Study, BP-26-FS-BPA-01, Appendix A. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.4.1. Monthly and diurnally PF melded rates are calculated as described in Section 4.1.3 below. *Id.*, Tables 2.4.2 and 2.4.3. Because the IP-PF Link calculation maintains a set relationship between the levels of the IP and PF rates for each year and simultaneously allocates costs between the two rates, and to avoid multiple iterations, RAM2026 has an algebraic formula to approximate a solution and then uses an intrinsic Excel function, "Goal Seek," to converge on a solution for each year of the rate test period. *Id.*, Table 2.4.4.

After allocation of the 7(c)(2) delta in the IP-PF Link reallocation, the IP floor rate test determines if the currently calculated IP rate is below the IP rate that was in effect for the contract year ending on June 30, 1985, as required by Section 7(c)(2) of the Northwest Power Act. 16 U.S.C. § 839e(c)(2). The BP-26 IP rate at this point in the modeling is not below the IP floor rate, and no floor rate adjustment is needed.

2.2.2.2 Determination of Active Exchanging Utilities

With the proper relationship between the IP rate and the unbifurcated PF rate established, the base PFx rates for the IOUs and the COUs can be calculated. The base PFx rate for the IOUs is the average unbifurcated PF rate plus a transmission adder. The base PFx rate for the COUs begins with the IOU rate and removes Tier 2 costs and loads. A test is again conducted to determine if the ASCs of the potential IOU and COU exchanging utilities are greater than the IOU and COU base PFx rates. If a utility's ASC is greater than its base PFx rate, the utility is included as an active exchanging utility.

2.2.2.3 7(b)(2) Rate Protection and 7(b)(3) Reallocations

The next step is to calculate the level of rate protection due to preference customers as a result of the ASC and PFx calculation and pursuant to Section 7(b)(2) of the Northwest Power Act. 16 U.S.C. § 839e(b)(2). The rate test specified in Section 7(b)(2) of the Northwest Power Act ensures that BPA's rates for public body, cooperative, and federal agency customers (collectively referred to as preference customers or 7(b)(2) customers) are no higher than rates calculated using specific assumptions that remove certain effects of the Northwest Power Act. *Id.* The BP-26 rates are calculated pursuant to a settlement of litigation associated with the REP and the Section 7(b)(2) rate test. *See* 2012 REP Settlement, REP-12-A-02A, at 1. The 2012 REP Settlement was evaluated for compliance with, among other statutory provisions, Sections 7(b)(2) and 7(b)(3). 16 U.S.C. § 839e(b)(2)-(3).

Rate modeling for the REP under the 2012 REP Settlement begins with total IOU REP benefits, as specified in the 2012 REP Settlement, known as Scheduled Amounts. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.4.9.

The 2012 REP Settlement rate modeling first calculates the Unconstrained Benefits, which are the REP benefits that would be in place if there were no PFp rate protection. In such a circumstance, the REP benefits for each exchanging utility would be its ASC minus its appropriate Base PFx rate multiplied by its qualified exchange load. The Unconstrained Benefits are shown in Table 2.4.10. *Id.* These Unconstrained Benefits are then used to calculate COU REP benefits, as specified in individual settlements with each eligible COU.

COU REP benefits are calculated using a ratio of 1) the IOU Scheduled Amounts to 2) the total IOU Unconstrained Benefits for IOUs. This ratio is then multiplied by COU Unconstrained Benefits to derive COU REP benefits.

The total rate protection provided to preference customers is composed of two parts. With the Unconstrained Benefits and the total IOU and COU REP benefits determined, the first part of rate protection due to preference customers is calculated as the Unconstrained Benefits minus the sum of REP benefits. The REP Settlement modeling then allocates this amount to individual REP participants. This allocation to each REP participant is divided by the exchange load for each participant, calculating a utility-specific 7(b)(3) Surcharge that is added to the appropriate Base PFx rates to produce a utility-specific PFx rate. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.4.11. After the utility-specific PFx rates are calculated, the utility-specific REP benefits are calculated and summed after any reallocations necessary under Section 6.2 of the 2012 REP Settlement Agreement. *See id.*, Tables 2.4.11 and 2.4.12 (showing reallocations between participating IOUs pursuant to Section 6.2 of the 2012 REP Settlement Agreement).

A second part of rate protection, the REP Surcharge, is calculated and allocated to the IP and NR rate pools. The REP Surcharge is determined by multiplying the REP benefit costs determined above (REP Recovery Amounts plus COU REP benefits) by a scalar specified in the 2012 REP Settlement. The scalar is based on the WP-10 7(b)(3) rate surcharge to the IP and NR rates and increases this historical 7(b)(3) rate surcharge in direct proportion to increases in REP Recovery Amounts relative to WP-10 REP benefit levels. The REP Surcharge, when multiplied by the forecast sales under the IP and NR rate schedules, produces an amount of rate protection dollars. *Id.*, Table 2.4.14. This amount is allocated to the IP and NR rate pools.

The REP Settlement rate protection allocations increase the IP, NR, and PFx rates while decreasing the PFp rate. *Id.*, Tables 2.4.13, 2.4.14, and 2.4.15.

2.2.2.4 Second IP-PF Rate Link

After the IP and NR adjustment, the now-lower PFp rate and the now-higher IP rate must be adjusted to maintain the proper 7(c)(2) rate directive cost relationship. For this second IP-PF Link calculation, monthly/diurnal PFp energy rates are determined, and the IP rate is set equal to the flat PFp rate plus the net Industrial Margin plus the REP Surcharge. At this point in the ratemaking process, a reallocation of costs (consistent with Section 2.2.2.5 below) establishes the NR rate. *Id.*, Tables 2.4.16, 2.4.17, 2.4.18, and 2.4.19.

2.2.2.5 IP Rate

The IP rate is calculated using directives in Sections 7(c)(1), 7(c)(2), and 7(c)(3) of the Northwest Power Act. 16 U.S.C. § 839e(c)(1)-(3). As discussed in Section 2.2.1 above, Section 7(c)(1)(B) provides that, after July 1, 1985, the rates to DSI customers will be set "at a level which the Administrator determines to be equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers in the region." *Id*. § 839e(c)(1). "Equitable in relation" pursuant to Section 7(c)(2) is defined as basing the DSI rate on BPA's "applicable wholesale rates" to its COU customers plus the "typical margins" included by those customers in their retail industrial rates. *Id*. § 839e(c)(2). Section 7(c)(3) provides that the DSI rate is to be adjusted to account for the value of power system reserves provided through contractual rights that allow BPA to restrict portions of the DSI load. *Id*. § 839e(c)(3). This adjustment is made through a VOR Credit. Thus, the rate for the DSIs, the IP rate, is set equal to the applicable wholesale rate, plus the typical margin, plus the VOR Credit, subject to the DSI floor rate test and the outcome of the determination of PFp rate protection.

2.2.2.5.1 Applicable Wholesale Rate

The applicable wholesale rate is calculated as the rate(s) at which BPA is selling power to COUs, that is, the PFp rate (for general requirements, as defined in Section 7(b)(4) of the Northwest Power Act) and the NR rate (for power used to serve NLSL). 16 U.S.C. § 839e(c)(4). The IP rate begins by being set to the average of the PF and NR rates, weighted by sales to COUs at each rate and reflecting the DSI class load factor.

2.2.2.5.2 Typical Margin, Value of Reserves, and Net Industrial Margin

As noted above, the DSI rate is set by adding the VOR Credit and typical margin to the applicable wholesale rate. The VOR Credit is calculated as described in Section 4.3.1.1.1 below. The typical margin is calculated in Appendix A. The typical margin plus the VOR Credit yields the net industrial margin. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.4.1. The net industrial margin is added to the applicable wholesale rate, and the result is multiplied by the forecast DSI load to determine the costs for the IP rate pool.

2.2.2.5.3 IP-PF Link 7(c)(2) Adjustment

The IP-PF Link 7(c)(2) adjustment accounts for the difference between the revenues expected to be recovered from the DSIs at the final IP rate and the costs allocated to the rate. This difference, known as the 7(c)(2) delta, is allocated to non-DSI rates, primarily the PF rate. Because the allocation of the 7(c)(2) delta changes the PF and the NR rates, together forming the applicable wholesale rate upon which the IP rate is based, the 7(c)(2) delta must be recalculated. The interaction between the applicable wholesale rate and the IP rate has been reduced to an algebraic formula to approximate a solution, and then the RAM uses an intrinsic Excel function, "Goal Seek," to converge on a solution for each year of the rate test period. *Id.*, Table 2.4.4.

2.2.2.5.4 IP Floor Rate Verification

Section 7(c)(2) of the Northwest Power Act requires that the rates to DSI customers will not be less than the rates in effect for the contract year ending June 30, 1985 (the floor rate). 16 U.S.C. § 839e(c)(2). Accordingly, a test is performed to determine if the IP rate is at a level below the 1985 IP rate. If so, an adjustment is made that raises the IP rate to the floor rate and credits other customers with the increased revenue from the DSIs. If the IP rate is set at a level above the floor rate, no floor rate adjustment is necessary.

The first step in calculating the floor rate is to apply the IP-83 Standard rate components to rate period (FY 2026-2028) DSI Billing Determinants. The resulting revenue figure is divided by total IP rate period energy loads to arrive at an average rate in mills per kilowatthour. This rate is reduced by an Exchange Cost Adjustment and a Deferral Adjustment, which were included in the IP-83 rate but are no longer applicable. Both adjustments are made on a mills-per-kilowatthour basis.

In addition, the transmission component of the IP-83 rate is removed to allow a power-only floor rate comparison. The floor rate is adjusted for transmission costs by subtracting total transmission costs in mills per kilowatthour from the IP-83 rate in the same manner as the Exchange Cost Adjustment and Deferral Adjustment are removed. The unit transmission component is determined by dividing total transmission costs in the IP-83 rate by the total Energy Billing Determinants for that rate period. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.4.6.These calculations result in an “undelivered” IP floor rate. The floor rate is applied to the current rate period DSI Billing Determinants to determine floor rate revenue. Revenue at the IP rates is compared to the revenue at the floor rate. Because revenue from the IP rate is greater than the floor rate revenue, no floor rate adjustment is necessary. *Id.*, Tables 2.4.6 and 2.4.7.

2.3 Rate Modeling Iterations

Several iterations—both within RAM2026 and between other models and RAM2026—are required before the ratemaking process is complete. These iterations ensure that the appropriate costs are computed and allocated consistent with the principles of the Northwest Power Act and TRM rate design.

2.3.1 Iterations Internal to the Model

2.3.1.1 Participation in the Residential Exchange Program

For a utility participating in the REP to be eligible to receive REP benefits, the modeling requires that the applicable Base PFx rate be less than a participating utility's ASC. The applicable Base PFx rate is either 1) the Base Tier 1 PFx rate for COUs, or 2) the Base PFx rate for IOUs (the difference being the inclusion of Tier 2 costs in the Base PFx rate for IOUs). If a utility has an ASC less than its applicable Base PFx rate, that utility is ineligible to receive financial benefits through the REP as an "active" exchanger for the upcoming rate period. *See* Section 2.2.2.2 above. RAM2026 uses a macro loop feature to test whether, for each year of the exchange period, each utility with an ASC qualifies for REP benefits. If a utility does not qualify, a binary index is used to exclude it, and if it does qualify, the index is set to include it. This test is performed such that the exchange resource costs are calculated including the resources purchased from only REP-active participants. It is performed before the Rate Directives Step of the 7(c)(2) linking of the IP and PF rates, the determination of rate protection, and subsequent reallocation of rate protection.

2.3.1.2 Costs of Rate Discounts

The costs of the LDD and IRD are included in the Composite customer charge, but these costs are jointly determined with other aspects of ratemaking, such as REP benefits and IP and NR revenues. Because these revenues change depending on the costs of the LDD and

IRD programs, the amounts of these costs are determined through iteration in the model. As explained in Sections 2.1.4.3-4 above, RAM2026 computes the cost of the LDD program by applying the applicable discount percent to the forecast billing determinants, which are then applied to the rates. The IRD program cost is based on a historical percentage and a resulting $/MWh rate discount, which is then applied to internally computed customer charges. For each iteration, the appropriate charges are applied and new discount costs are computed. These new discount costs are allocated in the COSA Step, whereupon the Rate Directives Step and rate design under the TRM are performed again. New charges and rates are computed, which are again applied to the discount calculations. The iterative process continues until convergence.

2.3.1.3 Contract Formula Rates

If a power sales contract rate was agreed to be tied contractually to a result of rate modeling, an iterative approach might be required to solve for the amount of revenue to be credited in the COSA Step. No internal iterations are currently required to model contracts at formula rates.

2.3.2 Iterations External to the Model

Some aspects of the ratemaking process are dependent upon the rates computed in RAM2026. Many of these dependencies have been integrated within RAM2026, as described above. Other dependencies are simply too large to incorporate into one model. Thus, external iterations must be performed before rates can be finalized.

2.3.2.1 Consumer-Owned Utility Average System Costs

The ASCs of COUs participating in the REP are based in part on the cost of power purchased from BPA at rates determined in RAM2026. Moreover, the COU customer’s FRP Surcharge

Amount is dependent upon the COU's Non-Slice Tier 1 Cost Allocator (TOCA). These two factors require a recomputation of ASCs for COUs based on the PFp rate level and the FRP Surcharge Amount. This iteration is manually performed between RAM2026 and the ASC forecast model. Revised ASCs are included in RAM2026, and rate levels are recomputed until the results converge.

2.3.2.2 Risk Analysis and Mitigation: PNRR

As discussed in Section 2.1.5.4 above, the amount of PNRR added to rates to meet the TPP standard is the result of an iterative process among three models: RAM2026, RevSim, and ToolKit. *See* Power and Transmission Risk Study, BP-26-FS-BPA-05, § 4. The iterative process is initiated with a $0 seed value for PNRR in the revenue requirement used in RAM2026. The resultant rates are used in RevSim to produce distributions of net revenues. These distributions are then used in the ToolKit to measure TPP. If the TPP standard is not met, iterations are run using updated PNRR values until PNRR just satisfies the TPP standard. Because this portion of PNRR for the BP-26 rates is determined to be zero, no iteration is required.

2.3.2.3 Revised Revenue Test

The revised revenue test is described in the Power Revenue Requirement Study, BP-26-FS-BPA-02, Section 3.3. The revised revenue test demonstrates that the BP-26 rates are sufficient to recover the revenue requirement, and no further rate adjustment is needed.

3. RATE DESIGN AND COST ALLOCATION

3.1 Introduction

BPA follows the rate-setting directives of Section 7 of the Northwest Power Act. As explained in the legislative history of that Act, the rate directives govern the amount of revenue the Administrator collects from each class of customers, not the rate form. *See, e.g.*, H.R. Rep. No. 96-976, 2d Sess., pt. I, at 69 (1980). Northwest Power Act Section 7(e) reserves rate design (how the revenue is collected) to the Administrator.

Section 7(e) states:

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

16 U.S.C. § 839e(e). Rate design uses the results of the cost and credit allocations of the COSA, as modified by the rate directives, to develop the rate components that will recover the costs allocated to each rate pool. Thus, rate design is applied after BPA has allocated its total power revenue requirement to the five rate pools discussed earlier: Priority Firm Public Power (PFp), Priority Firm Exchange Power (PFx), Industrial Firm Power (IP), New Resource Firm Power (NR), and Firm Power and Surplus Products and Services (FPS). Rate design does not change the amount of the revenue requirement allocated to each of the five rate pools. Rather, rate design determines how the revenue requirement is collected through rates for each of the five rate pools. Rate design resolves the revenue collection within a particular rate pool and distinguishes between different types of service and power consumption of individual wholesale power customers. Rate design also conveys price signals to customers to encourage more efficient power usage, differentiating between the relative market values of the products and services BPA offers to its customers.

Based on the results of the Rate Directives Step, RAM2026 designs rates for each rate pool. For the PFx rate, the IP rate, and the NR rate, the rate design from the model can be applied without further processing.

3.2 PFp Rates

The rate design for the PFp rate is established in the TRM. *See* TRM, BP-12-A-03. As described in the TRM, the PFp rate design includes two tiers and different products within each tier. The costs and credits are allocated to the Tier 1 and Tier 2 cost pools based upon the principle of cost causation. While the TRM cost allocations do not change the costs allocated to the PFp rate pool, they do assign cost responsibility to the rates paid by customers purchasing the PFp products offered in the CHWM contracts: Load Following, Slice/Block, Block, and Tier 2. *Id.*

The TRM specifies that all costs and credits constituting BPA's PFp revenue requirement be allocated to one of four customer cost pools: Composite, Non-Slice, Slice, or Tier 2. The Tier 2 cost pool is further divided into Short-Term, Load Growth, and Vintage cost pools, if any sales are being forecast in those cost pools. *Id.* After reflecting the cost allocations to other rate pools, the end result of the TRM cost allocations is that the total costs allocated to the four customer charge cost pools will equal the total costs allocated to the PFp rate pool after the COSA Step and the Rate Directives Step. Thus, the TRM cost allocations neither increase nor decrease the cost allocations to the PFp rate pool after the Rate Directives Step. A mathematical proof is included in RAM2026 that shows that the revenue requirement allocated to the PFp rate pools in the COSA equals the revenue collected from the seven cost pools under the PFp tiered rate design. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Tables 3.1.7.1 and 3.1.7.2.

While the TRM cost allocations do not change the costs allocated to the PFp rate pool, they do assign cost responsibility to the rates paid by customers purchasing the three primary products offered in the CHWM contracts: Load Following, Slice/Block, and Block. In addition, the TRM cost allocations recognize that, even though the rate-setting methodology described in this section is performed as if the REP were an actual purchase and sale of power, at this point in the rate-setting process the PFp rate can be determined based on its allocated share of the total REP benefit costs, rather than exchange resource costs and PFx revenues.

The sections below detail the calculation of PFp rates consistent with the TRM.

3.2.1 PFp Tier 1 Costs

3.2.1.1 Composite Costs

The Composite cost pool includes all Tier 1 costs and credits that are not otherwise allocated to the Non-Slice and Slice cost pools. The Composite cost pool forms the cost basis for the Composite Customer Charge, which is paid by all preference customers with CHWM contracts. Generally speaking, all costs associated with FBS resource costs, exchange resource costs (net of exchange program revenues), new resource costs, conservation costs, BPA program costs, and power transmission costs not otherwise allocated to the Non-Slice or Slice cost pools are allocated to the Composite cost pool.

In addition to the costs from expense and capital programs (as outlined in the Power Revenue Requirement Study, BP-26-FS-BPA-02), significant ratemaking costs allocated to the Composite cost pool are as follows:

- Costs of the IRD and LDD programs.

- Net costs associated with the REP:
    - Costs are calculated using the ASC and exchange load for each qualifying REP participant, net of
    - Revenues that are calculated at the PFx Rates, incorporating REP Surcharges.
- System augmentation costs required to achieve annual load-resource balance.

See Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.1.1.1*.*

3.2.1.2 Non-Slice Costs

The Non-Slice cost pool includes only those costs and credits that are specifically and uniquely attributed to the Load Following and Block products (including the Block portion of the Slice/Block product). Tier 1 costs and credits, primarily secondary revenues that are not associated with the Slice product, are allocated to the Non-Slice cost pool. The Non-Slice cost pool forms the cost basis for the Non-Slice customer rate, which is paid by preference customers that have selected the Load Following product or the Block product, and the Block purchases under the Slice/Block product. Significant Non-Slice costs include:

- Balancing power purchase costs required to serve the monthly/diurnal loads of Load Following customers.
- Hedging costs associated with winter-shaping or locational swapping that result in changes to anticipated secondary revenues.
- Transmission costs incurred to deliver secondary sales.
- Costs (or credits) associated with the Composite interest obligation when financial reserves available for Power are less than the $570.3 million starting balance of the reserves at the inception of the Slice product offering.

See id., Table 3.1.1.2.

3.2.1.3 Slice Costs

The Slice cost pool includes only those costs and credits that are specifically and uniquely attributed to the Slice product. Tier 1 costs and credits that are associated with the Slice product are allocated to the Slice cost pool. The Slice cost pool forms the cost basis for the Slice customer rate, which is paid by preference customers that have selected the Slice/Block product for their Slice purchases. In the BP-26 rates there are no costs allocated to this cost pool. *Id.*

3.2.2 PFp Tier 2 Costs

Costs and credits that are associated with the sale of power to serve a customer's Above-RHWM Load are allocated to Tier 2 cost pools. The primary costs allocated to a Tier 2 cost pool are the FCRPS and/or purchased power costs discussed in Section 3.2.2.1, including the cost of real power losses, designated by BPA as being for this purpose discussed in Section 3.2.2.1.1. In addition to power purchase costs, Tier 2 cost pools recover Resource Support Services (RSS), overhead costs, and other BPA costs that are not necessarily incurred solely for the purpose of serving Above-RHWM Load, but support making such sales. The initial allocation of these other costs is to either the Composite cost pool or the Non-Slice cost pool. Therefore, a portion of these other costs is allocated to Tier 2 cost pools. Tier 2 rates are set to recover costs within the respective Tier 2 cost pool. The Tier 2 rate can be broken down on a dollars per megawatthour basis and consists of an energy component plus four adders: 1) Transmission Scheduling Service (TSS) costs; 2) capacity; 3) losses; and 4) overhead costs.

For BP-26, Tier 2 customers taking either the Tier 2 Short-Term Rate or Load Growth Rate will have the option to elect between a fixed-rate option (default election) or a formula-rate option. These two options speak only to the energy component portion of the Tier 2 rate, and the four adders are the same in both options. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, PF-26, § 2.2

The CHWM contracts include the following Tier 2 rate alternatives: Load Growth, Vintage, and Short-Term. In FY 2026, FY 2027, and FY 2028, BPA will have sales of power only at the Tier 2 Short-Term and Load Growth rates; therefore, there are two Tier 2 cost pools: the Short-Term cost pool and the Load Growth cost pool. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Tables 3.5.1 and 3.5.2.

3.2.2.1 Tier 2 Power Purchase Costs

BPA does not have any committed firm power purchases for Tier 2 rate service for the FY 2026-2028 rate period and expects power sold at Tier 2 rates to be served with power from the FCRPS, including balancing purchases and uncommitted market purchases referred to as Tier 2 augmentation.

For ratemaking purposes, RAM2026 assumes all power sourced from the federal system, including Tier 2 augmentation to serve Tier 2 load, will be priced using the fixed-rate option, which uses the forecast Aurora P10 market price plus the capacity adder. The Aurora P10 market price is based on the average of the annual Mid-C market price under firm generation conditions for each fiscal year informed by the Aurora model. *See* Power Market Price Study, BP-26-FS-BPA-04, Figure 5. The capacity adder is based on the Demand Rate. *See* Section 3.2.7 below.

Tier 2 power purchase costs under the formula-rate option will use the observed Day Ahead Index—currently the Intercontinental Exchange (ICE) Mid-Columbia Day Ahead

Index—for the energy component of the Tier 2 Rate, plus the capacity adder. *See* Section 3.2.7 below.

3.2.2.1.1 Tier 2 Real Power Losses

Power purchased at Tier 2 rates is delivered power and thus must include the cost of real power losses. The cost of real power losses is calculated using the federal transmission loss factor from the BP-26 Power Loads and Resources Study, BP-26-FS-BPA-03, Section 3.1.7. The federal transmission loss factor represents the generation loss factor and must be adjusted to calculate the equivalent loss factor at the load. Given this adjustment, the real power loss factor is 3.21 percent. The power purchase costs include the cost of energy associated with this real power loss factor.

3.2.2.2 Tier 2 Resource Support Services

A cost for Transmission Scheduling Service (TSS) is added to each Tier 2 cost pool. A TSS Adder is calculated by dividing Power Services' scheduling costs for the rate period by the total megawatthours actually scheduled in FY 2021, FY 2022, and FY 2023 to produce a yearly dollars per megawatthour value. Inputs to this calculation are shown in the Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.4. This value is multiplied by the amount of planned Tier 2 sales in each year for each Tier 2 alternative to produce the annual cost for the TSS Cost Adder included in each cost pool for each year. The Tier 2 TSS Cost Adder is one of the credits to the Composite cost pool summed in the RSS Revenue Credit. *See* Section 3.2.3.1.4 below. The calculated costs assigned to the Tier 2 rate cost pools in each year are shown in the Power Rates Study Documentation, BP-26-FS-BPA-01A, Tables 3.5.1 and 3.5.2. The TSS rate adder for BP-26 is $0.12/MWh for each year of the rate period. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.9

Service at Tier 2 rates includes Transmission Curtailment Management Service (TCMS), which is a service that addresses transmission curtailment events. *See* Section 5.6.1.5 below. To recover costs associated with TCMS, Tier 2 rates are subject to the Tier 2 Rate TCMS Adjustment, described in Section 5.4.6 below. For the BP-26 rate period, the Tier 2 cost pools do not include any costs associated with financially flattening a resource because there are no variable, non-dispatchable resources assigned to the Tier 2 rates.

3.2.2.3 Tier 2 Overhead Cost Adder

Section 6.3.3 of the TRM, BP-12-A-03, describes an Overhead Cost Adder to be included as part of the Tier 2 rates. The overhead cost components used to calculate the Tier 2 Rate Overhead Cost Adder are listed in the Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.6. The rate period total of these overhead costs is divided by BPA's total forecast of revenue-producing energy sales (PFp, IP, NR, FPS, Downstream Benefits and Pumping Power, Pre-Subscription, Generation Inputs for Ancillary and Other Services Revenue, and Secondary sales). The result is a $1.76/MWh adder for FY 2026, a $1.90/MWh adder for FY 2027 and a $1.93/MWh adder for FY 2028. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.6. The dollars per megawatthour value in each year is multiplied by the number of planned sales in each year for each Tier 2 alternative to produce the Overhead Cost Adder included in each Tier 2 cost pool for each year. The Tier 2 Overhead Cost Adder provides the revenue credit to the Composite cost pool (called Tier 2 Overhead Adjustment). *See* Section 3.2.5 below. The specific cost and sales values used in these calculations are shown in the Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.6.

3.2.2.4 Tier 2 Risk Adder

Section 6.3.1 of the TRM, BP-12-A-03, describes a possible cost adder for risk when BPA has not made all the market purchases needed to serve the Tier 2 obligation. In accordance with the Tier 2 Risk Analysis described in the Power and Transmission Risk Study, BP-26-FS-BPA-05, Section 4.3.1, BPA does not have a discrete risk adder included in the Tier 2 cost pools to cover Tier 2 risks in the BP-26 rate period. Instead of including a discrete risk adder for the remaining power purchase needs for the Tier 2 cost pools, BPA uses the Aurora P10 market price as a risk adjusted energy price for physically delivered power for the Tier 2 fixed-rate option. The combination of Aurora P10 prices, which inherently include an energy risk premium due to using a monthly 10th percentile firm generation forecast, and the addition of the capacity adder, mitigates Tier 2 risk from being recovered in Tier 1 rates. The capacity adder recovers the value of holding capacity in advance of delivery. See Section 3.2.7 below. Using this price construct for valuing Tier 2 power that has not been transacted for in advance helps ensure that Tier 2 rates are not subsidized by Tier 1 rates. *See* Power and Transmission Risk Study, BP-26-FS-BPA-05, Section 4.3.1.

The Tier 2 formula-rate option, when elected by customers, would move the energy price-forecast risk from BPA to those customers, so no additional risk provision would be necessary to ensure Tier 2 rates are not subsidized by Tier 1 rates.

3.2.2.5 Reallocated Power from Remarketing

When power purchased for a Tier 2 rate pool exceeds Above-RHWM Loads, BPA remarkets the excess amounts and reallocates the value of that power to other Tier 2 pools if there is a need. Similarly, BPA remarkets excess non-federal amounts and reallocates and values that power in the same manner. The remarketing values are determined in accordance with Section 3.2.6 below.

The treatment of remarketing varies by the type of Above-RHWM service, including individual Tier 2 Cost Pools remarketing the energy. When non-federal resource and Tier 2 Vintage amounts are remarketed, the value from such reallocations is credited to the individual customers, as required under the CHWM contract and the TRM, and as described in Section 5.7 below. When remarketing for the Tier 2 Load Growth pool, the value of remarketed energy is credited to the Tier 2 Load Growth pool and not directly to individual customers.

The remarketed Tier 2 energy amounts are first reallocated to another Tier 2 pool with Above-RHWM Loads that exceed the power purchased for that pool, then purchased by BPA for augmentation if there is a need, or deemed surplus power available for resale into the market. *See* TRM, BP-12-A-03, § 3.4. Table 3.8 of the Power Rates Study Documentation, BP-26-FS-BPA-01A, summarizes the sources of remarketed power meeting the various Tier 2 loads. It includes remarketed power from other Tier 2 cost pools, if any, and remarketed power from non-federal resources with Diurnal Flattening Service (DFS), if any.

3.2.3 PFp Tier 1 Revenue Credits

The Composite and Non-Slice cost pools contain credits for revenues collected from other components of the PFp rates. All these rate design credits are necessary to ensure that the PFp rates do not over-collect the allocated revenue requirement and that the costs and credits have been allocated as specified in the TRM.

3.2.3.1 Composite Cost Pool Revenue Credits

As stated in Section 3.2.1.1, the Composite cost pool includes all Tier 1 costs and credits that are not otherwise allocated to the Slice and Non-Slice cost pools. As described in

Section 2.1.6, revenue credits are directly assigned to the TRM cost pool according to cost causation principles at the same time the COSA steps are completed. Significant ratemaking credits allocated to the Composite cost pool after the ratemaking steps in Section 2 are completed include revenues BPA receives from the following:

- DSI customers
- Power sales under the NR rate schedule
- Capacity revenue from NR Energy Shaping Service (NR ESS)
- Capacity revenue associated with RSS
- Capacity revenue associated with the sale of Real Power Losses

3.2.3.1.1 Revenues from DSI Customers

These are forecast IP rate revenues consistent with sales forecasts from the Power Loads and Resources Study applied to the IP rate as determined in Section 4.3 below.

3.2.3.1.2 Revenues from Power sales under the NR rate schedule

These are forecast NR rate revenues.

3.2.3.1.3 Revenues from NR Energy Shaping Service

The New Resource Firm Power rate schedule includes NR ESS, which includes a capacity (demand) component. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.12. Forecast revenue from the capacity component of the NR ESS is credited to the Composite cost pool by means of the NR Revenue Credit. *See id.*, Table 2.3.6.

3.2.3.1.4 Revenues from Resource Support Services

BPA provides Resource Support Services (RSS) and related services, which generate revenue from preference customers. *See* Section 5.6 below. Revenues received from the capacity components of RSS are credited to the Composite cost pool. For transparency purposes, BPA committed in the TRM to apply the applicable RSS to resources serving system augmentation needs (currently Klondike III) and to resources supporting the Tier 2 rates, if appropriate. In these situations, the source of the RSS revenue credit to the Composite cost pool is provided through either an RSS adder to the system augmentation cost or an RSS cost allocated to a Tier 2 cost pool. Revenues provided by the energy components of RSS are credited to the Non-Slice cost pool. Unlike the capacity used to provide RSS, which operationally impacts the Slice/Block, Block, and Load Following products, the provision of RSS energy operationally impacts the Non-Slice products only (including the Block portion of the Slice/Block product).

BPA committed in the TRM to apply RSS to resources serving RHWM Augmentation needs (*e.g.*, Klondike III). The cost of Klondike III, a wind plant, is assigned to Tier 1 Augmentation in the Composite cost pool. The TRM states that RSS pricing will be used to make certain federal resource acquisitions financially equivalent to a flat block. *See* TRM, BP-12-A-03, § 8. Tier 1 Augmentation is assumed to be in the shape of an annual flat block purchase for ratemaking purposes. *See id.* § 3.5. Because Klondike III's generation is variable and non-dispatchable, the RSS module of RAM2026 calculates a DFS capacity charge, a DFS energy charge, a Resource Shaping charge, and a TSS charge for Klondike III, and the resulting costs are allocated to the Composite cost pool. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.11. The total annual RSS revenue credit for FY 2026-2028 is shown in Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.2.

3.2.3.1.5 Capacity Revenue Associated with the Sale of Real Power Losses

These are forecast revenues associated with the capacity portion of Real Power Losses settled financially. *See* Section 4.4.2.2 below (describing how the capacity cost for Real Power Losses is determined).

3.2.3.2 Non-Slice Cost Pool Revenue Credits

As stated in Section 3.2.1.2, the Non-Slice cost pool includes all Tier 1 costs and credits that are not otherwise allocated to the Composite and Slice cost pools. As described in Section 2.1.6, revenue credits are directly assigned to the TRM cost pool according to cost causation principles as the COSA steps are completed. Significant ratemaking credits allocated to the Non-Slice cost pool after the ratemaking steps in Section 2 are completed include revenues BPA receives from the following:

- Secondary Energy (including Firm Surplus Secondary Sales)
- Load Shaping
- Demand
- Resource Shaping Charge (RSC)

3.2.3.2.1 Revenues from Secondary Energy

These are revenues associated with non-firm secondary sales and Firm Surplus Secondary Sales, as calculated in the Power Market Price Study, BP-26-FS-BPA-04, but excluding secondary energy sold under the Slice product as described in Section 2.1.6.9 above.

3.2.3.2.2 Revenues from Load Shaping

The Load Shaping charge is designed to recover costs associated with shaping the firm output of the Tier 1 System Resources to the monthly/diurnal shape of a customer's Tier 1 load. The Load Shaping charge applies to Non-Slice products, Block (including the Block portion of the Slice/Block product), and Load Following, but not the Slice portion of the Slice/Block product. As stated in Section 5.2 of the TRM, BP-12-A-03, forecast revenue from the Load Shaping charge is credited to the Non-Slice cost pool by means of the Load Shaping Revenue Credit. *See* Section 4.1.1.3 below.

3.2.3.2.3 Revenues from Demand

The Priority Firm Demand Charge is designed to send a price signal to a limited portion of a customer's overall demand on BPA and applies to customers purchasing Load Following and Block with Shaping Capacity products. As stated in Section 5.3 of the TRM, BP-12-A-03, forecast revenue from the Demand Charge is credited to the Non-Slice cost pool by means of the Demand Revenue Credit. *See* Section 4.1.1.2 below.

3.2.3.2.4 Revenues from the Resource Shaping Charge

All balancing purchase costs, either resource or load, are allocated to the Non-Slice cost pool. The RSC collects additional revenues for balancing purchase costs associated with balancing resources against a flat annual block. *See* Sections 5.6.1.2 and 5.6.1.3. To pair cost allocation with revenue collection of balancing purchase costs, the forecast RSC revenue credit is applied to the Non-Slice cost pool.

BPA committed in the TRM to apply RSC to resources serving system RHWM Augmentation needs (*e.g.*, Klondike III) and to resources supporting the Tier 2 rates in order to make these acquisitions financially equivalent to a flat block. *See* TRM, BP-12-A-03, § 8. In these situations, the source of the RSC revenue credit is provided through either an RSC adder to the system augmentation cost or an RSC adder within a Tier 2 cost pool. The forecast annual RSC revenue credit for FY 2026-2028 is shown in the Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.2.

3.2.4 Rate Design Adjustments Made Between Tier 1 Cost Pools

Once costs and rate design revenue credits have been balanced with the revenue requirement, additional adjustments to the PFp cost pools are made to the extent necessary to avoid cost shifts among products (Load Following, Block, and Slice/Block) and tiers (Tier 1 and Tier 2). These rate design adjustments move dollars from one cost pool to another through equal credits and debits and do not change the total revenue requirement for PFp. These rate design adjustments include three adjustments made within Tier 1 and one adjustment made between Tier 1 and Tier 2. *See* Section 3.2.5 below. The three types of adjustments made within Tier 1 are the 1) Transmission Loss Adjustments; 2) Firm Surplus and Secondary Adjustments from Unused RHWM; and 3) Balancing Augmentation Load Adjustments. The adjustment made between Tier 1 and Tier 2 is the Tier 2 Overhead Adjustment. *See* Section 3.2.5 below. The TRM allocation of these rate design adjustments is shown in the Power Rates Study Documentation, BP-26-FS-BP-01A, Tables 3.1.6.1 and 3.1.6.2.

3.2.4.1 Transmission Loss Adjustments

Transmission Loss Adjustments provide a credit to the Composite cost pool and an equal debit to the Non-Slice cost pool based on Non-Slice transmission losses. Transmission Loss Adjustments address the different accounting of transmission losses for the Slice/Block and Non-Slice products. The Non-Slice products and the Block portion of the Slice/Block product are delivered to the purchaser's load service area, while the Slice product is delivered to the purchaser at BPA's generation bus bar. The cost of generating the real power losses for the transmission of Non-Slice sales is included in the Composite cost pool. Conversely, the cost of generating the real power losses for the transmission of Slice sales is borne by the purchaser.

Transmission Loss Adjustments transfer the cost of generating the real power losses for the transmission of Non-Slice PF sales from the Composite cost pool to the Non-Slice cost pool. Transmission Loss Adjustments are calculated by multiplying the network losses associated with the Non-Slice PF products, including the Block portion of the Slice/Block product, by the average Slice and Non-Slice Tier 1 rate. The calculation and result of the Transmission Loss Adjustments are shown in the Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.1.3.

3.2.4.2 Firm Surplus and Secondary Adjustments from Unused RHWM

Unused RHWM occurs when a customer's Forecast Net Requirement is less than its RHWM. Firm Surplus and Secondary Adjustments from Unused RHWM reallocate costs between the Composite cost pool and the Non-Slice cost pool.

Unused RHWM reduces the need for system augmentation and/or increases firm power available for sale in the market. The reduced augmentation expenses and/or increased firm power market revenues are reflected in three lines on the TRM cost table: 1) Augmentation, 2) Secondary Energy Credit, and 3) Balancing Purchases from RevSim. *See id.*, Tables 3.1.1.1-3. The Augmentation line is part of the Composite cost pool, and the Secondary Energy Credit and Balancing Purchases are part of the Non-Slice cost pool. To share the entire benefit of Unused RHWM with all customers, the Composite and Non-Slice cost pools contain a Firm Surplus and Secondary Adjustment (from Unused RHWM), which appears as a credit to the Composite cost pool and an equal and offsetting charge to the Non-Slice cost pool.

Firm Surplus and Secondary Adjustments have two purposes. The first is to reflect the difference between the value of a flat annual block of system augmentation and the value of the Unused RHWM when the Unused RHWM displaces augmentation. The difference between a flat annual block of system augmentation and the shape of the Unused RHWM is reflected in changes in the assumed balancing purchases and associated costs. These changes in balancing purchase costs are captured in the Non-Slice cost pool. A Firm Surplus and Secondary Adjustment reallocates the change in balancing purchase costs associated with the difference in value from the Non-Slice cost pool to the Composite cost pool.

The second purpose of Firm Surplus and Secondary Adjustments is to reflect the full value of the Unused RHWM when the Unused RHWM creates firm surplus power. The revenue associated with this change in firm surplus power related to the Unused RHWM is reflected in the secondary revenue credit in the Non-Slice cost pool. A Firm Surplus and Secondary Adjustment reallocates this change in secondary revenues associated with the Unused RHWM from the Non-Slice cost pool to the Composite cost pool.

The value of Unused RHWM consists of portions of RHWM Augmentation, Tier 1 System Firm Critical Output, and an associated portion of secondary energy. Each of these three components is valued at its respective price: the Augmentation price for the RHWM Augmentation component; the market price (as expressed by the Load Shaping rates) for the Tier 1 System Firm Critical Output component; and the market price (as expressed by the average price received for secondary sales) for the secondary component. The value of Unused RHWM (expressed in dollars per megawatthour) also will be calculated for use in the Slice True-Up of the Firm Surplus and Secondary Adjustments line item in the Composite cost pool. See *id.*, Table 3.1.2 (displaying the results and calculation of Firm Surplus and Secondary Adjustments from Unused RHWM and the dollar-per-megawatthour Slice True-Up value of Unused RHWM).

3.2.4.3 Balancing Augmentation Load Adjustments

As explained further in the subsections below, balancing augmentation load is 1) Above-RHWM Load that is forecast to be served at Load Shaping rates; 2) Above-RHWM Load that is no longer forecast to occur (net negative Load Shaping Billing Determinants); or 3) changes to the Tier 1 System during the applicable Section 7(i) ratemaking process from that used to establish each customer's allocation of the cost of the Tier 1 System during the applicable RHWM Process.

The sum total of these conditions is either a charge or credit to the Composite cost pool and an offsetting credit or charge, respectively, to the Non-Slice cost pool. *See id.*, Tables 3.1.6.1 and 3.1.6.2.

3.2.4.3.1 Above-RHWM Load Forecast to be Served at Load Shaping Rates

This first condition occurs when Above-RHWM Load is forecast to be served at Load Shaping rates either 1) when a Load Following customer's annual Above-RHWM Load is less than 8,760 MWh and the Load Following customer made no alternative election to serve its Above-RHWM Load, or 2) when Above-RHWM Load is determined in the RHWM Process and the load forecast is updated during the rate proceeding to reflect the forecast of a larger load. When either 1) or 2) is true and the amount of system augmentation purchases is equal to or greater than the amount of balancing augmentation load, the acquisition costs attributable to supplying balancing augmentation load are included as a system augmentation expense in the Composite cost pool. The revenue from supplying balancing augmentation load is credited to the Non-Slice cost pool through the Load Shaping charge revenue credit. Without a Balancing Augmentation Load Adjustment, only Non-Slice customers would receive credits through an increased Load Shaping Charge revenue credit, but both Slice and Non-Slice customers would bear the cost of increased system augmentation expense. The Balancing Augmentation Load Adjustment corrects this situation with a credit to the Composite cost pool and an equal debit to the Non-Slice cost pool.

This condition causes the sum of Load Shaping Billing Determinants to be positive. Balancing Augmentation Load Adjustments to the Composite and Non-Slice cost pools are calculated as the lesser of 1) the sum of the Load Shaping Billing Determinants for each fiscal year, or 2) the incurred system augmentation amount for each fiscal year. The result is multiplied by the augmentation price for the respective fiscal year.

3.2.4.3.2 Above-RHWM Load No Longer Forecast to Occur

The second condition that creates a change to balancing augmentation occurs when the load forecast decreases from the forecast used in the RHWM Process. When this condition occurs, there is a reduction in system augmentation expenses from what otherwise would have occurred. The Composite cost pool would have received an implicit reduction in costs due solely to load variation attributable to Non-Slice customer loads. In this case, the Balancing Augmentation Adjustment is a debit to the Composite cost pool and an equal credit to the Non-Slice cost pool.

All other things being equal, this condition causes the sum of the Load Shaping Billing Determinants to be negative. Balancing Augmentation Load Adjustments to the Composite and Non-Slice cost pools are calculated as the greater of 1) the sum of the Load Shaping Billing Determinants for each fiscal year, or 2) the avoided augmentation amount (expressed as a negative number) for each fiscal year. The result is multiplied by the augmentation price for the respective fiscal year.

3.2.4.3.3 Changes to the Tier 1 System During the Applicable 7(i) Rate-setting Process

The third condition occurs when the forecast of Tier 1 System output is updated from the Tier 1 System forecast in the RHWM Process. Any change in the Tier 1 System that changes the amount of System Augmentation will cause either a cost or a credit to be included in the Balancing Augmentation Load Adjustment. System Augmentation is allocated to the Composite cost pool, and therefore any change to the Tier 1 System which changes the cost allocated to this pool requires an adjustment. The cost or credit is included as an addition to the Balancing Augmentation Adjustment rather than in the Balancing Power Purchase costs computed in RevSim. Tier 1 System Firm Critical Output changes will increase or decrease, on an annual average basis, the amount of augmentation required, and such augmentation is considered Balancing Power Purchases under the TRM.

RevSim computes Balancing Power Purchase costs after load-resource balance has been achieved under firm generation conditions. *See* TRM, BP-12-A-03, § 3.3. If the Tier 1 System increases relative to the RHWM Process Tier 1 System output, the Non-Slice cost pool will receive a credit for this additional anticipated energy equal to the avoided System Augmentation expense due to the change. Alternatively, if the Tier 1 System decreases, the Non-Slice cost pool will be charged for the reduction in anticipated energy to the extent that the reduction contributed to a higher System Augmentation expense. Equal and offsetting costs/credits are applied to the Composite cost pool. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Tables 3.1.6.1 & 3.1.6.2.

Balancing Augmentation Load Adjustments to the Composite and Non-Slice cost pools are calculated as the avoided augmentation amount for each fiscal year multiplied by the augmentation price for the respective fiscal year.

3.2.5 Rate Design Adjustment Made Between Tier 1 and Tier 2 Cost Pools

The Tier 2 Overhead Adjustment Credits the Composite cost pool for the overhead costs charged to the Tier 2 cost pools. Each of the Tier 2 cost pools includes an Overhead Cost Adder, which reflects a proportionate share of BPA's total overhead costs. *See* Section 3.2.2.3 above. The Tier 2 Overhead Adjustment credited to the Composite cost pool is equal to the sum of the Overhead Cost Adders charged to all of the Tier 2 cost pools. The calculation of the Tier 2 Overhead Adjustment for FY 2026-2028 is shown in the Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.6.

3.2.6 Remarketing Value

The Remarketing Value is used to price any uncommitted market purchases associated with all forms of firm system augmentation including Tier 1 and Other Augmentation in addition to valuing all forms of remarketing (Tier 2, non-federal, and RRS). *See* Section 5.7 below. The Remarketing Value may differ by fiscal year. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.10.

The Remarketing Value is calculated for each fiscal year using the annual Aurora P10 price with negative prices removed plus the capacity adder. The Aurora P10 market price is based on the average of the annual Mid-C Market Price under firm generation conditions for each Fiscal Year. *See* Power Market Price Study, BP-26-FS-BPA-04, Figure 5. The capacity adder is described in Section 3.2.7 below.

3.2.7 Capacity Adder

The capacity adder is the cost of capacity associated with an advanced sale of firm power. The $/MWh capacity adder is calculated using the annual Demand Rate multiplied by 1,000 to convert to megawatthours, then multiply by 12 to reflect total months in a year which is then divided by 8,760 hours in a non-leap year or 8,784 in a leap year. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.9.

3.2.8 Allocation of New Expenses and Credits

BPA will allocate New Expenses or New Credits, as defined in the TRM, to the cost pools based on the cost allocation principles stated in Section 2 of the TRM. TRM Section 2.3 states that BPA will propose an allocation of the New Expenses and New Credits, if any, to the appropriate cost pools in the next applicable Section 7(i) process. TRM, BP-12-A-03, § 2.3.

For BP-26, four new expenses and one new credit line were added to RAM2026. The new costs and credit line, including the designated cost pool and PF public rate design cost pool, are listed below:

1. Amortization of P2IP Settlement Payments, a composite cost. 2.
2. Long Term Funding Agreements (Accords), a composite cost
3. Long Term Funding Agreements (Accords), a composite cost.
4. Payments for Litigation of Stay Agreements (P2IP), a composite cost.
5. Other Augmentation, a new resource cost.
6. Tiered Rates Adjustment, a composite credit.

Consistent with the Update to BPA's BP-26 Cost Projections, issued on July 14, 2025, cost projections in power rates associated with the Memorandum of Understanding filed on December 14, 2023, in the Columbia River System litigation, *National Wildlife Federation v. National Marine Fisheries Service*, 3:01-cv-640-SI (D.Or.), ECF No. 2450-1 (MOU), were removed. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Tables 2.3.1.1-5.

4. RATE SCHEDULES

BPA's power rate schedules state the applicability of each rate schedule to the products that BPA offers, the rates for the products, the billing determinants to which the rates are applied, and the sections of the GRSPs that apply to each rate schedule. The power rate schedules described in this section are presented in their entirety in the 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01.

4.1 Priority Firm Power (PF-26) Rate

The PF-26 rate applies to sales of firm (continuously available) power to be used within the Pacific Northwest by public bodies, cooperatives, federal agencies, and investor-owned utilities participating in the REP. The PF-26 rate schedule is available for the contract purchase of Firm Requirements Power pursuant to Section 5(b) of the Northwest Power Act. 16 U.S.C. § 839c(b). Utilities participating in the REP under Section 5(c) of the Northwest Power Act may purchase PF power pursuant to a Residential Purchase and Sale Agreement (RPSA) or Residential Exchange Program Settlement Implementation Agreement (REPSIA). 16 U.S.C. § 839c(c); *see* Section 8 below.

The PF Public rate applies to firm requirements purchases under CHWM contracts and includes Tier 1 and Tier 2 charges. *See* Sections 4.1.1 and 4.1.2. Rates for firm requirements purchases under arrangements other than CHWM contracts include the PF Melded rate and the Unanticipated Load Service rate. *See* Sections 4.1.3 and 4.1.4.

4.1.1 PFp Tier 1 Charges

The majority of PF Public revenue is collected from firm requirements power purchased at Tier 1 rates. Tier 1 charges (rates and billing determinants) apply to PF power purchased to meet a customer's RHWM Load. Tier 1 charges include:

- Customer Charges (Composite, Non-Slice, Slice)
- Demand Charge
- Load Shaping Charge

PF Public Tier 1 Non-Slice rates are subject to risk adjustments during the Rate Period pursuant to the Power Cost Recovery Adjustment Clause (Power CRAC); the Power Reserves Distribution Clause (Power RDC); and the Power FRP Surcharge. *See* Section 5.2 below. Any adjustments to rates and GRSPs during the Rate Period due to such risk adjustments will be summarized in Appendix A of the Power Rate Schedules and GRSPs. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, PF-26, § 2.1.4.

4.1.1.1 Customer Charges

4.1.1.1.1 Customer Charge Rates

Rates for the Composite, Non-Slice, and Slice customer charges are expressed as dollars per 1 percentage point of Billing Determinant (TOCA, Non-Slice TOCA, or Slice percentage, respectively). Each of the three rates is calculated by dividing the total costs allocated to each cost pool, as described in Section 3.2.1 above, by the sum of the respective forecast Billing Determinants, as described in Section 4.1.1.1.2 below. The quotient of that calculation is then divided by 12 to yield a monthly rate per 1 percent of the applicable Billing Determinant.

The resulting monthly rates are shown in Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.1.6.3.

4.1.1.1.2 Customer Charge Billing Determinants

The TOCA is the customer-specific Billing Determinant applied to the Composite Customer rate. The majority of BPA's costs to be collected through PF rates are allocated among customers through the TOCA. Each customer's annual TOCA percentage is calculated by dividing the lesser of an individual customer's RHWM or its Forecast Net Requirement by the total of the RHWMs for all PFp customers.

The Forecast Net Requirement and RHWM for the individual customer and the sum of RHWMs for all customers are expressed in average annual megawatts. The total of the RHWMs for all customers is shown in Power Rates Study Table 1, and the sum of TOCAs used for FY 2026-2028 is shown in Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.1.6.3.

The Non-Slice TOCA is the customer-specific billing determinant applied to the Non-Slice Customer rate. The Non-Slice TOCA is equal to a customer's TOCA if the customer is purchasing the Load Following or Block product. The Non-Slice TOCA for customers purchasing the Slice/Block product is computed as the difference between the customer's TOCA and its Slice percentage. The forecast sum of Non-Slice TOCAs used for FY 2026–2028 is shown in *id.,* Table 3.1.6.3.

The Slice percentage is the customer-specific billing determinant applied to the Slice Customer rate. Initial Slice percentages appear in Exhibit J of each Slice customer's CHWM contract. These percentages can be adjusted each year pursuant to TRM Section 3.6, and the final Slice percentage is established in Exhibit K of the customer's CHWM contract. TRM, BP-12-A-03, § 3.6.

4.1.1.2 Tier 1 Demand Charge

4.1.1.2.1 Demand Charge Rates

Demand rates are based on the annual fixed costs (capital and operations and maintenance [O&M]) of a marginal capacity resource, a Wärtsilä 18V50SG reciprocating generator, as determined by the Northwest Power and Conservation Council's (NPCC or Council) Microfin model. For the BP-26 Rate Period, a dampening methodology is applied to the demand rate in order to allow half of the increase that would otherwise be indicated by the model. The application of this dampening methodology is discussed below.

The Microfin model estimates the nominal all-in capital costs of a Wärtsilä 18V50SG reciprocating generator with a 2026 in-service date. The all-in capital cost under these specifications is $1,798/kW as shown in Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 4.1.

The projected debt payment on the $1,798/kW fixed capital costs is estimated at $101.32/kW/yr., based on a cost of debt of 3.79 percent financed over 30 years. The plant is assumed to be owned by a publicly owned utility with BPA-backed bonds. The cost of debt is from BPA's FY 2026 Third-Party Tax-Exempt 30-Year Borrowing Rate Forecast. *See* Power Revenue Requirement Study Documentation, BP-26-FS-BPA-02A, § 6, FY 2024 Interest Rate and Inflation Forecast Memorandum.

The cost of fixed O&M included in the demand rate calculation is obtained from the Microfin model. The calculation of the demand rate uses the Microfin model's estimate of $5/kW/yr. escalated to 2026, 2027, and 2028 dollars using the 2016-to-2023 average (seven-year) rate of 3.18 percent calculated from Implicit Price Deflators from the

U.S. Bureau of Economic Analysis. The three-year average annual cost for fixed O&M is $7.05/kW/yr. Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 4.1.

Insurance and fixed fuel costs are also included in the calculation of the demand rate. The average annual insurance cost of $4.27/kW/yr. is calculated based on 0.25 percent of the mid-year assessed value obtained from the Council's Microfin model. The average annual fixed fuel cost assumed in the demand rate calculation is $27.76/kW/yr. The fixed fuel cost is estimated using Microfin's lifetime average rate of 8,797 Btu/kWh applied to the average of the existing eastside and westside Pacific Northwest fixed fuel costs for the applicable fiscal year. *Id.*

The average annual expense as estimated by the model is $140.40/kW. The previous BP-24 calculated average annual expense, using the same model, was $114.54/kW. Applying the dampening methodology described above, half of the increase is allowed, resulting in a dampened value of $127.47/kW. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 4.1, line 30. This annual value is shaped into the 12 months of the year using the shape of the Heavy Load Hours (HLH) Load Shaping rates, resulting in demand rates specific to each month. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 4.1; 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, PF-26, § 2.1.2.1.

4.1.1.2.2 Demand Charge Billing Determinant

The Demand Billing Determinant applies to customers purchasing the Load Following and Block with Shaping Capacity products. TRM Sections 5.3.1-5 contain a detailed explanation of how to calculate the customer-specific Demand Billing Determinant, which is only a limited portion of a customer's overall demand on BPA. TRM, BP-12-A-03. The following discussion summarizes the TRM explanation.

Four quantities are used in calculating a PFp customer's Demand Charge Billing Determinant: 1) the Tier 1 Customer's System Peak (CSP); 2) the average amount of a customer's electric load (measured in average kilowatts) that was served at Tier 1 rates during the HLH of a month; 3) the customer's Contract Demand Quantity (CDQ, expressed in kilowatts); and 4) any applicable Super Peak Credit as specified in a customer's CHWM contract.

The Demand Billing Determinant is determined by measuring a customer's CSP and then subtracting the other three quantities. The Demand Billing Determinant calculation can never result in a negative billing determinant; if the calculation results in a value less than zero, the Billing Determinant is deemed to be zero.

The Tier 1 CSP is equal to a customer's maximum Actual Hourly Tier 1 Load (measured in kilowatts) during the HLH of a month. Twelve CDQs are specified for each PFp customer in the customer's CHWM contract.

The Super Peak Credit is determined pursuant to a customer's CHWM contract. If a customer does not supply the Super Peak amount listed in Section 9 of Exhibit A of its CHWM contract for any hour of the Super Peak Period, then the customer does not receive a Super Peak Credit for that month. The Super Peak Period for FY 2026-2028 is defined in the 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP III.B.30.

There are two possible adjustments that may be made to a customer's Demand Billing Determinant. The first is an adjustment to offset anomalous recovery load peaks that occur after a customer has had power restored to its service territory following a weather-related system outage or other extreme peak event. The second is an adjustment to offset extreme load changes that have severely and adversely affected a customer's load factor. The 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.D, include the calculations for applying these adjustments, applicable qualifying criteria, and notice requirements. *See* Section 5.4.3 below (providing more information regarding this adjustment).

4.1.1.3 Tier 1 Load Shaping Charge

4.1.1.3.1 Load Shaping Charge Rates

The PFp rate design includes 24 Load Shaping rates (two diurnal periods—HLH and LLH—for each of 12 months). The Load Shaping rates are set equal to the rate period average marginal cost of power for each monthly/diurnal period as determined in the Power Market Price Study and Documentation, BP-26-FS-BPA-04, § 2.4. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 4.2. *See* Section 5.4.4 below (providing information on the Load Shaping Charge True-Up Adjustment).

4.1.1.3.2 Load Shaping Charge Billing Determinant

The Billing Determinant for the Load Shaping charge is the difference between 1) a customer's actual load served at Tier 1 rates and 2) the System Shaped Load, which is the customer's annual load reshaped into the monthly/diurnal shape of RHWM Tier 1 System Capability. The Load Shaping Billing Determinant can have either a positive or a negative value. Pursuant to the TRM, a Load Following customer's Above-RHWM Load that is forecast to be less than 8,760 MWh and is not served with non-federal resources will be served by BPA at the Load Shaping rate and is reflected in this Billing Determinant. *See* TRM, BP-12-A-03, § 4.3.

A customer's System Shaped Load is calculated as the RHWM Tier 1 System Capability (*see* Section 1.4.2) for each of the 24 monthly/diurnal periods of the fiscal year multiplied by the customer's Non-Slice TOCA. The Load Shaping Billing Determinants are calculated as the amount of a customer's actual monthly/diurnal load (measured in kilowatts) to be served at Tier 1 rates minus the customer's System Shaped Load for the same monthly/diurnal period.

4.1.1.3.3 Monthly/Diurnal RHWM Tier 1 System Capability

The TRM prescribes that the monthly/diurnal shape of the RHWM Tier 1 System Capability will be used to compute the System Shaped Load for purposes of computing Load Shaping Billing Determinants. The System Shaped Load is not updated if the RHWM Tier 1 System Capability that was determined in the RHWM Process is updated in the rate proceeding. The system shape is computed to be constant across both years of the rate period and is the average of each year's respective monthly/diurnal megawatthour amount. In a rate period that does not include a leap year, there will be 24 monthly/diurnal amounts for the RHWM Tier 1 System Capability specified in the GRSPs. In a rate period that includes a leap year, there will be 26 amounts, with a unique value for each February to account for the additional day. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.A.

4.1.2 PFp Tier 2 Charges

Tier 2 charges (rates and billing determinants) apply to PF power purchased to meet a customer's Above-RHWM Load. Tier 2 charges include:

- Load Shaping Charge

- Short-Term Charge
- Load Growth Charge

See 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, PF-26, § 2.2.

4.1.2.1 Tier 2 Load Shaping Charge

Pursuant to the TRM, a Load Following customer's Above-RHWM Load that is forecast to be less than 8,760 MWh and that is not served with non-federal resources will be served at Tier 2 rates set equal to the Load Shaping rate. For ease of ratemaking and billing, and since it would create no material difference because the rate for the two is the same, BPA does not separate the Tier 2 Load Shaping Billing Determinant from the Tier 1 Load Shaping Billing Determinant. Rather, the Tier 1 Load Shaping Billing Determinant can include power purchased at Tier 1 and Tier 2 rates. *See* Section 4.1.1.3 above.

4.1.2.2 Tier 2 Short-Term and Load Growth Charges

With the exception of the Tier 2 Load Shaping Charge, Tier 2 rates are calculated in a module of RAM2026 and are summarized in Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.5.1 and 3.5.2. Each rate is calculated by dividing the annual costs allocated to the specific Tier 2 cost pool (*see* Section 3.2.2 above) by the billing determinants (based on the annual average megawatt load obligations, excluding real power losses, for each Tier 2 rate alternative) in that same fiscal year. Each Tier 2 rate is established to recover all of the allocated costs associated with the product. The Tier 2 rates may be adjusted under certain circumstances, as shown in PF-26, Section 7.

The Tier 2 Billing Determinant is equal to each customer's commitment to purchase from BPA all or a portion of the customer's Above-RHWM Load. Each customer's Tier 2 rate service amount is contractually established for FY 2026-2028. The totals for all customers are summarized in Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 4.3.

4.1.3 PFp Melded Rates (Non-Tiered Rate)

The PF Melded rate is a non-tiered rate applicable to the sale of Firm Requirements Power under contracts other than CHWM contracts. No sales under the PF Melded rate are forecast during the rate period, FY 2026-2028.

Melded PF Public rates are included in Section 3 of the PF rate schedule and consist of 12 HLH energy rates, 12 LLH energy rates, and 12 demand rates. The PFp melded energy rates are equal to the PFp Load Shaping rates less a scalar. The scalar is a single mills per kilowatthour value that adjusts the Load Shaping rates so that the PFp melded energy rates, in conjunction with the demand revenue, do not collect more or less revenue than the Tier 1 and Tier 2 revenue requirement allocated to the PFp loads. Calculation of the PFp melded energy rate components, including the scalar, is shown in Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.1.8.2. The applicable demand rates are equal to the PFp Tier 1 demand rates.

The PFp melded energy rates are subject to risk adjustments during the rate period pursuant to the Power CRAC; the Power RDC; and the Power FRP Surcharge. *See* Section 5.2 below. Any adjustments to rates and GRSPs during the rate period due to such risk adjustments will be summarized in Appendix A of the Power Rate Schedules and GRSPs. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, PF-26, § 3.

4.1.4 Unanticipated Load Service Charge

BPA provides Unanticipated Load Service (ULS) for Load Following customers under the PF rate schedule and provides a similar service under the NR and FPS rates. ULS is described in Section 5.10 below and in the 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.M.

4.1.5 PFp Resource Support Services Rates

BPA offers RSS and related services for customers' variable, non-dispatchable non-federal resources in accordance with the CHWM contract. In general, RSS are designed to financially convert these resources into a flat annual block of power or the specified monthly/diurnal resource shape found in Exhibit A of the customer's CHWM contract. RSS available under the PFp rate schedule include the following:

- DFS, as discussed in Section 5.6.1.1 below and the 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.I.1.
- Grandfathered Generation Management Service, as discussed in Section 5.6.1.7 below and the 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.I.6.
- Resource Shaping Charge, as discussed in Sections 5.6.1.2-3 below and the 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.I.2.
- Secondary Crediting Service (SCS), as discussed in Section 5.6.1.6 below and the 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.I.3.

The related services include Transmission Scheduling Service, Transmission Curtailment Management Service, and RRS. These related services are provided under the FPS rate schedule and are discussed in Section 4.4 below.

4.1.6 Priority Firm Exchange (PFx) Rate

A utility-specific PFx rate applies to each participant in the REP for sales and purchases of exchange energy pursuant to an RPSA (for eligible consumer-owned utilities) or a REPSIA (for eligible investor-owned utilities).

The 2012 REP Settlement (*see* Section 5.12) requires that BPA pay a fixed sum of REP benefits to IOUs eligible for the REP pursuant to a schedule of payments set forth in the 2012 REP Settlement. 2012 REP Settlement, REP-12-A-02A. The yearly fixed sum is included in BPA's revenue requirement and collected in BPA's rates. Each IOU's share of the fixed amount of REP benefits is determined pursuant to the calculations contained in Section 6 of the 2012 REP Settlement. In particular, Section 6.2 of the 2012 REP Settlement describes a series of adjustments BPA is required to make to certain IOUs' shares of the REP benefits. BPA's implementation of Section 6.2, including the specific calculations BPA used to reach the resulting REP allocations, is shown in Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.4.12.

The PFx rate has two components: 1) two common Base PFx rates (one for COUs with CHWM contracts and another for all other REP participants); and 2) utility-specific REP Surcharges. The COUs have a different Base PFx rate because the PFp rate is tiered. Neither component of the PFx rate is diurnally differentiated or contains an additional charge for demand. Each participant's ASC is a single mills per kilowatthour rate applied to all kilowatthours. Likewise, the rate design for each participant's PFx rate is a single mills per kilowatthour rate applied to all kilowatthours.

Base PFx rates are based on the average PF rate immediately prior to the determination of Section 7(b)(2) rate protection. The PFx rate applicable to IOUs (and any eligible COU without a CHWM contract) is computed by dividing all costs allocated to the PF rate pool by all PF rate pool loads and then adding a transmission charge for delivering the exchange power to the customer. The PFx rate applicable to COUs with CHWM contracts is calculated in the same manner, except that the costs allocated to Tier 2 cost pools are excluded from the numerator and loads served at Tier 2 rates are excluded from the denominator.

Under the 2012 REP Settlement, the utility-specific 7(b)(3) surcharge to recover the cost of providing 7(b)(2) rate protection continues to be assessed. *See* 2012 REP Settlement, REP-12-A-02A; Section 2.2.2.3 above. The amount of 7(b)(2) rate protection costs allocated to the PFx rates is allocated to each IOU REP participant on a pro-rata basis using REP Unconstrained Benefits calculated from the difference between utility-specific ASCs and the Base PFx rate for IOUs as the allocator. The cost of 7(b)(2) protection recovered from the 7(b)(3) Surcharge applied to the PFx rate for exchanging COUs is imputed from the aggregate protection allocated to IOUs relative to the aggregate Unconstrained Benefits among the IOUs, so that exchanging COUs bear an equitable responsibility for 7(b)(2) rate protection owed to the PFp rate pool. The total amount allocated to each REP participant is divided by the participant's exchange load to derive its utility-specific 7(b)(3) surcharge.

For each REP participant, the applicable Base PFx rate is added to its utility-specific 7(b)(3) surcharge to determine its utility-specific PFx rate. For each month of the rate period, the participant will submit its exchange load to BPA for the prior month. Under either RPSA or REPSIA, a utility-specific PFx rate is applied to BPA's sales of exchange energy and the participating utility's ASC is applied to BPA's purchase of exchange energy, where the exchange energy is equal to the utility's eligible residential and farm load. The difference between the amount BPA pays for exchange "purchases" and the amount BPA receives for exchange "sales" determines the amount of monetary REP benefits BPA pays the utility. BPA will multiply this invoiced exchange load by the difference between the participant's

ASC and its PFx rate to calculate the amount of REP benefits payable to the participant. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.4.11.

4.2 New Resource Firm Power (NR-26) Rate

The NR-26 rate applies to sales to investor-owned utilities under Northwest Power Act Section 5(b) requirements contracts. 16 U.S.C. § 839c(b). The NR-26 rate is also applicable to sales to any public body, cooperative, or federal agency to the extent such power is used to serve any NLSL, as defined by the Northwest Power Act, including planned NLSLs, as defined in Exhibit D of a customer's CHWM contract. The NR-26 rate includes energy and demand rates.

4.2.1 NR Energy Charge

Monthly and diurnal differentiation of NR energy rates is calculated based on the HLH and LLH differentiation of the PFp Load Shaping rates. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.1.8.4. The NR energy rates are determined by adjusting each PFp Load Shaping rate by an equal scalar until the NR energy rates recover the allocated NR revenue requirement minus the forecast NR Demand Charge revenue. *Id.*

After the scaling process is complete, an REP Surcharge is added to each of the monthly/diurnal energy rates. Section 7(b)(3) of the Northwest Power Act provides that the cost of 7(b)(2) rate protection afforded to preference customers is allocated to all other power sold, which includes power sold at the NR rate. 16 U.S.C. § 839e(b)(2)-(3); *see* Section 2.2.2.4 above. The cost of rate protection allocated to the NR rate is determined pursuant to the 2012 REP Settlement. Refer to Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.4.14, for the calculation of the REP Surcharge.

A customer's billing determinant for the NR Energy charge is the total of the customer's NR hourly loads for each diurnal period.

The NR Energy rates are subject to risk adjustments during the rate period pursuant to the Power CRAC, the Power RDC, and the Power FRP Surcharge. *See* Section 5.2 below. Any adjustments to rates and GRSPs during the rate period due to such risk adjustments will be summarized in Appendix A of the Power Rate Schedules and GRSPs. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, NR-26, § 2.1.1.2.

4.2.2 NR Demand Charge

The demand rates for the NR rate schedule are equal to the PFp demand rates described in Section 4.1.1.2 above. As with the PFp Demand Charge, the NR Demand Billing Determinant is only a portion of the peak demand placed on BPA. The NR Demand Billing Determinant is equal to the highest NR hourly load during HLH minus the average hourly HLH energy purchased in that particular month at the NR energy rates.

4.2.3 Unanticipated Load Service Charge

ULS is available under the NR-26 rate schedule for NLSLs and requirements service requested by IOUs. See Section 5.10 below and the 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.M, for details.

4.2.4 NR Services

NR Services for NLSLs are applicable to Load Following customers serving NLSLs with non-federal resources. NR Energy Shaping Service is discussed in Section 5.6.2.1 below and specified in the 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.J.1.

4.3 Industrial Firm Power (IP-26) Rate

The IP-26 rate schedule is available for firm power sales to DSIs pursuant to Section 5(d) of the Northwest Power Act. 16 U.S.C. § 839c(d). The IP-26 rate includes energy and demand rates. DSIs purchasing power pursuant to the IP-26 rate schedule are required to provide the Minimum DSI Operating Reserve–Supplemental.

4.3.1 IP Energy Charge

4.3.1.1 IP Energy Rates

The IP rate design includes 24 monthly/diurnal energy rates, two for each month, and one each for HLH and LLH. The IP energy rates are shaped using the PFp Melded rates. *See* Section 4.1.3 above.

As described below, IP Energy rates are calculated by adjusting the PFp melded rates by the VOR Credit for operating reserves provided by the DSI load, the typical industrial margin, and an REP Surcharge. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.1.8.3.

The IP energy rates are subject to risk adjustments during the rate period pursuant to the Power CRAC; the Power RDC; and the Power FRP Surcharge. *See* Section 5.2 below. Any adjustments to rates and GRSPs during the rate period due to such risk adjustments will be summarized in Appendix A of the Power Rate Schedules and GRSPs. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, IP-26, § 2.1.1.3.

4.3.1.1.1 IP Adjustment for Value of Reserves Provided

A VOR Credit is included in the IP rate, as provided in Section 7(c)(3) of the Northwest Power Act. 16 U.S.C. § 839e(c)(3); *see* Section 2.2.2.5.2 above. The forecast DSI load amount is shown in the Power Loads and Resources Study, BP-26-FS-BPA-03, § 2.4. Based on provisions of DSI contracts currently in place, these power sales are assumed to provide interruption reserve rights (operating reserves) to BPA, and therefore the IP rate includes a VOR Credit.

The first step for valuing operating reserves provided by DSIs is to determine a marginal price for these reserves. Because the DSI-supplied reserves are used to meet BPA's reserve obligations, the cost of Operating Reserves–Supplemental service is used to establish the marginal value.

The second step in valuing the DSI reserves is to determine the quantity of reserves provided. To calculate this quantity, the total DSI load is reduced to account for wheel-turning load that cannot be curtailed. The wheel-turning load is forecast to be 0 aMW. The interruption reserves provided are 10 percent of the remaining DSI load (11 MW), or 1.1 MW.

The VOR Credit included in the IP-26 rate is 0.675 mills/kWh. See Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.4.1, for calculation of the value of DSI reserves.

4.3.1.1.2 IP Rate Typical Margin

Another component of the IP rate is the typical margin, as provided in Section 7(c)(2) of the Northwest Power Act. 16 U.S.C. § 839e(c)(2); *see* Section 2.2.2.5.2 above. The typical margin is based generally on the overhead costs that COUs add to the cost of power in setting their retail industrial rates. The typical margin included in the IP-26 rate is 0.966 mills/kWh. The typical margin is calculated in Appendix A.

4.3.1.1.3 REP Surcharge

The final component of the IP rate is the REP Surcharge. Section 7(b)(3) of the Northwest Power Act provides that the cost of 7(b)(2) rate protection afforded to preference customers must be allocated to all other power sold, which includes power sold at the IP rate. 16 U.S.C. §§ 839e(b)(2)-(3); *see* Section 2.2.2.3 above. The cost of rate protection allocated to the IP rate is determined pursuant to the 2012 REP Settlement and is included in the IP-26 rate. See Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.4.14, for calculation of the REP Surcharge.

4.3.1.2 IP Energy Charge Billing Determinant

The customer-specific Energy Billing Determinant is the Energy Entitlement specified in the customer's contract.

4.3.2 IP Demand Charge

The demand rates for the IP rate schedule are equal to the PFp demand rates described in Section 4.1.1.2 above. As with the PFp demand charge, the IP Demand Billing Determinant is applied to only a portion of the DSI peak demand placed on BPA. The IP Demand Billing Determinant in each billing month is equal to a DSI's highest HLH schedule, or metered amount, minus the average HLH schedule amount, or metered amount, less any applicable Industrial Demand Adjuster. The Industrial Demand Adjuster is a monthly demand (expressed in kilowatts) that is subtracted from the hourly peak schedule amount when calculating the IP Demand Billing Determinant. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, IP-26, § 2.2.2.

4.4 Firm Power and Surplus Products and Services (FPS-26) Rate

Products and services available under the FPS rate schedule are listed in the next paragraph and described in the FPS-26 rate schedule. 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. Products priced under the FPS-26 rate schedule may be sold at market-based or negotiated rates, which may have a demand component, an energy component, or both. Rates and billing determinants for the products and services sold under the FPS rate schedule are either specified by BPA or mutually agreed upon by BPA and the customer. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, FPS-26.

4.4.1 FPS Charges

When available for use within and outside the Pacific Northwest, the FPS-26 rate schedule has nine categories of products and services:

1. Firm power (capacity and/or energy), including secondary energy or firm capacity.
2. Capacity without energy: stand-alone capacity products.
3. Energy shaping services.
4. Reservations and rights to change services: reservations of power and services, when available, and the rights to change sales and services.
5. Reassignment or remarketing of surplus transmission capacity: Power Services may reassign or remarket its surplus transmission capacity that has been purchased from a transmission provider, including BPA's Transmission Services, consistent with the terms of the transmission provider's Open Access Transmission Tariff.
6. Other capacity, energy, and power scheduling products and services, as available.
7. Services for non-federal resources:
    a. Transmission Scheduling Service and Transmission Curtailment Management Service, Section 5.6.1.5 below and 2026 Power Rate

Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.I.5.

b. Forced Outage Reserve Service, Section 5.6.1.4 below and 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.I.4.

c. Resource Remarketing Service, § 5.6.1.8 below and 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.I.7.

8. Unanticipated Load Service, Section 5.10 below and 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.M.4.

9. Real Power Losses: Power Services may sell power to BPA Transmission customers for Real Power Loss returns as defined by BPA Transmission Services.

See 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, FPS-26.

4.4.2 FPS Real Power Losses Service

When power is sent across a transmission system a portion of the power transmitted is lost. Customers have a choice to physically provide that lost power (in-kind loss returns or using Slice Output), meaning provide additional power to cover the loss, or to purchase power equal to the lost amount from BPA (FPS real power loss returns). This section describes the methodology used to calculate the cost of real power loss returns when a customer chooses to purchase the lost power from Power Services.

4.4.2.1 Energy Cost of Providing Real Power Losses

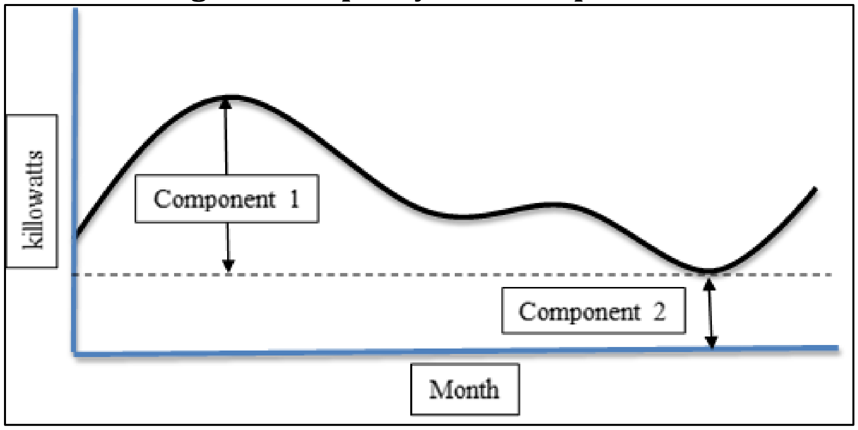
The energy cost of providing real power losses will be based on actual hourly market prices from the hour the loss obligation occurred. The market prices will be the greater of 0 and the hourly Load Aggregation Point (LAP) price for BPA as determined by the Market Operator (MO) under Section 29.11(b)(3)(C) of the MO Tariff for the hour in which the loss occurred. In the event of a Market Contingency pursuant to Section 10 of Attachment Q to the BPA Tariff, BPA will use an available energy index in the Pacific Northwest.

4.4.2.2 Capacity Cost of Providing Real Power Losses

The methodology used to establish the cost for the FPS Real Power Losses Service uses three historical years (FY 2019, FY 2020, and FY 2021) of losses data to calculate the capacity cost to BPA had all customers with loss obligations during these historical years chose to purchase those losses from Power Services. That total capacity cost is divided by the average annual amount of lost energy (kilowatthours) included in that same data set to calculate a volumetric capacity rate in mills per kilowatthour that is applied to losses purchased through Power Services FPS rate schedule.

Two capacity cost components are quantified and summed to calculate the total capacity cost. The first component captures the cost of the capacity needed to flex between the minimum energy provided and the max energy provided in a month. The second component captures the cost of the capacity (or premium) typically included when a block of power is purchased well in advance of the operating hour. Together, these two components capture the entire stack of capacity (zero to maximum amount) needed to serve the load requirement of those three years of transmission loss data (see Figure 2 below).

Figure 2. Capacity Cost Components



Capacity Cost Component 1:

Capacity cost component 1 is calculated by multiplying the average monthly quantity of incremental (*inc)* capacity provided for a year (using FY 2019, FY 2020, and FY 2021) by the unit cost of Supplemental Operating Reserve capacity as documented in Section 9.3.1 below. The average monthly quantity of *inc* capacity is calculated by taking the average maximum hourly amount by month in kilowatts (*i.e.,* for the month of March, the calculation would be the average of the maximum hourly March 2019, maximum hourly March 2020, and maximum hourly March 2021) minus the average minimum hourly amount of energy for the same month (*i.e.,* for the month of March, the calculation would be the average of the minimum hourly March 2019, minimum hourly March 2020, and minimum hourly March 2021). The net of these two values is calculated for all 12 months of the year and summed to equal the quantity of *inc* capacity provided in capacity cost component 1.

$$AveMaxMonth_i = \sum_{i=1}^{12} \frac{[HrMaxMonth_{i_{2019}} + HrMaxMonth_{i_{2020}} + HrMaxMonth_{i_{2021}}]}{3}$$

$$AveMinMonth_i = \sum_{i=1}^{12} \frac{[HrMinMonth_{i_{2019}} + HrMinMonth_{i_{2020}} + HrMinMonth_{i_{2021}}]}{3}$$

$$AnnualSumMonthlyCapacity_{inc} = \sum_{i=1}^{12} AveMaxMonth_i - AveMinMonth_i$$

$$CapacityCostComp_1 = AnnualSumMonthlyCapacity_{inc}\ x\ UC_{sup}$$

Where:

i refers to a particular month in the fiscal year with 1 being October and 12 being September.

$HrMaxMonth_{i_{2019}}$ refers to the maximum hourly value in month i of fiscal year 2019.

$HrMaxMonth_{i_{2020}}$ refers to the maximum hourly value in month i of fiscal year 2020.

$HrMaxMonth_{i_{2021}}$ refers to the maximum hourly value in month i of fiscal year 2021.

$HrMinMonth_{i_{2019}}$ refers to the minimum hourly value in month i of fiscal year 2019.

$HrMinMonth_{i_{2020}}$ refers to the minimum hourly value in month i of fiscal year 2020.

$HrMinMonth_{i_{2021}}$ refers to the minimum hourly value in month i of fiscal year 2021.

UC_{Sup} refers to the unit cost for Supplemental Operating reserves.

$CapacityCostComp_1$ refers to the total annual cost of capacity cost component one.

Capacity Cost Component 2:

Capacity cost component 2 is calculated in two steps. Step one is to multiply the average minimum amount of power provided for each month of the year (*i.e.,* for the month of March, the calculation would be the average of the minimum hourly March 2019, minimum hourly March 2020, and minimum hourly March 2021) by the average amount of hours for that same month (*i.e.,* for the month of March, the calculation would be the average of the hours in March 2019, the hours in March 2020, and the hours in March 2021). Step two is to multiply the total amount of kilowatthours calculated in step one by 14.55 mills/kWh.

$$AveMinMonth_i = \sum_{i=1}^{12} \frac{[HrMinMonth_{i_{2019}} + HrMinMonth_{i_{2020}} + HrMinMonth_{i_{2021}}]}{3}$$

$$AveHrsMonth_i = \sum_{i=1}^{12} \frac{[HrsMonth_{i_{2019}} + HrsMonth_{i_{2020}} + HrsMonth_{i_{2021}}]}{3}$$

$$AveAnnualPower = AveMinMonth_i \times AveHrsMonth_i$$

$$CapacityCostComp_2 = AveAnnualPower \times 14.55\ mill\ per\ kWh$$

Where:

i refers to a particular month in the fiscal year with 1 being October and 12 being September.

$HrMinMonth_{i_{2019}}$ refers to the maximum hourly value in month i of fiscal year 2019.

$HrMinMonth_{i_{2020}}$ refers to the maximum hourly value in month i of fiscal year 2020.

$HrMinMonth_{i_{2021}}$ refers to the maximum hourly value in month i of fiscal year 2021.

$HrsMonth_{i_{2019}}$ refers to the minimum hourly value in month i of fiscal year 2019.

$HrsMonth_{i_{2020}}$ refers to the minimum hourly value in month i of fiscal year 2020.

$HrsMonth_{i_{2021}}$ refers to the minimum hourly value in month i of fiscal year 2021.

$CapacityCostComp_2$ refers to the total annual cost of capacity cost component two.

Capacity cost component 1 and 2 are summed and divide by the average annual amount of kilowatt-hours from the same historical dataset to compute a volumetric dollars per kilowatthour capacity charge applied in addition to the energy charge for real power losses purchases from BPA. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 4.4.

5. GENERAL RATE SCHEDULE PROVISIONS

The GRSPs describe the adjustments, charges, and special rate provisions applicable to BPA's rate schedules. The GRSPs also define the power products and services BPA offers and other applicable terms. The GRSPs described in this section are presented in their entirety in the 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSPs.

5.1 RHWM Tier 1 System Capability

The Rate Period High Water Mark Tier 1 System Capability (RT1SC) is determined in the RHWM Process outside the rate proceeding, as described in Section 1.4 above and the TRM, BP-12-A-03, § 4.2.1.

As described in Section 4.1.1.3.2 above, BPA uses the monthly/diurnal shape of RT1SC and the resulting System Shaped Load in developing the Billing Determinant for the Load Shaping charge. The Billing Determinant for the Load Shaping charge is the difference between a customer's actual load served at Tier 1 rates and the customer's annual load used to calculate its TOCA reshaped into the monthly/diurnal shape of RT1SC. The monthly/diurnal RT1SC values for the FY 2026-2028 rate period are shown in the 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.A, Table A.

5.2 Risk Adjustments

Power risk adjustment clauses will not be applicable to the portion of a customer's service at PF Tier 1 rates that has been converted from a Slice product to a non-Slice product beginning October 1, 2025. However, the three risk adjustment clauses will apply to such customer's entire service at PF Tier 1 rates for FY 2027 and FY 2028. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.O, II.P, and II.Q.

5.2.1 Power Cost Recovery Adjustment Clause (Power CRAC)

For each year of the rate period, the Power CRAC may result in an upward rate adjustment to respond to the financial circumstances BPA experiences before BPA can conduct a Section 7(i) rate proceeding to adjust its rates. If stated conditions are met, the CRAC will trigger, and a rate increase will go into effect for the period of December 1 through September 30 of the applicable year. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.O; Power and Transmission Risk Study, BP-26-FS-BPA-05, § 4.2.

5.2.2 Power Reserves Distribution Clause (Power RDC)

For each year of the rate period, the Power RDC may result in deployment of Power financial reserves in order to further Power's objectives. RDC funds may be used for debt reduction, incremental capital investment, rate reduction through a Power Dividend Distribution (Power DD), a distribution to customers, or any other Power-specific purposes determined by the Administrator. The RDC will trigger if 1) financial reserves attributed to Power exceed a defined threshold, and 2) BPA's financial reserves exceed a defined threshold. If the RDC triggers, the Administrator will determine what part of the RDC Amount will be devoted to the Power objectives noted above. If reserves are allocated to a Power DD, the resulting rate decrease will go into effect for the month following the issuance of the Power RDC decision through September 30 of the applicable year.

No cap on the Power RDC is included for the BP-26 rate period. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.P; Power and Transmission Risk Study, BP-26-FS-BPA-05, § 4.2.

5.2.3 Power FRP Surcharge

For each year of the rate period, the Power FRP Surcharge may result in an upward adjustment to certain rates to increase financial reserves when reserves are below the lower threshold for Power. *See* Power and Transmission Risk Study, BP-26-FS-BPA-05, § 4.2. If stated conditions are met, 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. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.Q.

For FY 2026, FY 2027 and FY 2028, Power's FRP Surcharge amount will be the lesser of $40 million per year or the amount needed to fully recover financial reserves up to the lower financial reserves threshold for Power. *See* Power and Transmission Risk Study, BP-26-FS-BPA-05, Appendix A (FRP), § 4.2.2.

5.3 Slice True-Up Adjustment

Slice customers pay their share of BPA's actual costs. Therefore, Slice customers are subject to an annual Slice True-Up Adjustment for expenses, revenue credits, and adjustments allocated to the Composite cost pool and to the Slice cost pool. *See* § 7; 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.R.

5.4 Discounts and Other Adjustments

5.4.1 Low Density Discount (LDD)

Pursuant to Section 7(d)(1) of the Northwest Power Act, the LDD is a rate discount for customers with low system densities that meet the criteria specified in the 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.B. 16 U.S.C. § 839e(d)(1). As set forth in the TRM, LDD percentages are calculated to provide a discount on power purchased at Tier 1 rates that approximates the discount the customer would have received under non-tiered rates. LDD credits for FY 2026, FY 2027 and FY 2028 are listed in Table 4, Line 9.

5.4.2 Irrigation Rate Discount (IRD)

The IRD is a discount to the PFp Tier 1 rates for eligible irrigation load served by customers. An irrigation credit is available to customers with eligible irrigation load as set forth in Exhibit D of the customers' CHWM contracts. The amount of irrigation credit a customer will receive on its monthly bills during the irrigation season is based on the lesser of the customer's actual Tier 1 energy purchase and the eligible irrigation load amounts in the customer's CHWM contract. The discount will appear as a credit on customers' bills to offset Tier 1 charges for eligible irrigation loads. This discount is available to eligible loads during May, June, July, August, and September during the BP-26 rate period. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.C. IRD Credits for FY 2026, FY 2027 and FY 2028 are shown in Table 4, Line 8.

5.4.2.1 Irrigation Rate Discount True-Up and Reimbursement

At the end of each irrigation season, each customer with eligible irrigation load will provide to BPA its measured May-through-September irrigation load amounts, which will be used to determine if a true-up and reimbursement to BPA is applicable. If BPA determines that the measured irrigation load amounts are less than the billed irrigation load amounts, then the purchaser must reimburse BPA for the excess IRD Credits. Excess IRD Credits are calculated as the IRD rate multiplied by the difference between the billed irrigation load and the measured irrigation load. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.C.3.

5.4.2.2 Calculation of the Irrigation Rate Discount

The TRM establishes the method for calculating the IRD. The process begins with a fixed Irrigation Rate Mitigation Program (IRMP) percentage of 37.06 percent. *See* TRM, BP-12-A-03, § 10.3; BP-12 Power Rates Study Documentation, BP-12-FS-BPA-01A, Table 3.12.

The IRMP percentage is multiplied by the sum of the forecast revenue that irrigation loads will pay through the Composite customer charge, Non-Slice customer charge, and Load Shaping charge, adjusted for any applicable LDD, divided by the sum of the irrigation loads (expressed in megawatthours) to derive a dollars-per-megawatthour discount. The applicable LDD is calculated as the weighted average LDD of eligible irrigation customers, weighted with eligible irrigation loads. See Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 5.1 for the calculation of the applicable LDD.

Forecast revenue for irrigation loads is calculated using an IRD TOCA derived by dividing the sum of the irrigation loads (expressed in average megawatts) by the sum of all RHWMs. The IRD TOCA is applied consistent with TRM Section 5 for calculation of forecast irrigation revenues from the Composite customer charge, Non-Slice customer charge, and Load Shaping charge. The calculation is shown in Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.3.3.1.

5.4.3 Demand Rate Billing Determinant Adjustment

As described in GRSP II.D, in two limited circumstances BPA may reduce an unusually high Demand Charge Billing Determinant and provide some demand billing relief to a customer. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.D.

First, when a customer's loads differ significantly from one part of the month to another, the customer may experience overall low average HLH energy use, relatively high customer system peak, and a resulting high Demand Billing Determinant. In this situation, BPA may adjust the Demand Billing Determinant by calculating partial-month billing determinants and use the higher of the two (or more) partial-month billing determinants for the entire billing month. Example loads include large industrial or irrigation loads that occur during only a part of a month.

Second, when an Uncontrollable Force outage occurs on a customer's system, the restoration of service may result in a spike in usage, called a recovery peak. BPA may reduce the customer's system peak established by a recovery peak to the next highest peak of the month and thereby reduce that month's billing determinant.

5.4.4 Load Shaping Charge True-Up Adjustment

As noted in TRM Section 5.2.4, at the end of each fiscal year BPA will calculate the Load Shaping Charge True-Up for each Load Following customer. The purpose of the true-up is to avoid charging or crediting the market-based Load Shaping rate for energy within the customer's RHWM rather than charging or crediting the cost-based Tier 1 rate for that energy. BPA applies the true-up when a Load Following customer's TOCA Load or Actual Annual Tier 1 Load is less than its RHWM. The LSTUR is the difference between 1) the Non-Slice load-weighted average of the Load Shaping rates, and 2) the Composite Customer rate plus the Non-Slice Customer rate, converted to mills per kilowatthour. The process for calculating the Load Shaping True-Up Adjustment is shown in TRM, BP-12-A-03, Section 5.2.4, Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.1.8.5, and the 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.E.

5.4.5 Special Implementation Provision for Load Shaping True-Up

The Load Shaping True-Up Adjustment includes a special implementation provision that applies if two conditions are met: 1) a customer has Above-RHWM Load, and 2) the customer has unused RHWM. If these conditions are met, the customer may be eligible for a Load Shaping True-Up Credit in addition to the one described above. The amount of the additional Load Shaping True-Up Credit depends on a second calculation. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.E.3.

The special implementation provision was originally designed to solve a transitional implementation issue caused by setting Above-RHWM Load based on a forecast different from the one used to determine a customer's TOCA. This provision also has a longer term application, because Above-RHWM Load is determined in the RHWM Process (prior to the Initial Proposal of each rate proceeding). A Load Following customer's TOCA can be updated prior to each fiscal year, or within a fiscal year, if there is substantial reason for BPA to believe the customer's Actual Annual Tier 1 Load will be different than the forecast Tier 1 Load determined in the RHWM Process or the applicable year. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.G.1. A consequence of using forecasts prepared at different times is the possibility that a customer could have both Above-RHWM Load and unused RHWM.

5.4.6 Tier 2 Rate Transmission Curtailment Management Service Adjustment

The Tier 2 rate schedule includes an adjustment for TCMS-related costs. This adjustment will recover the cost BPA incurs as a result of a transmission event—either a planned transmission outage or a transmission curtailment. The event would occur along the transmission path used to deliver energy associated with power purchases for the Tier 2 cost pools; that is, it would occur between the Point of Receipt (POR) and the Point of

Delivery (POD). The adjustment is described in the 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.F.

5.4.7 TOCA Adjustment

For each customer purchasing Firm Requirements Power under a CHWM contract, a TOCA for each year of the rate period is calculated in the BP-26 7(i) process. A Load Following customer's TOCA for a fiscal year may be adjusted 1) to account for a significant change in the customer's total load, and 2) within a fiscal year due to a change to the customer's Existing Resource amounts within the same fiscal year, as detailed in the 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.G.1. A Slice/Block or Block customer's TOCA may be adjusted 1) for a fiscal year as part of the CHWM contract annual Net Requirement process, and 2) within a fiscal year due to a change to the customer's Specified Resource amounts within the same fiscal year, as detailed in the 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.G.2. Additionally, a customer's TOCA may be modified for a fiscal year or within a fiscal year if the customer's CHWM and associated RHWM have changed due to load annexations between customers with CHWM contracts.

5.4.8 DSI Reserves Adjustment

In the event BPA agrees to acquire an additional reserve product from a DSI, this provision 1) establishes the mechanism through which BPA compensates the DSI, and 2) places a cap on the unit price of any supplemental operating reserve product to be purchased to ensure that the reserve acquisition is cost-effective. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.H.

5.5 Conservation Surcharge

Section 7(h) of the Northwest Power Act states that BPA may apply to rates a surcharge recommended by the NPCC pursuant to Section 4(f)(2) of the Act. 16 U.S.C. §§ 839e(h), 839b(f)(2). BPA does not currently anticipate applying such a surcharge in the FY 2026-2028 rate period. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.U.

5.6 Resource Support Services and Related Services

BPA offers services to support resources under the PF, NR, and FPS rate schedules. These services are designed to support non-federal resources; however, there are situations for ratemaking purposes where these services are used to financially flatten federal resources. *See* Section 3.2.3.1.4 above. The RSS rates relevant to the PFp rate schedule include:

- Diurnal Flattening Service (DFS) Charges
- Resource Shaping Charge (RSC) and Resource Shaping Charge Adjustment
- Secondary Crediting Service (SCS) Charges
- Grandfathered Generation Management Service (GMS) Reservation Fee

The RSS and related service rates relevant to the NR rate schedule for NLSLs include:

- NR Energy Shaping Service Charges (NR ESS)

The RSS and related rates relevant to the FPS rate schedule include:

- Forced Outage Reserve Service (FORS) Charges
- Transmission Scheduling Service (TSS) Charges
- Transmission Curtailment Management Service (TCMS) Charges
- Resource Remarketing (RMS) Service Credits

Forecast revenue from RSS and related services is used to credit Tier 1 cost pools. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Tables 3.2 and 3.7. For this rate period, three RSS model runs were conducted with data from FY 2026 and FY 2027, FY 2027 and FY 2028, and FY 2026 and FY 2028, and averaged together to calculate the RSS and related rates discussed in the following sections.

5.6.1 Resource Support Services and Transmission Scheduling Service

5.6.1.1 Diurnal Flattening Service

DFS is an optional service that financially converts the output of a variable, non-dispatchable non-federal resource to an equivalent flat amount of power within each diurnal period of a month. When DFS charges are coupled with RSC, the variable output of a generating resource is financially converted to a flat annual block of power. DFS applies to any non-federal resource the customer applies to its load and any portion of the resource remarketed by BPA.

The RSS module of RAM2026 calculates a unique set of rates and charges for each resource to which DFS is applied. Included in Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.11, are the final rates and charges calculated for customers that have requested DFS for their resources. PF-26 rate schedule Sections 5.1 and 5.2 describe the general rate application of the DFS-related charges. GRSP II.I includes DFS rates and RSC. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSPs.

DFS charges include the following elements:

- A DFS capacity charge based on the PFp Tier 1 demand rate applied to the difference between the calculated firm capacity of the resource and the planned average HLH generation of the resource. This charge reflects the costs of reserving an amount of capacity to smooth the variable generation of a resource into a flat block of power.

- A DFS energy charge based on the potential cost of storing and releasing power using a resource capable of storing energy (pumped storage) to balance the hourly shape of the resource to which DFS is applied. This charge reflects the costs of energy storage to smooth the hourly generation variation into a flat monthly/diurnal block of power.

When DFS is applied to a resource, the RSC and Adjustment must be added to the DFS charges to complete the financial conversion to a flat annual block of power. *See* Sections5.6.1.2-3 below.

Typically, the RSS module of RAM2026, which computes resource-specific RSS rates, will use scheduled amounts for resources that require e-Tags and meter amounts for "behind-the-meter" resources. However, for small resources or small shares of a resource, BPA may apply a meter amount instead of a schedule amount for purposes of pricing RSS if the meter amount produces lower RSS rates and charges.

5.6.1.1.1 DFS Energy Charge

A unique DFS energy rate is developed for each resource to which DFS is applied. The purpose of this rate is to reflect the potential cost of storing and releasing energy to offset the hourly variability of the resource's Exhibit D amounts. The DFS Energy Billing Determinant is the total actual generation. The DFS energy charge, GRSP II.I.1(a), is the product of multiplying the DFS energy rate by the DFS Energy Billing Determinant for each month. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSPs. Power Rates

Study Documentation, BP-26-FS-BPA-01A, Table 3.11 shows the DFS energy rates for the individual resources.

5.6.1.1.2 DFS Capacity Charge

The DFS capacity charge is a fixed monthly amount calculated as noted in GRSP II.I.1(b)(3) and is based on the monthly PF Tier 1 demand rates, monthly planned amounts in Exhibit D, and the calculated monthly firm capacity of the resource. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSPs.

The RSS module of RAM2026 calculates the monthly firm capacity amounts for each resource. This calculation represents the lowest level of historical generation in an HLH period for each month after accounting for planned and forced outages. The firm capacity of a resource is the percentile of the forced outage rating calculated from the historical monthly HLH generation levels. For example, a resource with a 5 percent forced outage rating would have a firm capacity amount equal to the 5th percentile of the hourly historical generation amounts for the HLH period of a month.

Each type of generating resource has a standard forced outage rating. This rating represents the average percentage of time that a generating resource is unavailable for load service due to unanticipated breakdown. BPA uses a minimum 5 percent forced outage rating for hydroelectric resources, 7 percent for thermal resources, and 10 percent for all other resources. Customers taking services that have charges including the use of a forced outage rating may request that BPA increase the forced outage rating for their resource, and those with a resource other than a hydroelectric resource may request that BPA decrease the forced outage rating to as low as 7 percent.

The monthly calculated HLH firm capacity of the resource also includes a planned outage adjustment. If the historical hourly data reflects an outage that was planned, the model does a second calculation of the monthly firm capacity amount. This test runs the same calculation as above but calculates the value approximately equal to the forced outage percentile of an hourly sample that does not include the hours that were identified as a planned outage. If the number of planned outage hours is less than 25 percent of the HLH in the month, no further adjustments are made to the value calculated by the planned outage calculation of firm capacity. If the number of planned outage hours is equal to 25 percent or more of the HLH in the month but less than 75 percent of the hours in the month, the planned outage adjusted firm capacity value is reduced by multiplying it by one minus the percentage of planned outage hours in the month. If the number of planned outage hours in the month is equal to or greater than 75 percent of the HLH in the month, the firm capacity of the resource in that particular month is set to zero.

Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.11 shows the individual DFS capacity charges that are calculated for the individual resources to which DFS is applied.

5.6.1.2 Resource Shaping Charge

The purpose of the RSC, GRSP II.I.2(a), is to reflect the value of buying and selling flat monthly/diurnal blocks of power in the market to convert a diurnally flat resource within the month into one that, on a planned basis, is flat across the year. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSPs. The Resource Shaping rates are set equal to the PFp Tier 1 Load Shaping rates, which represent a proxy market price. On a monthly basis the RSC can be a charge or a credit. The flat monthly RSCs are shown in Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.11 for individual resources.

For Small, Non-Dispatchable Resources (as defined in the CHWM contract), the RSC will not apply. The actual generation amounts of these resources will be used in the calculation of the Actual Monthly/Diurnal Tier 1 Load when calculating the PFp Tier 1 Load Shaping charge and demand charge.

5.6.1.3 Resource Shaping Charge Adjustment

The purpose of the RSC Adjustment, GRSP II.I.2(b), is to capture the cost or value of the energy differences between the Exhibit D amounts and the actual generation of the resource. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSPs. This adjustment is a true-up of the RSC and completes the financial conversion to a flat annual block of power by making up for any energy cost differences between planned and actual generation amounts. The RSC Adjustment can result in either a charge or a credit.

5.6.1.4 Forced Outage Reserve Service (FORS)

FORS in GRSP II.I.4 is an optional service for BPA to provide an agreed-upon amount of capacity and energy to a customer with a qualifying resource that experiences a forced outage. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSPs. FORS is offered under the FPS rate schedule to customers with resources that meet requirements specified in the CHWM contract.

The charges for FORS are intended to reflect the cost of BPA 1) reserving capacity to back up a resource as insurance to cover a potential forced outage, and 2) providing replacement energy should a forced outage occur.

The FORS charges include the following elements:

- A FORS capacity charge based on the PFp Tier 1 demand rate, the calculated firm capacity of the resource for customers whose resource is also taking DFS, and the forced outage rating for the applicable resource. Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.11, shows the FORS capacity charges calculated for each resource. The calculations regarding firm capacity and forced outage ratings are described above in Section 5.6.1.1.2. Additionally, the firm capacity amounts used to calculate the FORS capacity charges may be adjusted to account for planned outages if such planned outages are included in the DFS capacity charge.
- A FORS energy charge designed to pass through the cost of replacement energy that BPA provides during a customer's forced outage. The energy rate is based on a market price under two conditions and the amount of energy supplied during a forced outage event.

Additionally, customers with FORS are limited to a maximum amount of energy provided during a fiscal year and a purchase period, as defined in the CHWM contracts. Such fiscal year and purchase period limits are calculated in the RSS module of RAM2026 and listed in Exhibit D of the customer's CHWM contract. The fiscal year limits are set equal to two times the product of the following: 1) the forced outage rating of the applicable resource, and 2) the sum of the monthly planned amounts in Exhibit D in megawatthours. The purchase period limits are set equal to the product of the following: 1) the forced outage rating of the applicable resource; 2) the annual average planned amounts in Exhibit D in megawatthours; and 3) the number of years in the purchase period.

5.6.1.5 Transmission Scheduling Service (TSS) and Transmission Curtailment Management Service (TCMS)

TSS is offered under the FPS rate schedule. It is a required service for customers with resources that meet eligibility requirements specified in the CHWM contract. 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: 1) full service (TSS-Full), in which BPA creates e-Tags for a customer's resources or Tier 2 purchases; and 2) partial service (TSS-Partial), in which a customer (or its scheduling agent) creates e-Tags for its non-federal resources and carbon copies Power Services on each tag. TCMS is an optional service related to TSS that is also offered under the FPS rate schedule for customers with resources that meet eligibility requirements specified in the CHWM contract. TCMS is a feature of TSS (both TSS-Full and TSS-Partial) under which BPA provides either replacement transmission or replacement energy to customers with qualifying resources that experience transmission events pursuant to the conditions specified in Exhibit F of the CHWM contract.

If a Load Following customer is served by Transfer Service or is purchasing DFS or SCS services from BPA, it is required to have the TSS provisions added to its CHWM contract. However, only customers that have non-federal resources requiring e-Tags will be charged for TSS services. Customers that have one or multiple non-federal resource(s) requiring e-Tags may choose either TSS-Full or TSS-Partial for all of their non-federal resources that require e-Tags. Load Following customers that are not contractually required to take TSS can elect this optional service if they wish to have BPA produce the e-Tags for their resources. Without this service, the customer must supply replacement transmission or power when the resource's transmission path experiences an outage or curtailment. If it is unable to do so, it may face an Unauthorized Increase charge. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.N.

Application of TSS to Tier 2 rates is described in Section 3.2.2.2 above. Application of the TCMS Adjustment to Tier 2 rates is described in Section 5.4.6 above.

5.6.1.5.1 TSS-Full Pricing Summary

The charge for TSS-Full reflects the cost of scheduling a resource to its POD. A unique set of charges will be calculated for each resource to which TSS-Full is applied. The TSS-Full Charges, GRSP II.I.5(a), include the following elements:

- For resources requiring e-Tags, a monthly TSS charge based on the applicable resource's FY 2026-2028 Dedicated Resource amounts listed in Exhibit A of the Load Following CHWM contract.
- A TSS-Full rate that is based on the forecast operations scheduling cost for the rate period (including costs associated with power scheduling preschedule, real-time, and after-the-fact functions) divided by the total megawatthours of power BPA scheduled in FY 2021, FY 2022 and FY 2023. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.4.
- An Annual Open Access Technology International, Inc. (OATI), registration fee, $200 per customer, which is spread evenly across the customer's resources and billing periods.
- A transaction-based cap for the monthly TSS-Full charge (not including adjustments made to recover the cost of the OATI registration fee). See Section 5.6.1.5.2 below for details.

The RSS module of RAM2026 calculates a TSS-Full rate that is applied to each non-federal resource receiving service during the rate period. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.11.

5.6.1.5.2 Transaction-Based Cap Applied to TSS-Full Charge

The TSS-Full Charge, not including adjustments made to recover the cost of the OATI registration fee described above, is subject to a cap. For a Specified Resource or Unspecified Resource Amounts serving Above-RHWM Load, if the annual cost calculated using the TSS rate exceeds $1,038 when divided by 12, then the monthly charge is capped at $1,038/month. The cap is the result of multiplying 30 schedules per month (*e.g.*, one schedule per day on average) by the forecast operations scheduling cost for the rate period, divided by the total number of schedules Power Services produced in FY 2021, FY 2022, and FY 2023. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.I.5(a)(3).

For Unspecified Resource Amounts serving an NLSL or a 9(c) export decrement obligation, if the annual cost calculated using the TSS rate exceeds $3,115 when divided by 12, then the monthly charge is capped at $3,115/month. This cap follows the same methodology applied to Specified Resources and Unspecified Resource Amounts serving Above-RHWM Load but assumes three daily transactions. It is the result of multiplying 90 schedules per month (*e.g.*, three schedules per day on average) by the forecast operations scheduling cost for the rate period, divided by the total number of schedules Power Services produced in FY 2021, FY 2022, and FY 2023. *Id.*

5.6.1.5.3 TSS-Partial Pricing Summary

A customer with TSS-Partial takes on all scheduling and tagging functions for its non-federal resources and is required to carbon copy Power Services on each tag. TSS-Partial charges are based on the staffing time costs that are incurred by BPA when a customer fails to carbon copy BPA on an e-Tag or when BPA provides replacement power or transmission for a resource supported with TCMS. The TSS-Partial charges, GRSP II.I.5(b), include the following elements:

- A TSS-Partial rate of $246 per TSS-Partial event, which is based on three hours of BPA Full-Time Employee (FTE) staffing time. An average BPA employee costs $170,795 (including benefits) per year, or $82.11 per hour.
- A TSS-Partial Billing Determinant, which is a count 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 Power Services on a schedule, except if the power being scheduled was purchased from Power Services (including Slice output) and Power Services was included in the market path on the tag; or 2) a day that a customer has a TCMS charge.

See 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSPs.

5.6.1.5.4 TCMS Pricing Summary

The charge for TCMS reflects the cost of providing either replacement transmission or replacement energy when a transmission event occurs. TCMS is not available to support a resource to which TSS does not apply. The TCMS charges, GRSP II.I.5(c), include the following elements:

- A TCMS charge for the cost of replacement power that is based on: 1) the cost of replacement power if actually purchased by BPA; or 2) the LAP price for BPA as determined by the MO under Section 29.11(b)(3)(C) of the MO Tariff when a distinct replacement power purchase was not made by BPA.

- A TCMS charge if alternative transmission is provided that is designed to pass through the cost to deliver the customer's resource plus any additional costs, including real power losses, associated with using the replacement transmission.

See 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSPs.

5.6.1.6 Secondary Crediting Service (SCS)

The PF-26 rate schedule includes SCS Charges, GRSP II.I.3, which provide a credit or charge to a Load Following customer that dedicates its entire share of the output of a hydroelectric Existing Resource to its load. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSPs. The customer will receive a credit for the energy produced by that resource in excess of the monthly/diurnal amounts specified in CHWM contract Exhibit A. The additional generation would increase BPA's revenues because of the increased secondary energy BPA can market, or would lower BPA's costs because of reduced balancing purchases. The customer will receive a charge for any energy shortfall by the resource from the monthly/diurnal Exhibit A amounts, because BPA's secondary revenues would be lower or BPA's balancing costs would be higher. If a customer does not take this service, it must apply the exact Exhibit A amounts to its load unless the resource is a small, non-dispatchable resource or qualifies for GMS.

The charges and credits for SCS are intended to reflect the cost or value of reshaping the customer's resource into its Exhibit A amounts. The SCS Charges include the following elements:

- SCS Energy Charge or Credit, priced at the Resource Shaping rate. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.11.
- An Administrative Charge based on the forced outage rating of the hydro resource, the PFp Tier 1 Demand rate, and the monthly HLH Exhibit A amounts.

GRSP II.I.3(a) includes the calculation for the SCS Shortfall Energy Charges and Secondary Energy Credits for the individual resources to which SCS is applied. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSPs.

5.6.1.7 Grandfathered Generation Management Service (GMS) Reservation Fee

The PF Tier 1 rate includes GMS, which allows a Load Following customer dedicating the entire output of an Existing Resource that received GMS during Subscription to run that resource against its load and offset its Tier 1 load and charges. The only charge specific to GMS is the GMS Reservation Fee, GRSP II.I.6, which is based on the forced outage rating of the applicable resource, the PFp Tier 1 Demand rate, and the resource's firm capacity. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSPs.

5.6.1.8 Resource Remarketing Service

RRS is available under the FPS rate schedule. It is a service that BPA may make available, at its discretion, to Load Following customers. Under RRS, BPA remarkets non-federal resources on behalf of customers and provides them with a remarketing credit net of possible remarketing fees for doing so. Further details on RRS are provided in Section 5.7.2.4 below.

5.6.2 NR Services for New Large Single Loads

5.6.2.1 NR Energy Shaping Service (NR ESS) for NLSL

The NR-26 rate schedule includes NR ESS. NR ESS is required for Load Following customers serving NLSLs with non-federal resources. NR ESS is a service provided by BPA to shape the energy provided by customers to the energy needs of NLSLs. This service allows customers some flexibility in the accuracy of meeting the real-time energy needs of

NLSLs. This service includes a capacity component on a monthly basis, and an energy component settled on both an hourly and monthly basis.

The capacity component, the NR ESS Capacity Charge, is based on the percentage level of service that a customer elects BPA to stand ready to provide to the customer's NLSL(s). The customer is required to take a minimum of a 2 percent level of service (the default election) and can elect up to a maximum of a 5 percent level of service. The service election must be made in whole percentage amounts (*e.g.*, 2, 3, 4, or 5 percent), and meet deadline requirements as defined in the GRSPs and the customer's contract . The monthly NR ESS Capacity Charge is calculated as the measured maximum actual hourly load of the NLSLs for a month multiplied by the customer's level of service multiplied by the applicable monthly NR demand rate. A NR Data Sharing Discount of 10 percent may also apply to the NR ESS Capacity Charge if the customer elects and meets the data sharing requirements as described in the GRSPs. A customer purchasing NR ESS and receiving the NR Data Sharing Discount may be eligible to further offset its NR ESS Capacity Charge by providing BPA access to capacity, via a demand or a resource response, based on terms and conditions negotiated between BPA and the customer.

A monthly check is applied to ensure that the customer capacity use in any hour of the month did not exceed the monthly amount of capacity purchased from BPA through NR ESS. If the actual capacity used in an hour exceeds the amount of capacity purchased, then an Unauthorized Increase Charge (UAI) will apply.

The energy component, the NR ESS Energy Charge either credits or debits the customer for the difference between energy amounts supplied by the customer's non-federal resources serving NLSLs and the measured actual load of the NLSLs in every hour. The NR ESS

Energy Charge can be either positive or negative and is then calculated as the NR ESS Energy Billing Determinant multiplied by the NR ESS Energy Rate. The NR ESS Rate is equal to the hourly LAP price for BPA as determined by the Market Operator (MO) under Section 29.11(b)(3)(C) of the MO Tariff for the same hour as the calculated NR ESS Billing Determinant. In the event of a Market Contingency pursuant to Section 10 of Attachment Q to the BPA Tariff, BPA will use an available energy index in the Pacific Northwest. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.J.1(b)(2).

5.7 Resource Remarketing for Individual Customers

The Remarketing Credit conveys the value BPA receives when it remarkets 1) committed Tier 2 purchases in excess of need, and 2) non-federal resources to which DFS applies that are temporarily in excess of need. The excess power is created when commitments to purchase are made prior to establishing need in the RHWM Process. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.K.

5.7.1 Tier 2 Remarketing

5.7.1.1 Tier 2 Remarketing for Load Following Customers

Section 10 of the CHWM contract states that a Load Following customer may elect to have BPA remarket its Tier 2 rate purchase amount in the event its Above-RHWM Load as forecast for an upcoming rate period year is less than the sum of its Tier 2 rate purchase amounts and new resource amounts. The Load Following customer must provide BPA notice of such election by October 31 of the year preceding the rate period for which the customer elects to have BPA remarket its Tier 2 purchase amount.

5.7.1.2 Tier 2 Remarketing for Slice/Block or Block Customers

Section 10 of the CHWM contract states that a Slice/Block or Block customer may elect to have BPA remarket its Tier 2 rate purchase amount in the event its forecast Net Requirement for the upcoming fiscal year is less than the sum of its RHWM and Tier 2 rate purchase amounts. Notice of such election must be provided by August 31 of each fiscal year for the upcoming fiscal year.

5.7.1.3 Calculating the Remarketed Tier 2 Proceeds for Load Following and Slice/Block or Block Customers

Section 6.4 of the TRM states that if BPA remarkets a customer's Tier 2 purchase obligation pursuant to the CHWM contract, BPA will credit the proceeds from the remarketing (net of any remarketing costs) to such customer. TRM, BP-12-A-03. The customer must continue to pay for the entire purchase at the appropriate Tier 2 rate.

The remarketed Tier 2 proceeds are computed for Load Following customers using 1) the remarketed amount of Tier 2 service (in megawatthours) plus real power losses, and 2) the Remarketing Value determined in accordance with Section 3.2.6 above.

After notice is provided by a Slice/Block or Block customer, the remarketed Tier 2 proceeds will be computed for that customer using 1) the remarketed amount of Tier 2 service (in megawatthours) plus real power losses, and 2) the flat annual equivalent market price forecast after the time the notice is provided to BPA, for the applicable fiscal year, plus any additional costs incurred by BPA in purchasing power from other entities.

The annual remarketing proceeds for each customer are divided by 12 to compute a flat monthly credit that is applied to the customer's bill. No Load Following customers are forecast to have monthly remarketing Tier 2 proceeds for FY 2026, FY 2027 and FY 2028.

Slice/Block and Block customers' monthly remarketed Tier 2 proceeds are calculated in the annual Net Requirements process, which occurs after the Section 7(i) process concludes.

5.7.2 Non-Federal Resource Remarketing

5.7.2.1 Non-Federal Resource with DFS for Load Following Customers

Section 10 of the CHWM contract states that a customer may elect to remove a new non-federal resource in the event its Above-RHWM Load, as forecast for an upcoming rate period year, is less than the sum of its Tier 2 rate purchase amounts and New Resource amounts. A Load Following customer must provide BPA notice of such election by October 31 of the year preceding the rate period for which the customer elects to remove its new non-federal resource. Section 10.5 of the CHWM contract states that BPA shall remarket the amounts of removed resources for which the customer purchases DFS in the same manner BPA remarkets Tier 2 rate purchase amounts. The customer will continue to pay for DFS on the entire resource amount that is applied to load and any portion of the resource remarketed by BPA.

5.7.2.2 Non-Federal Resource with DFS for Slice/Block or Block Customers

Section 10 of the CHWM contract states that a customer may elect to remove a new non-federal resource in the event its forecast Net Requirement for the upcoming fiscal year is less than the sum of its RHWM, Tier 2 rate purchase amounts, and new resource amounts. Notice of such election must be provided by August 31 of each fiscal year for the upcoming fiscal year. Additionally, Slice/Block and Block customers are responsible for remarketing removed new resource amounts unless such resource is supported with DFS. Section 10.9 of the CHWM contract states that BPA shall remarket the amounts of removed resources for which the customer purchases DFS in the same manner BPA remarkets Tier 2 rate purchase amounts.

The customer will continue to pay for DFS on the entire resource amount that is applied to load and any portion of the resource remarketed by BPA.

5.7.2.3 Calculating the DFS Remarketing Proceeds for Load Following and Slice/Block or Block Customers

The DFS remarketing proceeds are computed for Load Following customers using the Remarketing Value determined in accordance with Section 3.2.6 above for the applicable fiscal year. The DFS remarketing proceeds are computed for Slice/Block and Block customers using the flat annual equivalent market price forecast, as determined by BPA after the time the notice to remarket has been received, for the applicable fiscal year, plus any additional costs incurred by BPA in purchasing power from other entities.

For each applicable non-federal resource to which DFS applies, the billing determinant is 1) the customer's total non-federal resource, less 2) the amount of the customer's non-federal resource needed to meet Above-RHWM Load, as reflected in the customer's CHWM contract Exhibit A, when updated.

For each resource, the DFS Remarketing Credit will be the product of multiplying the DFS remarketing rate by the DFS Remarketing Billing Determinant for each applicable year of the rate period. The annual value is divided by 12 to calculate a flat monthly credit. Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 5.2 shows the forecast monthly DFS

Remarketing Credits that are calculated for the individual resources to which the DFS Remarketing Credit is applied for Load Following customers. Slice/Block and Block customers' DFS remarketing credits are calculated in the annual Net Requirements process, which occurs after the Section 7(i) process concludes.

5.7.2.4 Resource Remarketing Service

Exhibit D of the CHWM contract for Load Following customers offers an optional service for customers that have purchased non-federal resources in anticipation of future need. At the customer's request and with BPA's agreement, BPA will remarket the excess non-federal resource amounts on the customer's behalf until the customer's need meets or exceeds the non-federal resource amount. To qualify for this service, the customer must also request DFS for the non-federal resource. The DFS Charges will be applicable to both the non-federal resource amounts the customer dedicates to its load and any portion that BPA remarkets on the customer's behalf.

5.7.2.4.1 RRS Credits

RRS is administered in accordance with GRSP II.I.7 and includes the following components:

- RRS Rate. For each non-federal resource, the rate will be based on the Remarketing Value determined in accordance with Section 3.2.6.
- RRS Billing Determinant. The RRS Billing Determinant will be the annual average megawatt Resource Remarketed Amounts in the customer's CHWM contract Exhibit D (when updated).
- RRS Credit. For each resource, the RRS Credit will be the product of multiplying the RRS rate by 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.

- RRS Fee. The fee for providing RRS to customers is determined on a case-by-case basis.

See 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSPs.

5.8 Transfer Service

About half of BPA's power customers are served by the transmission systems of third parties (entities other than BPA). Under the CHWM contract, BPA must acquire transmission services from these third-party transmission providers to deliver federal power to BPA's power customers. This third-party transmission service is commonly referred to as Transfer Service. For information about Transfer Service, see Section 6 below and the 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.L.

5.9 Rate Payment Options

5.9.1 Flexible PF Rate Option

The Flexible PF rate option, offered at BPA's discretion, allows PF-26 rates and billing determinants to be modified to accommodate a customer's request to change the way power is charged under the PF-26 rate schedule. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.W.

5.9.2 Priority Firm Power Shaping Option

If requested, BPA will, to the maximum extent practicable while ensuring timely BPA cost recovery, accommodate individual customer requests to reshape charges within each year of the rate period to mitigate adverse cash flow effects on the customer. Such reshaping of charges must recover the same number of dollars on a net present value basis within the fiscal year as would have been recovered without the reshaping. The reshaping of the payments will be agreed upon between BPA and the customer prior to the start of the rate period. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.X.

5.9.3 Flexible NR Rate Option

The Flexible NR rate option, offered at BPA's discretion, allows NR-26 rates and billing determinants to be modified to accommodate a customer's request to change the way power is charged under the NR-26 rate schedule. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.Y.

5.10 Unanticipated Load Service

ULS applies to any request for Firm Requirements Power received after February 1, 2025, that results in an unanticipated increase in a customer's load placed on BPA during the FY 2026-2028 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. 16 U.S.C. § 839f(i). ULS may also apply to a customer that adds load through retail access, including load that was once served by the customer and returns under retail access. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.M.

5.10.1 PF Unanticipated Load Service

The energy rate is equal to the greater of the following: 1) the PF Tier 1 Equivalent rate for the applicable diurnal period in GRSP II.AA; or 2) the projected market price for the applicable diurnal period calculated after a request for ULS is made plus any additional costs incurred by BPA in purchasing power from other entities. See Section 5.14 below for a description of the PF Tier 1 Equivalent rates. The PF ULS also includes a demand charge, which uses the PF-26 demand rate. The ULS under the PF-26 Rate Schedule is specified in GRSP II.M.2. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSPs.

5.10.2 NR Unanticipated Load Service

The energy rate is equal to the greater of 1) the NR energy rate for the applicable diurnal period; or 2) the projected market price for the applicable diurnal period calculated after a request for ULS is made plus any additional costs incurred by BPA in purchasing power from other entities. See Section 4.2.1 above for a description of the NR energy rates. The NR ULS also includes a Demand Charge, which uses the NR-26 Demand Rate. The ULS under the NR-26 Rate Schedule is specified in GRSP II.M.3. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSPs.

5.10.3 FPS Unanticipated Load Service

Under the FPS-26 rate schedule, the Resource Replacement (RR) rate or a projected market price will be applied to ULS for circumstances that cause an increase in a customer's load placed on BPA not anticipated in the rate case. Such circumstances could include, but are not limited to, delays in the online date of a customer's specified resource for Above-RHWM service; New Specified Resources that are 10 aMW or less and either experience permanent failure during the rate period or fail to come online; and transfer service customers that both 1) cannot secure Firm Network Transmission (NT) from source to sink for their dedicated non-federal resource to their Above-RHWM Load by the time power deliveries begin under the Regional Dialogue contract, and 2) are expected to face high TCMS Charges due to their reliance on Secondary Network Transmission while they pursue Firm Network Transmission. The provision of ULS will be at BPA's sole discretion.

The energy rate is the greater of 1) the RR rate for the applicable diurnal period; or 2) the projected market price calculated after the time when the request for ULS is made plus any additional costs incurred by BPA in purchasing power from other entities. The RR rates are equal to the PF Tier 1 Equivalent rates. See Section 5.14 below for a description of the

PF Tier 1 Equivalent rates. The FPS ULS also includes a Demand Charge, which uses the Demand Rate in the PF, NR, and IP Rate Schedules. The ULS under the FPS-26 Rate Schedule is specified in GRSP II.M.4. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSPs.

5.11 Unauthorized Increase (UAI) Charges

The UAI Charge is applied to customers taking more power from BPA than they are contractually entitled to take. The UAI demand rate is 1.25 times the applicable monthly demand rate. The UAI energy rate is the greater of 1) 150 mills/kWh, or 2) two times the hourly EIM LAP price for firm power for the hour in which the overage occurred. There is no cap for either demand or energy components. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.N.

5.12 Residential Exchange Program Settlement Implementation

The 2012 REP Settlement established a fixed stream of financial benefits payable to the IOUs beginning in FY 2012 and ending in FY 2028. These benefits are allocated among the IOUs based on their specific ASCs, PFx rates, and eligible residential and farm loads (Residential Loads). GRSPs II.S and II.T address two issues specific to the implementation of the 2012 REP Settlement. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSPs.

Pursuant to the terms of the 2012 REP Settlement, REP Residential Loads are normally calculated using a two-year monthly average of the IOUs' eligible residential and farm actual loads. The FY 2026, FY 2027 and 2028 Residential Load monthly averages for each IOU are listed in the 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.S, Table H.

GRSP II.T addresses the recalculation of the PFx rate in the event of a change to an IOU's ASC. *See* 2026 Power Rate Schedules and GRSPs, BP-26-EFSBPA-10, GRSPs. Calculation of the PFx rate is described in detail in Section 4.1.6 above. The PFx rate calculation is dependent upon, among other factors, the IOUs' Final ASCs. ASCs are determined outside the rate proceeding in an ASC Review Process that BPA conducts pursuant to the 2008 ASC Methodology (ASCM). *See* ASCM, 18 C.F.R. § 301 *et seq.* (2008). Forecast ASCs for participating IOUs and participating COUs are used for establishing rates in the Initial Proposal. *See* Section 8. Final ASCs are determined coincident with the Final Proposal and are incorporated therein. An IOU's Final ASC can change after final rates are set, although such changes are rare. In the event of such a change, the PFx rate must be recalculated for each REP participating utility. GRSP II.T describes the process for such recalculation. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSPs.

5.13 Cost Contributions

In accordance with Section 7(j) of the Northwest Power Act, BPA provides the approximate cost contributions of different resource categories to BPA's rates for the sale of energy and capacity. 16 U.S.C. § 839e(j). The rate schedules also indicate the cost of resources BPA acquires to meet load growth and the relationship of such cost to BPA's average resource cost. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.Z.

5.14 PF Tier 1 Equivalent Rates

For use in contracts that have rates tied to a traditional PF HLH/LLH rate design without tiering, the PFp Tier 1 Equivalent rates consist of 12 HLH energy rates, 12 LLH energy rates, and 12 demand rates. The PFp Tier 1 Equivalent Energy rates are equal to the Load Shaping rates less a scalar. The scalar is a single mills per kilowatthour value that adjusts the Load Shaping rates to a level at which the PFp Tier 1 equivalent energy rates, in conjunction with the demand revenue, would collect the Tier 1 revenue requirement allocated to the PFp Non-Slice loads (the Composite cost pool plus the Non-Slice cost pool). This mills per kilowatthour value is equivalent to the Tier 1 load shaping true up rate (LSTUR). This calculation is shown in Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 3.1.8.5. The Demand rates are equal to the Tier 1 Demand rates. The PF Tier 1 Equivalent rates are subject to adjustment during the rate period to reflect the Power CRAC, the Power RDC, and the Power FRP Surcharge. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.AA.

5.15 Washington Cap-and-Invest Program Charge

This charge will be applicable if BPA becomes the First Jurisdictional Deliverer (FJD) in the Washington Cap-and-Invest Program. If BPA elects to be the FJD, BPA presumes that customers will 1) register to receive no-cost allowances from the Washington Department of Ecology and 2) transfer to BPA their no-cost allowances that they receive from the Washington Department of Ecology for emissions forecasted for federal power deliveries. If this does not occur, the customer will be subject to the new rate and charged for the cost that BPA incurs purchasing allowances to cover emissions for federal service to its load plus a 25 percent cost adder. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.AB.

5.16 Resource Adequacy Service

This service will be applicable during any period in which BPA is a binding participant in the Western Resource Adequacy Program (WRAP) Binding Program. The Resource Adequacy Service includes two components 1) a 4.48 mills/kWh credit for Load Following customers that use non-federal resources to serve Above-RHWM Load that meet the WRAP forward-showing qualifying capacity capability (QCC) requirements, and 2) a

4.48 mills/kWh charge for Load Following customers with NLSLs that do not submit to BPA an approved exclusion attestation for the NLSL or provide QCC resource information for any non-federal resources serving the NLSL. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.AC. This rate is based on the Operating Reserves - Supplemental rate, converted to a kilowatthour figure, summed by the number of days during the binding period, and spread over an annual Energy Billing Determinant.

6. TRANSFER SERVICE

6.1 Introduction

More than half of BPA's power customers are served by the transmission systems of third parties; *i.e.,* entities other than BPA. Under the CHWM contracts, BPA must acquire transmission services from these third-party transmission providers to deliver federal power to BPA's power customers. This third-party transmission service is commonly referred to as Transfer Service.

Transfer Service customers may be subject to one or more separate charges from BPA: 1) the Transfer Service Operating Reserve Charge, 2) the Transfer Service Regulation and Frequency Response Charge, and 3) the Transfer Service Regional Compliance Enforcement Charge. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.L. In addition to these charges, Transfer Service customers are responsible for the cost of any distribution upgrades associated with their respective PODs, as provided in the Supplemental Direct Assignment Guidelines. *Id*. at GRSP I.E. BPA will continue to follow the cost allocation methodology developed in BP-16 for Southeast Idaho Load Service.

6.2 Supplemental Guidelines

The Supplemental Guidelines for Direct Assignment of Facilities Costs Incurred Under Transfer Agreements address how BPA will recover the costs for facility expansions and upgrades on third-party transmission systems for transfer service customers. The Supplemental Guidelines, in conjunction with the Transmission Services Facility Ownership and Cost Assignment Guidelines, are used to determine whether and in what way specific facility or expansion costs should be assigned to particular transfer service customers. *Id.*

6.3 Transfer Service Operating Reserve Charge

The Transfer Service Operating Reserve Charge is designed to compensate BPA for the cost of acquiring operating reserves assessed by third-party transmission providers and non-BPA balancing authorities for service to transfer service customers' loads. Assessment of the Transfer Service Operating Reserve Charge is conditioned on the satisfaction of two criteria:

1. BPA serves the power customer by Transfer Service; and
2. The Transfer Service customer is not already paying BPA for operating reserves for the customer's load under the ACS-24 rate schedule.

The Transfer Service Operating Reserve rates are the same as the ACS-26 rates for operating reserves that BPA charges customers that have load in the BPA balancing authority area (BAA); *i.e.*, the Transfer Service Spinning Operating Reserve rate is equal to the ACS-26 Operating Reserve – Spinning Reserve service rate, and the Transfer Service Supplemental Operating Reserve Charge is equal to the ACS-26 Operating Reserve – Supplemental Reserve service rate. The monthly billing determinant for both Transfer Service Operating Reserves Charges is the amount of the customer's metered load served by transfer (non-BPA BAA load).

To compute a revenue forecast for these charges, the forecast TRL of BPA customers served under Transfer Service is aggregated for each Transfer Service provider. These loads are responsible for operating reserves charges (spinning and supplemental) and are applied to Transfer Service customers in the same manner as operating reserves are applied to directly connected customers under ACS-26.

6.4 Transfer Service Regulation and Frequency Response Charge

The Transfer Service Regulation and Frequency Response Charge is designed to compensate BPA for the cost of acquiring regulation and frequency response service assessed by third-party transmission providers and non-BPA BAAs for service to transfer service customers' loads. Assessment of the Transfer Service Regulation and Frequency Response Charge is conditioned on the satisfaction of two criteria:

1. BPA serves the power customer by Transfer Service; and
2. The Transfer Service customer is not already paying BPA for regulation and frequency response for the customer's load under the ACS-26 rate schedule.

The Transfer Service Regulation and Frequency Response rate is equal to the ACS-26 rate for regulation and frequency response that BPA charges customers with load in the BPA BAA. The monthly billing determinant for the Transfer Service Regulation and Frequency Response Charge is the amount of the customer's metered load served by transfer (non-BPA BAA load).

To compute a revenue forecast for these charges, the forecast TRL of BPA customers served under Transfer Service is aggregated for each Transfer Service provider. These loads are billed at the ACS-26 Regulation and Frequency Response rate.

6.5 Revenue Received from Transfer Service Charges

Revenue received from Transfer Service Charges includes revenues associated with Transfer Service Operating Reserve and Regulation and Frequency Response service, and any other charges for regional compliance as outlined in Section 6.7 below. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.3.1.5, line 244. These revenues offset the ancillary service costs Power Services will pay to third-party transmission systems for providing similar services, which are included as a cost in the Power Revenue Requirement. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.3.1.2, lines 56-58.

6.6 Transfer Service Regional Compliance Enforcement Charge

The Transfer Service Regional Compliance Enforcement Charge applies to all transfer service customer loads located outside of the BPA BAA. The Transfer Service Regional Compliance Enforcement Charge is a separate stand-alone charge.

6.6.1 Background on Regional Compliance Enforcement Charge

The Regional Compliance Enforcement Charge recovers costs associated with funding the North American Electric Reliability Organization (NERC) and the regional entity, which is the Western Electricity Coordinating Council (WECC). WECC develops and assesses a charge to loads located in BAAs within the Western Interconnection to support its regional operations. The charge is based on a Net Energy for Load (NEL) value, which includes all loads within a BAA, including system losses. Each BAA submits its NEL to WECC yearly. WECC adds the NEL amounts for all BAAs to identify a total NEL for all loads in the Western Interconnection. The annual revenue requirement for WECC is then divided by the total NEL to establish a dollars-per-megawatthour assessment.

6.6.2 Regional Compliance Enforcement Assessment

The Regional Compliance Enforcement Charge is assessed to the individual loads identified in the NEL data submitted by the BAAs. The format of each BAA's NEL submission to WECC varies across the region; *i.e.*, some BAAs identify each individual customer load in their NEL submissions, including both native and non-native load. In the past for these BAAs, WECC would issue an invoice to each customer for WECC Charges. Other BAAs identify and submit single load quantities for their BAAs, with no differentiation between native and non-native loads. In these instances, the BAA receives a single invoice from WECC for all loads in the BAA. BPA's transfer service customer loads are located in BAAs that report in both manners.

6.6.3 BPA's Transfer Services Regional Compliance Enforcement Charge

For FY 2026-2028, WECC will bill Power Services for all NEL quantities reported by the BAAs that are associated with transfer service customer loads outside the BPA BAA. BPA will recover this billed amount from all Transfer Service customer loads located outside of the BPA BAA through the Transfer Service Regional Compliance Enforcement Charge, regardless of how each BAA reports the Transfer Service customer's load in its NEL submission.

6.6.4 Regional Compliance Enforcement Charge

6.6.4.1 Regional Compliance Enforcement Revenue Requirement

To forecast the BPA revenue requirement for the Transfer Service Regional Compliance Enforcement rate, total NEL reported to WECC is computed for BPA Transfer Service customer loads outside BPA's BAA. The 2024 WECC NEL assessment list is used to identify specific transfer service customers by name, their corresponding NEL amounts, and NEL amounts associated with only BPA by the reporting BAAs. All of these NEL amounts are then summed to establish a total transfer service NEL value. The NEL quantities include losses, as do the NEL quantities WECC uses to assess its charges. The 2024 WECC NEL assessment is based on 2023 load information, which is the most current information available for forecasting BPA's WECC assessment for transfer service customers for FY 2026-2028.

The revenue requirement for the Transfer Service Regional Compliance Enforcement rate is $342,459 and is computed by summing all individual assessment amounts as calculated by WECC and given to BPA. Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 6.1.

6.6.4.2 Regional Compliance Enforcement Rate Calculation

The Transfer Service Regional Compliance Enforcement rate is computed by dividing the above revenue requirement by the total of all BPA Transfer Service customers' load from outside the BPA BAA. All non-BPA BAA Transfer Service customer loads are included, regardless of NEL reporting standards. For FY 2026-2028 this quantity of 6,583,287 MWh is used to calculate the Transfer Service Regional Compliance Enforcement rate of 0.05 mills/kWh.

6.7 Southeast Idaho Load Service Cost Allocation

From 1989 to 2016, BPA used an exchange agreement with PacifiCorp and a transmission wheeling agreement to deliver power to BPA's preference customers in Southeast Idaho. The exchange agreement with PacifiCorp expired in June 2016. Because of limited transmission capability between BPA's system and BPA's Southeast Idaho customers, BPA entered into five-year market purchases as part of an interim plan of service for a portion of BPA's transfer customer load located in Southeast Idaho. The first interim plan of service included two, five-year fixed-price market purchases from July 2016 through June 2021. The second interim plan of service included five-year market purchases based at index beginning July 2021 through June 2026. The assumptions associated with the second interim plan have been carried forward to FY 2027 and FY 2028.

Due to the index pricing structure of these purchases, for FY 2021-2026, costs will not be allocated to the Composite cost pool as in the BP-20 rate case where a fixed market price was used to determine the delta between the forward market and the price at which the purchases were made. In the previous five-year interim service plan, the fixed price of the market purchases, less a market delta (difference), was allocated to balancing purchases, which are assigned to the Non-Slice cost pool. The remaining cost of the purchases, the market delta, was allocated to the Transfer Service budget, which is a component of the Composite cost pool.

For the five-year interim service plan, starting in July 2021, BPA has acquired market purchases based at index. One market index purchase includes an adder to the Mid-C index. An adder is a fixed amount of additional dollars added to the Mid-C Index at the time energy is delivered. Therefore, if at the time of delivery the Mid-C index was $35 and the adder was $2, then the total transaction price would be $37 for that interval. The second index purchase includes a Mid-C minus component. Using the example above, and replacing the adder with a minus component, the result of the total transaction price for that interval would be $33. When we net the adder and minus component together by multiplying the hours, megawatts, and index addition or subtraction for each contract there is a net benefit of $663,380. Unlike the first interim service plan where the fixed price resulted in a market delta cost, the offsetting nature of the Mid-C index adder and minus component results in no added cost to BPA related to these market purchases. Since there is no added cost, the full result will be included in the Non-Slice cost pool.

7. SLICE TRUE-UP

7.1 Slice True-Up Adjustment

Slice customers are subject to an annual Slice True-Up Adjustment for expenses, revenue credits, and adjustments allocated to the Composite cost pool and to the Slice cost pool. The annual Slice True-Up Adjustment will be calculated for each fiscal year as soon as BPA's audited actual financial data are available (usually in November). *See* TRM, BP-12-A-03, § 2.7.

7.2 Composite Cost Pool True-Up

The Composite Cost Pool True-Up is the calculation of the annual Slice True-Up Adjustment for the Composite cost pool for each fiscal year. For each Slice customer, the annual Slice True-Up Adjustment Charge for the Composite cost pool will be calculated as shown in the 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.R.1. The dollar amount calculated may be positive or negative. The Composite Cost Pool True-Up Table shows the forecast expenses, revenue credits, and adjustments that form the basis for the Slice True-Up Adjustment calculation for the Composite cost pool for the applicable fiscal year. *Id.* at GRSP II.R, Table F.

The following sections discuss the treatment of certain expenses, revenue credits, and adjustments included in the Composite Cost Pool True-Up.

7.2.1 System Augmentation Expenses

System augmentation expenses are included in the FY 2026-2028 Composite cost pool. Some of these augmentation expenses are a cost for service to Non-Slice customers' Above-

RHWM Load that is served at Load Shaping rates. For a description of these system augmentation expenses, see Section 3.2.4.3.2 above.

System augmentation expenses are not subject to the Composite Cost Pool True-Up. However, implicit in the Composite Cost Pool True-Up of the Firm Surplus and Secondary Adjustment (for Unused RHWM) and the DSI Revenue Credit are adjustments that reflect the effects of additional power purchases (or lack thereof) or additional power sales to the market. Sections 3.2.4.2 and 7.2.3 describe the treatment of the Firm Surplus and Secondary Adjustment (for unused RHWM) for Composite Cost Pool True-Up purposes. Section 7.2.4 below describes the DSI revenue credit.

BPA's purchase of output from the Klondike III resource is a Tier 1 augmentation expense, and the Composite cost pool includes the cost of RSS and RSC applicable to Klondike III. Because the RSS and RSC Charges financially convert the variable output of Klondike III to a firm annual block of power and are committed to in advance, the augmentation expense and RSS and RSC costs associated with generation output from the Klondike III resource are not subject to the Composite Cost Pool True-Up.

7.2.2 Balancing Augmentation Load Adjustment

The Balancing Augmentation Load Adjustment can result in a positive or negative credit to the Composite cost pool. Section 3.2.4.3 describes the Balancing Augmentation Load Adjustment, the circumstances that would result in a credit, and the circumstances that would result in a negative credit. The Balancing Augmentation Load Adjustment is not subject to the Composite Cost Pool True-Up.

7.2.3 Firm Surplus and Secondary Adjustment (from Unused RHWM)

The Firm Surplus and Secondary Adjustment (from Unused RHWM) is subject to the Composite Cost Pool True-Up. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.R.1(b). This adjustment reflects the fact that when the sum of actual TOCAs is greater than the sum of forecast TOCAs, additional power is sold to customers at the Composite Customer rate, and it is assumed that BPA incurs additional costs in the form of forgone market sales or increased power purchases. Likewise, when the sum of actual TOCAs is less than the sum of forecast TOCAs, less power is sold to customers at the Composite Customer rate, and it is assumed that BPA sells more power in the market or faces lower power purchase costs.

7.2.4 DSI Revenue Credit

The forecast costs associated with service to the DSIs are included in the Composite cost pool. *See* TRM, BP-12-A-03, § 3.2.1.3. DSI revenues received by BPA are included in the Composite cost pool as credits. The DSI Revenue Credit thus is subject to the Composite Cost Pool True-Up. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.R.1(c).

The calculation of the DSI Revenue Credit starts with the forecast DSI revenue credit, which is adjusted to calculate the actual DSI revenue credit. When actual DSI sales are greater than the rate case forecast DSI sales, it is assumed that additional power is sold to the DSIs at the IP rate, and BPA incurs additional costs in the form of forgone market sales or increased power purchases. The adjustment to the forecast DSI revenue credit reflects both the revenues from the additional power sold to the DSIs and the additional costs that are incurred. Likewise, when actual DSI sales are less than the rate case forecast DSI sales, it is assumed that BPA sells less power to DSIs at the IP rate and sells more power in the market, or it is assumed that such power may be used to meet BPA obligations so that fewer power purchase costs are incurred. The adjustment to the forecast DSI revenue credit reflects these effects. The adjustment also includes any DSI take-or-pay revenues recorded by BPA, if applicable.

7.2.5 Interest Earned on the Bonneville Fund

On the first day of the Slice contract, October 1, 2001, BPA had $495.6 million in financial reserves attributed to the Power function. TRM Section 2.5 provides for an interest credit that BPA will allocate to the Composite cost pool based on the pre-FY 2002 (FY 2002 began on October 1, 2001) level of reserves. TRM Section 2.5 further provides that future circumstances may occur that make it reasonable and fair to make adjustments to the size of the base amount of financial reserves attributed to the Power function as of October 1, 2001, for purposes of calculating the interest credit allocated to the Composite cost pool.

BPA made several adjustments to the base reserve amount in setting the BP-14 rates, as shown in Table 5. In addition, there were adjustments made in FY 2018. The adjustments reflected in Table 5 are not amounts that have been shared with or collected from Slice customers through a prior Slice True-Up. As a result, these amounts are reflected as adjustments to the size of the base amount of financial reserves. As shown in Table 5, Line 32, the revised reserve amount for purposes of calculating the interest credit is $586.596 million. BPA has not made any adjustments to the revised reserve amount from the BP-14 rate proceeding in setting the proposed BP-26 rates. The forecast interest credit for the Composite cost pool is $18.891 million in FY 2026, $17.369 million in FY 2027 and $17.252 million in FY 2028. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.3.1.3.

The interest credit on the financial reserves amount is subject to the Composite Cost Pool True-Up. The actual interest credit calculated on the revised base amount of financial reserves can change from the forecast interest credit if there are changes in the factors used to calculate the forecast interest credit.

7.2.6 Bad Debt Expenses

Bad debt expenses, if any, are allocated between the Composite cost pool and the Non-Slice cost pool, as specified in the TRM, BP-12-A-03, Table 2A. There is no forecast bad debt expense for the FY 2026-2028 period for ratemaking purposes. If a bad debt expense is identified and accounted for in BPA's actual audited financial reports for a given fiscal year, BPA will determine whether the expense should be included in the actual expenses and revenue credits that are allocable to the Composite cost pool in the applicable fiscal year of the rate period. If so, then the expense may be included for purposes of the Composite Cost Pool True-Up, and the bad debt expense would be allocated according to the principle of cost causation, as described generally in the TRM, BP-12-A-03, Section 2.1.

Any bad debt expense associated with a sale to any customer that purchased federal power exclusively at the FPS-24 and FPS-26 rates would be excluded for Composite Cost Pool True-Up purposes. Bad debt expenses associated with sales of power at only these FPS rates are related solely to BPA's sales of surplus power after the inception of the Slice product and not to sales of requirements power. The expenses and revenues from such sales are included in the Non-Slice cost pool. *See* TRM, BP-12-A-03, § 2.2.3.

Any bad debt expense associated with a sale to a customer that purchases power at only the PF or IP rate will be included for purposes of the Composite Cost Pool True-Up. The allocation to the Composite cost pool of any bad debt expense associated with a sale to a customer that purchases power at both the PF rate and the FPS rate, or a sale to a customer that purchases power at both the IP rate and the FPS rate, will be contingent on the circumstances of the particular instance of a full or partial non-payment of a power bill.

Revenue recoveries of bad debt expenses will be included for Composite Cost Pool True-Up purposes if Slice customers paid for the bad debt expense through their Slice True-Up Adjustment Charge.

7.2.7 Settlement and Judgment Amounts

BPA payments or receipts of money related to settlements and judgments will be allocated on a case-by-case basis to either the Composite cost pool or the Non-Slice cost pool. If an amount (payment or receipt) is accounted for in BPA's actual audited financial reports for any given fiscal year (reports are produced after rates are set), BPA will determine whether such amount will be included or excluded for Composite Cost Pool True-Up purposes. Such a determination will be made based on the principle of cost causation. *See id.* § 2.1.

7.2.8 Transmission Costs for Designated BPA System Obligations

Transmission and Ancillary Services expenses are allocated between the Composite cost pool and the Non-Slice cost pool, as specified in the TRM, BP-12-A-03, Table 2A. The Transmission and Ancillary Services expenses associated with Designated BPA System Obligations are allocated to the Composite cost pool. Such Transmission and Ancillary Services expenses are not subject to the Composite Cost Pool True-Up.

Transmission reservations are set aside for non-discretionary obligations (*e.g.,* Designated BPA System Obligations). Because Power Services does not know the actual amounts of transmission usage until the preschedule period for such obligations, the transmission reservations for those obligations are purchased based on the maximum need for the year. Therefore, the forecast cost of the reservations for Designated BPA System Obligations is included in the Composite cost pool, and such costs are not subject to the Composite Cost Pool True-Up.

Any revenues from the resale of transmission that appear to be the result of BPA sales of unused transmission inventory associated with set-aside transmission will be excluded for Composite Cost Pool True-Up purposes. Because the cost of additional transmission purchased (or of using Non-Slice transmission inventory) to serve Designated BPA System Obligations in excess of what was forecast in the ratemaking process is not included in the Composite Cost Pool True-Up, revenues from sales of surplus transmission inventory also are excluded from the Composite Cost Pool True-Up.

7.2.9 Power Services Third-Party Transmission and Ancillary Services

These costs are associated with transmission or losses for federal generation telemetered into BPA's BAA and delivered under BPA's Open Access Transmission Tariff. These costs are tied to any federal resources or generation included in the RHWM Tier 1 System Capability and delivered in the Slice product. Therefore, these costs are allocated to the Composite cost pool and are subject to the Composite Cost Pool True-Up.

7.2.10 Transmission Loss Adjustment

A transmission loss adjustment is included in the Composite cost pool. Without such an adjustment, Slice customers would pay not only for real power losses (through loss return schedules to BPA) on the transmission of their Slice purchases, but also a proportionate share of losses on the transmission of non-Slice products. See Section 3.2.4.1 above for an explanation of the calculation of this credit. The transmission loss adjustment is not subject to the Composite Cost Pool True-Up.

7.2.11 Resource Support Services Revenue Credit

A credit for RSS revenue is included in the Composite cost pool. The credit is for revenues earned by uses of capacity to support resources that receive RSS. *See* Section 3.2.3.1.4 above. This revenue credit is not subject to the Composite Cost Pool True-Up.

7.2.12 Generation Inputs for Ancillary and Other Services Revenue Credit

The uses of the generating capacity available to BPA to support the transmission system and maintain reliability are generally referred to as generation inputs. Generation inputs include capacity-related and energy-related services that BPA uses to provide Ancillary and Control Area Services, support transmission, and maintain the reliability of the transmission system. These services include balancing reserve services, operating reserve services, synchronous condensing, generation dropping, redispatch service, station service, and U.S. Army Corps of Engineers (Corps)/Reclamation segmentation. A credit for Generation Inputs revenue is included in the Composite cost pool. *See* TRM, BP-12-A-03, Table 2, line 120, and Table 3.4, line 44. This revenue credit is subject to the Composite Cost Pool True-Up Table. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.

7.2.13 Tier 2 Rate Adjustments

Tier 2 rate adjustments are ratemaking adjustments to the Composite cost pool to reflect a share of expenses incurred by Power Services that are allocable to all power sold. *See* Section 3.2.2 above. There are two types of rate adjustments: the Tier 2 overhead cost adder and the Tier 2 transmission scheduling service cost adder.

The Tier 2 overhead cost adder is an adjustment for administrative costs incurred by Power Services. *See* Section 3.2.2.3. The Tier 2 overhead cost adder is included in the Composite cost pool. This adjustment is estimated for ratemaking purposes and is not subject to the Composite Cost Pool True-Up.

The Tier 2 Transmission Scheduling Service cost adder is an adjustment for administrative costs incurred by Power Services. For a description of this adjustment, see Section 3.2.2.2 above. The forecast of this adjustment is included in the RSS revenue credit. This adjustment is not subject to the Composite Cost Pool True-Up.

7.2.14 Residential Exchange Program Expense

Forecast REP benefits are included in the Composite cost pool for ratemaking purposes. The forecast of REP expense on the Composite Cost Pool True-Up Table is equal to the forecast of REP benefits expected to be paid to REP participants. The forecast REP expense is subject to the Composite Cost Pool True-Up.

7.2.15 Canadian Designated System Obligation Annual Financial Settlements

The Non-Treaty Storage Agreement (NTSA) is an agreement between BPA and BC Hydro that allows water transactions to be financially settled between them. The NTSA provides two mechanisms to settle the transaction benefits, which BPA designates as a system obligation: 1) energy deliveries during the year, and 2) a financial settlement based on the August 31 balance at the end of the fiscal year. The Short-Term Libby Agreement (STLA) and subsequent updates are agreements between the U.S. and Canada that allow water transactions to be financially settled between BPA, acting on behalf of the U.S., and BC Hydro, acting on behalf of Canada. The STLA does not have a provision to settle transactions by energy delivery. BPA designates the STLA as a system obligation, and the financial settlement is based on the August 31 balance at the end of the fiscal year. Financial settlements in a fiscal year and the financial accrual amount recorded for the month of September of the same fiscal year are charged or credited to other power purchases, and Slice customers pay their share of the charge or receive their share of the credit through the Composite Cost Pool True-Up Table.

7.2.16 Participating Resource Scheduling Coordinator (PRSC) Net Credit

In the EIM, when Power Services bids in participating resource amounts, any net credits, or charges, associated with balancing reserves will be included in the PRSC Net Credit line item under Revenue Credits. The PRSC Net Credit will be equal to the actual charges and credits allocated from the California Independent System Operator (CAISO) to Power Services as a PRSC multiplied by the following percentages calculated using data from the same time period in which the charges and credit were incurred: 1) Non-Regulating balancing capacity offered by Power Services in an hour, divided by 2) total amount of capacity bid into the EIM by Power Services in that same hour. For an hour in which Power Services offers incremental (*inc)* and decremental (*dec)* capacity into the EIM, there will be two percentages for the hour, one for *inc* capacity and one for *dec* capacity. The calculated percentages will be capped at 100 percent. Any CAISO charges or credits that are not associated with either a sale or purchase of power will be allocated as a monthly sum multiplied by the *inc* and *dec* ratio of balancing capacity to all capacity offered to the CAISO EIM for the same period.

The PRSC Net Credit is subject to the Composite Cost Pool True-Up. The amount calculated as part of the True-Up process may be a negative number (a charge).

7.2.17 Other Potential Adjustments

A few new lines have been added to the Composite Cost Pool True-Up Table in the BP-26 rate proceeding. New line items and other changes include:

1. Amortization of P2IP settlement payments
2. Long-Term funding Agreements (Accords)
3. FPS Real Power Losses, previously designated as Non-Slice
4. Other Augmentation is now included in Augmentation Purchases

Consistent with the Update to BPA's BP-26 Cost Projections, issued on July 14, 2025, cost projections in power rates associated with the Memorandum of Understanding filed on December 14, 2023, in the Columbia River System litigation, *National Wildlife Federation v. National Marine Fisheries Service*, 3:01-cv-640-SI (D.Or.), ECF No. 2450-1 (MOU), were removed. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Tables 2.3.1.1-5.

7.3 Slice Cost Pool True-Up

The Slice Cost Pool True-Up is the calculation of the annual Slice True-Up Adjustment for the Slice cost pool, as described in TRM, BP-12-A-03, Section 2.7.2. Calculation of the Annual Slice Cost Pool True-Up is described in GRSP II.R.2 and is shown in GRSP Table G. *See* 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01. Slice expenses and credits are forecast to be zero in FY 2026, FY 2027, and FY 2028. If there are any actual Slice expenses and credits incurred during the rate period, such expenses and credits will be subject to the Slice Cost Pool True-Up.

8. AVERAGE SYSTEM COSTS (ASC)

8.1 Overview of the Residential Exchange Program

The REP, established by Section 5(c) of the Northwest Power Act, was designed to provide residential and farm customers of Pacific Northwest utilities a form of access to low-cost federal power. 16 U.S.C. § 839c(c). Under the REP, BPA purchases power from each participating utility at that utility's ASC. The ASC (dollars per megawatthour or mills per kilowatthour is a rate determination that is calculated for each utility participating in the REP. (For ratemaking purposes, the power purchased by BPA is called "exchange resources.") BPA sells to the utility, in exchange for the power it purchases, an equivalent amount of electric power at BPA's Priority Firm Power Exchange (PFx) rate. (For ratemaking purposes, the power purchased by the utilities is called "exchange loads.")

The "exchange" transfers no actual power to or from BPA; it is an accounting transaction in which dollars are exchanged rather than electric power. However, to ensure proper cost allocations and rate determinations, RAM2026 models the REP as purchases of power by BPA (priced at the participants' respective ASCs) and simultaneous sales of power to the REP participants (priced at the participants' respective PFx rates).

BPA is implementing the 2012 REP Settlement with IOU exchange participants through REPSIA and with COU participants through RPSA. Total REP costs are included in rates for FY 2026-2028.

The 2012 REP Settlement established a fixed stream of REP benefits payable to the IOU REP participants beginning in FY 2012 and ending in FY 2028. 2012 REP Settlement, REP-12-A-02A. Individual IOU REP benefit determinations under the 2012 REP Settlement will continue to be calculated as under the traditional REP; that is, BPA will compare each

IOU's ASC for FY 2026-2028 with its respective BP-26 PFx rate and, if the difference is positive, multiply the difference by the IOU's exchange load to calculate its REP benefit (in dollars). *Id.* Similarly, pursuant to the RPSAs with the two COUs participating in the REP, BPA will compare each COU's ASC for FY 2026-2028 with its respective BP-26 PFx rate and, if the difference is positive, multiply the difference by its exchange load to calculate its REP benefit. The COUs' REP benefits are in addition to (*i.e.,* are not included in) the fixed stream of IOU REP benefits under the 2012 REP Settlement. *Id.* For a forecast of individual utility annual REP benefit payments for FY 2026-2028, see Table 6 of this Study.

8.2 ASC Determinations

BPA determines participating utilities' ASCs outside the rate proceeding in an ASC Review Process conducted pursuant to the substantive and procedural requirements of the 2008 ASC Methodology (ASCM), 18 C.F.R. § 301, *et seq*. FERC granted final approval to the 2008 ASCM on September 4, 2009.

A utility's ASC for the rate period is calculated by dividing the utility's allowable resource costs and revenues (Contract System Cost) by its allowable load (Contract System Load). The quotient is the utility's rate period ASC. Contract System Cost is the sum of the utility's allowable generation-related and transmission-related costs and overheads; distribution-related costs are not included. Contract System Load is calculated as the total retail sales of a utility as measured at the meter, plus distribution losses, less any NLSLs, if applicable.

Under the 2008 ASCM, the ASC for each utility may change if the utility adds a new resource, retires an existing resource, or adds an NLSL. However, under the 2012 REP Settlement, participating IOUs agreed not to submit ASC revisions based on new resources coming online or being removed during the Exchange Period (the Exchange Period is the same as the rate period, currently FY 2026-2028). 2012 REP Settlement, REP-12-A-02A, § 6.4. Therefore, for COUs only, the ASC may change if the utility adds a new resource or retires an existing resource during the Exchange Period. The revised ASC takes effect in the month after a new resource comes online, an existing resource is retired, or a new NLSL begins taking service. The ASCs for the BP-26 rate period are shown in Table 8.1 of the Power Rates Study Documentation, BP-26-FS-BPA-01A.

Under the 2012 REP Settlement, the IOU ASCs that are effective on the first day of the rate period will continue to be in effect throughout the Exchange Period, with the exception of the addition of an NLSL. 2012 REP Settlement Agreement, REP-12-A-02A. These "day-one" IOU ASCs are developed for use in establishing rates for the BP-26 rate period. Section II.T of the 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, specifies how the PFx rate applicable to each REP participant will change if a revised ASC takes effect.

The ASCs used in the BP-26 Final Proposal were determined in the separate ASC Review Processes and published in the Final ASC Reports on July 24, 2025. The ASCs reflected in the Final ASC Reports were based on REP Staff's assessment of the utilities' ASCs filings. BPA issued Final ASC Reports for eight utilities: Avista Utilities, Idaho Power Company, NorthWestern Energy, PacifiCorp, Portland General Electric, Puget Sound Energy, Clark County PUD, and Snohomish County PUD. These reports are available at: https://www.bpa.gov/energy-and-services/power/residential-exchange-program/asc-utility-filings.

8.3 Residential Exchange Program Load

Exchange loads are defined as a utility's qualifying residential and farm consumer loads as determined in accordance with the utility's RPSA or REPSIA.

Under the 2012 REP Settlement, participating IOUs agreed to use a two-year historical average for determining monthly exchange load, referred to as Residential Load, to calculate IOU REP benefits. 2012 REP Settlement, REP-12-A-02A, § 2 ("Residential Load"). For the BP-26 rate period, the historical years are calendar year (CY) 2023 and CY 2024. The monthly loads applicable to both years of the BP-26 rate period are shown in GRSP II.S, Table H. 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSPs.

The COUs' RPSAs do not specify the use of historical exchange loads in computing COU REP benefits; therefore, forecasts are used to estimate COU REP benefits for ratemaking purposes. For the COUs, the FY 2026-2028 exchange load forecasts are based on the exchange load information provided by the COUs in the ASC Review Process. Each COU's exchange load forecast is adjusted for the COU's Tier 1 percentage (if applicable), as required by the TRM. The Tier 1 percentage is defined as BPA's forecast percentage of the COU's load that is expected to be served by purchases of power at Tier 1 rates from BPA and from the COU's Existing Resources for CHWM. COU REP benefits will be paid on actual residential and farm sales as adjusted by the Tier 1 percentage for each COU, as submitted after each month during the rate period. The monthly IOU Residential Loads and monthly forecast COU exchange loads are shown in Table 8.2 of the Power Rates Study Documentation, BP-26-FS-BPA-01A.

8.4 REP 7(b)(3) Surcharge Adjustment

The REP § 7(b)(3) surcharge is a utility-specific addition to the base PFx rates that recovers each REP participant's allocated share of rate protection provided pursuant to § 7(b)(2) of the Northwest Power Act. 16 U.S.C. § 839e(b)(2)-(3). Each REP participant's initial 7(b)(3) surcharge is determined in the § 7(i) rate proceeding based on the base PFx rates, the ASCs, and the forecast exchange loads of all utilities assumed for ratemaking to participate in the

REP. *Id.* at § 839e(i). Each REP participant's initial 7(b)(3) surcharge is displayed in Section 6.1 of the PF-26 rate schedule. 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, PF-26, § 6.1. Each participating utility's 7(b)(3) surcharge is subject to change during the rate period if any participant's ASC changes during the rate period due to the addition of an NLSL in the utility's service territory. For COUs only, the addition or removal of a resource from the participant's resource portfolio will also change its 7(b)(3) surcharge. The procedures for modifying the 7(b)(3) surcharges of all REP participants are codified in GRSP II.T. 2026 Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSPs.

9. REVENUE FORECAST

The revenue forecast calculates the expected revenue from power rates and other sources for the rate period, FY 2026-2028, and the current fiscal year, FY 2025. Two revenue forecasts are prepared. The first uses rates from the rate schedules currently in effect (BP-24 rates), and the second uses proposed rates (BP-26 rates). The revenue forecasts are used to test whether current rates and proposed rates will recover the power revenue requirement. If the revenue test shows that revenues at current rates will not generate sufficient revenue to recover the power revenue requirement, new rates are calculated, and revenues at proposed rates are generated. *See* Power Revenue Requirement Study, BP-26-FS-BPA-02, §§ 3.2-3. Both forecasts are based on the Power Loads and Resources Study, BP-26-FS-BPA-03, forecast of firm loads for the current fiscal year and the rate period.

In addition to forecasts of revenues, this section of the Study presents power purchase expenses that are directly related to balancing purchases needed to meet load under different water conditions. Power purchases are included in the forecast for FY 2026-2028 and discussed in Section 9.5 below.

The revenue forecast includes revenue calculations for the current fiscal year, FY 2025, to help estimate the amount of financial reserves available to BPA at the beginning of the rate period. *See* Power and Transmission Risk Study, BP-26-FS-BPA-05, § 4.2.2.1.

The revenue forecast is divided into four main categories: 1) revenues from gross sales, described in Section 9.1 below; 2) miscellaneous revenues, described in Section 9.2; 3) revenues from generation inputs for ancillary, control area, and other services, described in Section 9.3; and (4) U.S. Treasury credits, described in Section 9.4.

9.1 Revenue Forecast for Gross Sales

Gross Sales is Power Services' largest category of revenue. There are eight sources of revenue in this category:

1. PF power sales under the CHWM contracts, described in Section 9.1.1;
2. IP sales to DSIs, described in Section 9.1.2.1;
3. NR sales, described in Section 9.1.2.2;
4. Scheduling products under the FPS rate, described in Section 9.1.3;
5. Short-term market sales, described in Section 9.1.4;
6. Long-term contractual obligations, described in Section 9.1.5;
7. Canadian entitlement returns, described in Section 9.1.6; and
8. Other sales, described in Section 9.1.7.

9.1.1 Priority Firm Power Sales under CHWM Contracts

For FY 2025, the revenues from PF power sales pursuant to CHWM contracts are calculated using the product of 1) forecast loads documented in the Power Loads and Resources Study, BP-26-FS-BPA-03, Section 2.2, and accompanying Power Loads and Resources Documentation, BP-26-FS-BPA-03A, Table 1.2.1 for energy, Table 1.2.2 for HLH, and Table 1.2.3 for LLH; and 2) PF-26 rates. Revenues from PF sales pursuant to CHWM contracts for FY 2025 are listed in Table 4 of this Study, lines 3-12, and in Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.2, lines 3-12.

For FY 2026, FY 2027 and FY 2028, revenues from PF sales pursuant to CHWM contracts are computed using the product of 1) forecast loads assuming normal weather, documented in the Power Loads and Resources Study, BP-26-FS-BPA-03, and accompanying Power Loads and Resources Documentation, BP-26-FS-BPA-03A; and 2) the appropriate PF rates derived by RAM2026. Inputs and results for the revenue forecast are managed and calculated pursuant to the CHWM contracts using the Revenue Forecasting Application (RFA). Revenues are reported for Tier 1 Customer charges (Composite, Slice, and Non-Slice), Load Shaping, and demand, including the LDD and IRD credits, and any additional Tier 2 and/or RSS charges.

9.1.1.1 Composite and Non-Slice Customer Charges

Revenues from each customer for the Composite and Non-Slice Customer Charges are based on the customer's TOCA and the customer's contractually specified products. There are no Slice charges for FY 2023-2025. Revenues obtained from the Composite and Non-Slice Customer Charges represent the majority of revenues from firm power sales under CHWM contracts for FY 2025-2028. The calculation of forecast Composite and Non-Slice revenues is shown in Power Rates Study Documentation, BP-26-FS-BPA-01A, Tables 3.1.6.1-3. Composite and Non-Slice revenues for FY 2025-2028 are listed in Table 4 of this Study, lines 3-4, and Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.2, lines 3-4.

9.1.1.2 Load Shaping Charge

The Load Shaping Charge reflects the costs and benefits of shaping the Tier 1 System Capability to the monthly/diurnal shape of a customer's below-RHWM load. A charge to the customer results when the customer's shaped load is greater than its share of the Tier 1 System Output in any month for both HLH and LLH; the customer receives a credit from BPA when the opposite occurs. The Load Shaping Charge is described in Section 4.1.1.3 above. The forecast of Load Shaping revenues for FY 2025-2028 is listed in Table 4 of this Study, line 6, and Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.2, line 6.

9.1.1.3 Demand Charge

The demand charge is applicable to customers purchasing Load Following or Block with shaping capacity products; for FY 2025-2028, there are no customers purchasing Block with shaping capacity. The demand charge is calculated using customer-specific information including actual Customer Tier 1 System Peak, average actual monthly below-RHWM load occurring in HLH, Contract Demand Quantities (CDQs), and Super Peak Credit (if applicable). Calculation of a customer's demand charge is described in Section 4.1.1.2.2 above. The demand revenue forecast for FY 2025-2028 is also shown in Table 4 of this Study, line 7, and Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.2, line 7.

9.1.1.4 Irrigation Rate Discount (IRD)

The IRD is a rate credit available to eligible customers and provides a fixed rate discount on Tier 1 rates (the discount does not apply to loads served at Tier 2 rates). May through September eligible irrigation loads are identified in each customer's CHWM contract. The methodology for calculating the IRD end-of-year true-up appears in GRSP II.C.3. *See* Power Rate Schedules and GRSPs, BP-26-A-01-AP01. Forecast credits for irrigation loads are calculated using an IRD that is derived by multiplying the irrigation loads identified in the CHWM contracts by the IRD rate. The IRD is described in Section 5.4.2. Forecast IRD credits for FY 2025-2028 are listed in Table 4 of this Study, line 8, and Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.2, line 8.

9.1.1.5 Low Density Discount (LDD)

The LDD is prescribed in § 7(d)(1) of the Northwest Power Act and offers a discount of up to 7 percent for customers that meet the criteria specified in the Power Rate Schedules and GRSPs, BP-26-A-01-AP01, GRSP II.B. 16 U.S.C. § 839e(d)(1). As set forth in the TRM, LDD percentages are calculated to provide a discount on power purchased at Tier 1 rates that approximates the discount the customer would have received under non-tiered rates. Forecast LDD credits for FY 2025-2028 are listed in Table 4 of this Study, line 9, and Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.2, line 9.

9.1.1.6 Tier 2 and Resource Support Services

Tier 2 rates are based on a cost allocation that recovers the cost of BPA service to Above-RHWM Load. Tier 2 revenues are based on sales to customers that have elected to have BPA serve their Above-RHWM Loads. Forecast Tier 2 revenues for FY 2025-2028 are listed in Table 4 of this Study, line 10, and Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.2, line 10.

RSS revenues are based on known services chosen by customers. Forecast RSS revenues for FY 2025-2028 are listed in Table 4 of this Study, line 11, and Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.2, line 11.

9.1.2 Industrial Firm Power Sales and New Resource Power Sales

9.1.2.1 Industrial Firm Power Sales to Direct Service Industrial Customers

BPA sells power to DSIs at the IP rate. Revenues from the IP rate are computed using the product of 1) forecast loads documented in Power Loads and Resources Study, BP-26-FS-BPA-03, Section 2.4, and accompanying Power Loads and Resources Documentation, BP-26-FS-BPA-03A, Tables 1.2.1 for energy, 1.2.2 for HLH, and 1.2.3 for LLH; and 2) the appropriate IP rate from RAM2026. For FY 2025, the revenues for DSI customers are calculated using the IP-24 rate. Forecast IP revenues for FY 2025-2028 are listed in Table 4 of this Study, line 14, and Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.2, line 14.

9.1.2.2 New Resource Firm Power Sales

The NR-26 rate applies to sales to investor-owned utilities under Northwest Power Act Section 5(b) requirements contracts. 16 U.S.C. § 839c(b). The NR-26 rate is also applicable to sales to any public body, cooperative, or federal agency to the extent such power is used to serve any NLSL, as defined by the Northwest Power Act, including planned NLSLs, as defined in Exhibit D of a customer's CHWM contract. The NR-26 rate includes energy and demand rates. Forecast NR revenues for FY 2025-2028 are listed in Table 4 of this Study, line 13, and Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.2, line 13.

9.1.3 Products and Services under the FPS Rate

During FY 2025-2028, BPA is providing power products and services under the FPS rate described in Section 4.4 of this Study. Revenues from the products and services are derived by multiplying individual customer billing determinants by the appropriate FPS rate. Forecast FPS revenues for FY 2025-2028 are listed in Table 4 of this Study, line 15, and Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.2, line 15.

9.1.4 Short-Term Market Sales

The revenue forecast includes revenues from the sale of surplus energy, which can be a combination of secondary energy and firm energy in excess of that required to serve firm loads. The wholesale market price impacts various components in determining the forecast of surplus sales revenue. For FY 2025, the surplus energy revenue included in the revenue forecast consists of the average of the surplus energy revenues in forecast months computed during RevSim simulations of 40 iterations for each of 30 historical water years, for a total of 2,700 iterations. For FY 2025-2028, the surplus energy revenue is the median of the surplus energy revenues across those 2,700 iterations. In addition, BPA includes a credit to account for the incremental value of marketing power to extra-regional PODs. *See* Power and Transmission Risk Study, BP-26-FS-BPA-05, § 4.1.1.2.3.

The revenue forecast for short-term market sales is computed using RevSim to calculate monthly HLH and LLH energy surpluses for each of the 2,700 iterations, applying corresponding market prices developed for each iteration. Additionally, the short-term market sales forecast contains revenue from contract sales for FY 2025-2028. The contract sales portion consists of DSI sales and sales outside the Pacific Northwest. *See* Power and Transmission Risk Study, BP-26-FS-BPA-05, § 4.1.1.2.3. Revenues for FY 2025-2028 are shown in Table 4 of this Study, line 16, and Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.2, line 16.

9.1.5 Long-Term Contractual Obligations

Long-term obligation contracts include a wind energy exchange and capacity and energy exchanges. For FY 2025-2028, revenue from these contractual obligations is calculated pursuant to the individual contracts and then summed and added to the forecast as a group. BPA has long-term contracts to provide energy and capacity. Each contract is an advanced noticed right to power. See the Power and Transmission Risk Study, BP-26-FS-BPA-05, for more information. Forecast revenue for FY 2025-2028 is listed in Table 4 of this Study, line 17, and Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.2, line 17.

9.1.6 Canadian Entitlement Return

The Canadian Entitlement Return is an obligation for BPA to deliver power to Canada at the border pursuant to Columbia River Treaty between Canada and the U.S. No revenues are generated from the delivery of this power, but energy amounts are listed in the revenue forecast to represent this system obligation. The average megawatt deliveries for FY 2025-2028 are listed in Table 4 of this Study, line 18, and Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.2, line 18.

9.1.7 Other Sales

Other Sales include forecast revenues from primarily the Slice True-Up and Load Shaping True-Up, which are applicable only for FY 2025. The forecast of Other Sales revenue for FY 2025-2028 is listed in Table 4 of this Study, line 19, and Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.2, line 19.

9.2 Revenue Forecast for Miscellaneous Revenues

Miscellaneous Revenues include revenues from the Transfer Service Charges, Downstream Benefits, Reclamation power for irrigation, and the Upper Baker project.

The Transfer Service revenue forecast accounts for costs of the delivery of federal power over non-federal transmission systems and is described in Section 6 of this Study. Included in the Transfer Service revenue forecast are revenues from the Operating Reserve Charge, Regulation and Frequency Response Charge, and Regional Compliance Enforcement Charge as described in Sections 6.3-6.6.

Downstream Benefits are revenues BPA receives from utilities that benefit from the coordinated planning and operation of Corps and Reclamation upstream storage reservoirs as part of the Pacific Northwest Coordination Agreement. 62 Fed. Reg. 40,512 (July 7, 1997). For FY 2025-2028, revenues from downstream benefits are estimated by applying a three-year average from the three most recent studies of downstream benefits conducted by the Northwest Power Pool (NWPP).

Reclamation power for irrigation includes power that has been reserved from the FCRPS for use at Reclamation projects. For revenue forecasting purposes, power that has been reserved for Reclamation irrigation projects is classified as either reserved power or irrigation pumping power. Revenue from reserved power for FY 2025-2028 is forecast in equal monthly amounts based on an annual amount that is aggregated for Reclamation projects. The annual aggregated amounts are forecast based on an average of actual results from the prior three years provided by Reclamation. Revenue from Irrigation Pumping Power for FY 2025-2028 is calculated using the same methodology as reserved power.

Finally, revenues from the Upper Baker project are forecast. Puget Sound Energy keeps 58,000 acre-feet of flood control at this reservoir, which must be held at a lower level during the winter than it would be without flood control, creating head losses. On behalf of the Corps, BPA compensates Puget by delivering non-firm energy and capacity during the flood control season of November through March. In turn, BPA offsets the value of energy and capacity delivered to Puget from the yearly U.S. Treasury payment, and the deduction is listed as a revenue receipt from the Corps.

Miscellaneous revenues for FY 2025-2028 are listed in Table 4 of this Study, line 21, and Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.2, lines 21-27.

9.3 Revenue Forecast for Generation Inputs for Ancillary, Control Area, and Other Services and Other Inter-Business Line Allocations

Power Services receives revenue from Transmission Services for providing generation inputs for ancillary and control area services. Generation inputs cost allocations and the unit cost of balancing and operating capacity are described in detail below in Section 9.3.1. Revenue forecasts (inter-business line allocations) for Synchronous Condensing, Generation Dropping, Redispatch, Segmentation of Corps and Reclamation network and delivery facilities costs, and Station Service costs are included in the Power Rates Study Documentation, BP-26-FS-BPA-01A, Tables 9.3.2-9.3.5.

The revenues (inter-business line allocations) are shown in Table 4, line 22, of this Study and the Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.2, line 48.

9.3.1 Capacity Cost Methodology

9.3.1.1 Introduction

Various Ancillary and Control Area Services provided through BPA's transmission rates require the use of generation capacity—specifically balancing and operating reserve services. All of this required capacity is sourced from the generating resources available to BPA and is considered a "generation input" into transmission rates. This section of the Study describes how the cost of this capacity is calculated.

The Ancillary and Control Area Services that require the use of capacity are Regulation and Frequency Response Service, Balancing Services (VERBS and DERBS), and Operating Reserve Services (Spinning and Supplemental). Capacity required for Regulation and Frequency Response Service and the Balancing Services is further categorized as either Regulating or Non-Regulating Reserves. Both Regulating and Non-Regulating Reserves include *inc* capacity or *dec* capacity. Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.1.7.

The total cost of incremental capacity is calculated as the sum of two components: an embedded cost component and a variable cost component. The total cost of decremental capacity includes only a variable cost component. The embedded cost component accounts for the fixed cost of the federal system. The variable cost component accounts for the lost efficiency (impact to available energy) associated with holding and deploying capacity. The calculation of the embedded costs is explained in detail in Section 9.3.1.2. The calculation of the variable costs is explained in detail in Section 9.3.1.3. The calculation of a rate design cost adjustment is explained in detail in Section 9.3.1.4. The calculation of total unit capacity costs and the associated revenue forecasts is described in Section 9.3.1.5.

Once the unit cost of capacity is determined, the unit cost is multiplied by the forecast amount of capacity to be provided by Power Services and is treated as a revenue credit to power rates. Conversely, this amount is treated as a cost to Transmission Services. *See* Transmission Revenue Requirement Study Documentation, BP-26-FS-BPA-09A, Table 3-5.

9.3.1.2 Embedded Cost Methodology

BPA's embedded unit cost of capacity is calculated by dividing all of BPA's capacity costs by the amount of capacity available to BPA under monthly P10 firm generation from the 30 water year set. BPA's capacity costs are determined using a capacity-and-energy-cost-classification methodology, where fixed costs are classified as capacity and variable costs are classified as energy. In general, this methodology associates the cost of building a plant with capacity, and the cost of fuel and other operational costs with energy, while also encompassing the broader set of costs that BPA pays and accounting for the fuel constraints and regulations associated with hydroelectric generation. The costs classified as capacity as a result of this method are: capital-related costs, Fish and Wildlife Program costs, a portion of power purchase costs, and two cost adjustments. The total amount of capacity available to BPA under monthly P10 water conditions is calculated as the sum of the monthly average one-hour capability of physical resources, any forecast or actual augmentation purchase amounts, and all capacity reserved for Transmission Services for Ancillary and Control Area Services.

9.3.1.2.1 Capacity Cost Classification

To calculate a capacity unit cost, BPA must first separate its revenue requirement into costs classified as capacity (fixed costs) and costs classified as energy (variable costs). For purposes of this calculation, fixed costs are defined as: 1) all capital-related costs, 2) costs that do not vary with resource output and are directly attributable to the generation capability of the resources available to BPA, and 3) the capacity-attributed portion of power purchase costs. For example, BPA's Fish and Wildlife Program costs are attributable to capacity because these costs are an obligation directly attributable to the resources available to BPA that do not vary with resource output. Costs that are not defined as fixed costs are considered variable costs. An example of an energy-attributable cost is BPA's staffing cost because these costs are not directly attributable to the generation capability of the resources available to BPA.

Further, with only three exceptions, simplicity in the cost classification method is achieved by classifying 100 percent of each line item in the Cost of Service Analysis Disaggregated Costs and Credits table in RAM (*see* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.3.1.5) to either energy or capacity, with no split attributions. The first exception to this 100-percent-to-capacity or 100-percent-to-energy classification approach is in power purchases that provide both energy and capacity to BPA. The second exception is in the 4(h)(10)(C) credit where the credit is tied to specific costs. The third exception is Synchronous Condensing where a portion of the costs of providing this service is associated with plant investment (capacity) and the other portion associated with energy. Each of these adjustments are described below. The net cost attributed to capacity for the rate period is $1,269.7 million per year. Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.1.3, line 24.

Capital-Related Costs

As stated above, all capital-related costs are classified as capacity costs. Capital-related costs include depreciation, amortization, interest expense, decommissioning costs, and minimum required net revenues. Capital-related costs average $902.4 million for the rate period. *Id.*, line 7.

Fish and Wildlife Costs

In addition to capital-related costs, fixed costs include costs that do not vary with resource output and are directly attributable to the generation capability of the resources available to BPA. The only costs that fit this definition are BPA's Fish and Wildlife Program costs. In addition to direct BPA fish and wildlife costs, BPA pays U.S. Fish and Wildlife Service program costs associated with the Lower Snake River Hatcheries and pays the Northwest Power and Conservation Council (NPCC) to help finance its Fish and Wildlife Program (50 percent of BPA's payments to NPCC go toward fish and wildlife and the other 50 percent goes toward conservation). The total of all directly attributable fish and wildlife costs average $368.9 million per year for the rate period. *Id.*, line 12.

Power Purchase Costs

Power purchase costs are included in the embedded cost of capacity calculation if they are flat annual blocks of power, such as system augmentation, or if they are the purchase of the output from a dispatchable resource. Power purchases from variable resources, such as wind and solar output, are attributed entirely to energy and are not relied upon for capacity. Power purchase costs are included because they increase the capacity available to BPA but are not captured by the inclusion of capital-related or fish and wildlife costs. Unlike BPA's physical resources—where a capacity-and-energy-cost-classification methodology can be used—the cost of power purchases often includes a single dollars-per-megawatthour cost only, with no visibility into the capacity and energy cost components. In these situations, a ratio of maximum-output to maximum-output-plus-average-generation is used to classify the portion of the total cost that is attributable to capacity.

For a flat annual block of power, this method attributes 50 percent of the cost to energy and the other 50 percent to capacity. This is because, for a flat block of power, the maximum generation and average generation are the same. For Clearwater Hatchery Generation, which is the only physical hydro resource that BPA currently pays for the output in a single dollars-per-megawatthour cost, this method attributes 39.5 percent to energy and 60.5 percent to capacity. The total rate period average of power purchase costs classified as capacity costs for purposes of calculating BPA's unit cost of capacity is $83.4 million per year. Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.1.3., line 18.

Cost Adjustments

Two cost adjustments are made to the total embedded costs, one for the 4(h)(10)(C) credit and another for Synchronous Condensing. The portion of the 4(h)(10)(C) credit that is associated with program costs is included because Fish and Wildlife Program costs are included in the capacity cost calculation, and a portion of 4(h)(10)(C) credit is an offset to those costs. The portion of the 4(h)(10)(C) credit that is associated with the cost of balancing purchases is excluded because the cost of balancing purchases is classified as an energy cost. The portion of BPA's capacity costs that are allocated to Synchronous Condensing—the investments in plant modifications at the John Day and The Dalles projects that are necessary to provide Synchronous Condensing—are removed ($189,000 per year) to avoid double counting, since these capacity costs are associated with Synchronous Condensing and are already assigned to Transmission through that methodology, as described in Section 9.3.2 of this Study. *Id.,* line 22. The portion of the 4(h)(10)(C) credit associated with capacity and the removal of the costs associated with Synchronous Condensing totals an average of $84.9 million per year for the rate period. *Id.*, line 23.

Treatment of Conservation

All costs associated with conservation are excluded from the calculation of the embedded capacity cost. This is because, although energy conservation provides both capacity and energy benefits, the amount of capacity provided from BPA's conservation investments is not readily available. Given this, both the costs of conservation and conservation's contribution to the system capability of the resources available to BPA are excluded.

9.3.1.2.2 The Capacity Available to BPA

The capacity of all the resources available to BPA, excluding conservation (*see* Section 9.3.1.2.1 above), is made up of 1) physical resources (regulated hydro, independent hydro, small hydro, and thermal); and 2) forecast or actual generation augmentation purchases. Non-hydro renewable generation, described in detail in the Power Loads and Resources Study, BP-26-FS-BPA-03, § 3.1.3, is excluded. Although these wind and solar resources produce energy, they are excluded from capacity because these forms of generation are variable. The sum of these two sources is equal to an annual average one-hour system capability (under monthly P10 firm generating conditions) of 16,571 MW for the rate period. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.1.2, line 33.

Capacity from Physical Resources

BPA's primary source of capacity is from physical resources and is equal to 16,295 MW. Physical resource capacity is established as described in the Power Loads and Resources Study, BP-26-FS-BPA-03, § 3.1.2. The 14-period one-hour capacity of each federal resource type is averaged to create an annual average one-hour capacity under monthly P10 firm generating conditions. These average annual one-hour capacities are then averaged across the three-year rate period, and reduced for transmission losses, to create rate period average one-hour capacities after losses. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.1.2.

Capacity from Power Purchases

BPA may also obtain additional capacity through forecast and actual power purchases. All forecast and actual power purchase amounts considered augmentation purchases are included in the total amount of capacity available to BPA. System augmentation is discussed in the Power Loads and Resources Study, BP-26-FS-BPA-03, § 4.2, and System augmentation amounts are presented in that Study in Table 2. All augmentation purchases, including Tier 1, Tier 2 and Other Augmentation, are assumed to be made on a flat annual basis. These flat augmentation purchases increase the amount of capacity available to the federal system by an equal amount in all months. *See* Power Rates Study Documentation BP-26-FS-BPA-01A, Table 9.3.1.2, lines 31-32.

9.3.1.2.3 Embedded Unit Cost Calculation

The embedded unit cost of capacity is calculated by taking the costs attributable to capacity (*see* Section 9.3.1.2.1) and dividing by the capacity of the resources available to BPA. The embedded unit cost of capacity is equal to $6.39/kW per month. Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.1.4, line 8.

9.3.1.3 Variable Cost Pricing Methodology

9.3.1.3.1 Introduction and Purpose

When BPA holds reserve capacity, it incurs variable costs due to efficiency losses. To hold reserves on stand-by, BPA incurs fuel costs as water is used in a manner less efficient than had BPA not been required to hold reserves. Efficiency losses impact the federal system in regard to output in MWhs, timing of energy generation, and therefore net revenues received from sales. The Variable Fuel Cost Model (VFCM) calculates the variable costs of holding reserves on the federal system for the duration of the rate period.

The changes in efficiency are determined by conducting an "A B" test in which two scenarios are compared. The A case is a scenario in which all required reserves are held and modeled. The B case is a hypothetical scenario in which a reserve constraint is relaxed. The delta between the generation levels of these two cases are priced to determine the efficiency costs of holding reserves. Two types of costs are calculated in the model. First, energy shift costs are the costs associated with the change in daily generation shape due to holding reserves. Second, net generation delta costs are associated with the overall change in available daily generation due to holding reserves.

9.3.1.3.2 Inputs

This section describes the preparation of the input data for the VFCM.

RiverWare System Generation Forecast

The VFCM uses the hourly total system generation values for each case used in the A B test. See Power Loads and Resources Study, BP-26-FS-BPA-03, § 3.1.2.1.4, as well as the BPA 2024 White Book for additional information on how the RiverWare application is used for system planning.

The RiverWare model simulates the operation of the FCRPS and produces a measure of aggregated system generation for each hour, day, month, and rate period year assuming hydrological conditions for each year of a representative 30-year sample. The sample water years are 1989 to 2018. The model simulates the generation levels given system constraints, including reservoir targets, flood control, and fish passage.

These hourly generation values are used in combination with prices produced by the Aurora production cost model. The Aurora Market Price Forecast is discussed more below.

In order to perform the A B test, but separate the impact of *inc* versus *dec* reserves, three scenarios were run through the RiverWare model: Base, *Inc* Reserves, and *Dec* Reserves.

1. The first scenario is classified as the Base Case. This is the case where *inc* and *dec* reserves are assumed to be held in the RiverWare modeled run. In other words, in this scenario, total generation measures include all assumed reserve constraints.
2. The second scenario is classified as *Inc* Reserves. This is the case where the constraint to hold *inc* reserves is removed from the RiverWare modeled run. All other constraints from the base case remain. The capacity quantities that are counted in this scenario are quantities necessary for Regulating *inc* balancing reserves as well as operating reserves (spinning and supplemental).
3. The third scenario is classified as *Dec* Reserves. This is the case where the constraint to hold *dec* Reserves is removed from the RiverWare modeled run. All other constraints from the base case remain. The capacity quantities that are counted in this scenario are quantities necessary for Regulating *dec* balancing reserves.

Aurora Market Price Forecast

Another input into the VFCM is the Mid-Columbia (Mid-C) Aurora market price forecast. See Power Market Price Study, BP-26-FS-BPA-04, Section 2.4. The Aurora market price forecast applies variability to several inputs (such as loads, natural gas market prices, transmission system constraints, and long-term resource build assumptions across the WECC) to simulate 90 iterations for each year of the 30 water samples to produce a total of 2,700 iterations from which to compute average monthly diurnal prices at the Mid-C hub. The 90 iterations for each water year are averaged across months, or monthly diurnal periods, to produce a set of flat monthly prices, and a set of flat monthly diurnal prices, for each water year.

9.3.1.3.3 Pre-calculation data processing

Generation Delta Using RiverWare

The generation delta is measured as the difference between the Case B generation levels where reserve constraints have been relaxed ("Unconstrained Gen") and the Case A generation level ("Base Case Gen") for each hour (H) in a day. The following equation summarizes this calculation:

$$Generation\ Delta_H = Unconstrained\ Gen_H - Base\ Case\ Gen_H$$

Positive generation deltas indicate that for each given hour the unconstrained case simulates higher levels of generation than the constrained case. The reverse is true for negative generation deltas; for each given hour the unconstrained case simulates lower levels of generation than the constrained case.

To mitigate the potential for biased results, the total generation delta was adjusted to exclude outliers by removing observations below the 5th percentile and above the 95th percentile for each month and water year. Unique months within each water year that had less than five standard deviations were deemed to have no outliers and therefore did not have any observations excluded.

The total sum of hourly generation deltas for a day is split into two separate cost components that consist of energy shift and net generation delta, as described below.

Energy Shift

In the VFCM, energy shift is the term used to describe the measured losses of system flexibility because of the need to hold reserves. Flexibility allows system operators to engage in load factoring which is a process in which water is saved in one period in order to use it during a later high load or high value period. An example of load factoring is when operators minimize generation during low load periods such as the early morning (*e.g.*, 3 a.m.) in order to save water for high load periods later in the day such as the evening (*e.g.*, 4-8 p.m.). Load factoring does not necessarily occur in equal time periods. For example, load factoring may be conducted by saving water during a concentrated period (two or three hours) and then using that water over a longer period (five to seven hours). Energy shifts are measured in megawatthours on a daily basis and reflect the changing dynamics of hydro conditions as well as seasonal load variations. This means that load factoring looks different in different parts of the year. Because RiverWare produces hourly generation data for the rate period, the model captures the energy shifts that are unique to each day of simulated generation.

As modeled by the VFC, energy shifts are energy neutral within a day in that they do not result in any more or less MWh in the given day. The losses are associated with shifting a given amount of energy from an opportune period to a less opportune period.

The VFCM calculates the MWh of energy shift for each water year and day by selecting the smaller absolute value of either 1) the total hourly sum of negative generation deltas for each day, or 2) the total hourly sum of positive generation deltas for each day. This is calculated for both the *inc* scenario as well as the *dec* scenario. In this way, energy shifts are modeled as energy neutral for a given day, and the model is designed to establish the daily quantity of megawatthours of either positive or negative generation deltas as a quantity of shifted energy. The following equation summarizes this calculation:

$$Energy\ Shift\ Delta = \min\left(\left|\sum_{H=1}^{24} Negative\ Delta_H\right|, \left|\sum_{H=1}^{24} Positive\ Delta_H\right|\right)$$

$where$:

$$Negative\ Delta_H\ is\ Generation\ Delta_H < 0, and$$

$$Positive\ Delta_H\ is\ Generation\ Delta_H > 0.$$

Net Gen Delta

The daily net generation delta represents the sum daily megawatthour impacts of holding reserves after energy shifts have been accounted for. These are the impacts that are not energy neutral over the course of a day within each water year. Some key factors that are estimated in the net generation delta are forced spill and changes in system efficiency. Because the VFCM uses RiverWare simulation data for the whole system, the impacts of holding reserves are not isolated for particular projects within the FCRPS or particular types of impacts. Net generation deltas are typically a positive value, but for some days they can be negative. A positive net generation delta represents a situation in which holding reserves results in lower levels of generation for a given day. Appearing less frequently, negative net generation deltas represent a situation in which holding reserves results in higher levels of generation for a given day.

Daily Net Generation Deltas are calculated by summing the hourly generation deltas for a single day in each of the water years. The generation deltas that offset each other throughout the day are considered energy shift and the remaining generation deltas are summed as the net generation delta for each day. The following equation summarizes this calculation:

$$\textit{Net Generation Delta} = \sum_{\mathrm{H}=1}^{24} \mathrm{Delta}_{\mathrm{H}}$$

Aurora Mid-C Market Price Forecast

The VFCM utilizes two price sets from the Mid-C Aurora forecast. The first is the monthly flat price forecast. This price set is averaged across iterations for each water year, fiscal year, and month. The second price set is the LLH/HLH price set. This price set is also averaged across iterations for each condition, LLH and HLH. The monthly flat price for each water year is used as-is without further adjustments. The VFCM adapts a month's LLH and HLH into a high and low price set by taking the maximum and minimum value from each month's HLH and LLH price set.

9.3.1.3.4 Calculation of Reserve Costs

The total variable reserve cost is the sum of the energy shift costs and the net generation delta costs. For each water year and day, energy shift costs are calculated by multiplying the quantity of shifted energy (megawatthours) by the price spread between the high and low price for the matching water year and month. The price spread is calculated by subtracting the low price from the high price for each water year and month. The logic behind pricing energy shift in this manner is that the price spread signifies the costs to hold reserves. For example, if the requirement to hold reserves results in over-generation in particular periods, and under-generation in other periods it is assumed that the periods of forced over-generation are during periods of lower prices and times of forced under-generation are during periods of higher prices. The net result of the modeled forced sale (over-generation or negative generation deltas) and foregone sale/forced purchase (under-generation or positive generation deltas) is calculated by multiplying the sum of daily energy shift MWh (for each water year) by each water year's monthly price spread. The daily total costs are then averaged across the 30 water years before summing those daily values to create monthly totals.

The net generation delta cost for each water year and day is calculated by multiplying the quantity of net generation delta (megawatthours) by the monthly average price for each water year. The logic follows that the overall change in system efficiency as measured by total generation cannot be associated with any particular period within each day and thus it is appropriate to assume the monthly average price rather than a price associated with a monthly high or low price or particular diurnal time frame such as HLH and LLH. After daily total costs are calculated, they are averaged across the 30 water years before summing those for each month within the rate period.

Once each component part is calculated the total monthly variable reserve cost is calculated by summing the monthly energy shift cost and the monthly net generation cost. A sum of each month per fiscal year produces an annual total variable fuel cost of reserves.

The following equations summarize the calculations described above:

$$Energy\ Shift\ Delta\ Cost_M = Energy\ Shift\ Delta_M \times (High\ Price_M - Low\ Price_M)$$

$$Net\ Generation\ Delta\ Cost_M = Net\ Generation\ Delta_M \times Average\ Price_M$$

$$Total\ Variable\ Fuel\ Costs_M = Energy\ Shift\ Delta\ Cost_M + Net\ Generation\ Delta\ Cost_M$$

$$Total\ Annual\ Variable\ Fuel\ Costs = \sum_{M=1\ Month}^{12} Total\ Variable\ Fuel\ Costs_M$$

9.3.1.3.5 Variable Cost of Reserves

The purpose of the VFCM is to determine the costs associated with holding reserves on the FCRPS system. These costs are attributed to two categories of reserves, *inc* and *dec*. For simplicity, the VFCM does not account for potential further subcategorization such as spinning versus non-spinning *inc* reserve capacity. (Accounting for the differences in the types of *inc* and *dec* reserves is applied in the rate design step described below in Section 9.3.1.4 below.) While costs are calculated for *inc* and *dec* in aggregate, the model does, however, differentiate between costs that are incurred due to energy shifts and general net changes in generation. The output from the VFCM thus includes information for each of these categories of costs that are incurred due to holding reserves.

The VFCM was calculated for the Initial Proposal, using quantities that were part of the forecast at that time. The results of the VFCM analysis completed for the Initial Proposal have been applied to here for the Final Proposal. For the BP-26 rate period, the VFCM measures the costs associated with 1,111 MW of *inc* Reserves and 609 MW of *dec* Reserves. These values include the assumption that the FCRPS reaches its maximum threshold of 900 MW *inc* and 1,100 MW *dec* for balancing reserves as described in the Generation Inputs Study, BP-26-FS-BPA-06, § 2.10. For the *inc*, 578 MW of the total is associated with Regulation Balancing Reserves and the remaining, 533 MW, is associated with Operating Reserves. For *dec*, the entire 609 MW is associated with Regulation Balancing Reserves. Non-Regulating Balancing Reserves, both *inc* and *dec*, were excluded from the VFCM because BPA has an opportunity to recoup the costs associated with holding Non-Regulating Balancing Reserves through its participation in the Western EIM.

Total variable costs associated with *inc* and *dec* are provided by month in Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.1.5. For the BP-26 rate period, the annual average associated with *dec* is $1.3 million and with *inc* is $14.5 million. Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.1.5, line 38.

9.3.1.4 Rate Design Cost Adjustment Methodology

After embedded and variable costs have been calculated and before final reserve capacity rates are established, a rate design step is applied to incremental capacity reserves to reflect the relative opportunity costs associated with providing different types of capacity—fast and flexible capacity as compared to slower and less flexible capacity. The value delta is equal to the difference in costs between thermal generators designed for each type of reserve capacity type. The outcome of this benchmarking process illustrates that faster and more flexible capacity is more costly than slower and less flexible capacity. The process by which BPA applies the value delta to Regulating and Non-Regulating *inc* balancing reserves and spinning and supplemental operating reserves is detailed in Section 9.3.1.5.1 below.

9.3.1.4.1 Fast and Flexible vs. Slower and Less Flexible Incremental Benchmarking

Measuring the cost differential between fast and flexible versus slower and less flexible reserves begins by selecting benchmarking generators that are appropriate for providing each type of *inc* service. The Wärtsilä 18V50SG reciprocating generator is selected to benchmark costs associated with providing fast and flexible reserve services and the General Electric 7HA.02 combustion turbine is selected for providing slower and less flexible services. The Wärtsilä reciprocating generator (RG) is used to benchmark Regulating and spinning operating reserves due to its technical capability to provide fast and flexible reserve capacity. The 7HA.02 turbine, on the other hand, is a standard in providing slower and less flexible capacity due to its fuel efficiency and lower long-term costs. The 7HA.02 turbine is used to benchmark Non-Regulating and supplemental operating reserves.

Benchmarking is conducted by calculating the annual average expense to own, operate and maintain the Wärtsilä RG and the 7HA.02 combustion turbine (CT). A detailed description of how annual fixed costs associated with the Wärtsilä RG are calculated is available in Section 4.1.1.2.1 above and shown in Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 4.1. The same process is applied to the 7HA.02 CT to determine the annual average expense to own, operate and maintain the generator. Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.1.6. The annual average expense is divided by 12 to calculate the monthly average cost to operate each generator. The average dollars per kilowatt per month costs for the Wärtsilä RG and 7HA.02 CT are compared to derive the cost differential. This cost differential is used to create the value delta between the spinning and non-spinning *inc* reserve capacity.

For FYs 2026-2028, the estimated average cost for the Wärtsilä RG is $11.70/kW/month and for the 7HA.02 CT is $7.04/kW/month. Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 4.1, line 26, column J, and Table 9.3.1.6, line 14. The value delta for FYs 2026-2028 is thus $4.66/kW/month. Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.1.6, line 26, column J.

9.3.1.5 Capacity Cost Calculation

9.3.1.5.1 Unit Cost by Reserve Type

The variable costs allocated to *inc* balancing, *dec* balancing, and operating reserves are divided by their respective quantities of capacity to calculate a unit cost of the allocated variable costs. As discussed above, the VFCM calculates costs associated with the Regulating portion of the *inc* balancing reserve requirement; however, those variable unit costs are allocated into a general *inc* balancing reserve cost bucket due to the fact that they are differentiated in a later rate design step that is described below. The unit cost for Non-Regulating *dec* reserves has no allocated variable costs. The variable unit costs for each type of capacity are as follows:

- For *inc* balancing the unit cost of allocated variable costs is $0.87/kW/month.
- For Regulating *dec* balancing the unit cost of allocated variable costs is $0.21/kW/month.
- For Non-Regulating dec balancing the unit cost of allocated variable costs is $0.00/kW/month.
- For operating reserves the unit cost of allocated variable costs is $0.87/kW/month.

The embedded unit cost of $6.39/kW/month (Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.1.9, line 2) is added to the unit cost of allocated variable costs for *inc* balancing and operating reserves. The unit cost for *dec* reserves has no embedded cost component. The total unit costs of allocated embedded and variable costs for each type of capacity are as follows:

- The total unit cost for *inc* balancing is $7.26/kW/month (*id.*, lines 12, 14).
- The total unit cost for Regulating *dec* balancing is $0.21/kW/month (*id.*, line 13).
- The total unit cost for Non-Regulating *dec* balancing is $0.00/kW/month (*id.*, line 15).
- The total unit cost for operating reserves is $7.26/kW/month (*id.*, line 16).

Once the total unit cost is determined, a rate design step is applied to create a price differential between Regulating and Non-Regulating *inc* balancing reserves as well as between spinning and supplemental operating reserves to reflect the differing opportunity costs (*i.e.*, the value delta as described above) associated with providing these capacity types. The goal of this step is to establish a fixed price delta between unit costs of faster services and slower services without collecting more revenue than the amount of costs allocated to each service prior to applying the rate design step.

Costs of the BPA's available capacity are allocated to each service (Non-Regulating and Regulating, spinning and supplemental) in proportions equal to the overall balancing area needs. These are the proportions that reflect the required reserve capacity established by the BAA irrespective of the supplier of that reserve capacity. BPA's application of a rate design through a fixed value delta looks to these proportions to establish suitable price signals that incent efficient decisions concerning supply alternatives. Power Rates Study Documentation, BP-26-FS-BPA-01A, Tables 9.3.1.7 and 9.3.1.8. The proportions used for this cost allocation were established in the Initial Proposal. These same proportions are applied here.

The process of applying the rate design step begins with the total allocated costs (embedded and variable) of each service along with the total MW quantities forecasted for the two capacity types within each service (Regulating and Non-Regulating for the balancing service and spinning and supplemental for the operating reserve service). The following set of two equations are then applied to calculate the cost of the two balancing reserves types (Regulating and Non-Regulating):

Balancing inc Reserves

$$UC_R - UC_{NR} = VD$$

$$UC_R(MW_R) + UC_{NR}(MW_{NR}) = TotalAllocatedCost_{Bal\_Inc}$$

Where:

UC_R refers to the unit cost for Regulating *inc* reserves.

UC_{NR} refers to the unit cost for Non-Regulating *inc* reserves.

VD refers to the Value Delta (*i.e.*, the opportunity cost rate design goal), as described in Section 9.3.1.4.1 above, and is equal to $4.66/kW/month.

MW_R refers to the quantity of regulation *inc* reserves.

MW_{NR} refers to the quantity of Non-Regulating *inc* reserves.

$TotalAllocatedCost_{Bal\_Inc}$ refers to the total costs allocated to *inc* balancing services.

The average annual Regulating balancing *inc* reserves forecasted for the rate period is 434,000 kW and Non-Regulating balancing *inc* reserves are 404,000 kW. Power Rates

Study Documentation, BP-26-FS-BPA-01A*,* Table 9.3.1.8, lines 3, 4. The average annual amount of costs allocated to Regulating and Non-Regulating balancing *inc* is $73.0 million. *Id.,* line 6. Given this information, the Regulating balancing *inc* service receives a value adjustment of +$2.25/kW/month and Non-Regulating balancing *inc* service receives a value adjustment of –$2.41/kW/month. *Id.,* Table 9.3.1.9, lines 21-22. After the rate design step is applied, the unit cost for Regulating *inc* balancing capacity is $9.51/kW/month, and the unit cost for Non-Regulating *inc* balancing capacity $4.85/kW/month. *Id.*, lines 27, 29.

The following set of two equations are applied to calculate the cost of the two operating reserves types (spinning and supplemental):

$$\textit{Operating inc Reserves}$$

$$UC_{Spin} - UC_{Sup} = VD$$

$$UC_{Spin}\left(MW_{Spin}\right) + UC_{Sup}\left(MW_{Sup}\right) = TotalAllocatedCost_{OP}$$

Where:

UC_{Spin} refers to the unit cost for spinning operating reserves.

UC_{Sup} refers to the unit cost for supplemental operating reserves.

VD refers to the Value Delta (*i.e.*, the opportunity cost rate design goal) as described in Section 9.3.1.4.1 above and is equal to $4.66/kW/month.

MW_{Spin} refers to the quantity of operating spinning reserves.

MW_{Sup} refers to the quantity of operating supplemental reserves.

$TotalAllocatedCost_{OP}$ refers to the total costs allocated to operating reserves service.

The average annual operating reserves forecasted for this rate period are 504,000 kW, half of which are spinning and half of which are supplemental. Power Rates Study Documentation, BP-26-FS-BPA-01A*,* Table 9.3.1.8, lines 11-12. The average annual amount of costs allocated to operating reserves is $43,949. *Id.*, line 14. Given this information, spinning operating reserves receives a value adjustment of +$2.33/kW/month and supplemental operating reserves an adjustment of –$2.33/kW/month. *Id.,* Table 9.3.1.9, lines 23-24. After the rate design step is applied, the unit cost is $9.59/kW/month for spinning operating reserves capacity and $4.93/kW/month for supplemental operating reserves capacity. *Id.*, lines 31-32.

9.3.1.5.2 Forecast of Revenue from Balancing Reserves

The revenue from providing Regulating reserves is forecast by applying the unit costs to the Regulating reserves *inc* and *dec* quantity forecasted to be purchased by Transmission. Transmission has forecasted the purchase of an average of 482,000 kW (annual average) of Regulating reserves *inc*, and 503,00 kW (annual average) of Regulating reserves *dec*. Power Rates Study Documentation, BP-26-FS-BPA-01A*,* Table 9.3.1.10, lines 14, 15. These quantities do not include quantities necessary to provide balancing services for federal generation. The revenue forecast is an average annual amount of $56.3 million. *Id.*, lines 21-22.

The revenue from providing Non-Regulating Reserves is forecast by applying the unit costs to the Non-Regulating Reserves *inc* and *dec* quantity forecasted to be purchased by Transmission. Transmission has forecasted the purchase of an average of 334,000 kW (annual average) of Non-Regulating Reserves *inc*, and 466,000 kW (annual average) of Non-Regulating Reserves *dec*. *Id.*, lines 16, 17. These quantities do not include quantities necessary to provide balancing services for federal generation. The revenue forecast is an average annual amount of $19.4 million. *Id.*, lines 23-24.

9.3.1.5.3 Forecast of Revenue from Operating Reserves

The revenue from providing spinning operating reserves is forecast by applying the unit cost calculated above to the spinning operating reserves quantity forecast. The revenue forecast is an average annual amount of $29.0 million. *Id.*, line 27.

The revenue from providing non spinning operating reserve is forecast by applying the unit cost calculated above to the non spinning operating reserve quantity forecast. The revenue forecast is an average annual amount of $14.9 million. *Id.*, line 28.

9.3.2 Synchronous Condensing

9.3.2.1 Introduction

This section describes the method used to determine the amount of energy consumed by those FCRPS hydro generators that operate as synchronous condensers, and the determination of the cost of that energy that is allocated to BPA Transmission Services. It also describes the costs allocated to Transmission Services associated with the investment in plant modifications necessary to provide synchronous condensing at the John Day and The Dalles projects. Synchronous condensing costs allocated to Transmission Services are recovered through transmission rates and passed to BPA Power Services as an inter-business-line transfer.

9.3.2.2 Description of Synchronous Condensers

A synchronous condenser is essentially a motor with a control system that enables the unit to regulate voltage. These machines dynamically absorb or supply reactive power as necessary to maintain voltage as needed by the transmission system. Some FCRPS generators operate in synchronous condenser or "condense" mode for voltage control and for other purposes (*i.e.,* to accommodate operational constraints associated with taking a unit offline). A generator operating in condense mode provides the same voltage control function as the unit does when generating real power. As with any motor, a unit operating in condense mode consumes real energy. Generators operating in condense mode in the FCRPS consume energy supplied by other units in the FCRPS.

9.3.2.3 Synchronous Condenser Costs

Synchronous condensing costs include the cost of 1) investment in plant modification at John Day and The Dalles projects necessary to provide synchronous condensing, and 2) energy consumed by FCRPS generators while operating in condense mode for voltage control.

The investments in plant modifications at the John Day and The Dalles projects result in an average cost of $189,333 per year. Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.2.3, line 1; Power Revenue Requirement Study Documentation, BP-26-FS-BPA-02A, Table 2F. These costs are the annual capital-related costs in the power revenue requirement associated with the investment that Power Services made in the plants at the request of Transmission Services to enable synchronous condense capability.

For the costs associated with the energy used in condense mode operations, the amount of forecast energy is priced at an average annual market price. The methodology to determine the amount and cost of energy consumption is described below.

9.3.2.4 General Methodology to Determine Energy Consumption

For the FY 2026-2028 rate period, the FCRPS generators capable of operating in condense mode are identified, and the number of hours that the generators would operate in condense mode for voltage control is forecast. The forecast is derived from historical synchronous condenser operations, based on an average of the following three years of data, which are fiscal years 2021, 2022, and 2023. The average number of hours is multiplied by the fixed hourly energy consumption for the generators to determine the amount of energy consumed. The fixed hourly energy consumption is the motoring power consumption of the specific generator units when they are operated in condense mode. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.2.1.

Finally, the market price forecast is applied to the amount of energy consumed to calculate the cost of synchronous condensing. The methodology for assigning historical synchronous condenser operations to the voltage control function and calculating the associated energy use for each of the FCRPS projects capable of operating in condense mode is described below.

9.3.2.4.1 Grand Coulee Project

Six generators (Units 19-24) at the Grand Coulee project are capable of operating as synchronous condensers, although only three are typically operated in condense mode. The Study forecasts the number of hours that the Grand Coulee units will operate in condense mode based on historical condenser operations for the three-year historical period. The transmission system typically needs additional voltage control from the Grand Coulee project during nighttime hours (generally hours 20:00 to 06:00), when the lightly loaded transmission system results in excess reactive power and causes excess voltage on the system. Historical reactive demand and unit operations are examined, and units operated in condense mode are allocated to either Transmission Services or Power Services, based on the reactive demand of the transmission system, the reactive capability of the units, the number of units on-line producing real power, and operation of the shunt reactor (which absorbs reactive power and reduces voltage). The method for assigning condensing units to the voltage control function and developing the forecast is described below.

For the forecast, BPA first determines the total measured reactive demand that the transmission system placed on the six units only during the nighttime hours. This measured reactive demand is based on archived reactive meter readings for the historical three-year period. The total measured reactive demand represents the total reactive support (*e.g.*, megavolt amperes reactive) provided by all six units, regardless of whether the units are condensing or generating real power (units operating in generation mode also provide reactive support in addition to real power). For each hour, the total measured reactive demand is compared to the reactive capability of the units online generating real power plus, if not operating, the reactive capability of the shunt reactor.

If the reactive capability of online units and the shunt reactor is less than the total measured reactive demand for the hour, one or more units operating in condense mode are allocated to voltage control for that hour. If a condensing unit is allocated to voltage control for a single nighttime hour, the condensing operation of that unit is allocated to voltage control for the entire nighttime period to reflect the fact that, in practice, a unit would not be started and stopped on an hourly basis. Condensing units are allocated to voltage control in whole increments until the total measured reactive demand is met or exceeded. The number of condensing hours for the three-year historical period is averaged, and energy consumption is determined by multiplying the average annual condensing hours by the fixed hourly energy consumption of the generators. The forecast of total energy consumed by the Grand Coulee generators operating in synchronous condense mode for voltage control is 16,104 MWh/yr. Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.2.1, line 4.

9.3.2.4.2 John Day, The Dalles, and Dworshak Projects

The John Day project has four generators (Units 11-14), The Dalles has six generators (Units 15-20), and the Dworshak project has three generators (Units 1-3) capable of operating as synchronous condensers. These three projects condense only when requested by Transmission Services, so all hours in condense mode are assigned to voltage control. The number of condensing hours for the three-year historical period is averaged, and energy consumption is calculated by multiplying the average annual condensing unit hours by the fixed hourly energy consumption of the applicable hydro units. The forecast of total energy consumed by the generators operating in condense mode for voltage control is 18,718 MWh/yr. for John Day and The Dalles (*id.*, line 3), and 350 MWh/yr. for the Dworshak project (*id.*, lines 5-6).

9.3.2.4.3 Palisades Project

The Palisades project has four generators (Units 1-4) that are capable of synchronous condensing. Units are operated in condense mode pursuant to standing instructions from Transmission Services based on operational studies, so all hours in condense mode are assigned to voltage control. The number of condensing hours for the three-year historical period is averaged. Energy consumption is determined by multiplying the average annual condensing unit hours by the fixed hourly energy consumption of the project. The forecast of energy consumption by the Palisades generators operating in condense mode for voltage control is 2,031 MWh/yr. Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.2.1, line 7.

9.3.2.4.4 Willamette River Projects

The Willamette River projects have seven generators capable of condensing, which include units in the Detroit project (Units 1-2), the Green Peter project (Units 1-2), and the Lookout Point project (Units 1-3). Historically these units have been operated at times in condense mode. However, BPA studies indicate that condensing is not required from these projects for voltage support except under rare conditions. Therefore, the energy for condensing operation for voltage control is forecast to be zero for the Willamette River projects. *Id.*, lines 8-10.

9.3.2.4.5 Hungry Horse Project

The Hungry Horse project has four generators (Units 1-4) capable of condensing. Although capable of condensing, Hungry Horse was not requested to operate in condense mode during the three-year historical period. Therefore, the energy consumption for the Hungry Horse generators is forecast to be zero. *Id.*, line 11.

9.3.2.5 Summary—Costs Assigned to Transmission Services

Synchronous condensing costs assigned to Transmission Services are the investments in plant modifications and the energy consumed for condensing operation. As stated above, the investments in plant modifications at the John Day and The Dalles projects result in an average cost of $189,333 per year. Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.2.3, line 1; Power Revenue Requirement Study Documentation, BP-26-FS-BPA-02A, Table 2F.

The energy forecast to be consumed by FCRPS generators operating in condense mode totals 37,202 MWh. Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.2.1, line 13. The energy consumed for condensing operation is priced at the market price forecast. *See* Power Market Price Study and Documentation, BP-26-FS-BPA-04, § 2.4. Applying the market price forecast of $38.91 per MWh to the energy consumed results in a total cost of $1,447,543 per year. Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.2.1, line 13. This amount is made up of $728,317 per year in energy costs for the Southern Intertie, and $719,225 associated with energy costs for voltage control for the Network. *Id.*, lines 3, 12. Total synchronous condensing cost allocated to Transmission Services, then, is the sum of the $189,333 per year in plant investments for the Southern Intertie and the total cost of energy consumed of $1,447,543, which equals $1,636,876 per year. *Id.*, Table 9.3.2.3, lines 1, 5.

9.3.3 Generation Dropping

9.3.3.1 Introduction

This section describes the method for allocating costs of Generation Dropping, including identifying the assumptions used in the methodology and establishing the generation input cost allocation that is applied to determine the annual revenue forecast for generation inputs.

9.3.3.2 Generation Dropping Requirement

The BPA transmission system is interconnected with several other transmission systems. To maximize the transmission capacity of these interconnections while maintaining reliability standards, Remedial Action Schemes (RAS) are developed for the transmission grids. These schemes automatically make changes to the system when a contingency occurs to maintain loadings and voltages within acceptable levels. Under one of these schemes, Transmission Services requests that Power Services instantaneously drop (disconnect from the system) large increments of generation (at least 600 MW). To satisfy this requirement, the generation must be dropped virtually instantaneously from a certain region of the transmission grid. Under the current configuration of the transmission grid and the individual generating plant controls, Power Services can most expeditiously provide this service by dropping one of the Grand Coulee Third Powerhouse hydroelectric units (each of which exceeds 600 MW capacity).

9.3.3.3 General Methodology

The methodology for calculating the cost of Generation Dropping starts with two factors: the impact to the equipment involved and the lost revenue associated with that impact. These factors are applied to a single generating unit at the Grand Coulee Third Powerhouse to arrive at an estimate of a single generation drop. This number is then multiplied by the estimated average drops per year to arrive at an estimate of the cost of Generation Dropping for each year of the rate period. Generation Dropping causes additional wear and tear on equipment that will decrease the life and increase the maintenance of the unit. For each major component that is affected by this service. Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.3.1 shows the cost associated with incremental equipment deterioration, replacement, and overhaul, and the cost associated with incremental routine operation and maintenance.

Historical data for the Grand Coulee Third Powerhouse generating units and statistical data for other hydroelectric units provide capital cost, operation and maintenance costs, and frequency of operation information for the Generation Dropping analysis. Stresses on the equipment from Generation Dropping versus stresses during normal operation are compared. Through the application of this data, the capital and operation and maintenance costs for Generation Dropping are developed. The impacts are converted into a percentage change in equipment life and percentage increase in operations and maintenance for each operation.

9.3.3.4 Generation Dropping Cost

9.3.3.4.1 Incremental Equipment Deterioration, Replacement, or Overhaul Costs

One effect of additional deterioration because of Generation Dropping is a reduced period of time between major maintenance activities, such as major overhauls or replacements. For purposes of this analysis, a "major overhaul" is defined as a maintenance activity for which at least partial disassembly of the affected equipment is required. The analysis focuses on evaluating the costs of additional, short-term deterioration of specific components or items for which statistical data are readily available. The costs of a major overhaul are derived from estimates or similar work performed in the past.
The percentage life reductions are determined using industry standards or actual project records. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.3.1, column B. For example, turbine overhaul is a major maintenance effort that will increase in frequency as a result of Generation Dropping.

Power Services previously contracted with Harza Engineering Company to work with Reclamation and the Corps (which operate and maintain the FCRPS projects) to evaluate the costs of providing Generation Dropping. The evaluation estimated the cost incurred by a typical Reclamation or Corps generating unit. These cost estimates are applied to a generating unit at the Grand Coulee Third Powerhouse. The costs in the original engineering study are updated using the Handy-Whitman Index to reflect price escalation of equipment and labor costs.

The Handy-Whitman Index multiplier is applied to the equipment costs in the study performed by Harza Engineering Company. The annual Incremental Equipment Deterioration, Replacement, and Overhaul Cost per drop for FY 2026-2028 is calculated by multiplying the percentage of Life Reduction per drop by the cost of a Major Overhaul. *Id.*, column D, line 6.

9.3.3.4.2 Incremental Routine Operation and Maintenance Costs

In addition to more frequent major overhauls, increases in routine operations and maintenance costs are expected due to the additional deterioration caused by Generation Dropping. The Incremental Routine Operations and Maintenance (O&M) Cost per drop is calculated using the Percentage Increase O&M Per Drop and expected annual operations and maintenance costs per major piece of equipment. The percentage increase in O&M costs is assumed to be equivalent to the percentage life reductions used to determine the incremental deterioration, replacement, or overhaul costs (*e.g.*, a 0.1 percent reduction in life per drop will result in a 0.1 percent increase in annual O&M costs). Annual O&M costs are increased by an inflation factor of 2.35 percent for FY 2026-2028. The annual Incremental Routine O&M Cost per Drop for FY 2026-2028 is calculated by multiplying the Percentage Increase O&M Per Drop by the Annual O&M Cost. *See id.*, column G, line 6. It is assumed that these outages are longer than scheduled or unpredictable outages, and cannot be scheduled to avoid a loss in total project generation.

9.3.3.4.3 Incremental Lost Revenue in the Event of Replacement or Overhaul

The revenue lost during outages for the overhaul or replacement of equipment is significant for the large generating units with a capacity exceeding 600 MW. Lost revenues are calculated based on the forecast market price averaged over the rate period, FY 2026-2028.

The Downtime Cost is calculated by multiplying the average monthly generation loss for a Unit 22, 23, or 24 outage by the assumed months of downtime for each piece of equipment by the market price forecast. *See* Power Market Price Study and Documentation, BP-26-FS-BPA-04, § 2.4. The annual Cost per Drop for FY 2026-2028 is calculated by multiplying the Probability of Failure by the Down Time Cost. Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.3.1, column K, line 6.

9.3.3.5 Costs to be Allocated to Transmission Services

The factors described above are analyzed for their application on a single generating unit at the Grand Coulee Third Powerhouse and their effects combined to produce a single, overall cost associated with each generation drop. From these analyses, the total cost associated with a single generator drop of one of the Grand Coulee Third Powerhouse Units is calculated to be $714,375. *Id.*, column L, line 6.

Historically, large generating units at Grand Coulee have been dropped 27 times over the last 28 years (1996 through 2024). Therefore, the average of approximately 1 drop per year is used as the Generation Dropping estimate.

Multiplying the 1 drop per year by the cost of a single drop ($714,375), the forecast annual cost is $714,375. *Id.*, column D, line 7. This cost is assigned to Transmission Services for recovery in transmission rates. The rate period annual average cost for Generation Dropping is a revenue credit to the power rates. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.1.1 line 10.

9.3.4 Redispatch

9.3.4.1 Introduction

Under the Tariff and the Redispatch and Curtailment Business Practice, Transmission Services can initiate redispatch as part of congestion management efforts. Generally, redispatch results in actions that can effectively relieve a transmission constraint that may impair the reliability of BPA's transmission system and maintains service to loads.

The Business Practice provides three types of redispatch that Transmission Services can request from Power Services to relieve congestion: Discretionary Redispatch, NT Redispatch, and Emergency Redispatch. Additionally, the Business Practice provides Power Services the ability to purchase transmission to ensure delivery to load, such as in the form of redispatch for stranded Load. Power Services may provide redispatch through *inc* and *dec* of federal generation, through purchases and/or sales of energy, or through transmission purchases. The purposes of each of these types of redispatch are discussed further below. The price of redispatch is calculated based on one of two sources, depending on how the redispatch is provided: 1) for redispatch provided from federal generation, market prices for incrementing and decrementing federal generation at the time the redispatch is provided; or 2) for redispatch provided by purchases and/or sales of energy or purchases of transmission, the actual cost to Power Services of purchasing and/or selling power or purchasing transmission.

This Study forecasts the cost of redispatch that will be transferred as revenue to Power Services from Transmission Services for the provision of redispatch during the FY 2026-2028 rate period. The forecast is based on actual redispatch costs from October 2019 to August 2024.

9.3.4.2 Discretionary Redispatch

Under the Redispatch and Curtailment Business Practice, Transmission Services may request Discretionary Redispatch from federal resources to *inc* and *dec* generation prior to curtailment of any transmission schedules.

Discretionary Redispatch totaled $0 in FY 2020, $0 in FY 2021, $43,565 in FY 2022, $0 in FY 2023, and $12,500 in FY 2024 (through August), averaging $11,419. Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.4.1, column B provides the actual annual Discretionary Redispatch details for October 2019 to August 2022. For FY 2026 through FY 2028, Transmission Services forecasts Discretionary Redispatch of $ 11,419 per year.

9.3.4.3 Network Integration Redispatch

Under the Redispatch and Curtailment Business Practice, Transmission Services requests NT Redispatch from Power Services to maintain firm NT schedules. NT Redispatch can be requested only after all non-firm Point-to-Point and secondary NT schedules are curtailed in a sequence consistent with NERC curtailment priority. Power Services must provide NT Redispatch when requested by Transmission Services to the extent that it can do so without violating non-power constraints.

NT Redispatch totaled $262,326 in FY 2020, $87,437 in FY 2021, $97,539 in FY 2022, $51,492 in FY 2023, and $30,414 in FY 2024 (through August), averaging $107,782. *Id.*, columns C-D. Of this total amount from 2020 through August 2024, only $9,541was associated with Power Services providing NT Redispatch through the redispatch of federal generation or through power purchases or sales. The rest ($519,668 over the same period) represents payments from Transmission Services to Power Services associated with NT Redispatch provided through transmission purchases only. Power Rates Study

Documentation, BP-26-FS-BPA-01A, Table 9.3.4.1 provides, for FY 2020 through FY 2024 (through August), the actual annual NT Redispatch cost. The NT Redispatch forecast for FY 2026-2028 is $107,782 per year.

9.3.4.4 Emergency Redispatch

Under the Redispatch and Curtailment Business Practice, Transmission Services may request Emergency Redispatch from Power Services to minimize the risk and/or scope of a transmission system reliability condition. Power Services must provide Emergency Redispatch when requested.

Emergency Redispatch for FY 2020, FY 2021, FY 2022, FY 2023, and FY 2024 (through August) totaled $0. The average from FY 2020 to FY 2024 (through August) was $0. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.4.1, column E.

Because Emergency Redispatch is a rare event, it is forecast to be $0 for FY 2026-2028. *Id*.

9.3.4.5 Redispatch for Stranded Load

Under the Redispatch and Curtailment Business Practice, Power Services may purchase transmission to ensure delivery to load. Specifically, BPA serves certain load that, in cases of planned outages, "strand" that load from being electrically connected to BPA and must be served through third-party transmission service. In these situations Power Services purchases the third-party transmission service to ensure delivery to BPA's load is not interrupted. These redispatch for stranded load costs are then reimbursed by Transmission Services.

Redispatch for stranded load totaled $71,779 in FY 2020, $208,361 in FY 2021, $203,618 in FY 2022, $36,560 in FY 2023 and $96,784 in FY 2024 (through August), averaging $125,682. The redispatch for stranded load forecast for FY 2026-2028 is $125,682 per year. Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.4.1, column F.

9.3.4.6 Revenue Forecast for Redispatch Service

Based on the analysis above, total revenues of $244,883 per year is forecast for FY 2026-2028 for Redispatch services provided by Power Services to Transmission Services. *Id.*, line 7.

9.3.5 Station Service

9.3.5.1 Introduction

Station service refers to real power that Transmission Services takes directly off the BPA power system for use at substations and other locations, such as facilities located on BPA's Ross Complex and Big Eddy/Celilo Complex. For purposes of this Study, station service does not include power that BPA purchases from another utility or that is supplied by another utility for station service purposes. Because there are locations on the system where BPA does not have meters to measure station service use, the amount of energy use at BPA substations and other facilities is estimated. The annual average forecast market price from the Power Market Price Study, BP-26-FS-BPA-04, § 2.4, is applied to the estimated annual energy use adjusted for transmission losses to yield the annual costs that are allocated to Transmission Services for station service energy use. This section describes the station service energy use and the procedure used to determine the costs that are allocated to Transmission Services for station service energy use.

9.3.5.2 Overview of Methodology

The station service costing methodology consists of the following steps: First, a historical monthly average station service energy use was determined based on measured load data for a sample of BPA's substations based on size (large, medium, and small). Second, an average load factor of 9.45 percent was derived based on the ratio of installed station service transformation and energy use for those substations. Third, that average load factor of 9.45 percent is then applied to the total amount of installed transformation, measured in kilovolt amperes (kVA), at all BPA substations served directly by the BPA power system to determine a total usage. Fourth, the station service energy use for all facilities other than the Ross and Big Eddy/Celilo complexes is estimated by applying the average load factor to the total installed station service transformer capacity. This energy use is then added to the historical use for the Ross and Big Eddy/Celilo complexes to estimate total average monthly energy use. The monthly amount is multiplied by 12 to yield an annual average estimated total energy use for all substations, which is then adjusted for transmission losses by applying the BPA network loss factor, 2.05 percent. The annual average forecast market price from the Power Market Price Study, BP-26-FS-BPA-04, § 2.4, is applied to the estimated annual energy use adjusted for transmission losses to yield the annual costs that are allocated to Transmission Services for station service energy use.

9.3.5.3 Assessment of Installed Transformation

This methodology begins by identifying the amount of installed transformation for all BPA substations. Installed transformation transforms power to a lower voltage to supply power to the buildings and equipment at the substations. The total installed transformation is 46,784 kVA. Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.5.2, line 6.

Of this amount, the total amount of installed transformation at BPA substations for which load data exists is 15,456 kVA. *Id.,* Table 9.3.5.1, line 41.

9.3.5.4 Assessment of Station Service Energy Use

The historical average monthly use for the Ross Complex is 1,749,300 kWh, and for Big Eddy/Celilo Complex is 1,822,937 kWh, for a total of 3,572,237 kWh. *Id.*, Table 9.3.5.2, lines 4-5.

The total historical average monthly use for other BPA locations for which load data exists is 1,066,446 kWh. *Id.,* Table 9.3.5.1, line 41. Because not all use is metered, the total average monthly use for BPA substations is estimated based on the historical average monthly use multiplied by the average load factor. *Id.*, Table 9.3.5.2, lines 1-3.

9.3.5.5 Calculation of Average Load Factor

The average monthly load factor is calculated by dividing the total historical monthly use for BPA substations for which load data is available by the total installed station service transformation for these BPA substations. This yields an average 9.45 percent load factor. *Id.,* Table 9.3.5.1, line 41.

9.3.5.6 Calculating the Total Station Service Average Use

The total installed transformation is multiplied by the average calculated load factor to yield the calculated historical average monthly use for all facilities other than the Ross and Big Eddy/Celilo complexes. *See id.,* Table 9.3.5.2, lines 1-3. The historical station service energy use for the Ross Complex and the Big Eddy/Celilo Complex is then added to the calculated amount of energy use at all other BPA substations. *Id.,* lines 4-5. The total quantity of station service average use that Power Services supplies directly to BPA substations and other facilities is then adjusted for transmission losses by multiplying the average use by the BPA Transmission Network loss factor of 2.05 percent pursuant to Schedule 11 of BPA's Tariff. The adjusted quantity of station service average use supplied to BPA substations and other facilities after adding in the network losses is estimated to be 81,604 MWh per year. *Id.*, line 6.

9.3.5.7 Determining Costs to Allocate to Station Service

The annual average forecast market price (*see* Power Market Price Study, BP-26-FS-BPA-04, § 2.4) applied to the estimated annual quantity of station service energy use, including network losses, yields the energy costs per year to be allocated to Station Service. The capacity rate for Real Power Losses (Section 4.4.2) applied to the estimated quantity of network losses, yields the capacity costs associated with network losses. The sum of the energy costs and the capacity costs associated with Real Power Losses equals the total costs to allocate to station service. This rate period annual average cost is $3.265 million. Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.3.5.2, line 6.

9.3.5.8 Impact on Power Rates and Transmission Rates

The rate period annual average cost for station service is a revenue credit to the power rates. *See id.*, Table 9.3.1.1, line 13.

9.4 Revenue from Treasury Credits

Revenues are also forecast from two kinds of Treasury credits, or deductions, made from BPA's annual Treasury payment. These credits represent a partial reimbursement by the Treasury for expenses incurred by BPA throughout the year.

9.4.1 Section 4(h)(10)(C) Credits

BPA pays all the costs relating to the obligations of Northwest Power Act Section 4(h)(10)(C) regarding protecting, enhancing, and mitigating fish and wildlife in the region. 16 U.S.C. § 839b(h)(10)(C). BPA is reimbursed by the U.S. Treasury for 22.3 percent of the replacement power purchases BPA is expected to make due to fish mitigation, as well as an equal percentage of program and capital expenses related to the fish and wildlife programs. The 22.3 percent represents the non-power portion of the total FCRPS costs, which is the responsibility of taxpayers rather than BPA ratepayers. This Treasury credit is treated as Power Services revenue.

Expenses relating to fish and wildlife programs are discussed in the Power Revenue Requirement Study, BP-26-FS-BPA-02, Section 1.2.1.4. The methodology for estimating the replacement power purchases resulting from changes in hydro system operations to benefit fish and wildlife is described in the Power Loads and Resources Study, BP-26-FS-BPA-03, Section 3.3.1. The cost of the increased purchases is estimated using RevSim and the market price forecast and is included in the Power and Transmission Risk Study, BP-26-FS-BPA-05, Section 4.1.1.1.5.6, and the Power and Transmission Risk Study Documentation, BP-26-FS-BPA-05A, Table 13. Forecast 4(h)(10)(C) credits are listed in Table 4 of this Study, line 23, and Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.2, line 49.

9.4.2 Colville Settlement Credits

The Colville Settlement Agreement obligates BPA to make annual payments to the Colville Tribes. BPA receives annual credits from the U.S. Treasury against payments due the Treasury to defray a portion of the costs of making payments to the Colville Tribes. The Treasury credit for the Colville Settlement in FY 2026, FY 2027, and FY 2028 is set by legislation at $4.6 million per year. *See* Confederated Tribes of the Colville Reservation

Grand Coulee Settlement Act, Pub. L. No. 103-436, 108 Stat. 4577 (Nov. 2, 1994). The credit is shown on Table 4 of this Study, line 24, and Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.2, line 50.

9.5 Power Purchase Expense Forecast

Power Services forecasts three types of power purchase expenses: Augmentation Purchases, Balancing Purchases, and Other Power Purchases. Although most expenses, including some power purchase expenses, such as long-term generating resources, are forecast in the Power Revenue Requirement Study, the power purchase expenses described here are directly related to load, resource, and price assumptions used to develop power rates. Therefore, they are included in the Power Services revenue forecast.

9.5.1 Augmentation Purchase Expense

For planning purposes, the forecast of firm FCRPS output is based upon firm generation conditions. *See* Power Loads and Resources Study, BP-26-FS-BPA-03, § 3.1.2.1.3. The forecast annual firm FCRPS output under firm generation conditions plus the output of other federal resources may not be adequate to meet annual average firm loads. Therefore, system augmentation is added to federal resources to balance firm annual resources with firm annual loads. The forecast expense for the augmentation is based on the remarketing value. *See* Section 3.2.6 above. Augmentation purchase amounts for FY 2025-2028 are listed in Table 4 of this Study, line 26, and Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.2, line 52.

The cost of uncommitted market purchases for Tier 2 augmentation in FY 2025-2028 is listed in Table 4 of this Study, line 28, and Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.2, line 54.

9.5.2 Total Balancing Costs

Total balancing costs include balancing power purchases calculated by RevSim and committed purchases BPA has made to serve preference customer loads in Southeastern Idaho.

RevSIM calculates the balancing power purchases by finding any monthly HLH and LLH energy deficits by simulations of 40 iterations in each of the 30 water years, for a total of 2,700 iterations, and application of the corresponding market prices developed for each iteration. Similar to the treatment of short-term market sales, the median value for balancing purchases over the 2,700 iterations is reported for FY 2025 for forecast months and added to actual purchases in past months, and the median value is reported for FY 2025-2028. Total balancing purchase expense for FY 2025-2028 is listed in Table 4 of this Study, line 27, and Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.2, line 53. A full description is found in the Power and Transmission Risk Study, BP-26-FS-BPA-05, Section 4.1.1.2.2.

Total balancing costs include committed purchases BPA has made to serve preference customer loads in Southeastern Idaho. *See* Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 2.3.2. In those months and water years in which firm loads exceed resources, Southeast Idaho Load Service (SILS) purchases reduce balancing purchases. Conversely, in those months and water years in which resources are sufficient to serve firm loads, SILS purchases increase the amount of surplus sales. RevSim accounts for the energy related to SILS purchases in the balancing purchases category. A full description is found in the Power and Transmission Risk Study, BP-26-FS-BPA-05, Section 4.1.1.2.1, and in Section 6.6 of this Study.

9.5.3 Other Augmentation

Total Other Augmentation expense for FY 2025-2028 is listed in Table 4 of this Study, line 29, and Power Rates Study Documentation, BP-26-FS-BPA-01A, Table 9.2, line 55.

9.6 Summary of Power Revenues

A detailed summary of power revenues at current and proposed rates is found in Tables 3 and 4 of this Study, and in Power Rates Study Documentation, BP-26-FS-BPA-01A, Tables 9.1 and 9.2.

POWER RATES TABLES

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Table 1: Rate Period High Water Marks for FY 2026-2028

Table of RHWMs for FY 2026-2028			
	A	*B*	*C*
	Customer ID	**Customer Name**	**RHWM annual aMW**
1	10055	Albion, City of	0.400
2	10057	Ashland, City of	21.190
3	10015	Asotin County PUD #1	0.577
4	10059	Bandon, City of	7.683
5	10024	Benton County PUD #1	202.081
6	10025	Benton REA	60.003
7	10027	Big Bend Elec Coop	61.547
8	10029	Blachly Lane Elec Coop	17.718
9	10061	Blaine, City of	8.797
10	10062	Bonners Ferry, City of	5.350
11	10064	Burley, City of	14.145
12	10044	Canby, City of	20.426
13	10065	Cascade Locks, City of	2.391
14	10046	Central Electric Coop	82.323
15	10047	Central Lincoln PUD	157.576
16	10066	Centralia, City of	24.512
17	10067	Cheney, City of	15.908
18	10068	Chewelah, City of	2.786
19	10101	Clallam County PUD #1	76.466
20	10103	Clark County PUD #1	320.329
21	10105	Clatskanie PUD	93.373
22	10106	Clearwater Power	24.016
23	10109	Columbia Basin Elec Coop	12.188
24	10111	Columbia Power Coop	3.253
25	10113	Columbia REA	37.910
26	10112	Columbia River PUD	58.586
27	10116	Consolidated Irrigation District #19	0.229
28	10118	Consumers Power	45.937
29	10121	Coos Curry Elec Coop	41.111
30	10378	Coulee Dam, City of	2.033
31	10123	Cowlitz County PUD #1	552.365
32	10070	Declo, City of	0.361

Table of RHWMs for FY 2026-2028			
	A	*B*	*C*
	Customer ID	**Customer Name**	**RHWM annual aMW**
33	10136	Douglas Electric Cooperative	18.644
34	10071	Drain, City of	1.925
35	10142	East End Mutual Electric	2.702
36	10144	Eatonville, City of	3.387
37	10072	Ellensburg, City of	24.120
38	10156	Elmhurst Mutual P & L	32.424
39	10157	Emerald PUD	50.246
40	10158	Energy Northwest	2.807
41	10170	Eugene Water & Electric Board	252.544
42	10173	Fall River Elec Coop	33.321
43	10174	Farmers Elec Coop	0.510
44	10177	Ferry County PUD #1	11.732
45	10179	Flathead Elec Coop	167.784
46	10074	Forest Grove, City of	26.836
47	10183	Franklin County PUD #1	118.028
48	10186	Glacier Elec Coop	21.440
49	10190	Grant County PUD #2	5.221
50	10191	Grays Harbor PUD #1	131.973
51	10197	Harney Elec Coop	22.884
52	10597	Hermiston, City of	13.012
53	10076	Heyburn, City of	4.845
54	10202	Hood River Elec Coop	13.174
55	10203	Idaho County L & P	6.249
56	10204	Idaho Falls Power	80.015
57	10209	Inland P & L	105.495
58	12026	Jefferson County PUD #1	45.433
59	13927	Kalispel Tribe Utility	4.097
60	10230	Kittitas County PUD #1	9.758
61	10231	Klickitat County PUD #1	36.870
62	10234	Kootenai Electric Coop	51.293
63	10235	Lakeview L & P (WA)	33.304
64	10236	Lane County Elec Coop	29.271
65	10237	Lewis County PUD #1	114.388
66	10239	Lincoln Elec Coop (MT)	14.081

Table of RHWMs for FY 2026-2028			
	A	*B*	*C*
	Customer ID	**Customer Name**	**RHWM annual aMW**
67	10242	Lost River Elec Coop	9.581
68	10244	Lower Valley Energy	86.533
69	10246	Mason County PUD #1	9.039
70	10247	Mason County PUD #3	80.389
71	10078	McCleary, City of	3.739
72	10079	McMinnville, City of	88.687
73	10256	Midstate Elec Coop	47.015
74	10080	Milton, Town of	7.480
75	10081	Milton-Freewater, City of	10.515
76	10082	Minidoka, City of	0.119
77	10258	Mission Valley	38.171
78	10259	Missoula Elec Coop	27.141
79	10260	Modern Elec Coop	26.436
80	10083	Monmouth, City of	8.411
81	10273	Nespelem Valley Elec Coop	5.915
82	10278	Northern Lights	36.135
83	10279	Northern Wasco County PUD	65.138
84	10284	Ohop Mutual Light Company	10.768
85	10285	Okanogan County Elec Coop	6.566
86	10286	Okanogan County PUD #1	46.176
87	10288	Orcas P & L	24.877
88	10291	Oregon Trail Coop	79.638
89	10294	Pacific County PUD #2	36.536
90	10304	Parkland L & W	14.149
91	10306	Pend Oreille County PUD #1	25.917
92	10307	Peninsula Light Company	72.400
93	10086	Plummer, City of	3.968
94	10298	PNGC Aggregate	762.537
95	10087	Port Angeles, City of	85.973
96	10706	Port of Seattle - SETAC In'tl. Airport	17.378
97	10331	Raft River Elec Coop	36.813
98	10333	Ravalli County Elec Coop	18.622
99	10089	Richland, City of	104.814
100	10338	Riverside Elec Coop	2.386

Table of RHWMs for FY 2026-2028			
	A	*B*	*C*
	Customer ID	**Customer Name**	**RHWM annual aMW**
101	10091	Rupert, City of	9.477
102	10342	Salem Elec Coop	38.914
103	10343	Salmon River Elec Coop	31.570
104	10349	Seattle City Light	526.931
105	10352	Skamania County PUD #1	15.998
106	10354	Snohomish County PUD #1	803.675
107	10094	Soda Springs, City of	3.054
108	10360	Southside Elec Lines	6.804
109	10363	Springfield Utility Board	101.286
110	10379	Steilacoom, Town of	4.836
111	10095	Sumas, Town of	3.664
112	10369	Surprise Valley Elec Coop	16.527
113	10370	Tacoma Public Utilities	404.709
114	10371	Tanner Elec Coop	11.096
115	10376	Tillamook PUD #1	56.352
116	10097	Troy, City of	2.049
117	10172	U.S. Airforce Base, Fairchild	6.137
118	10406	U.S. DOE Albany Research Center	0.461
119	10426	U.S. DOE Richland Operations Office	42.226
120	10326	U.S. Naval Base, Bremerton	30.635
121	10408	U.S. Naval Station, Everett (Jim Creek)	1.536
122	10409	U.S. Naval Submarine Base, Bangor	20.539
123	10388	Umatilla Elec Coop	113.876
124	10482	Umpqua Indian Utility Cooperative	4.137
125	10391	United Electric Coop	30.150
126	10434	Vera Irrigation District	27.313
127	10436	Vigilante Elec Coop	19.263
128	10440	Wahkiakum County PUD #1	5.034
129	10442	Wasco Elec Coop	13.473
130	11680	Weiser, City of	6.365
131	10446	Wells Rural Elec Coop	96.323
132	10448	West Oregon Elec Coop	8.530
133	10451	Whatcom County PUD #1	26.987
134	10502	Yakama Power	18.815

Table 2: Overview of BP-26 Final Proposal Rates

Tiered PF Rate Summary

1	A	B	C	D
2		**BP-26**	**% above BP-24**	
3	Unbifurcated PF	$ 52.63	9.0%	
4	PF Public (Tier 1 + Tier 2)	$ 40.16	12.2%	
5	PF Exchange	$ 75.98	7.8%	
6	IP	$ 45.60	10.2%	
7	NR	$ 111.27	30.4%	
9	**Annual Average $ (1000s)**	**BP-24**	**BP-26**	**Change**
10	Composite Rate Revenues	$2,380,887	$2,448,350	2.8%
11	Non-Slice Rate Revenues	$(331,991)	$(366,991)	-10.5%
12	Slice Rate Revenues	$-	$-	
13	Load Shaping Rate Revenues	$60,953	$73,880	21.2%
14	Demand Rate Revenues	$61,442	$148,772	142.1%
15	Tier 1 Revenue Requirement	$2,171,291	$2,304,011	6.1%
16	Tier 2 Revenue Requirement	$160,289	$344,445	114.9%
17	Value of Slice Surplus	$(111,312)	$(57,713)	48.2%
18	Value of CHWM RECs (credit)	Not applicable for BP-26		
19	Lookback Return (credit)	Not applicable for BP-26		
20	Net Power Cost to All PF	$2,220,268	$2,590,743	16.7%
21	Surcharges	$-	$-	
22	Annual PF Load (w/firm Slice) (GWh)	61,983	64,506	4.1%
23	PF Average Net Cost ($/MWh)	$ 35.82	$ 40.16	12.1%
25	Tier 1 Average Net Cost without FRP	$ 34.69	$ 37.77	8.9%
26	Tier 1 Average Net Cost max FRP	Not applicable for BP-26		
27	Tier 2 Short-Term ($/MWh)	$ 61.50	$ 68.51	11.4%
29	**Slice Sales**	**BP-24**	**BP-26**	**Change**
30	Composite+Slice	$491,768	$301,796	
31	Surcharges	$-	$-	
32	Tier 1 Average Cost ($/MWh)	$40.21	$41.22	2.5%
33	Value of Slice Surplus Credits	$(111,312)	$(57,713)	
34	Net Cost of Slice Power	$380,456	$244,082	
35	Tier 1 Average Net Cost ($/MWh)	$ 31.11	$ 33.34	7.2%
37	**Non-Slice Sales**	**BP-24**	**BP-26**	**Change**
38	Composite+NonSlice+Shape+Demand	$1,679,622	$2,002,363	
39	Tier 1 Average Cost ($/MWh)	$35.63	$38.40	7.8%
40	Credits	$-	$-	
41	Net Cost of Non-Slice Power	$1,679,622	$2,002,363	
42	Surcharges	Not applicable for BP-26		
43	Tier 1 Average Net Cost without FRP	$ 35.63	$ 38.40	7.8%
44	Tier 1 Average Net Cost max FRP	Not applicable for BP-26		
46	**Tiered PF Rate Components**	**BP-24**	**BP-26**	**Change**
47	Composite Rate ($/ pct/month)	$2,075,946	$2,141,296	3.1%
48	Non-Slice Rate ($/ pct/month	$(364,823)	$(366,092)	0.3%

Table 3: Revenues at Current Rates

	A B C D	E	F	G	H	I	J	K	L
1	**Revenues at Current Rates**	**2025**		**2026**		**2027**		**2028**	
2	**Category**	**$ (000's)**	**aMW**	**$ (000's)**	**aMW**	**$ (000's)**	**aMW**	**$ (000's)**	**aMW**
3	Composite Revenue	$2,371,835	5,323	$2,363,988	5,916	$2,374,213	6,776	$2,382,532	6,800
4	Non-Slice Revenue	($330,400)	-	($364,084)	-	($365,881)	-	($367,343)	-
5	Slice	$0	1,403	$0	840	$0	826	$0	842
6	Load Shaping Revenue	$60,782	24	$45,408	4	$49,590	16	$46,056	3
7	Demand Revenue	$68,661	-	$129,117	-	$135,109	-	$142,389	-
8	Irrigation Rate Discount	($21,737)	-	($21,770)	-	($21,770)	-	($21,770)	-
9	Low Density Discount	($33,490)	-	($38,116)	-	($38,116)	-	($38,116)	-
10	Tier 2	$199,730	391	$298,286	538	$304,931	588	$335,477	627
11	RSS (Non-Federal) and Other	$221	-	$1,056	-	$1,036	-	$1,046	-
12	PF customers (CHWM) sub-total	**$2,315,602**	**7,140**	**$2,413,884**	**7,298**	**$2,439,112**	**8,206**	**$2,480,271**	**8,272**
13	NR sub-total	($3,919)	(0)	$0	1	$0	20	$0	25
14	DSIs sub-total	$4,266	8	$3,987	11	$3,987	11	$3,999	11
15	FPS sub-total	$11,150	-	$9,852	-	$10,063	-	$10,346	-
16	Short-term market sales sub-total	$588,214	1,482	$746,846	1,729	$618,090	1,738	$645,514	1,758
17	Long Term Contractual Obligations sub-total	$0	-	$0	-	$0	-	$0	-
18	Canadian Entitlement Return	$0	462	$0	462	$0	462	$0	461
19	Other Sales sub-total	($33,259)	-	$0	-	$0	-	$0	-
20	**Gross Sales**	**$2,882,054**	**9,093**	**$3,174,570**	**9,501**	**$3,071,251**	**10,437**	**$3,140,130**	**10,528**
21	**Miscellaneous Revenues**	**$28,175**	**175**	**$24,778**	**175**	**$24,769**	**175**	**$24,749**	**175**
22	**Generation Inputs / Inter-business line**	**$113,167**	**9**	**$115,267**	**9**	**$133,903**	**9**	**$150,512**	**9**
23	4(h)(10)(c)	$146,741	-	$124,911	-	$131,117	-	$132,163	-
24	Colville Settlement	$4,600	-	$4,600	-	$4,600	-	$4,600	-
25	**Treasury Credits**	**$151,341**	-	**$129,511**	-	**$135,717**	-	**$136,763**	-
26	Augmentation Power Purchase total	$0	-	$0	-	$0	-	$0	-
27	Balancing Power Purchase sub-total	$454,090	1,129	$104,101	211	$83,251	178	$98,969	209
28	Tier 2 Augmentation total	$0	-	$319,432	554	$329,517	599	$354,163	638
29	Other Augmentation total	$0	-	$7,021	12	$17,440	31	$20,974	38
30	**Power Purchases**	**$454,090**	**1,129**	**$430,554**	**777**	**$430,208**	**809**	**$474,106**	**885**

Table 4: Revenues at Proposed Rates

	A B C D	E	F	G	H	I	J	K	L
1	**Revenues at Proposed Rates**	**2025**		**2026**		**2027**		**2028**	
2	**Category**	**$ (000's)**	**aMW**	**$ (000's)**	**aMW**	**$ (000's)**	**aMW**	**$ (000's)**	**aMW**
3	Composite Revenue	$2,371,835	5,323	$2,438,459	5,916	$2,449,006	6,776	$2,457,587	6,800
4	Non-Slice Revenue	($330,400)	-	($365,300)	-	($367,103)	-	($368,571)	-
5	Slice	$0	1,403	$0	840	$0	826	$0	842
6	Load Shaping Revenue	$60,782	24	$72,093	4	$76,824	16	$72,724	3
7	Demand Revenue	$68,661	-	$141,637	-	$148,212	-	$156,468	-
8	Irrigation Rate Discount	($21,737)	-	($22,034)	-	($22,034)	-	($22,034)	-
9	Low Density Discount	($33,490)	-	($42,155)	-	($43,297)	-	($44,391)	-
10	Tier 2	$199,730	391	$328,238	538	$339,794	588	$365,302	627
11	RSS (Non-Federal) and Other	$221	-	$836	-	$5,582	-	$4,839	-
12	PF customers (CHWM) sub-total	**$2,315,602**	**7,140**	**$2,551,774**	**7,298**	**$2,586,983**	**8,206**	**$2,621,924**	**8,272**
13	NR sub-total	($3,919)	(0)	$10,208	1	$30,593	20	$38,924	25
14	DSIs sub-total	$4,266	8	$4,394	11	$4,394	11	$4,406	11
15	FPS sub-total	$11,150	-	$9,852	-	$10,063	-	$10,346	-
16	Short-term market sales sub-total	$588,214	1,482	$746,846	1,729	$618,090	1,738	$645,514	1,758
17	Long Term Contractual Obligations sub-total	$0	-	$0	-	$0	-	$0	-
18	Canadian Entitlement Return	$0	462	$0	462	$0	462	$0	461
19	Other Sales sub-total	($33,259)	-	$0	-	$0	-	$0	-
20	**Gross Sales**	**$2,882,054**	**9,093**	**$3,323,075**	**9,501**	**$3,250,123**	**10,437**	**$3,321,114**	**10,528**
21	**Miscellaneous Revenues**	**$28,175**	**175**	**$24,778**	**175**	**$24,769**	**175**	**$24,749**	**175**
22	**Generation Inputs / Inter-business line**	**$113,167**	**9**	**$115,267**	**9**	**$133,903**	**9**	**$150,512**	**9**
23	4(h)(10)(c)	$146,741	-	$124,911	-	$131,117	-	$132,163	-
24	Colville Settlement	$4,600	-	$4,600	-	$4,600	-	$4,600	-
25	**Treasury Credits**	**$151,341**	**-**	**$129,511**	**-**	**$135,717**	**-**	**$136,763**	**-**
26	Augmentation Power Purchase total	$0	-	$0	-	$0	-	$0	-
27	Balancing Power Purchase sub-total	$454,090	1,129	$104,101	211	$83,251	178	$98,969	209
28	Tier 2 Augmentation total	$0	-	$319,432	554	$329,517	599	$354,163	638
29	Other Augmentation total	$0	-	$7,021	12	$17,440	31	$20,974	38
30	**Power Purchases**	**$454,090**	**1,129**	**$430,554**	**777**	**$430,208**	**809**	**$474,106**	**885**

Table 5: Adjustments to Financial Reserves Base Account

	B	C	D	E	F	G
1	Unit	Account	Stat Amt	Ref	Line Descr	Reason for adjustment
2	POWER	999044	$ (673,094.63)	AR00114197	Receipt from DOJ	1
3	POWER	999044	$ (104,552.35)	AR00117261	Receipt from FERC	1
4	POWER	999044	$ (53,497.33)	AR00119524	Receipt from DOJ	1
5	POWER	999044	$ (2,789.38)	AR00122086	Receipt from DOJ	1
6	POWER	999044	$ (5.04)	AR00129431	Stock dividend	2
7	POWER	999044	$ (6,667.74)	AR00127956	Receipt from FERC	1
8	POWER	999044	$ (1,528.11)	AR00128358	Receipt from DOJ	1
9	POWER	999044	$ (1,080.25)	AR00143938	Receipt from DOJ	1
10	POWER	999044	$ (2,700.63)	AR00152218	Receipt from DOJ	1
11	POWER	999044	$ (43,791.87)	AR00153347	Receipt from FERC	1
12	POWER	999044	$ (5.04)	AR00144929	Stock dividend	2
13	POWER	999044	$ (5.04)	AR00147994	Stock dividend	2
14	POWER	999044	$ (5.04)	AR00151401	Stock dividend	2
15	POWER	999044	$ (5.04)	AR00156308	Stock dividend	2
16	POWER	999044	$ (5.04)	AR00158673	Stock dividend	2
17	POWER	999044	$ (73,765,314.86)		CAL ISO/PX Receipt	1
18	POWER	999044	$ (41,271.39)	AR00242805	Receipt from FERC	1
19	POWER	999045	$ (16,300,000.00)	AR00249656	CA Refund Settlement	1
20						
21			**$ (90,996,318.78)**			
22						

23 **Reasons for adjustments**

24 1) BPA's receipt of payments for settlements or judgments pertaining to power marketing transactions that occurred before FY 2002.

25 2) BPA's receipt of funds as collections of outstanding receivables relating to revenues that occurred before FY 2002.

26 3) BPA's payment for settlements or judgments pertaining to power marketing transactions that occurred before FY 2002.

28 Base amount of financial reserves = $495,600,000

30 Adjustment to the base amount of financial reserves = $495,600,000 + $90,996,319

32 **Resulting amount of financial reserves = $586,596,319**

34 Adjustment amounts, if negative, are added to the base amount of financial reserves, thereby increasing the size of the base amount.

35 Adjustment amounts, if positive, are subtracted from the base amount of financial reserves, thereby decreasing the size of the base amount.

Table 6: Residential Exchange Benefits

($000)

	A	B	C	D
1		**FY 2026**	**FY 2027**	**FY 2028**
2	Avista Corporation	$9,253	$9,253	$9,278
3	Idaho Power Company	$2,997	$2,997	$3,006
4	NorthWestern Energy, LLC	$6,200	$6,200	$6,217
5	PacifiCorp	$111,415	$111,415	$111,720
6	Portland General Electric Company	$78,906	$78,906	$79,122
7	Puget Sound Energy, Inc.	$77,068	$77,068	$77,279
8	**Net IOU Exchange**	**$285,839**	**$285,839**	**$286,622**
9	Refund Amt	$ -	$ -	$ -
10	**Total IOU REP Benefits (Rate Period Average)**			**$286,100**
11	Clark Public Utilities	$ -	$ -	$ -
12	Franklin	$ -	$ -	$ -
13	Snohomish County PUD No 1	$1,212	$1,229	$1,253
14	**Net COU Exchange**	**$1,212**	**$1,229**	**$1,253**
15	**Total REP Benefits (Rate Period Average)**			**$287,331**

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Appendix A: 7(c)(2) Industrial Margin Study

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APPENDIX A

7(c)(2) Industrial Margin Study

1. INTRODUCTION

The purpose of this appendix is to describe BPA's calculation of the "typical margin" included by the Administrator's public body and cooperative customers in their retail industrial rates. The resulting margin is added to the PF-26 energy rates, which become the energy rates used in the IP-26 rate for BPA's direct-service industrial customers (DSIs).

Section 7(c)(1)(B) of the Northwest Power Act provides that rates applicable to BPA's DSI customers shall be set "at a level which the Administrator determines to be equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers in the region." Section 7(c)(2) provides that this determination shall be based on "the Administrator's applicable wholesale rates to such public body and cooperative customers and the typical margins included by such public body and cooperative customers in their retail industrial rates." This section further provides that the Administrator shall take into account:

1. the comparative size and character of the loads served;
2. the relative costs of electric capacity, energy, transmission, and related delivery facilities provided and other service provisions; and
3. direct and indirect overhead costs, all as related to the delivery of power to industrial customers.

2. METHODOLOGY

2.1 Administrator's Applicable Wholesale Rates to Public Body and Cooperative Customers

The Administrator's applicable wholesale rates to public body and cooperative customers are the PF-26 demand and energy rates before any 7(b)(2) or floor rate adjustments are applied.

2.2 Typical Margin

The typical margin is based generally on the overhead costs that consumer-owned utilities add to the cost of power in setting their retail industrial rates; *see* Section 2.3 below.

2.3 Margin Determination Factors

Comparative Size and Character of the Loads Served. The data base used for the study includes utilities that serve at least one industrial consumer with a peak demand of at least 3.5 MW.

Relative Costs of Electric Capacity, Energy, Transmission, and Related Delivery Facilities Provided and Other Service Provisions. The utility margins in this study are based to the extent possible on utility cost of service analyses and incorporate costs allocated to the industrial consumer class. The utilities segregate these costs into various cost categories, and only those categories considered to be appropriate margin costs are included in the industrial margin calculation.

In the past, BPA has accounted for "other service provisions" through a character of service adjustment for service to the first quartile of DSI load, which was interruptible as defined in the DSIs' power sales contract. Because the DSI contracts no longer include these provisions, this adjustment is not included in this study.

Direct and Indirect Overhead Costs. Cost of service studies and other spreadsheets prepared by the public body and cooperative customers provide information to calculate the per-unit overhead costs associated with service to large industrial consumers.

3. APPLICATION OF THE METHODOLOGY

3.1 Data Base

The data base consists of cost of service information from 33 utilities that have at least one industrial consumer with a peak load of at least 3.5 MW. The data was collected in 2011 from qualifying utilities by the Public Power Council (PPC) under the terms of a confidentiality agreement. Under the terms of that agreement, the names of the individual utilities and their industrial consumers were deleted from the data base, and the names were not publicly disclosed. Furthermore, all parties wishing to evaluate the utility margin data at the PPC offices were required to sign confidentiality agreements. All utility data reported has been identified by a randomly assigned number. Attachment 1 to this appendix displays each participating utility's individual data.

3.2 Utility Margins

The individual utility margins are based on costs allocated by the utilities to their industrial consumers. The categories of costs include production, transmission, distribution, taxes, and other overhead costs. Derivation of the margin involves three steps. First, an individual margin is determined for each utility in the study. Second, each margin is weighted according to energy sales to derive an overall weighted average margin. Third, the BPA DSI delivery facilities charge is added to replace the distribution costs that otherwise may be included in the margin.

3.3 Summary of Results

The final results of each step in the industrial margin calculation for each utility are shown on the summary table in Attachment 1 to this appendix. These results were used in the BP-12 rate case. As shown on the summary table, the weighted industrial margin for the BP-12 rate case was 0.685 mills/kWh.

4. THE INDUSTRIAL MARGIN FOR THE BP-26 RATE CASE

BPA did not conduct a new industrial margin survey for the BP-26 rate case. Instead, the industrial margin is escalated for inflation between the start of the BP-12 rate period and the start of the BP-26 rate period. The escalation factor uses the GDP Implicit Price Deflator using actuals from the Bureau of Economic Analysis and forecast from IHS Markit. Accordingly, the BP-12 industrial margin, 0.685 mills/kWh, is multiplied by 1.41. The BP-26 industrial margin is 0.966 mills/kWh.

Summary - 2012 Margin Study Results

Utility Code Number	Test Period Energy (KWh)	Total Cost	Production	Transmission	Distribution	Other	Taxes	Weighted Margin
1	51,410,428					$ 5.67		0.017
2	1,581,923,558					$ 0.04		0.004
3	95,688,000	$ 47.66	$ 36.62	$ -	$ 9.38	$ 0.45	$ 1.21	0.002
5	42,823,202	$ 57.46	$ 36.78	$ 0.85	$ 18.61	$ 0.42	$ 0.80	0.001
6	29,114,880	$ 43.02	$ 34.50	$ 2.36	$ 2.87	$ 0.72	$ 2.57	0.001
7	40,694,000					$ -		0.000
8	405,668,000					$ -		0.000
9	361,407,000	$ 4.78	$ 3.84	$ 0.01	$ 0.72	$ 0.07	$ 0.13	0.002
11	467,121,000	$ 45.11	$ 32.63	$ 5.45	$ 3.18	$ 0.81	$ 3.04	0.022
12	248,035,470	$ 36.22	$ 34.20	$ 0.25	$ 1.36	$ 0.00	$ 0.38	0.000
13	119,932,734	$ 38.94	$ 36.80	$ -	$ 0.04	$ 0.01	$ 2.09	0.000
14	61,910,899	$ 10.77	$ -	$ 0.47	$ 9.79	$ 0.51	$ -	0.002
15	966,012,620					$ 0.02		0.001
16	169,040,000					$ 0.47		0.005
17	352,800,436	$ 41.45	$ 30.46	$ 0.23	$ 10.69	$ 0.06	$ -	0.001
18	5,390,158,000	$ 49.42	$ 40.45	$ 0.90	$ 6.60	$ 0.88	$ 0.58	0.273
20	297,405,000					$ 0.15		0.003
21	340,000,000					$ 0.43		0.008
23	78,758,000	$ 43.69	$ 33.49	$ 0.12	$ 8.23	$ 1.11	$ 0.74	0.005
24	203,423,478	$ 62.26	$ 33.19	$ 4.05	$ 22.70	$ 0.10	$ 2.22	0.001
25	152,608,000	$ 40.67	$ 31.32	$ 0.77	$ 4.29	$ 3.40	$ 0.89	0.030
26	47,700,000	$ 46.82	$ 34.17	$ 0.85	$ 10.86	$ 0.32	$ 0.62	0.001
27	15,897,484					$ 0.32		0.000
28	3,022,602,000					$ 0.54		0.093
29	718,303,000					$ 0.35		0.015
30	808,561,000	$ 51.24	$ 47.77	$ 0.14	$ 0.30	$ 0.04	$ 2.99	0.002
31	223,878,000	$ 36.86	$ 29.79	$ -	$ 5.86	$ 0.71	$ 0.49	0.009
32	750,395,000	$ 54.12	$ 44.55	$ 2.13	$ 0.15	$ 4.19	$ 3.10	0.180
33	194,837,000	$ 46.71	$ 39.37	$ -	$ 4.53	$ 0.01	$ 2.81	0.000
34	21,884,198					$ 5.29		0.007
35	94,165,000	$ 26.69	$ 7.06	$ 0.66	$ 15.48	$ 0.03	$ 3.47	0.000
36	19,516,800					$ 0.03		0.000
37	38,909,777					$ 0.01		0.000
Total:	17,412,583,964							0.685

Utility Number: # 1

Two industrial customers; rates set through contract.

Customer 1: BPA rate plus $1.09/MWh; 2009 sales (kWh)	=				**31,485,920**
Margin	=			**$**	**34,320**
Customer 2: BPA rate plus $21,430/mo; 2009 sales	=				**19,924,508**
Margin	=			**$**	**257,160**
Total margin from Customers 1 & 2	=	**$**	**291,480**		
Sales to Customers 1 & 2 (kWh)	=		**51,410,428**		

Utility Number: # 2

Large Industrial includes sales under Schedules 14, 15, & 16

	Ave # of customers	Load (kWh)		Monthly basic charge
Schedule 14	3	123,852,000	$	200
Schedule 15	6	1,223,870,998	$	500
Schedule 16	10	234,200,560	$	200
		1,581,923,558		
		Total basic charges/year =	**$**	**67,200**

Utility Number: # 3							
	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Production:	$ 3,503,816	$ 3,503,816					$ 3,503,816
Transmission:	$ -						
Distribution:	$ 66,980			$ 66,980			$ 66,980
Customer Accounts:	$ 20,315				$ 20,315		$ 20,315
Customer Services:	$ 4,599				$ 4,599		$ 4,599
Admin & Genl:	$ 68,093			$ 49,632	$ 18,461		$ 68,093
Taxes:	$ 115,384					$ 115,384	$ 115,384
Depreciation:	$ 779,001			$ 779,001			$ 779,001
Interest:	$ 2,352			$ 2,352			$ 2,352
TOTAL	$ 4,560,540	$ 3,503,816		$ 897,965	$ 43,375	$ 115,384	$ 4,560,540

Utility Number: # 5							
	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Production:	$ 1,574,999	$ 1,574,999					$ 1,574,999
Transmission:	$ 14,196		$ 14,196				$ 14,196
Distribution:	$ 310,053			$ 310,053			$ 310,053
Customer Accounts:	$ 7,316				$ 7,316		$ 7,316
Meter Reading:	$ 194			$ 194.00			$ 194
Customer Service:	$ 3,456				$ 3,456		$ 3,456
Sales Exp:	$ 2,549				$ 2,549		$ 2,549
Admin & Genl (1):	$ 120,230		$ 5,056	$ 110,429	$ 4,744		$ 120,230
Depreciation:	$ 232,235		$ 10,168	$ 222,067			$ 232,235
Taxes:	$ 34,108					$ 34,108	$ 34,108
Interest:	$ 159,676		$ 6,991	$ 152,685			$ 159,676
Other:	$ 1,731		$ 76	$ 1,655			$ 1,731
TOTAL	$ 2,460,743	$ 1,574,999	$ 36,486	$ 797,084	$ 18,065	$ 34,108	$ 2,460,743

Utility Number: # 6	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Purchased Power:	$ 1,035,622	$ 1,035,622					$ 1,035,622
Transmission:	$ 712		$ 712	$ -			$ 712
Distribution:	$ 59,107			$ 59,107			$ 59,107
Meter Reading:	$ 18			$ 18			$ 18
Customer Records & Collection:	$ 54			$ 54			$ 54
Misc Customer Service:	$ 87				$ 87		$ 87
A & G:	$ 41,855		$ 497	$ 41,297	$ 61		$ 41,855
Taxes:	$ 74,851					$ 74,851	$ 74,851
Inrerest:	$ 46,721		$ 555	$ 46,166			$ 46,721
Capital Projects:	$ 88,598		$ 67,619		$ 20,979		$ 88,598
Other Deduction (2):	$ (63,872)		$ (758)	$ (63,021)	$ (93)		$ (63,872)
BPA Conservation, Con Aug, other:	$ (31,231)	$ (31,231)					$ (31,231)
TOTAL	$ 1,252,522	$ 1,004,391	$ 68,625	$ 83,621	$ 21,034	$ 74,851	$ 1,252,522

Utility Number: # 7
One industrial customer with a monthly peak of at least 3.5 MW; 2009 load = 40,694 MWh
Monthly Base Charge = $0.00
Demand Charge = $5.75/kW
Energy Charge = $0.0316/kWh

Utility Number: # 8
One industrial customer with a monthly peak of at least 3.5 MW; 2009 load = 405,668 MWh
Monthly Base Charge = $0.00
Industrial rates set by city ordinance

Utility Number: # 9

	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Power Costs:	$ 1,387,888	$ 1,387,888					$ 1,387,888
Transmission:	$ 1,320		$ 1,320				$ 1,320
Distribution:	$ 71,299			$ 71,299			$ 71,299
Customer Accounts:	$ 263				$ 263		$ 263
Public Relations & Info:	$ 11,873				$ 11,873		$ 11,873
Energy Services:	$ 3,159				$ 3,159		$ 3,159
Admin & Genl:	$ 63,036		$ 946	$ 51,079	$ 11,011		$ 63,036
Depreciation:	$ 75,872		$ 1,379	$ 74,493			$ 75,872
Taxes:	$ 48,396					$ 48,396	$ 48,396
Interest:	$ 65,238		$ 1,186	$ 64,052			$ 65,238
TOTAL	$ 1,728,344	$ 1,387,888	$ 4,831	$ 260,923	$ 26,306	$ 48,396	$ 1,728,344

Utility Number: # 11

	Two Industrial Customers	Production	Transmission	Distribution	Other	Taxes	Sum
Power:	$ 15,244,327	$ 15,244,327					$ 15,244,327
Transmission:	$ 2,544,405		$ 2,544,405				$ 2,544,405
Distribution:	$ 1,481,945			$ 1,481,945			$ 1,481,945
Meter Reading + Cust Records:	$ 5,366			$ 5,366			$ 5,366
Customer Education:	$ 77,324				$ 77,324		$ 77,324
Low Income Assist.:	$ 156,540				$ 156,540		$ 156,540
Electirc Marketing:	$ 142,594				$ 142,594		$ 142,594
Taxes:	$ 1,419,465					$ 1,419,465	$ 1,419,465
TOTAL	$ 21,071,966	$ 15,244,327	$ 2,544,405	$ 1,487,311	$ 376,458	$ 1,419,465	$ 21,071,966

Utility Number: # 12	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Generation:	$ 644,417	$ 644,417					$ 644,417
Purchased Power:	$ 8,379,469	$ 8,379,469					$ 8,379,469
Transmission:	$ 77,781		$ 77,781				$ 77,781
Distribution:	$ 412,110			$ 412,110			$ 412,110
Meter Reading + Customer Records:	$ 9,303			$ 9,303			$ 9,303
Customer Service:	$ 3,113				$ 3,113		$ 3,113
Admin & Genl:	$ 496,109	$ 278,795	$ 33,651	$ 182,317	$ 1,347		$ 496,109
Taxes:	$ 95,106					$ 95,106	$ 95,106
Interest:	$ 341,788	$ 192,595	$ 23,246	$ 125,947			$ 341,788
Capital Projects:	$ 455,818	$ 256,850	$ 31,002	$ 167,966			$ 455,818
Other Revenue:	$ (1,931,751)	$ (1,270,440)	$ (103,488)	$ (560,694)	$ (4,142)		$ (1,938,764)
TOTAL	$ 8,983,263	$ 8,481,687	$ 62,191	$ 336,948	$ 318	$ 95,106	$ 8,976,250

Utility Number: # 13	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Purchased Power:	$ 3,813,592	$ 3,813,592					$ 3,813,592
Transmission							
Distribution							
Conservation	$ 600,000	$ 600,000					$ 600,000
Meters & Services	$ 4,742			$ 4,742			$ 4,742
Accounting	$ 536				$ 536		$ 536
Customer Related	$ 789				$ 789		$ 789
Revenue Related	$ 250,374					$ 250,374	$ 250,374
TOTAL	$ 4,670,033	$ 4,413,592		$ 4,742	$ 1,325	$ 250,374	$ 4,670,033

Utility Number # 14

	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Production:	$ -						
Transmission:	$ 29,120		$ 29,120				$ 29,120
Distribution:	$ 560,614			$ 560,614			$ 560,614
Metering & Billing:	$ 45,398			$ 45,398			$ 45,398
Customer Services:	$ 31,565				$ 31,565		$ 31,565
TOTAL	$ 666,697		$ 29,120	$ 606,012	$ 31,565		$ 666,697

Utility Number: # 15

7 customers in High Voltage General rate class; load = 966,012,620 kWh

Customer Charge per meter per month = **$ 210**

Total customer charges per year = **$ 17,640**

Utility Number: # 16

1 large industrial customer with peak of at least 3.5 aMW

Total Insustrial sales in 2009 = 169,040 MWh

Fixed charge (equivalent to customer charge of $6,557/month; annual cost = $ 78,684

Utility Number: # 17	Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Purchased Power:	$ 10,747,941	$ 10,747,941					$ 10,747,941
Transmission:	$ 15,940		$ 15,940				$ 15,940
Distribution:	$ 735,733			$ 735,733			$ 735,733
Customer Accnts:	$ 4,917				$ 4,917		$ 4,917
Customer Svcs:	$ 1,963				$ 1,963		$ 1,963
Interest on Debt (2):	$ 398,427		$ 8,449	$ 389,978			$ 398,427
Depreciation (2):	$ 551,528		$ 11,696	$ 539,832			$ 551,528
Additional revenue req.:	$ 2,165,398		$ 45,621	$ 2,105,704	$ 14,073		$ 2,165,398
TOTAL	$ 14,621,847	$ 10,747,941	$ 81,706	$ 3,771,247	$ 20,953		$ 14,621,847

Utility Number: # 18

	Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Generation:	$ 45,179,704	$ 45,179,704					$ 45,179,704
Purchased Power:	$ 182,460,007	$ 182,460,007					$ 182,460,007
Conservation:	$ 26,968,662	$ 26,968,662					$ 26,968,662
Transmission:	$ 9,881,306		$ 9,881,306				$ 9,881,306
Distribution:	$ 72,213,558			$ 72,213,558			$ 72,213,558
Customer costs:	$ 4,980,734				$ 4,980,734		$ 4,980,734
Low income assistance:	$ 4,680,598				$ 4,680,598		$ 4,680,598
Franchise Adjustments:	$ 3,136,376					$ 3,136,376	$ 3,136,376
Revenue Credits:	$ (83,124,365)	$ (36,590,117)	$ (5,011,314)	$ (36,623,179)	$ (4,899,754)		$ (83,124,365)
TOTAL	$ 266,376,580	$ 218,018,256	$ 4,869,992	$ 35,590,379	$ 4,761,578	$ 3,136,376	$ 266,376,580

Utility Number: # 20

2 large industrial customers with peak of at least 3.5 aMW

Total Industrial sales in 2009 = 297,405 MWh

Margin charges = 0.0195 cents/kWh for first 19.1 aMW in a month, and 0.0098 cents for each kWh thereafter

167,316,000	kWh at 0.0195 cents
130,089,000	kWh at 0.0098 cents

Total margin charges for 2009 = **4,537,534** cents = **$ 45,375**

Utility Number: # 21

Industrial sales in 2010 = 340,000 MWh

Industrial customers in 2010 = 35

Customer cost per month in 2010 = **$349**

Total customer cost = **$146,639**

Utility Number: # 23	Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Purchased Power:	$ 2,626,334	$ 2,626,334					$ 2,626,334
Transmission:							
Distribution:	$ 318,070			$ 318,070			$ 318,070
Customer Services & Accts:	$ 63,752			$ 9,575	$ 54,177		$ 63,752
A & G:	$ 155,355	$ 11,293		$ 130,111	$ 13,951		$ 155,355
Depreciation:	$ 141,272		$ 9,761	$ 112,513	$ 18,998		$ 141,272
Interest:	$ 77,847			$ 77,847			$ 77,847
Taxes:	$ 58,569					$ 58,569	$ 58,569
TOTAL	$3,441,199	$2,637,627	$9,761	$648,116	$87,126	$58,569	$3,441,199

Utility Number: # 24

	(includes NLSL)	Production	Transmission	Distribution	Other	Taxes	Sum
Production:	$ 6,752,558	$ 6,752,558					$ 6,752,558
Transmission:	$ 414,702		$ 414,702				$ 414,702
Distribution:	$ 2,326,532			$ 2,326,532			$ 2,326,532
Customer Related:	$ 19,242				$ 19,242		$ 19,242
A & G:	$ 448,614		$ 67,395	$ 378,092	$ 3,127		$ 448,614
Depr & Amort:	$ 939,205		$ 142,086	$ 797,119			$ 939,205
Taxes:	$ 451,195					$ 451,195	$ 451,195
Interest:	$ 1,347,794		$ 203,898	$ 1,143,896			$ 1,347,794
Capital Requirements:	$ 232,129		$ 35,117	$ 197,011			$ 232,129
Other Income:	$ (267,290)		$ (40,154)	$ (225,272)	$ (1,863)		$ (267,290)
TOTAL	$ 12,664,681	$ 6,752,558	$ 823,043	$ 4,617,379	$ 20,506	$ 451,195	$ 12,664,681

Utility Number: # 25

	Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Purchased Power:	$ 4,780,364	$ 4,780,364					$ 4,780,364
Transmission:	$ 69,374		$ 69,374				$ 69,374
Distribution:	$ 393,197			$ 393,197			$ 393,197
Customer Related:	$ 1,729				$ 1,729		$ 1,729
A & G:							
Prop ins/inj & damag:	$ 17,112			$ 17,112			$ 17,112
Cust acct/serv & info/sales rel:	$ 480,913				$ 480,913		$ 480,913
Depreciation:	$ 328,871	$ 18	$ 48,211	$ 244,836	$ 35,806		$ 328,871
Taxes:	$ 135,572					$ 135,572	$ 135,572
TOTAL	$ 6,207,132	$ 4,780,382	$ 117,585	$ 655,145	$ 518,448	$ 135,572	$ 6,207,132

Utility Number: # 26

	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Purchased Power:	$ 1,629,832	$ 1,629,832					$ 1,629,832
Transmission:	$ 12,295		$ 12,295				$ 12,295
Distribution:	$ 150,666			$ 150,666			$ 150,666
Customer Related:							
Meter reading & cust. Records:	$ 6,440			$ 6,440			$ 6,440
Customer sales & service:	$ 7,343				$ 7,343		$ 7,343
Depreciation:	$ 129,443		$ 9,395	$ 120,048			$ 129,443
A & G + Other Expense:	$ 185,637		$ 12,914	$ 165,011	$ 7,712		$ 185,637
Taxes:	$ 29,545					$ 29,545	$ 29,545
Interest:	$ 74,929		$ 5,438	$ 69,491			$ 74,929
Other Expenses:	$ 7,009		$ 506	$ 6,200	$ 302		$ 7,008
TOTAL	$2,233,139	$1,629,832	$40,548	$517,856	$15,357	$29,545	$2,233,138

Utility Number: # 27

Utility # 27 has 1 large industrial customer; 2009 load = **15,897,484** kWh

Customer cost per month in 2010 = **$ 418.70**

Total customer cost = $ 5,024.40

Utility Number: # 28

Utility # 28 has 3 large industrial customers; 2009 load = 3,022,602,000 kWh
Margin charges set in contract with each customer; total margin charges in 2009 = $1,619,690

Utility Number: # 29

1 large industrial customer; 2009 load = 718,303 MWh			
Direct costs of contract administration for this customer (2 plants)	=	$	175,442
		$	79,376
		$	**254,818**

Utility Number: # 30

	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Production:	$ 42,669,341	$ 42,669,341					$ 42,669,341
Transmission:	$ -		$ -				$ -
Distribution:	$ 322,009			$ 322,009			$ 322,009
Meter reading + customer records:	$ 2,429			$ 2,429			$ 2,429
Customer related:	$ 1,301				$ 1,301		$ 1,301
A & G:	$ 260,302			$ 259,262	$ 1,040		$ 260,302
Taxes:	$ 2,418,041					$ 2,418,041	$ 2,418,041
Interest:	$ 673,382			$ 673,382			$ 673,382
Capital Projects:	$ 290,096		$ 110,346	$ 145,596	$ 34,154		$ 290,096
Other Revenues:	$ (5,209,277)	$ (4,047,303)		$ (1,157,333)	$ (4,641)		$ (5,209,277)
TOTAL	$ 41,427,624	$ 38,622,038	$ 110,346	$ 245,345	$ 31,854	$ 2,418,041	$ 41,427,624

Utility Number: # 31	Large Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Production	$ 6,669,764	$ 6,669,764					$ 6,669,764
Transmission							
Fixed Oper Costs (Distn)	$ 406,590			$ 406,590			$ 406,590
on Oper Exp (Cust Svc & Acct)	$ 71,114				$ 71,114		$ 71,114
Admin & Bus Exp	$ 530,588			$ 442,017	$ 88,571		$ 530,588
Taxes	$ 110,812					$ 110,812	$ 110,812
LTGO Debt Servd & Cap	$ 462,840			$ 462,840			$ 462,840
TOTAL	$ 8,251,708	$ 6,669,764	$ -	$ 1,311,447	$ 159,685	$ 110,812	$ 8,251,708

Utility Number: # 32

	Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Production:	$ 33,760,238	$ 33,760,238					$ 33,760,238
Transmission:	$ 145,001		$ 145,001				$ 145,001
Distribution:	$ 10,066			$ 10,066			$ 10,066
Customer Services & Accounts:	$ 2,171,387				$ 2,171,387		$ 2,171,387
A & G:	$ 989,157		$ 61,651	$ 4,280	$ 923,226		$ 989,157
Capital Projects:	$ 1,151,312		$ 1,076,576	$ 74,736			$ 1,151,312
Debt Service:	$ 333,697		$ 312,035	$ 21,662			$ 333,697
Direct Assignments:	$ 1,442,631		$ 89,915	$ 6,242	$ 1,346,474		$ 1,442,631
Other Revenue:	$ (1,721,861)	$ (329,663)	$ (86,749)	$ (6,022)	$ (1,299,426)		$ (1,721,860)
Taxes:	$ 2,329,920					$ 2,329,920	$ 2,329,920
TOTAL	$ 40,611,548	$ 33,430,575	$ 1,598,429	$ 110,963	$ 3,141,661	$ 2,329,920	$ 40,611,549

Utility Number: # 33

	Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Power:	$ 7,378,831	$ 7,378,831					$ 7,378,831
Conservation:	$ 134,032	$ 134,032					$ 134,032
Distribution:	$ 161,203			$ 161,203			$ 161,203
Customer Related:	$ 714				$ 714		$ 714
A & G:	$ 398,772	$ 180,599		$ 217,211	$ 962		$ 398,772
Broad Band:	$ 93,962	$ 42,554		$ 51,181	$ 227		$ 93,962
Interest:	$ 531,746			$ 531,746			$ 531,746
Cash Flow:	$ 495,596	$ 224,450		$ 269,950	$ 1,196		$ 495,596
Taxes:	$ 547,357					$ 547,357	$ 547,357
Other Revenue:	$ (640,934)	$ (290,272)		$ (349,116)	$ (1,546)		$ (640,934)
TOTAL	$ 9,101,279	$ 7,670,195	$ -	$ 882,175	$ 1,552	$ 547,357	$ 9,101,279

Utility Number: # 34

1 large industrial customer with peak of at least 3.5 aMW

2008 Industrial load = 21,884,198 kWh

Margin = $.00529/kWh

Total margin charges for 2008 = **$ 115,767**

Utility Number: # 35	Total Utility	Industrial	Production	Transmission	Distribution	Other	Taxes	Sum
Power Production:	$ 2,477,820	$ 318,447	$ 318,447					$ 318,447
Transmission:	$ 428,864	$ 55,117		$ 55,117				$ 55,117
Distribution:	$ 4,226,132	$ 543,138			$ 543,138			$ 543,138
Metering Reading:	$ 571,769	$ 73,483			$ 73,483			$ 73,483
Credit & Billing:	$ 853,653	$ 109,711			$ 109,711			$ 109,711
Information & Advertising:	$ 52,530	$ 6,751				$ 6,751		$ 6,751
Administrative & General Expenses:	$ 4,598,604	$ 591,008	$ 170,068	$ 29,435	$ 387,900	$ 3,605		$ 591,008
Taxes:	$ 2,541,360	$ 326,613					$ 326,613	$ 326,613
Debt Service:	$ 7,940,000	$ 1,020,441	$ 295,443	$ 51,135	$ 673,863			$ 1,020,441
Capital Projects:	$ 6,280,000	$ 807,100	$ 233,675	$ 40,445	$ 532,980			$ 807,100
Total Transfers:	$ 841,720	$ 108,177	$ 31,320	$ 5,421	$ 71,436			$ 108,177
Energy Sales:	$ (9,248,760)	$ (1,188,642)	$ (342,042)	$ (59,201)	$ (780,148)	$ (7,251)		$ (1,188,642)
Other Revenues:	$ (2,006,586)	$ (257,885)	$ (41,976)	$ (60,458)	$ (155,087)	$ (363)		$ (257,884)
TOTAL	$ 19,557,106	$ 2,513,460	$ 664,935	$ 61,895	$ 1,457,276	$ 2,742	$ 326,613	$ 2,513,461

Utility Number: # 36

1 large industrial customer; 2008 load = 19,516,800 kWh

Monthly Customer Charge = **$51.37** Total charges = **$ 616.44**

Utility Number: # 37

1 large industrial customer; 2010 load = 38,909,777 kWh

Customer charge = **$208**

Bonneville Power Administration
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