B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

BP-26 Rate Proceeding

Final Proposal

Power Rates Study Documentation

BP-26-FS-BPA-01A

July 2025

POWER RATES STUDY

DOCUMENTATION TABLE OF CONTENTS

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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
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
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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POWER RATES STUDY DOCUMENTATION

INTRODUCTION

The Power Rates Study Documentation shows the details of the calculation of BPA's proposed power rates.

"Section 1: Introduction and Background" contains an overview of the various models used in the rate development process and presents a flow chart showing the rate development process.

"Section 2: Ratemaking Methodology and Process" contains ratemaking tables that are the output of the Rate Analysis Model (RAM). RAM is a group of computer applications that perform most of the computations that determine BPA's final power rates. This group includes the RAM Core Excel-based model, a front-end and back-end database service, and separate modules for the computation of (1) TRM billing determinants, (2) Tier 2 rates, and (3) Resource Support Services (RSS) rates and revenues. The output tables of RAM include billing determinants, which are based on power sales forecasts and associated outputs from the RHWM Process, as well as revenue requirements used in the Power Rates Study's cost of service analysis (COSA). A series of tables shows the initial allocation of the revenue requirement over the billing determinants. The final table shows the calculation of the resource cost contributions that appear in GRSP II.Z.

"Section 3: Rate Design" documents the calculations for Tier 1 rate design and the results of the Tier 2 and RSS modules of RAM. The Tier 2 module results include the Tier 2 rates and charges, billing determinants, rate design adjustments and remarketing associated with Tier 2, and non-Federal remarketing. The results of the RSS module include the rate design revenue credits and adjustments associated with RSS and the Resource Shaping Charge, which are fed into RAM Core for ratemaking purposes. Other results include the associated RSS rates and charges, including the Resource Shaping Charge, the Transmission Scheduling Service Charge, and the Grandfathered Generation Management Service Charge.

"Section 4: Power Rate Schedules" includes tables for Load Shaping Rates, Demand Rates, and Tier 2 billing determinant assumptions.

"Section 5: Power General Rate Schedule Provisions (GRSPs)" includes tables for the Irrigation Rate Discount and Low Density Discount programs. It also includes customer specific non-Federal resource remarketing credits.

"Section 6: Transfer Service" includes a table showing information for transfer service costs and rates.

"Section 7: Slice" contains no documentation.

"Section 8: Average System Costs" documents monthly Residential Exchange Program loads and forecast ASCs.

"Section 9: The Revenue Forecast" documents revenue forecasts at both current and proposed rates for the rate period, FY 2026–2028, and at current rates for the fiscal year immediately preceding the three-year rate period, FY 2025.

SECTION 1: BACKGROUND

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RATE PROCESS MODELING

The components listed below, organized by rate proposal study, are the major analyses and computer models used in BPA's rate development process. Included is a brief description of the purpose of each component and how it fits in with the other components. See the flowchart on the page following this section for a picture of how the studies and models work together in the wholesale power rate development process.

POWER LOADS AND RESOURCES STUDY (BP-26-FS-BPA-03):

Federal System Load Obligation Forecasts

The Federal system load obligation forecasts estimate the firm energy load obligations that BPA expects to serve under its firm requirements power sales contracts (PSCs) and BPA's other contractual obligations. BPA's firm requirements PSC load obligation forecasts are used in BPA's rate development process and serve as the primary sources for (1) allocation factors used to apportion costs, and (2) billing determinants used to calculate rates and revenues. BPA's load obligation forecasts are composed of customer forecasts for consumer-owned utilities (COUs), Federal agencies, direct service industrial customers (DSIs), investor-owned utilities (IOUs), and other obligations, such as the U.S. Bureau of Reclamation's irrigation loads. Individual COU and Federal agency loads are forecast by ALF, BPA's Agency Load Forecast model.

BPA also has contract obligations other than those served under firm requirements PSCs. These "other contract" obligations include contract sales to utilities and marketers, and power commitments under the Columbia River Treaty. All of BPA's load obligations are detailed in the Power Loads and Resources Study.

Hydro Regulation Study (HYDSIM)

The Federal system regulated hydro resource estimates are derived by BPA's hydro regulation model (HYDSIM), which estimates project generation for 30 water years (1989 through 2018). BPA uses HYDSIM to estimate the Federal system energy production that can be expected from specific hydroelectric power projects in the PNW Columbia River Basin when operating in a coordinated fashion and meeting power and non-power requirements for the 30 water years of record. The hydro regulation study uses plant operating characteristics and conditions to determine energy production expected from each specific project. Physical characteristics of each project are provided by annual Pacific Northwest Coordination Agreement (PNCA) data submittals from regional utilities and government agencies involved in the coordination and operation of regional hydro projects. The HYDSIM model incorporates these operating characteristics along with power and non-power requirements to provide project by project monthly energy generation estimates for the Federal system's regulated hydro projects.

The HYDSIM studies encompass the power and non-power operating requirements expected to be in effect during the rate period, including those described in the Biological

Assessment of Effects of the Operations and Maintenance of the Federal Columbia River System on ESA-Listed Species (2020 BA) and any modifications that arose during the development of the associated biological opinions issued by the National Oceanic and Atmospheric Administration (NOAA) Fisheries and the U.S. Fish and Wildlife Service (USFWS). The HYDSIM studies also include operations described in the Northwest Power and Conservation Council's (NPCC) Fish and Wildlife Program published October 2014 and amended in 2020. The aforementioned assessments are summarized in the Columbia River System Operations (CRSO) Environmental Impact Statement (EIS) Record of Decision (ROD) released in September 2020. The hydroregulation studies in this rate proposal reflect the Selected Alternative operational measures in this ROD. Operational measures include seasonal flow objectives, minimum flow levels for fish, spill for juvenile fish passage, reservoir target elevations, ramp rate restrictions, and turbine operation requirements. Measures that are physical structural modifications (e.g., upgrading spill weirs) were typically excluded from the rate period based on estimated project implementation and completion timelines. The Federal system hydro generation is used in the Federal system load-resource balance and is detailed in the Power Loads and Resources Study.

Federal System Load-Resource Balance

The Federal system load-resource balance provides the complete picture of BPA's loads and resources by comparing Federal system load obligations to Federal system resources. Federal system load obligations include all of BPA's load obligations (firm requirements PSCs and other Federal contracts). Federal system resources include BPA's regulated and independent hydro resources under a monthly 10th percentile (P10) from the generation output of hydro-regulation studies to establish firm generation, contract purchases, and other non-hydro generating resources. The result of the Federal system resources less load obligations yields BPA's estimated Federal system monthly firm energy surplus or deficit, in average megawatts. Should the results indicate an energy surplus or deficit in the ratemaking process, firm surplus sales or augmentation purchases must be made to ensure the Federal system is in annual energy load resource balance. The surplus/deficit calculation is performed for each year of the rate period and is detailed in the Power Loads and Resources Study. Results from the Power Loads and Resources Study are used as input into the Power Rates Study, the Power Market Price Study, and the Power and Transmission Risk Study.

POWER REVENUE REQUIREMENT STUDY (BP-26-FS-BPA-02):

The Power Revenue Requirement Study develops BPA's generation revenue requirement for the rate test period. It uses repayment studies for the generation function to determine the schedule of amortization payments and to project annual interest expense for bonds and appropriations that fund the Federal investment in hydro, fish and wildlife recovery, conservation, and related generation assets. Repayment studies are conducted for each year of the rate test period and extend over the 50-year repayment period. The repayment studies establish a schedule of planned amortization payments and resulting interest expense by determining the lowest levelized debt service stream necessary to repay all generation obligations within the required repayment period. Repayment study results are combined with forecasts of program spending to create the revenue requirement. The Power Revenue Requirement Study then determines whether a given set of annual revenues is sufficient to meet projected annual expenses and to cover a given set of long-term obligations when applied in accordance with the requirements of DOE Order RA 6120.2.

POWER MARKET PRICE STUDY (BP-26-FS-BPA-04):

The Power Market Price Study is composed of two different electricity market price runs. These runs are the "market price" run, which is based on hydro generation for 30 water years, and the "critical water price" run, which is based on hydro generation under P10 streamflow conditions.

"Market Price" Run

The results from the "market price" run are used in the Power Rates Study for the following:

- Prices for secondary energy sales and balancing power purchases
- Prices for firm surplus energy sales
- Load Shaping rates
- Load Shaping True-Up rate
- Resource Shaping rates
- Resource Support Services (RSS) rates
- Priority Firm Power (PF), Industrial Firm Power (IP), and New Resource Firm Power (NR) demand rates
- PF Unused Rate Period High Water Mark (RHWM) Credit
- PF Tier 1 Equivalent rates
- PF Melded rates
- Balancing Augmentation Credit
- IP energy rates
- NR energy rates
- Energy Shaping Service (ESS) for New Large Single Load (NLSL) True-Up rate

"Critical Water Price" Run

The results from the "critical water price" run are used in the Power Rates Study for calculating system augmentation expenses.

Both of these sets of prices are also used for the risk analysis discussed in the Power and Transmission Risk Study, BP-26-FS-BPA-05.

The tool used to calculate electric energy prices is a model of the Western Electricity Coordinating Council (WECC) power system called AURORA©. AURORA© uses a linear program to minimize the cost of meeting load, subject to a number of operating constraints. Given the solution (an output level for all generating resources and a flow level for all interties), the price at any hub is the cost, including wheeling and losses, of delivering a unit of power from the least-cost available resource. This cost approximates the price of electricity by assuming that all resources are centrally dispatched (the equivalent of cost-minimization in production theory) and that the marginal cost of producing electricity approximates the price.

AURORA© produces a single electricity price forecast as a function of its inputs. Thus, to produce a given number of price forecasts requires that AURORA© be run that same number of times using different inputs. Risk models provide inputs to AURORA© and the resulting distribution of electricity price forecasts represents a quantitative measure of electricity price risk. As described in the Power and Transmission Risk Study, BP-26-FS-BPA-05, 2.700 independent games from the joint distribution of the risk models serve as the basis for the 2,700 electricity price forecasts. The monthly Heavy Load Hour (HLH) and Light Load Hour (LLH) electricity prices constitute the electricity price forecast for the "market price" run and the "critical water price" run.

POWER AND TRANSMISSION RISK STUDY (BP-26-FS-BPA-05)

The Power and Transmission Risk Study demonstrates that BPA's rates and risk mitigation tools together meet BPA's standard for financial risk tolerance—the Treasury Payment Probability (TPP) standard. The study includes quantitative and qualitative analyses of risks to net revenue and tools for mitigating those risks. It also establishes the adequacy of those tools for meeting BPA's TPP standard.

In addition to the Power operating net revenues used in the calculation of TPP, results from the modeling of various Power operating risks that are components of net revenues are provided for input into the Rate Analysis Model for the BP-26 rate case (RAM).

Results Provided for Input into RAM2026 and the Power Services Revenue Forecast

The RevSim model is used to forecast secondary energy revenues, firm surplus energy revenues, balancing power purchase expenses, and augmentation purchase expenses. After accounting for all loads and resources (including augmentation purchases), RevSim computes the monthly HLH and LLH quantities of secondary energy available to sell and power purchases needed to meet firm loads (balancing purchases) using hydro generation available under 30 years of historical streamflow conditions (1989-2018). Inputs used to calculate load and resource balance are forecast loads, non-hydro resources, and hydro generation.

RevSim uses the 80 water year results from the Loads and Resources Study to compute the available HLH and LLH surplus energy and deficits in the Federal hydro system under varying streamflow conditions. RevSim applies HLH and LLH monthly spot market prices supplied by the AURORA© model (see the Power Market Price Study subsection above for a description of the AURORA© model) to the sales and purchase amounts to calculate revenues from surplus energy sales and expenses from balancing power purchases. As described in the Power Rates Study, RAM and the Power Services Revenue Forecast both use the secondary energy revenues and balancing power purchase expenses computed by RevSIM.

Results from operating risks modeled external to RevSim that are input into RevSim are the 4(h)(10)(C) credits BPA is allowed to credit against its annual U.S. Treasury payment and Power Services' transmission and ancillary services expenses. The amount of the 4(h)(10)(C) credit is determined by summing the costs of the operational impacts (power purchases) and the direct program expenses and capital costs, and then multiplying the total cost by 0.223 (22.3 percent). The operational portion of the 4(h)(10)(C) credit is computed by taking the same AURORA© prices used for the calculation of secondary energy revenues and applying them to the replacement power purchase amounts. The calculation of the replacement power purchases for 4(h)(10)(C) is described in the Power Loads and Resources Study.

Power Services' transmission and ancillary services expense risk is based on comparisons between monthly firm Point-to-Point (PTP) Network transmission capacity that Power Services has under contract, the amount of existing firm contract sales, and the variability in secondary energy sales estimated by RevSim. Expense risk computations reflect how transmission and ancillary services expenses vary from the cost of the fixed take-or-pay firm PTP Network transmission capacity that Power Services has under contract.

Risk Analysis

RevSim, in conjunction with AURORA© and the Power Non-Operating Risk Model (P-NORM), is used to quantify Power Services' net revenue risk. RevSim estimates net revenue variability associated with various operating risks (load, resource, electricity price, 4(h)(10)(C) credit, and Power Services' transmission and ancillary service expense variations). P-NORM estimates the non-operating risks that are associated with uncertainties in the cost projections in the revenue requirement and revenue uncertainties not captured in RevSim and AURORA©. P-NORM also contains Accrual to Cash adjustments, which translates net revenue into cash flow. The results from RevSim and P-NORM are inputs into the ToolKit, which calculates the probability of Power Services making its portion of scheduled Treasury payments on time and in full.

Risk Mitigation

The ToolKit Model is used to determine Treasury Payment Probability (TPP), which is the probability of Power Services making all its planned Treasury payments during the rate period, given the net revenue risks quantified in RevSim and P-NORM and accounting for the impact of the risk mitigation tools. More specifically, ToolKit is used to assess the effects of various policies and risk mitigation measures, such as the Cost Recovery Adjustment Clause (CRAC) and Revenue Distribution Clause (RDC) on the level of year-end reserves available for risk that are attributable to Power Services.

POWER RATES STUDY (BP-26-FS-BPA-01)

Rate Analysis Model (RAM)

RAM is a group of computer applications that perform most of the computations that determine BPA's proposed power rates. RAM Core, a spread sheet-based model, has three main steps that perform the calculations necessary to develop BPA's wholesale power rates: Cost of Service Analysis (COSA), Rate Directives, and Rate Design.

1. Cost of Service Analysis. This step ensures that BPA's proposed rates are consistent with cost of service principles and comply with BPA's statutory rate directives. The COSA Step determines the costs associated with the three resource pools (Federal base system (FBS), Exchange Resources, and New Resources) used to serve sales load and then allocates those costs to the rate pools (Priority Firm Power (PF), Industrial Firm Power (IP), New Resource Firm Power (NR), and Firm Power Products and Services (FPS)). In addition, the COSA allocates the costs of conservation and other BPA programs to the rate pools.

2. Rate Directives. The Northwest Power Act requires that some rate adjustments be made after the initial allocation of costs to ensure that the rate levels for the individual rate pools (PF Preference, PF Exchange, IP, NR, and FPS) have the proper relationship to each other. The primary rate adjustments are described in sections 7(b) and 7(c) of the Northwest Power Act. The Rate Directives Step of RAM performs these rate adjustments. The amount of PF Public rate protection and the levels of the IP and NR rates are set using the 2012 settlement of legal issues associated with the Residential Exchange Program.

3. Rate Design. In the COSA and Rate Directive steps, costs are allocated to the various rate pools. Upon completion of these steps, a certain amount of costs has been allocated to the PF Preference pool. Section 7(e) affords BPA wide latitude in the design of rates to collect the costs allocated to each rate pool. The Tiered Rate Methodology (TRM) specifies a cost allocation methodology for PF Preference costs allocated in the COSA and Rate Directives steps. RAM accomplishes this separate cost allocation through a process of mapping costs (including net residential exchange costs) and revenue credits (including IP and NR revenues, if any) to the Tier 1 Composite, Non-Slice, Slice, and Tier 2 costs pools. It also demonstrates by "proof" that cost allocations under the TRM and the COSA and Rate Directives steps are equivalent in terms of aggregate costs recovered from the PF Preference, PF Exchange, IP, and NR rates. To provide a crosswalk of the differences between COSA allocations and TRM allocations, the mapping for each is shown in RAM using unique database keys.

RAM develops four rate designs: (1) a tiered rate design for the PFp rate, in which the Tier 1 rates are designed using customer charges and demand and energy rates; (2) a traditional demand and energy design for the PFp Melded rate, the IP rate, and the NR rate; (3) a constant annual energy rate for each PFp Tier 2 rate and the PFx rates; and (4)

Resource Support Service rates for customers with new non-Federal Dedicated Resources. RAM designs rates for each rate pool.

Resource Support Services Module of RAM2026

The Resource Support Services (RSS) module of RAM, a spreadsheet-based model, calculates the charges and rates applied to resources receiving RSS and related services. These services include Diurnal Flattening Service (DFS), Secondary Crediting Service (SCS), Forced Outage Reserve (FORS), and grandfathered Generation Management Service (GMS). The RSS module of RAM also calculates, as applicable, each customer's Resource Shaping Charge (RSC); Transmission Scheduling Service (TSS) and the Transmission Curtailment Management Service (TCMS) component of TSS (although the TCMS functionality in the RSS module is not currently implemented); the aggregate RSS and RSC revenue credits used in RAM Core (an Excel-based model, one of the computer applications in RAM); and the capacity obligations that will inform BPA generation planning and the Slice model. The RSS module is also the source of operating minimums, planned amounts, and FORS energy limits that are defined in the customer contracts. The RSS model calculates the above for non-Federal resources as well as Federal resources used as augmentation and Federal resources used to support the Tier 2 rate.

Tier 2 Module of RAM2026

The Tier 2 module of RAM, a spreadsheet-based model, calculates Tier 2 rates and the applicable Tier 2 revenue credits and adjustments used in RAM Core that are not already accounted for in the RSS module of RAM. This module also calculates customer remarketing credits for amounts of Tier 2 service, non-Federal resource DFS, and Resource Remarketing Service. It produces the aggregate revenue and cost data associated with remarketing between the Tier 2 cost pools used in the RAM Core calculation.

FY 2026-2028 Average System Cost (ASC) Forecasts

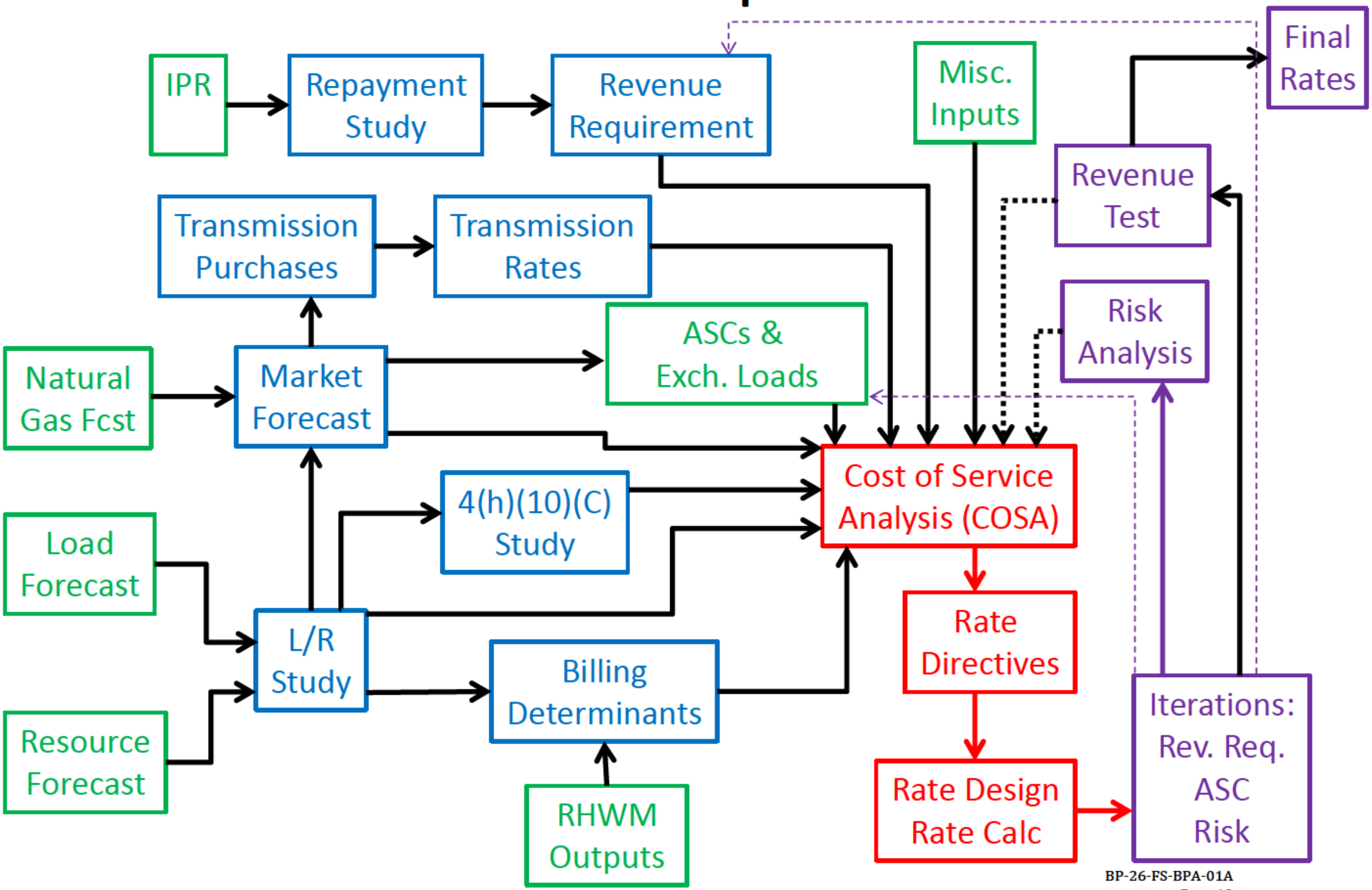
ASCs are used in determining the forecast of Residential Exchange Program (REP) benefits that exchanging utilities are entitled to during the rate period. For purposes of the BP-26 rates, BPA is using the ASC Reports published by BPA on July 24, 2025.

Revenue and Power Purchase Expense Forecast

The Revenue Forecast presents BPA's expected level of revenue and power purchase expense for FY 2025-2028, FY 2025 revenues are forecast to estimate the level of reserves at the beginning of the rate period. Selected power purchase expenses that affect the sales of surplus energy are also included. The revenue forecast documents the revenues at both current and proposed rates by applying rates (PF, IP, and NR, if applicable) to projected billing determinants. These two revenue forecasts, one with current rates and the other with proposed rates, are used to demonstrate whether current rates will recover BPA's revenue requirement and, if not, whether proposed rates will recover the revenue requirement. The revenue test is described in the Power Revenue Requirement Study. The

Revenue Forecast uses outputs from a number of sources to determine total revenues expected, and to obtain short-term marketing revenues, firm surplus energy revenues, balancing power purchase expenses, augmentation power purchase expenses, 4(h)(10)(C) credits, and Power Services' transmission and ancillary service expenses.

Power Rate Development Process



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SECTION 2: RATEMAKING METHODOLOGY AND PROCESS

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Description of Ratemaking Tables

Table 2.1.1
Disaggregated Load Input Data (RDI 01)
The "Loads" worksheet is the input site where disaggregated load data enters the model. The worksheet load data is displayed in average annual form as well as monthly diurnal form. Table 2.1.1 load data is displayed in average annual form. Energy values are in MWh.

Table 2.1.2
Disaggregated Resource Input Data (RDI 02)
The "Resources" worksheet is the input site where disaggregated resource data enters the model. The worksheet resource data is displayed in average annual form as well as monthly diurnal form. Table 2.1.2 resource data is displayed in average annual form. Energy values are in MWh.

Table 2.1.3
Exchange ASCs, Loads, and Gross Costs (RDI 03)
Worksheet displays the utilities that are forecast to be active in the REP with their average system costs and loads. Worksheet calculates the gross cost of exchange resources.

Table 2.2.1
Power Sales and Resources (EAF 01)
Worksheet aggregates the disaggregated sales and resource data from their input worksheets.

Table 2.2.2
Aggregated Loads and Resources (EAF 02)
Worksheet adds transmission losses to power sales from the previous worksheet and performs an annual energy loads and resource balance.

Table 2.2.3
Calculation of Energy Allocation Factors (EAF 03)
Worksheet displays the energy loads and resource balance from the previous worksheet and also calculates several sets of Energy Allocation Factors (EAFs). The EAFs measure the relative use of the different types of resources to serve the different types of loads in the COSA ratemaking step. In addition, EAFs are used to reallocate costs among load types to comport with specific Rate Directive steps.

Table 2.3.1
Disaggregated Costs and Credits (COSA 01)
Worksheet is the input site where disaggregated revenue requirement cost data as well as revenue credit data enters the model. Each line item in the worksheet is associated with aggregation keys that are used in the model to build the COSA and TRM cost tables used in the subsequent ratemaking calculations.

Table 2.3.2
Cost Pool Aggregation (COSA 02)
Worksheet aggregates the revenue requirement data from the previous worksheet into the COSA cost categories: FBS costs, New Resource costs, Residential Exchange Program costs, Conservation costs, BPA Program costs, and Power Transmission costs. The Residential Exchange Program, Balancing and Augmentation costs are calculated in the model.

Table 2.3.3
Computation of Low Density and Irrigation Rate Discount Costs (COSA 03) Worksheet calculates the forgone revenue due to the Low Density Discount and the Irrigation Rate Discount. The forgone revenue must be added to the power revenue requirement as a cost to be recovered from PF rates. A macro is used to iterate the costs of the LDD/IRD with the TRM rates so that the LDD/IRD costs are calculated with the current power rates.

Table 2.3.4.1.1
Allocation of Costs: FBS, LDD/IRD (COSA 04-1)
Worksheet allocates FBS costs as directed by section 7(b) of the Northwest Power Act. Worksheet allocates LDD/IRD costs due to the forgone revenue associated with the LDD and IRD rate discounts to PF load.

Table 2.3.4.1.2
Allocation of Costs: Transmission, General Transfer (COSA 04-1)
Worksheet allocates TBL Transmission/Ancillary Services (Non-Slice) costs are allocated using the FBS EAF. General Transfer costs are allocated to the rate pools receiving service.

Table 2.3.4.2
Allocation of Costs: New Resources and Exchange Resources (COSA 04-2)
Worksheet allocates New Resource costs as directed by sections 7(b) and 7(f) of the Northwest Power Act. Worksheet functionalizes Exchange resource costs between power and transmission before allocating the power portion as directed by sections 7(b) and 7(f) of the Northwest Power Act

Table 2.3.4.3
Allocation of Costs: Conservation, BPA Programs and Transmission (COSA 04-3)
Worksheet allocates Conservation costs, BPA Program costs and Transmission costs as directed by section 7(g) of the Northwest Power Act.

Table 2.3.5
Allocation of Costs Summary (COSA 05)
Worksheet displays the dollar amounts in the seven COSA cost categories or cost pools and the initial allocation of those costs to the four COSA rate pools.

Table 2.3.6
General Revenue Credits (COSA 06)
Worksheet displays and aggregates the revenue credits from the disaggregated cost worksheet above.

Table 2.3.7.1
Allocation of Revenue Credits: FBS (COSA 07-1)
Worksheet allocates FBS-related revenue credits as directed by section 7(b) of the Northwest Power Act.

Table 2.3.7.2
Allocation of Revenue Credits: Transmission (COSA 07-2)
Worksheet allocates revenue credits associated with transmission costs as directed by section 7(g) of the Northwest Power Act or based on cost causation principles.

Table 2.3.7.3
Allocation of Revenue Credits: New Resources(COSA 07-3)
Worksheet allocates New Resource-related revenue credits as directed by sections 7(b) and 7(f) of the Northwest Power Act.

Table 2.3.7.4
Allocation of Revenue Credits: Conservation(COSA 07-4)
Worksheet allocates revenue credits associated with Conservation costs as directed by section 7(g) of the Northwest Power Act.

Table 2.3.7.5
Allocation of Revenue Credits: Generals (COSA 07-5)
Worksheet allocates revenue credits associated with providing generation inputs and other revenues as directed by the Northwest Power Act.

Table 2.3.7.6
Allocation of Revenue Credits: Non-Federal RSS/RCS (COSA 07-6)
Worksheet allocates revenue credits associated with non-Federal RSS/RCS as directed by section 7(g) of the Northwest Power Act.

Table 2.3.8
Calculation and Allocation of Secondary Revenue Credit (COSA 08)
Worksheet calculates the secondary revenue credit for the rate test period. The secondary revenue credit is allocated to loads that recover FBS and New Resource costs.

Table 2.3.9
Calculation and Allocation of FPS Revenue Deficiency Delta (COSA 09)
Worksheet calculates the firm surplus sale revenue (surplus)/shortfall. The generation revenue requirement costs allocated to FPS sales are reduced by the excess revenue credit allocated to FPS sales in the previous worksheet. The resulting costs are compared with the revenues recovered from FPS sales, resulting in a revenue deficit. This revenue deficit is allocated based on the service provided by the FBS and NR resources to these rate pools.

Table 2.3.10
Calculation of Initial Allocation Power Rates (COSA 10)
Worksheet uses the cost and revenue credit allocations at this point in the rate modeling, when the COSA allocations have been completed and before the Rate Directive steps, to calculate initial rates.

Table 2.4.1
Calculation of the DSI Value of Reserves and Net Industrial Margin (RDS 01)
Worksheet is the input site where data used to calculate the Direct Service Industry (DSI) value of reserves (VOR), Industrial Margin and Net Industrial Margin are input into the model. Worksheet also calculates the Net Industrial Margin to be used in the calculation of the IP rates.

Table 2.4.2
Calculate Energy Rate Scalars First IP-PF Link Calculation (RDS 02)
Worksheet calculates the annual scalar adjustments needed to scale the market price monthly diurnal energy rates such that the resulting energy rates recover the PF rate and IP rate revenue requirements at this point in the ratemaking.

Table 2.4.3
Calculate Monthly Energy Rates Used in First IP-PF Link Calculation (RDS 03)
Worksheet uses the annual energy rate scalars calculated in the previous worksheet to produce monthly diurnal energy rates for PF and IP rates. The annual scalars for both PF and IP rates are then applied to the monthly market price curve to produce a monthly shape for the PF energy rates (at the PF load shape) and the IP energy rate (at the IP load shape).

Table 2.4.4
Calculation of First IP-PF Link Delta (RDS 04)
Worksheet uses shaped energy rates from the previous worksheet to calculate the first IP-PF link delta. The IP-PF Link 7(c)(2) adjustment is necessary to account for the difference between the revenues expected to be recovered from the DSIs at the IP rate and the costs allocated to the DSIs at this point in the ratemaking. This difference, known as the 7(c)(2) Delta, is allocated to non-DSI rates, primarily the PF rate. The IP rate is a formula rate based on the "applicable wholesale rate"—the load-weighted PF and NR rates. 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 to a solution for each year of the rate test period.

Table 2.4.5
Allocation of First IP-PF Link Delta and Recalculation of Rates (RDS 05)
Worksheet reallocates the first IP-PF link delta from the previous worksheet. The delta amount is reallocated from IP to all other loads (7(b) and 7(f) loads associated with PF Preference, PF Exchange, and NR).

Table 2.4.6
Calculation of the DSI Floor Rate (RDS 06)
The IP-83 rates are applied to the current DSI test period billing determinants to determine an average rate. Adjustments are made for Transmission, Exchange Cost, and Deferral to yield the DSI floor rate.

Table 2.4.7
DSI Floor Rate Test 1 (RDS 07)
A test is conducted comparing the IP rate at this stage in the ratemaking process to the floor rate established above.

Table 2.4.8
Calculation of IOU and COU Base Exchange Rates (RDS 08)
Worksheet calculates the Base Exchange rates for IOU and COU exchanging utilities. The IOU Base Exchange rate is the unbifurcated PF rate with transmission costs added. The COU Base Exchange rate differs in that it is calculated without Tier 2 costs and loads.

Table 2.4.9
Calculation of IOU REP Benefits in Rates (RDS 09)
Worksheet calculates the annual IOU REP Benefits to be recovered in power rates.

Table 2.4.10
Calculation of REP Base Exchange Benefits (RDS 10)
Worksheet calculates the REP benefits assuming no PF Public rate protection. The IOU and COU Base PF Exchange rates are subtracted from each IOU and COU individual utility average system cost and that difference is multiplied by the utility's exchangeable load to yield its Unconstrained Benefit.

Table 2.4.11
Calculation of Utility-Specific PF Exchange Rates and REP Benefits (RDS 11)
Worksheet calculates utility-specific PF Exchange rates by adding a utility-specific REP Settlement Charge to the Base Exchange rate. The IOU REP Settlement Charges are sized to collect the difference between the Unconstrained Benefits for the IOUs and the REP Settlement Benefit for the IOUs. This amount is the PF Public rate protection provided by the IOU Exchangers. The IOU Settlement Charges are computed for each utility by allocating this rate protection amount among the IOUs according to the relative size of their share of the Unconstrained Benefits. COUs' Settlement Charges are computed by imputing an amount of "protection" equivalent to the IOU Settlement.

Table 2.4.12
IOU Reallocation Balances (RDS 12)
Worksheet performs a reallocation of benefits between the IOUs to account for differential outstanding Lookback balances at the time of the REP Settlement. The procedure for the reallocation is included in section 6.2 of the Settlement Agreement. This table shows the outstanding balance each IOU is obligated to repay to other IOUs, if any, for the full term of the Regional Dialogue contracts. Provided that each utility has sufficient benefit amounts

prior to reallocation, these amounts (and scheduled future amounts) will not change. However, if a particular utility has insufficient benefits in any one rate period to pay down its reallocation obligation, the scheduled payment amounts will be recalculated.

Table 2.4.13
Allocation of the Increased PF Exchange Costs Due to Settlement (RDS 13)
The difference between the Unconstrained Benefits and the REP Settlement benefits is allocated to the Priority Firm Exchange loads and away from the PF Preference loads. Average power rates are calculated after this reallocation of costs.

Table 2.4.14
Calculation of PF, IP and NR Contribution to Net REP Benefit Costs (RDS 14)
At this point in the REP Settlement rate modeling, the cost of providing IOU and COU Net REP Benefits is assumed to be spread pro rata by load to all PF Public, IP, and NR load. A reallocation adjustment is performed to make the REP Benefit cost contribution of the various rate pools comport with the Net REP Exchange cost contribution present in the WP-10 rate proceeding. The ratio of BP-12 to WP-10 net benefits is used as a factor applied to scale down (or up) the supplemental surcharge from its WP-10 level, and apply this surcharge to IP and NR loads to determine the amount of net REP dollars which should be applied to IP and NR loads.

Table 2.4.15
Reallocate Rate Protection Provided by IP and NR Rates (RDS 15)
Worksheet reallocates the rate protection amount provided by the IP and NR rates from the previous worksheet to the PF Public rate pool. Rates are then computed.

Table 2.4.16
Annual PF and IP scalar under Settlement (RDS 16)
Worksheet calculates the annual scalar adjustments needed to scale the market price monthly diurnal energy rates such that the resulting energy rates recover the PF rate and IP rate revenue requirements at this point in the ratemaking.

Table 2.4.17
Monthly PF and IP rates under Settlement (RDS 17)
Worksheet uses the annual energy rate scalars calculated in the previous worksheet to produce monthly diurnal energy rates for PF and IP rates. The annual scalars for both PF and IP rates are then applied to the monthly market price curve to produce a monthly shape to the PF energy rates (at the PF load shape) and the IP energy rate (at the IP load shape).

Table 2.4.18
IP-PF Link (RDS 18)
Worksheet uses shaped energy rates from previous worksheet to calculate the IP-PF link delta. The IP-PF Link 7(c)(2) adjustment is necessary to account for the difference between the revenues expected to be recovered from the DSIs at the IP rate and the costs allocated to the DSIs at this point in the ratemaking. This difference, known as the 7(c)(2) Delta, is

allocated to non-DSI rates, primarily the PF rate. The IP rate is a formula rate based on the "applicable wholesale rate"—the load-weighted PF and NR rates. 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 to a solution for each year of the rate test period.

Table 2.4.19
Reallocation of IP-PF Link Delta (RDS 19)
Worksheet reallocates IP-PF Link Delta dollars from IP to PF preference and NR loads and recalculates average power rates.

Table 2.4.20
REP Benefit Reconciliation (RDS 20)
Worksheet compares calculated REP benefits to the cost/revenue allocations from the COSA step.

Table 2.5.1
Allocated Costs and Unit Costs, Priority Firm Power Rates
Table provides a summary of the various COSA cost allocations and Rate Design Adjustments associated with Priority Firm Public Power and Priority Firm Exchange Power. A percentage contribution to the final Priority Firm Preference Power rate and Priority Firm Exchange Power rate for each COSA cost allocation and Rate Design Adjustment is calculated.

Table 2.5.2
Allocated Costs and Unit Costs, Industrial Firm Power
Table provides a summary of the various COSA cost allocations and Rate Design Adjustments associated with Industrial Firm Power. A percentage contribution to the final Industrial Firm Power rate for each COSA cost allocation and Rate Design Adjustment is calculated.

Table 2.5.3
Allocated Costs and Unit Costs, New Resource Firm Power
Table provides a summary of the various COSA cost allocations and Rate Design Adjustments associated with New Resource Firm Power. A percentage contribution to the final New Resource Firm Power rate for each COSA cost allocation and Rate Design Adjustment is calculated.

Table 2.5.4
Resource Cost Percent Contribution to Rate Pools
Table provides a summary of the percentages of each resource pool--FBS, Residential Exchange, and New Resources--used in ratemaking to serve each of the rate pools: PF, IP, NR, and FPS.

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Table 2.1.1

Rate Data Input Disaggregated Loads
(MWh)

	A	B	C	E	F	G
4				2026	2027	2028
5	Preference			63,832,075	64,483,256	65,201,986
6		Block		4,918,460	5,039,549	5,169,788
7		Slice Block		5,292,030	5,389,019	5,263,272
8		Slice		7,358,172	7,234,395	7,371,809
9		Load Following		41,610,022	41,769,750	41,991,188
10		Tier 2		4,653,391	5,050,543	5,405,928
11	Industrial			96,360	96,360	96,624
12		Smelter		0	0	0
13		Other Industrial		96,360	96,360	96,624
14	New Resource			6,057	171,295	223,964
15	Firm Power and Services			4,572,202	4,576,534	4,617,352
16		Intraregional Transfer		13,418	17,424	13,542
17			WNP#3 Settlement	0	0	0
18				0	0	0
19			Transfer Gen Losses	13,418	17,424	13,542
27		FBS Obligation		4,558,785	4,559,109	4,603,811
28			Canadian Entitlement	2,671,801	2,671,801	2,679,121
29			USBR Pump Load	1,684,008	1,684,008	1,720,518
30			Hungry Horse	0	0	0
31			Upper Baker	11,228	11,116	11,340
32			Non-Treaty Storage	109,080	109,517	109,937
33			Libby Coordination	0	0	0
34			Dittmer Station Service	82,668	82,668	82,895
35				0	0	0
36				0	0	0
37				0	0	0
38		Seasonal or Capacity Exchange		0	0	0
39			Riverside Capacity	0	0	0
40			Riverside Seasonal	0	0	0
41			Pasadena Capacity	0	0	0
42			Pasadena Seasonal	0	0	0
43			PG&E	0	0	0
44			Intertie Losses	0	0	0
45			PacifiCorp	0	0	0
49	Firm Surplus Sale			0	0	0
50	Presale of Secondary			0	0	0
51	Conservation			0	0	0
52						
53						
54	Loss Percentage			2.966%	2.966%	2.966%

Table 2.1.2

Rate Data Input Disaggregated
Resources (MWh)

	A	B	C	E	F	G
5				2026	2027	2028
6	Hydro			58,555,764	58,685,546	58,878,586
7		Regulated		55,504,163	55,581,249	55,810,241
8		Independent		2,315,665	2,368,594	2,330,081
9			Cowlitz Falls	213,858	256,446	235,973
10			Idaho Falls	0	0	0
11			PreAct	2,101,807	2,112,148	2,094,109
19		Hydro Other		735,935	735,703	738,264
20			Canadian Entitlement	735,935	735,703	738,264
21			Libby Coordination	0	0	0
22			Other	0	0	0
30	Non Hydro			9,985,006	8,769,906	9,826,046
31		Water		23,039	23,039	23,102
32			Dworshak/Clearwater Small Hydropower	23,039	23,039	23,102
33			Elwha Hydro	0	0	0
34			Glines Canyon Hydro	0	0	0
42		Thermal		9,776,160	8,704,800	9,802,944
43			Columbia Generating Station	9,776,160	8,704,800	9,802,944
53		Wind		185,808	42,067	0
54			Foote Creek 1	0	0	0
55			Foote Creek 2	0	0	0
56			Foote Creek 4	0	0	0
57			Stateline Wind Project	185,808	42,067	0
58			Condon Wind Project	0	0	0
59			Klondike I	0	0	0
64		Renewable		0	0	0
65			Georgia-Pacific Paper (Wauna)	0	0	0
66			Fourmile Hill Geothermal	0	0	0
67			Ashland Solar Project	0	0	0
75	Contracts			711,004	708,468	711,303
76		Imports		711,004	708,468	711,303
77			Riverside Exchange Energy	0	0	0
78			Pasadena Exchange Energy	0	0	0
79			BC Hydro Power Purchase	8,760	8,760	8,784
80			Slice Return of Losses	150,644	148,108	150,919
81			Southeast Idaho Load Service	551,600	551,600	551,600
87		Seasonal or Capacity Exchange		0	0	0
88			Riverside Capacity	0	0	0
89			Riverside Seasonal	0	0	0
90			Pasadena Capacity	0	0	0
91			Pasadena Seasonal	0	0	0
92			PG&E Shaping	0	0	0
93			PacifiCorp Shaping	0	0	0
109	Augmentation and Balancing			105,505	105,505	3,283
110		Tier 1 Resources		105,505	105,505	3,283
111			Klondike III	103,302	103,302	1,080
112			Rocky Brook	2,203	2,203	2,203
113						
114	Transmission Losses			(2,049,117)	(2,073,167)	(2,097,705)

Table 2.1.3

Rate Data Input
Exchange ASCs, Loads, and Gross Costs

	B	C	D	E	F
7	**Exchange ASCs ($/MWh)**		**2026**	**2027**	**2028**
8					
9	Avista Corporation	1	$ 67.29	$ 67.29	$ 67.29
10	Idaho Power Company	1	$ 60.47	$ 60.47	$ 60.47
11	NorthWestern Energy, LLC	1	$ 89.44	$ 89.44	$ 89.44
12	PacifiCorp	1	$ 103.92	$ 103.92	$ 103.92
13	Portland General Electric Company	1	$ 93.89	$ 93.89	$ 93.89
14	Puget Sound Energy, Inc.	1	$ 82.24	$ 82.24	$ 82.24
15	Clark Public Utilities	0	$ -	$ -	$ -
17	Snohomish PUD	1	$ 59.28	$ 59.28	$ 59.28
18					
19	**Exchange Loads (GWh)**		**2026**	**2027**	**2028**
20					
21	Avista Corporation		4,201	4,201	4,213
22	Idaho Power Company		7,366	7,366	7,386
23	NorthWestern Energy, LLC		772	772	774
24	PacifiCorp		9,406	9,406	9,431
25	Portland General Electric Company		8,572	8,572	8,595
26	Puget Sound Energy, Inc.		12,557	12,557	12,592
27	Clark Public Utilities		0	0	0
29	Snohomish PUD		3,965	4,021	4,099
30			46,839	46,895	47,091
31					
32	**Exchange Resource Cost ($000)**		**2026**	**2027**	**2028**
33					
34	Avista Corporation		$ 282,716	$ 282,716	$ 283,491
35	Idaho Power Company		$ 445,468	$ 445,468	$ 446,688
36	NorthWestern Energy, LLC		$ 69,024	$ 69,024	$ 69,213
37	PacifiCorp		$ 977,396	$ 977,396	$ 980,074
38	Portland General Electric Company		$ 804,789	$ 804,789	$ 806,994
39	Puget Sound Energy, Inc.		$ 1,032,687	$ 1,032,687	$ 1,035,516
40	Clark Public Utilities		$ -	$ -	$ -
42	Snohomish PUD		$ 235,026	$ 238,349	$ 243,012
43			$ 3,847,106	$ 3,850,430	$ 3,864,988

Table 2.2.1.1

Energy Allocation Factor
Power Sales and Resources
(aMW)

	B	C	E	F	G
4			**2026**	**2027**	**2028**
5	**Sales**				
6	Public				
7		Load Following	4,750	4,768	4,780
8		Tier 2 (block net of remarketing)	531	577	615
9		Slice (output energy)	840	826	839
10		Block	1,166	1,190	1,188
11		Undistributted Conservation	0	0	0
12	Exports				
13		BC Hydro (Cdn Entitlement)	305	305	305
14		Non-Treaty Storage	12	13	13
15		Libby Coordination	0	0	0
16		Pasadena Capacity	0	0	0
17		Pasadena Seasonal	0	0	0
18		Riverside Capacity	0	0	0
19		Riverside Seasonal	0	0	0
20		PacifiCorp	0	0	0
21		PG&E	0	0	0
22		Federal Generation Transmission Losses	2	2	2
23		Intertie Losses	0	0	0
24		Dittmer/Substation Sale	9	9	9
25	Intra-regional Transfers				
26		Firm Surplus Sale	0	0	0
27					
28	Other Loads				
29		USBR Pump Load	192	192	196
30		Hungry Horse	0	0	0
31		Upper Baker	1	1	1
32		Direct Service Industries	11	11	11
33		New Resource	1	20	25
34	Total Firm Obligations		**7,820**	**7,914**	**7,985**
35					
36	**Resources**				
37	Hydro				
38		Regulated	6,336	6,345	6,354
39		Independent			
40		Cowlitz Falls	24	29	27
41		Idaho Falls	0	0	0
42		PreAct	240	241	238
43		Non-Fed CER (Canada)	84	84	84
44		Libby Coordination	0	0	0
45	Other Hydro Resources				
46					

Table 2.2.1.2

Energy Allocation Factor
Power Sales and Resources
(aMW)

	B	C	E	F	G
4			**2026**	**2027**	**2028**
47	Combustion Turbines				
48	Renewables				
49		Foote Creek 1	0	0	0
50		Foote Creek 2	0	0	0
51		Foote Creek 4	0	0	0
52		Stateline Wind Project	21	5	0
53		Condon Wind Project	0	0	0
54		Klondike I	0	0	0
55		Georgia-Pacific Paper (Wauna)	0	0	0
56		Klondike III	12	12	0
57		Fourmile Hill Geothermal	0	0	0
58		Ashland Solar Project	0	0	0
59		White Bluffs Solar	0	0	0
60	Cogeneration				
61	Imports				
62		Riverside Exchange Energy	0	0	0
63		Pasadena Exchange Energy	0	0	0
64		BC Hydro Power Purchase	1	1	1
65		Riverside Capacity	0	0	0
66		Riverside Seasonal	0	0	0
67		Pasadena Capacity	0	0	0
68		Pasadena Seasonal	0	0	0
69		Slice Losses Return	17	17	17
70	Regional Transfers (In)				
71		Southeast Idaho Load Purchase	63	63	63
72		PacifiCorp	0	0	0
73	Large Thermal		1,116	994	1,116
74	Non-Utility Generation				
75		Dworshak/Clearwater Small Hydropower	3	3	3
76		Elwha Hydro	0	0	0
77		Glines Canyon Hydro	0	0	0
78		Rocky Brook	0	0	0.25
79	Tier 2 Augmentation w/out losses		120	315	274
80	Federal Trans. Losses		(229)	(224)	(228)
81	Total Net Resources		**7,809**	**7,884**	**7,948**
82					
83	Total Federal System Surplus/Deficit after Tier 2 Augmentation		**(12)**	**(31)**	**(36)**

Table 2.2.2.1

Energy Allocation Factor
Aggregated Loads and Resources
(aMW)

	B	C	E	F	G
4			**2026**	**2027**	**2028**
7	**Loads**				
8	Priority Firm - 7(b) Loads				
9		Block	1,200	1,226	1,223
10		Load Following	4,891	4,910	4,922
11		Slice (output energy)	865	850	864
12		Tier 2	547	594	634
14		5(c) Exchange	5,506	5,512	5,520
15	Industrial Firm - 7(c) Loads				
16		Direct Service Industries	11	11	11
17	New Resources - 7(f) Loads				
18		NR	1	20	26
19	Surplus Firm - SP Loads				
20		Firm Surplus Sale	0	0	0
21					
22	Total Loads		**13,020**	**13,123**	**13,200**
23					
24	**Resources**				
25	Federal Base System				
26		Hydro	6,660	6,670	6,676
27		Other Resources			
28		Small Thermal & Misc.			
29		Combustion Turbines			
30		Renewables	0	0	0
31		Cogeneration			
32		Imports	1.0	1	1
33		Regional Transfers (In)	63	63	63
34		Large Thermal	1,116	994	1,116
35		Non-Utility Generation	0	0	0
36		Slice Loss Return	17	17	17
37		Augmentation Purchases	0.0	0.0	0.0
38		Tier 2 Augmentation	123	324	281

Energy Allocation Factor
Aggregated Loads and Resources
(aMW)

	B	C	E	F	G
4			**2026**	**2027**	**2028**
39	less: FBS Obligations				
40		BC Hydro (Cdn Entitlement)	(314)	(314)	(314)
41		Non-Treaty Storage	(13)	(13)	(13)
42		Libby Coordination	0	0	0
43		Hungry Horse	0	0	0
44		Upper Baker	(1)	(1)	(1)
45		USBR Pump Load	(198)	(198)	(202)
46		Dittmer/Substation Sale	(10)	(10)	(10)
47	less: FBS Uses				
48		Pasadena	0	0	0
49		Riverside	0	0	0
50		PacifiCorp	0	0	0
51		PG&E	0	0	0
52		Federal Generation Transmission Losses	(2)	(2)	(2)
53		Intertie Losses	0	0	0
54	Exchange Resources				
55		5(c) Exchange	5,506	5,512	5,520
56	New Resources				
57		Cowlitz Falls	24	29	27
58		Idaho Falls	0	0	0
59		Foote Creek 1	0	0	0
60		Foote Creek 2	0	0	0
61		Foote Creek 4	0	0	0
62		Stateline Wind Project	21	5	0
63		Condon Wind Project	0	0	0
64		Klondike I	0	0	0
65		Klondike III	12	12	0
66		Georgia-Pacific Paper (Wauna)	0	0	0
67		Fourmile Hill Geothermal	0	0	0
68		Ashland Solar Project	0	0	0
69		White Bluffs Solar	0	0	0
70		Dworshak/Clearwater Small Hydropower	3	3	3
71		Elwha Hydro	0	0	0
72		Glines Canyon Hydro	0	0	0
73		Rocky Brook	0	0	0
74		Other Augmentation	12	31	38
75	Total Resources		**13,020**	**13,123**	**13,200**

Energy Allocation Factor
Calculation of Energy Allocation Factors

	B	C	D	E
4		**2026**	**2027**	**2028**
5				
6	**Loads (after adjustments)**			
7	Public	7,503	7,579	7,643
8	Exchange	5,506	5,512	5,520
9	DSI	11	11	11
10	NR	1	20	26
11	FPS	0	0	0
12				
13	Load Pools -- Program Case			
14	Priority Firm - 7(b) Loads	13,008	13,091	13,163
15	Industrial Firm - 7(c) Loads	11	11	11
16	New Resources - 7(f) Loads	1	20	26
17	Surplus Firm - SP Loads	0	0	0
18	Total Firm Loads	13,020	13,123	13,200
19	Secondary	1,959	1,969	1,992
20	Surplus Firm - SP Loads (for rate protection)	0	0	0
21				
22	**Resources (after adjustments)**			
23	Federal Base System	7,442	7,531	7,613
24	Exchange Resources	5,506	5,512	5,520
25	New Resources	72	80	67
26	Total Firm Resources	13,020	13,123	13,200
27				
28	Allocators -- Program Case			
29	Federal Base System			
30	Priority Firm - 7(b) Loads	7,442	7,531	7,613
31	Industrial Firm - 7(c) Loads	0	0	0
32	New Resources - 7(f) Loads	0	0	0
33	Surplus Firm - SP Loads	0	0	0
34	Exchange Resources			
35	Priority Firm - 7(b) Loads	5,506	5,512	5,520
36	Industrial Firm - 7(c) Loads	0	0	0
37	New Resources - 7(f) Loads	0	0	0
38	Surplus Firm - SP Loads	0	0	0
39	New Resources			
40	Priority Firm - 7(b) Loads	60	49	30
41	Industrial Firm - 7(c) Loads	11	11	11
42	New Resources - 7(f) Loads	1	20	26
43	Surplus Firm - SP Loads	0	0	0

Table 2.2.3.2

Energy Allocation Factor Calculation of Energy Allocation Factors

	B	C	D	E
4		**2026**	**2027**	**2028**
44				
45	**Allocation Factors -- Program Case with Exchange**			
46	Federal Base System + NR			
47	Priority Firm - 7(b) Loads	0.9984	0.9959	0.9951
48	Industrial Firm - 7(c) Loads	0.0015	0.0015	0.0015
49	New Resources - 7(f) Loads	0.0001	0.0026	0.0034
50	Surplus Firm - SP Loads	0.0000	0.0000	0.0000
51	Federal Base System			
52	Priority Firm - 7(b) Loads	1.0000	1.0000	1.0000
53	Industrial Firm - 7(c) Loads	0.0000	0.0000	0.0000
54	New Resources - 7(f) Loads	0.0000	0.0000	0.0000
55	Surplus Firm - SP Loads	0.0000	0.0000	0.0000
56	Exchange Resources			
57	Priority Firm - 7(b) Loads	1.0000	1.0000	1.0000
58	Industrial Firm - 7(c) Loads	0.0000	0.0000	0.0000
59	New Resources - 7(f) Loads	0.0000	0.0000	0.0000
60	Surplus Firm - SP Loads	0.0000	0.0000	0.0000
61	New Resources			
62	Priority Firm - 7(b) Loads	0.8336	0.6078	0.4428
63	Industrial Firm - 7(c) Loads	0.1566	0.1412	0.1679
64	New Resources - 7(f) Loads	0.0098	0.2510	0.3893
65	Surplus Firm - SP Loads	0.0000	0.0000	0.0000
66	Conservation & General			
67	Priority Firm - 7(b) Loads	0.9991	0.9976	0.9972
68	Industrial Firm - 7(c) Loads	0.0009	0.0009	0.0009
69	New Resources - 7(f) Loads	0.0001	0.0015	0.0020
70	Surplus Firm - SP Loads	0.0000	0.0000	0.0000
81	Surplus Deficit			
82	Priority Firm - 7(b) Loads	0.9991	0.9976	0.9972
83	Industrial Firm - 7(c) Loads	0.0009	0.0009	0.0009
84	New Resources - 7(f) Loads	0.0001	0.0015	0.0020
85	Surplus Firm - SP Loads	-1.0000	-1.0000	-1.0000
89	Rate Protection			
90	PF Exchange	0.7364	0.7337	0.7312
91	Industrial Firm - 7(c) Loads	0.0015	0.0015	0.0015
92	New Resources - 7(f) Loads	0.0001	0.0027	0.0035
93	Secondary Sales	0.2620	0.2621	0.2639

Table 2.3.1.1

Cost of Service Analysis
Disaggregated Costs and Credits
($ 000)

	B	D	E	F
4		2026	2027	2028
5	**Power System Generation Resources**			
6	**Operating Generation**			
7	Columbia Generating Station (WNP-2)	348,985	413,666	380,974
8	Bureau of Reclamation	195,235	206,763	208,089
9	Corps of Engineers	300,597	315,949	333,121
10	CRFM Studies	12,510	12,914	13,329
11	Billing Credits Generation	5,860	5,988	6,095
12	Cowlitz Falls O&M	22,250	27,225	23,975
13	Clearwater Hatchery Generation	1,600	1,636	1,673
14	New Resources Integration Wheeling	772	789	806
15				
16	**Operating Generation Settlement Payment**			
17	Operating Generation Settlement Payment (Colville)	27,523	28,132	28,760
18	Operating Generation Settlement Payment (Spokane)	6,881	7,033	7,190
19	Amortization of P2IP Settlement Payments	14,222	14,222	14,222
20	Amortization of 6S Settlement Payments	-	-	-
21				
22	**Non-Operating Generation**			
23	Trojan Decomissioning	1,300	1,329	1,359
24	WNP-1&3 Decomissioning	1,400	1,431	1,463
25				
26	**Contracted and Augmentation Power Purchases**			
27	Augmentation Power Purchases	-	-	-
28	Balancing Purchases	79,624	58,774	74,492
29	PNCA Headwater Benefits	-	-	-
30	Tier 1 Augmentation Resources (Klondike III)	8,716	10,399	1,942
31	Hedging/Mitigation	24,232	24,232	24,232
32	Other Committed Purchase (excl. Hedging)	245	245	245
33	Bookout Adj to Contracted Power Purchases	-	-	-
34	Other Augmentation	7,021	17,440	20,974
35				
36	**Exchanges and Settlements**			
37	Residential Exchange (IOU)	285,839	285,839	286,622
38	Residential Exchange (COU)	1,212	1,229	1,253
39	Residential Exchange (Refund)	-	-	-
40	Residential Exchange Program Support	303	312	322
41	Residential Exchange Interest Accrual	-	-	-
42				
43	**Renewable and Conservation Generation**			
44	Renewables R&D	862	862	-
45	Renewable Generation	15,396	2,013	270
46	Conservation Infrastructure	32,443	32,492	32,497
47	Generation Conservation R&D	560	560	560
48	DR & Smart Grid	500	500	500
49	Conservation Acquisition	65,385	65,385	86,513
50	Low Income Energy Efficiency	6,005	6,005	6,005
51	Reimbursable Energy Efficiency Development	-	-	-
52	Legacy Conservation	-	-	-
53	Market Transformation	15,000	15,000	15,000

Cost of Service Analysis
Disaggregated Costs and Credits
($ 000)

	B	D	E	F
4		2026	2027	2028
54				
55	**Transmission Acquisition and Ancillary Services**			
56	Trans & Ancillary Svcs (non-slice)	83,653	83,208	84,336
57	Trans & Ancillary Svcs (sys oblig)	2,304	2,428	2,805
58	Third Party GTA Wheeling	92,013	94,644	96,736
59	Third Party GTA Wheeling (NR)	-	-	-
60	Power 3rd Party Trans & Ancillary Svcs (Non-Slice Cost)	-	-	-
61	Power 3rd Party Trans & Ancillary Svcs (Composite Cost)	3,300	3,300	3,300
62	Trans Acq Generation Integration	23,492	24,627	26,376
63	Power Telemetering/Equipment Replacement	-	-	-
64	EESC Charges (Composite)	-	-	-
65	EESC Charges (Non-Slice)	-	-	-
66				
67	**Power Non-Generation Operations**			
68	Efficiencies Program	-	-	-
69	Information Technology	-	-	-
70	Generation Project Coordination	4,501	4,615	4,732
71	Slice costs Charged to Slice Customers	-	-	-
72	Slice Implementation	835	863	891
73				
74	**PS Scheduling**			
75	Operations Scheduling	12,028	12,516	13,038
76	Operations Planning	11,861	12,170	12,499
77				
78	**PS Marketing and Business Support**			
79	Sales and Support	14,504	15,022	15,567
80	Strategy, Finance & Risk Mgmt	4,385	6,496	6,364
81	Executive and Administrative Svcs	-	-	-
82	Conservation Support	9,555	9,869	10,189
83	Power R&D	733	733	1,595
84	Grid Mod	324	351	378
85	Power Internal Support	23,020	23,701	24,425
86	KSI Commercial Operations Expense	-	-	-
87	EIM Support Costs	-	-	-
88				
89	**Fish and Wildlife/USF&W/Planning Council/Env Req.**			
90	Fish and Wildlife	275,484	282,484	289,505
91	USF&W Lower Snake Hatcheries	33,777	34,707	35,669
92	Planning Council	12,041	11,876	12,052
93	Long Term Funding Agreements	18,403	18,075	19,063
94				
95	**BPA Internal Support**			
96	Additional Post-Retirement Contribution	16,442	17,182	17,927
97	Agency Svs for Power for Rev Req schedule	98,864	106,653	111,162
98	F&W Corporate Support - G&A	21,720	23,347	24,124
99	Agency Svs for Energy Efficiency for Rev Req schedule	21,301	22,698	23,337
100				
101	**Bad Debt Expense/Other**			
102	Bad Debt Expense (composite)	-	-	-
103	Bad Debt Expense (non-slice)	-	-	-
104	Other Income & Expense (composite) - Decommissioning	-	-	-

Cost of Service Analysis
Disaggregated Costs and Credits
($ 000)

	B	D	E	F
4		**2026**	**2027**	**2028**
108				
109	**Depreciation and Amortization**			
110	**Depreciation**			
111	Depreciation - BPA	6,957	7,130	6,321
112	Depreciation - Corps	114,110	117,336	121,522
113	Depreciation - Bureau	27,492	27,985	28,603
114				
115	**Amortization**			
116	Amortization - Legacy Conservation	-	-	-
117	Amortization - Conservation Acquisitions	8,450	1,132	55
118	Amortization - CRFM	19,891	19,891	19,891
119	Amortization - Fish & Widlife	31,329	29,964	29,919
120	Amortization - Lower Snake Hatchery Agreement	-	-	-
121	Amortization -- CGS	198,383	231,081	256,864
122	Accretion -- CGS Decomm Trust liability	42,607	44,438	46,350
123	Amortization -- WNP1	32,755	32,755	32,755
124	Amortization -- WNP3	37,637	37,637	37,637
125	Amortization -- Cowlitz Falls	5,947	5,947	5,947
126	Amortization -- N. Wasco	-	-	-
127				
128	**Interest Expense**			
129	**Net Interest**			
130	Interest On Appropriated Funds	28,017	29,942	30,111
131	Capitalization Adjustment	(45,937)	(45,937)	(45,937)
132	Interest On Treasury Bonds	40,700	34,573	32,879
133	Non Federal Interest (Prepay)	3,329	2,064	740
134	Non Federal Interest (CGS)	171,389	183,914	193,473
135	Non Federal Interest (WNP 1)	34,637	29,790	25,544
136	Non Federal Interest (WNP 3)	43,781	39,344	34,978
137	Non Federal Interest (N Wasco)	-	-	-
138	Non Federal Interest (Lewis County)	2,145	1,874	1,589
139	Premiums/Discounts	-	-	-
140	Amortization of Refinancing Premiums/Discounts	(42,053)	(44,109)	(45,757)
141	Amortization of Cost of Issuance	208	308	408
142	Gains/losses on Extinguishment	-	-	-
143	AFUDC	(20,002)	(20,295)	(20,498)
144	Irrigation Assistance	20,662	6,370	11,634
145	Other Expense and (Income) (Gains/Losses on Decomm Trust)	-	-	-
146	Interest Earned on BPA Fund for Power (composite)	(18,891)	(17,369)	(17,252)
147	Interest Earned on BPA Fund for Power (non-slice)	(1,449)	(1,403)	(1,950)
148	Interest Income on Decommissioning Trust	(16,849)	(17,824)	(18,855)
149				
150	**Net Interest into Cost Pools**			
151	Power Net Interest - Hydro Allocation	5,233	(10,652)	(9,220)
152	Power Net Interest - Fish & Wildlife Allocation	1,139	(1,361)	(1,001)
153	Power Net Interest - Conservation Allocation	6		
154	Power Net Interest - BPA Programs Allocation	51	(41)	(52)
155				
156	**Net Interest into Cost Pools 7b2**			
157	Power Net Interest Hydro 7b2 Allocation	5,233	(10,652)	(9,220)
158	Power Net Interest Fish & Wildlife 7b2 Allocation	1,139	(1,361)	(1,001)
159	Power Net Interest BPA Programs 7b2 Allocation	57	(41)	(52)

Cost of Service Analysis
Disaggregated Costs and Credits
($ 000)

	B	D	E	F
4		2026	2027	2028
160				
161	**Net Revenue**			
162	**Minimum Required Net Revenue**			
163	Repayment of Treasury Borrowings	437,000	441,000	178,300
164	Depreciation (MRNR - Reverse sign)	(148,559)	(152,451)	(156,446)
165	Amortization (MRNR - Reverse sign)	(376,999)	(402,844)	(429,418)
166	Non Federal Interest (Prepay) (MRNR - Reverse Sign)	(3,329)	(2,064)	(740)
167	Capitalization Adjustment (MRNR - Reverse Sign)	45,937	45,937	45,937
168	Amortization of Refinancing Premiums/Discounts (MRNR - Revers	42,053	44,109	45,757
169	Amortization of Cost of Issuance (MRNR-reverse sign)	(208)	(308)	(408)
170	Gains/Losses on Extinguishment	-	-	-
171	Repayment of Federal Appropriations			406,699
172	Accrual Revenues (MRNR Adjustment - Reverse Sign)	-	-	-
173	Prepay Revenue Credits (MRNR - Reverse Sign)	30,600	30,600	30,600
174	Non-Cash Expenses	-	-	-
175	Repayment of NF Obligations (LOC)	-	-	-
176	Repayment of NF Obligations (CGS)	33,153	37,141	33,375
177	Repayment of NF Obligations (WNP 1)	(2,146)	(1,669)	-
178	Repayment of NF Obligations (WNP 3)	-	(1,351)	(4,054)
179	Repayment of NF Obligations (N Wasco)	-	-	-
180	Repayment of NF Obligations (Cowlitz Falls)	5,155	5,430	5,710
181	Payments for Litigation of Stay Agreements	10,600	10,843	11,079
182	Amortization of P2IP Settlement Payments	14,222	14,222	14,222
183	Amortization of 6S Settlement Payments	-	-	-
184	Cash Contribution to CGS Decomm Trust	15,700	16,300	17,000
185	Interest Income on Decommissioning Trust (MRNR - Reverse Sign)	16,849	17,824	18,855
186	Other Expense and (Income) (Gains/Losses on Decomm Trust) (M	-	-	-
187	Revenue Financing Requirement	39,000	43,000	44,000
188	Depreciation Exceeds Cash Expense	(130,583)	(117,276)	(232,024)
189				
190	**Minimum Net Revenue into Cost Pools**			
191	Power MNetRev - Hydro Allocation	106,298	103,634	208,243
192	Power MNetRev - Fish & Wildlife Allocation	23,121	13,242	23,278
193	Power MNetRev - Conservation Allocation	128	3	
194	Power MNetRev - BPA Programs Allocation	1,036	397	503
195				
196	**Minimum Net Revenue into Cost Pools 7b2**			
197	Power MNetRev - Hydro 7b2 Allocation	106,298	103,634	208,243
198	Power MNetRev - Fish & Wildlife 7b2 Allocation	23,121	13,242	23,278
199	Power MNetRev - PBA Programs 7b2 Allocation	1,164	400	503
200				
201	**Planned Net Revenues for Risk into Cost Pools**			
202	Power PNetRev - Hydro Allocation	-	-	-
203	Power PNetRev - Fish & Wildlife Allocation	-	-	-
204	Power PNetRev - Conservation Allocation	-	-	-
205	Power PNetRev - BPA Programs Allocation	-	-	-
206				
207	**Planned Net Revenues for Risk into Cost Pools 7b2**			
208	Power PNetRev - Hydro 7b2 Allocation	-	-	-
209	Power PNetRev - Fish & Wildlife 7b2 Allocation	-	-	-
210	Power PNetRev - BPA Programs 7b2 Allocation	-	-	-

Cost of Service Analysis
Disaggregated Costs and Credits
($ 000)

	B	D	E	F
4		2026	2027	2028
211				
212	**Internally Computed Line Items**			
213	Augmentation Power Purchases	-	-	-
214	Balancing Purchases	103,856	83,006	98,724
215	Secondary Energy Credit	(462,139)	(428,203)	(410,005)
216	Low Density Discount Costs	42,155	43,297	44,391
217	Irrigation Rate Mitigation Costs	22,034	22,034	22,034
218	Other Augmentation	7,021	17,440	20,974
219				
220	**Charges/Credits to Tiered Rate Pools**			
221	Firm Surplus and Secondary Credit (from unused RHWM)	(94,894)	(73,857)	(60,238)
222	Balancing Augmentation	(834)	(3,383)	(686)
223	Transmission Loss Adjustment	(35,579)	(35,836)	(35,988)
224	Demand Revenue	141,637	148,212	156,468
225	Load Shaping Revenue	72,093	76,824	72,724
226				
227	**Tier 2 and RSS Charges/Credits to Tiered Rate Pools**			
228	Augmentation RSS & RSC Adder	2,631	2,631	2,635
229	Tier 2 Purchase Costs	319,432	329,517	354,163
230	Tier 2 Rate Design Adjustments (Cost)	8,806	10,276	11,139
231	Tier 2 Other Costs	-	-	-
232				
233	**Revenue Credits / Rate Design Adjustments**			
234	Downstream Benefits and Pumping Power	(21,193)	(21,193)	(21,193)
235	Generation Inputs Revenue	(133,219)	(133,219)	(133,219)
236	Capacity for Delayed 168-hr Loss Returns	-	-	-
237	FPS Real Power Losses (Capacity)	(44,745)	(44,745)	(44,745)
238	FPS Real Power Losses (Energy)	-	-	-
239	4(h)(10)(C)	(124,911)	(131,117)	(132,163)
240	PRSC Net Credit (Composite)	-	-	-
241	PRSC Net Credit (Non-Slice)	-	-	-
242	Colville and Spokane Settlements	(4,600)	(4,600)	(4,600)
243	Green Tags (FBS resources)	-	-	-
244	Green Tags (New resources)	-	-	-
245	Energy Efficiency Revenues	-	-	-
246	Miscellaneous Credits (incl. GTA)	(8,647)	(8,831)	(9,078)
247	Pre-sub/Hungry Horse	-	-	-
248	Other Locational/Seasonal Exchange	-	-	-
249	Upper Baker	(485)	(476)	(456)
250	Other Surplus Sales (Non-Slice)	-	-	-
251	PF Load Forecast Deviation Liquidated Damages	-	-	-
252	NR Revenues from ESS (Capacity)	(9,502)	(11,522)	(14,047)
253	NR Revenues from ESS (Energy)	-	-	-
254	Tiered Rates Adjustment	(239,962)	(145,142)	(190,764)
255				
256	**Tier 2**			
257	Composite Augmentation RSS Revenue Debit/(Credit)	(1,560)	(1,560)	(1,561)
258	Composite Tier 2 RSS Revenue Debit/(Credit)	(563)	(610)	(651)
259	Composite Tier 2 Rate Design Adjustment Debit/(Credit)	(8,243)	(9,667)	(10,488)
260	Composite Non-Federal RSS Revenue Debit/(Credit)	(1,293)	(3,064)	(3,434)
261	Non-Slice Augmentation RSC Revenue Debit/(Credit)	(1,071)	(1,070)	(1,074)
262	Non-Slice Tier 2 RSC Revenue Debit/(Credit)	-	-	-
263	Non-Slice Tier 2 Rate Design Debit/(Credit)	-	-	-
264	Non-Slice Non-Federal RSC Revenue Debit/(Credit)	457	(2,518)	(1,405)

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Table 2.3.2

Cost of Service Analysis
Cost Pool Aggregation
($ 000)

	B		D	E	F
3			2026	2027	2028
4					
5	**Federal Base System**		**2,533,523**	**2,632,344**	**2,817,821**
6	Hydro		863,769	877,914	1,009,419
7		Operating Expense	752,238	784,932	810,396
8		Net Interest	5,233	(10,652)	(9,220)
9		PNRR	-	-	-
10		MRNR	106,298	103,634	208,243
11	BPA Fish and Wildlife Program		383,237	377,626	396,940
12		Operating Expense	358,977	365,745	374,663
13		Net Interest	1,139	(1,361)	(1,001)
14		PNRR	-	-	-
15		MRNR	23,121	13,242	23,278
16	Trojan		1,300	1,329	1,359
17	WNP #1		68,791	63,976	59,761
18	WNP #2		702,669	811,473	813,456
19	WNP #3		81,418	76,981	72,615
20	System Augmentation		-	-	-
21	Balancing		104,101	83,251	98,969
22	Tier 2 Costs		328,238	339,794	365,302
23					
24	**New Resources**		**64,709**	**68,185**	**57,177**
25	Idaho Falls		-	-	-
26	Tier 1 Aug (Klondike III)		8,716	10,399	1,942
27	Cowlitz Falls		28,197	33,172	29,922
28	Other NR		20,774	7,174	4,338
29	Other Augmentation		7,021	17,440	20,974
30	**Residential Exchange**		**3,847,409**	**3,850,742**	**3,865,310**
31					
32	**Conservation**		**165,193**	**159,631**	**180,753**
33		Operating Expense	165,059	159,628	180,753
34		Net Interest	6	-	-
35		PNRR	-	-	-
36		MRNR	128	3	-
37					
38	**BPA Programs**		**195,541**	**207,789**	**215,351**
39		Operating Expense	194,454	207,433	214,900
40		Net Interest	51	(41)	(52)
41		PNRR	-	-	-
42		MRNR	1,036	397	503
43					
44					
45	**Transmission**		**204,762**	**208,207**	**213,554**
46	TBL Transmission/Ancillary Services (System Obligation)		29,096	30,355	32,481
47	TBL Transmission/Ancillary Services (Non-Slice)		83,653	83,208	84,336
48	3rd Party Trans/Ancillary Services		-	-	-
49	General Transfer Agreements (NR)		-	-	-
50	General Transfer Agreements		92,013	94,644	96,736
51					
52	**Total PBL Revenue Requirement**		**7,011,137**	**7,126,898**	**7,349,965**
53					

Table 2.3.3.1

Cost of Service Analysis
Computation of Low Density and Irrigation Rate
Discount Costs ($ 000)

	B	D	E	F	G	H
18	**Program Totals**	**2026**	**2027**	**2028**		
19	**Low Density Discount Expenses....................**	**$ 42,155**	**$ 43,297**	**$ 44,391**		
20	**Irrigation Rate Discount.................................**	**$ 22,034**	**$ 22,034**	**$ 22,034**		
21						
22						
23	**TRM Costs after Adjustments**	**2026**	**2027**	**2028**		
24	**Composite...**	$ 2,438,459	$ 2,449,006	$ 2,457,587		
25	**Non-Slice...**	$ (365,300)	$ (367,103)	$ (368,571)		
26	**Slice...**	$ -	$ -	$ -		
27	**Tier 2..**	$ 328,238	$ 339,794	$ 365,302		
28	**Total Costs**	$ 2,401,397	$ 2,421,696	$ 2,454,318		
29						
30	**Low Density Discount**					
31	**Customer Charge LDD**	**2026**	**2027**	**2028**		
32	**TOCA LDD Offest %..**	1.76%	1.79%	1.81%		
33	**LDD Customer Charge ($000)........................**	$ 36,551	$ 37,251	$ 37,778		
34						
35	**Irrigation Rate Discount**					
36	**IRD Percentage..**	37.06%				
37	**Total Irrigation Load (MWh)..........................**	1,881,605				
38	**RT1SC..**	7,110				
39	**Irrigation Load Weighted LDD.......................**	4.6%				
40						
41		**2026**	**2027**	**2028**		
42	**Hours...**	8760	8760	8784		
43	**IRD TOCA...**	3.02122%	3.02122%	3.01296%		
44	**Composite Revenue..**	$ 77,631,906	$ 77,631,906	$ 77,419,661		
45	**Non-Slice Revenue..**	$ (13,272,543)	$ (13,272,543)	$ (13,236,256)		
46	**Load Shaping Revenue......................................**	$ (1,971,235)	$ (1,971,235)	$ (2,011,820)		
47	**Total after LDD...**	$ 59,518,274	$ 59,518,274	$ 59,311,692		
48						
49	**Irrigation Rate Discount.................................**	**11.71**				
50						
51						

Table 2.3.3.2

Cost of Service Analysis
Computation of Low Density and Irrigation Rate Discount Costs
($ 000)

	B	D	E	F		G		H	
52	Demand and Load Shaping Discount	Demand BD (kW)	LoadShp BD (MWh)	Demand Rate		LoadShp Rate		Total LDD Discount	
53	Oct-25	29,305	4,640	$	13.81	$	50.63	$	639,669
54	Oct-25	-	571	$	13.81	$	49.84	$	28,477
55	Nov-25	26,968	(8,500)	$	10.78	$	39.53	$	(45,293)
56	Nov-25	-	754	$	10.78	$	43.24	$	32,600
57	Dec-25	38,558	(378)	$	12.99	$	47.63	$	482,873
58	Dec-25	-	6,463	$	12.99	$	49.56	$	320,349
59	Jan-26	46,510	(3,028)	$	11.88	$	43.56	$	420,624
60	Jan-26	-	2,116	$	11.88	$	44.58	$	94,314
61	Feb-26	31,494	(989)	$	12.39	$	45.43	$	345,263
62	Feb-26	-	3,037	$	12.39	$	51.97	$	157,853
63	Mar-26	43,692	(11,301)	$	7.97	$	29.19	$	18,347
64	Mar-26	-	4,257	$	7.97	$	34.56	$	147,109
65	Apr-26	39,588	4,256	$	6.09	$	22.33	$	336,126
66	Apr-26	-	2,274	$	6.09	$	27.39	$	62,293
67	May-26	18,466	(11,106)	$	2.35	$	8.60	$	(52,080)
68	May-26	-	(3,536)	$	2.35	$	13.56	$	(47,950)
69	Jun-26	29,031	(8,669)	$	4.12	$	15.10	$	(11,301)
70	Jun-26	-	(1,871)	$	4.12	$	16.18	$	(30,281)
71	Jul-26	32,585	7,069	$	13.91	$	50.98	$	813,620
72	Jul-26	-	6,204	$	13.91	$	46.25	$	286,921
73	Aug-26	42,627	(2,421)	$	14.67	$	53.80	$	495,089
74	Aug-26	-	7,129	$	14.67	$	49.13	$	350,270
75	Sep-26	26,193	2,983	$	16.51	$	60.51	$	612,921
76	Sep-26	-	2,631	$	16.51	$	55.61	$	146,288
77	**Total**							**$**	**5,604,103**

Table 2.3.3.3

Cost of Service Analysis
Computation of Low Density and Irrigation Rate Discount Costs
($ 000)

	B	D	E	F	G	H
78	**Demand and Load Shaping Discount**	**Demand BD (kW)**	**LoadShp BD (MWh)**	**Demand Rate**	**LoadShp Rate**	**Total LDD Discount**
79	Oct-26	30,926	5,523	$ 13.81	$ 50.63	$ 706,722
80	Oct-26	-	319	$ 13.81	$ 49.84	$ 15,909
81	Nov-26	31,277	(8,732)	$ 10.78	$ 39.53	$ (8,024)
82	Nov-26	-	1,488	$ 10.78	$ 43.24	$ 64,326
83	Dec-26	40,690	388	$ 12.99	$ 47.63	$ 547,033
84	Dec-26	-	6,198	$ 12.99	$ 49.56	$ 307,198
85	Jan-27	54,809	(6,419)	$ 11.88	$ 43.56	$ 371,511
86	Jan-27	-	5,642	$ 11.88	$ 44.58	$ 251,512
87	Feb-27	34,075	(810)	$ 12.39	$ 45.43	$ 385,378
88	Feb-27	-	3,070	$ 12.39	$ 51.97	$ 159,519
89	Mar-27	45,716	(7,951)	$ 7.97	$ 29.19	$ 132,282
90	Mar-27	-	712	$ 7.97	$ 34.56	$ 24,601
91	Apr-27	43,784	4,368	$ 6.09	$ 22.33	$ 364,183
92	Apr-27	-	1,948	$ 6.09	$ 27.39	$ 53,375
93	May-27	22,198	(11,647)	$ 2.35	$ 8.60	$ (47,957)
94	May-27	-	(3,511)	$ 2.35	$ 13.56	$ (47,615)
95	Jun-27	30,652	(8,724)	$ 4.12	$ 15.10	$ (5,451)
96	Jun-27	-	(2,350)	$ 4.12	$ 16.18	$ (38,026)
97	Jul-27	33,814	7,532	$ 13.91	$ 50.98	$ 854,341
98	Jul-27	-	5,560	$ 13.91	$ 46.25	$ 257,121
99	Aug-27	47,800	(2,982)	$ 14.67	$ 53.80	$ 540,812
100	Aug-27	-	7,354	$ 14.67	$ 49.13	$ 361,308
101	Sep-27	29,476	3,122	$ 16.51	$ 60.51	$ 675,584
102	Sep-27	-	2,160	$ 16.51	$ 55.61	$ 120,102
103	**Total**					**$ 6,045,744**

Table 2.3.3.4

Cost of Service Analysis
Computation of Low Density and Irrigation Rate Discount Costs
($ 000)

	B	D	E	F		G		H	
104	**Demand and Load Shaping Discount**	**Demand BD (kW)**	**LoadShp BD (MWh)**	**Demand Rate**		**LoadShp Rate**		**Total LDD Discount**	
105	Oct-27	40,361	1,488	$	13.81	$	50.63	$	632,732
106	Oct-27	-	4,969	$	13.81	$	49.84	$	247,660
107	Nov-27	29,315	(4,259)	$	10.78	$	39.53	$	147,674
108	Nov-27	-	(2,664)	$	10.78	$	43.24	$	(115,205)
109	Dec-27	42,506	1,323	$	12.99	$	47.63	$	615,180
110	Dec-27	-	5,721	$	12.99	$	49.56	$	283,557
111	Jan-28	62,682	(6,234)	$	11.88	$	43.56	$	473,106
112	Jan-28	-	5,743	$	11.88	$	44.58	$	255,998
113	Feb-28	38,668	(579)	$	12.39	$	45.43	$	452,776
114	Feb-28	-	2,209	$	12.39	$	51.97	$	114,776
115	Mar-28	52,321	(7,631)	$	7.97	$	29.19	$	194,243
116	Mar-28	-	475	$	7.97	$	34.56	$	16,410
117	Apr-28	57,722	(407)	$	6.09	$	22.33	$	342,441
118	Apr-28	-	6,912	$	6.09	$	27.39	$	189,351
119	May-28	19,876	(7,124)	$	2.35	$	8.60	$	(14,534)
120	May-28	-	(8,417)	$	2.35	$	13.56	$	(114,149)
121	Jun-28	33,089	(8,444)	$	4.12	$	15.10	$	8,821
122	Jun-28	-	(2,826)	$	4.12	$	16.18	$	(45,731)
123	Jul-28	37,607	2,964	$	13.91	$	50.98	$	674,203
124	Jul-28	-	10,192	$	13.91	$	46.25	$	471,334
125	Aug-28	47,855	1,672	$	14.67	$	53.80	$	791,990
126	Aug-28	-	2,603	$	14.67	$	49.13	$	127,898
127	Sep-28	33,892	3,534	$	16.51	$	60.51	$	773,388
128	Sep-28	-	1,605	$	16.51	$	55.61	$	89,267
129	**Total**							**$**	**6,613,186**

Table 2.3.4.1.1 COSA 04-1

Cost of Service Analysis
Allocation of Costs
($ 000)

	B	C	D	E
4	**Costs ($000)**	**2026**	**2027**	**2028**
5	**FBS**	$ 2,533,523	$ 2,632,344	$ 2,817,821
6	**New Resources**	$ 64,709	$ 68,185	$ 57,177
7	**Residential Exchange**	$ 3,847,409	$ 3,850,742	$ 3,865,310
8	**Conservation**	$ 165,193	$ 159,631	$ 180,753
9	**BPAPrograms**	$ 195,541	$ 207,789	$ 215,351
10	**Transmission**	$ 204,762	$ 208,207	$ 213,554
11	**Irrigation/Low Density Discounts**	$ 64,189	$ 65,330	$ 66,424
12	Total	$ 7,075,326	$ 7,192,228	$ 7,416,390
13				
14	**Cost Allocation**			
15				
16	**FBS**	$ 2,533,523	$ 2,632,344	$ 2,817,821
17				
18	**Federal Base System Allocators**	**2026**	**2027**	**2028**
19	Priority Firm - 7(b) Loads	1.0000	1.0000	1.0000
20	Industrial Firm - 7(c) Loads	0.0000	0.0000	0.0000
21	New Resources - 7(f) Loads	0.0000	0.0000	0.0000
22	Surplus Firm - SP Loads	0.0000	0.0000	0.0000
23	Total	1.0000	1.0000	1.0000
24				
25	**FBS Cost Allocation**	**2026**	**2027**	**2028**
26	Priority Firm - 7(b) Loads	$ 2,533,523	$ 2,632,344	$ 2,817,821
27	Industrial Firm - 7(c) Loads	$ -	$ -	$ -
28	New Resources - 7(f) Loads	$ -	$ -	$ -
29	Surplus Firm - SP Loads	$ -	$ -	$ -
30	Total	$ 2,533,523	$ 2,632,344	$ 2,817,821
31				
32				
33	**Irrigation/Low Density Discounts**	$ 64,189	$ 65,330	$ 66,424
34				
35	**Irrigation/LDD Allocators**	**2026**	**2027**	**2028**
36	Priority Firm - 7(b) Loads	1.0000	1.0000	1.0000
37	Industrial Firm - 7(c) Loads	0.0000	0.0000	0.0000
38	New Resources - 7(f) Loads	0.0000	0.0000	0.0000
39	Surplus Firm - SP Loads	0.0000	0.0000	0.0000
40	Total	1.0000	1.0000	1.0000
41				
42	**Irrigation/LDD Cost Allocation**	**2026**	**2027**	**2028**
43	Priority Firm - 7(b) Loads	$ 64,189	$ 65,330	$ 66,424
44	Industrial Firm - 7(c) Loads	$ -	$ -	$ -
45	New Resources - 7(f) Loads	$ -	$ -	$ -
46	Surplus Firm - SP Loads	$ -	$ -	$ -
47	Total	$ 64,189	$ 65,330	$ 66,424
48				

Table 2.3.4.1.2

Cost of Service Analysis
Allocation of Costs
($ 000)

	B	C	D	E
4	**Costs ($000)**	**2026**	**2027**	**2028**
5	**FBS**	$ 2,533,523	$ 2,632,344	$ 2,817,821
6	**New Resources**	$ 64,709	$ 68,185	$ 57,177
7	**Residential Exchange**	$ 3,847,409	$ 3,850,742	$ 3,865,310
8	**Conservation**	$ 165,193	$ 159,631	$ 180,753
9	**BPAPrograms**	$ 195,541	$ 207,789	$ 215,351
10	**Transmission**	$ 204,762	$ 208,207	$ 213,554
11	**Irrigation/Low Density Discounts**	$ 64,189	$ 65,330	$ 66,424
12	Total	$ 7,075,326	$ 7,192,228	$ 7,416,390
13				
14	**Cost Allocation**			
49	**General Transfer Agreements**	$ 92,013	$ 94,644	$ 96,736
50				
51	**General Transfer Agreement Allocators**	**2026**	**2027**	**2028**
52	Priority Firm - 7(b) Loads	1.0000	1.0000	1.0000
53	Industrial Firm - 7(c) Loads	0.0000	0.0000	0.0000
54	New Resources - 7(f) Loads	0.0000	0.0000	0.0000
55	Surplus Firm - SP Loads	0.0000	0.0000	0.0000
56	Total	1.0000	1.0000	1.0000
57				
58	**General Transfer Agreement Allocation**	**2026**	**2027**	**2028**
59	Priority Firm - 7(b) Loads	$ 92,013	$ 94,644	$ 96,736
60	Industrial Firm - 7(c) Loads	$ -	$ -	$ -
61	New Resources - 7(f) Loads	$ -	$ -	$ -
62	Surplus Firm - SP Loads	$ -	$ -	$ -
63	Total	$ 92,013	$ 94,644	$ 96,736
64				
65	**TBL Transmission/Ancillary Services (Non-Slice)**	$ 83,653	$ 83,208	$ 84,336
66				
67	**TBL Transmission/Ancillary Services (Non-Slice) Allocation**	**2026**	**2027**	**2028**
68	Priority Firm - 7(b) Loads	$ 83,653	$ 83,208	$ 84,336
69	Industrial Firm - 7(c) Loads	$ -	$ -	$ -
70	New Resources - 7(f) Loads	$ -	$ -	$ -
71	Surplus Firm - SP Loads	$ -	$ -	$ -
72	Total	$ 83,653	$ 83,208	$ 84,336
73				

Cost of Service Analysis
Allocation of Costs
($ 000)

	B	C	D	E
4	**Costs ($000)**	**2026**	**2027**	**2028**
5	**FBS...**	$ 2,533,523	$ 2,632,344	$ 2,817,821
6	**New Resources...**	$ 64,709	$ 68,185	$ 57,177
7	**Residential Exchange...**	$ 3,847,409	$ 3,850,742	$ 3,865,310
8	**Conservation...**	$ 165,193	$ 159,631	$ 180,753
9	**BPAPrograms...**	$ 195,541	$ 207,789	$ 215,351
10	**Transmission...**	$ 204,762	$ 208,207	$ 213,554
11	**Irrigation/Low Density Discounts....**	$ 64,189	$ 65,330	$ 66,424
12	Total...	$ 7,075,326	$ 7,192,228	$ 7,416,390
13				
14	**Cost Allocation (continued)**			
15				
16	**New Resources...**	$ 64,709	$ 68,185	$ 57,177
17				
18	**New Resources Allocators**	**2026**	**2027**	**2028**
19	Priority Firm - 7(b) Loads...	0.8336	0.6078	0.4428
20	Industrial Firm - 7(c) Loads...	0.1566	0.1412	0.1679
21	New Resources - 7(f) Loads...	0.0098	0.2510	0.3893
22	Surplus Firm - SP Loads...	0.0000	0.0000	0.0000
23	Total...	1.0000	1.0000	1.0000
24				
25	**New Resources Cost Allocation...**	**2026**	**2027**	**2028**
26	Priority Firm - 7(b) Loads...	$ 53,940	$ 41,443	$ 25,318
27	Industrial Firm - 7(c) Loads...	$ 10,132	$ 9,628	$ 9,602
28	New Resources - 7(f) Loads...	$ 637	$ 17,113	$ 22,257
29	Surplus Firm - SP Loads...	$ -	$ 0	$ -
30	Total...	$ 64,709	$ 68,185	$ 57,177
31				
32				
33	**Residential Exchange...**	$ 3,847,409	$ 3,850,742	$ 3,865,310
34	Costs Functionalized to Transmission..	$ (291,806)	$ (292,155)	$ (293,377)
35	Costs Functionalized to Generation...	$ 3,555,603	$ 3,558,587	$ 3,571,933
36				
37	**Residential Exchange Allocators**	**2026**	**2027**	**2028**
38	Priority Firm - 7(b) Loads...	1.0000	1.0000	1.0000
39	Industrial Firm - 7(c) Loads...	0.0000	0.0000	0.0000
40	New Resources - 7(f) Loads...	0.0000	0.0000	0.0000
41	Surplus Firm - SP Loads...	0.0000	0.0000	0.0000
42	Total...	1.0000	1.0000	1.0000
43				
44	**Residential Exchange Cost Allocation**	**2026**	**2027**	**2028**
45	Priority Firm - 7(b) Loads...	$ 3,555,603	$ 3,558,587	$ 3,571,933
46	Industrial Firm - 7(c) Loads...	$ -	$ -	$ -
47	New Resources - 7(f) Loads...	$ -	$ -	$ -
48	Surplus Firm - SP Loads...	$ -	$ -	$ -
49	Total...	$ 3,555,603	$ 3,558,587	$ 3,571,933

Cost of Service Analysis
Allocation of Costs
($ 000)

	B	C	D	E
4	**Costs ($000)**	**2026**	**2027**	**2028**
5	**FBS**	$ 2,533,523	$ 2,632,344	$ 2,817,821
6	**New Resources**	$ 64,709	$ 68,185	$ 57,177
7	**Residential Exchange**	$ 3,847,409	$ 3,850,742	$ 3,865,310
8	**Conservation**	$ 165,193	$ 159,631	$ 180,753
9	**BPAPrograms**	$ 195,541	$ 207,789	$ 215,351
10	**Transmission**	$ 204,762	$ 208,207	$ 213,554
11	**Irrigation/Low Density Discounts**	$ 64,189	$ 65,330	$ 66,424
12	Total	$ 7,075,326	$ 7,192,228	$ 7,416,390
13				
14	**Cost Allocation (continued)**			
15				
16	**Conservation**	$ 165,193	$ 159,631	$ 180,753
17				
18	**BPAPrograms**	$ 195,541	$ 207,789	$ 215,351
19				
20	**Transmission & Ancillary Services (Non-Slice)**	$ 29,096	$ 30,355	$ 32,481
21				
22				
23	**Conservation & General Allocators**	**2026**	**2027**	**2028**
24	Priority Firm - 7(b) Loads	0.9991	0.9976	0.9972
25	Industrial Firm - 7(c) Loads	0.0009	0.0009	0.0009
26	New Resources - 7(f) Loads	0.0001	0.0015	0.0020
27	Surplus Firm - SP Loads	0.0000	0.0000	0.0000
28	Total	1.0000	1.0000	1.0000
29				
30	**Conservation Cost Allocation**	**2026**	**2027**	**2028**
31	Priority Firm - 7(b) Loads	$ 165,040	$ 159,248	$ 180,238
32	Industrial Firm - 7(c) Loads	$ 144	$ 138	$ 155
33	New Resources - 7(f) Loads	$ 9	$ 245	$ 360
34	Surplus Firm - SP Loads	$ 0	$ 0	$ 0
35	Total	$ 165,193	$ 159,631	$ 180,753
36				
37	**BPA Programs Cost Allocation**	**2026**	**2027**	**2028**
38	Priority Firm - 7(b) Loads	$ 195,360	$ 207,291	$ 214,738
39	Industrial Firm - 7(c) Loads	$ 170	$ 179	$ 185
40	New Resources - 7(f) Loads	$ 11	$ 319	$ 428
41	Surplus Firm - SP Loads	$ 0	$ 0	$ 0
42	Total	$ 195,541	$ 207,789	$ 215,351
43				
44	**Transmission Cost Allocation**	**2026**	**2027**	**2028**
45	Priority Firm - 7(b) Loads	$ 29,069	$ 30,282	$ 32,389
46	Industrial Firm - 7(c) Loads	$ 25	$ 26	$ 28
47	New Resources - 7(f) Loads	$ 2	$ 47	$ 65
48	Surplus Firm - SP Loads	$ 0	$ 0	$ 0
49	Total	$ 29,096	$ 30,355	$ 32,481

Table 2.3.5

Cost of Service Analysis
Allocation of Costs Summary
($ 000)

	B	C		D		E	
4	**Costs ($000)**		**2026**		**2027**		**2028**
5	**FBS..........**	$	2,533,523	$	2,632,344	$	2,817,821
6	**New Resources..........**	$	64,709	$	68,185	$	57,177
7	**Residential Exchange..........**	$	3,847,409	$	3,850,742	$	3,865,310
8	**Conservation..........**	$	165,193	$	159,631	$	180,753
9	**BPAPrograms..........**	$	195,541	$	207,789	$	215,351
10	**Transmission..........**	$	204,762	$	208,207	$	213,554
11	**Irrigation/Low Density Discounts....**	$	64,189	$	65,330	$	66,424
12	Total..........	$	7,075,326	$	7,192,228	$	7,416,390
13							
14	**Cost Allocation (continued)**						
15							
16							
17	**Initial Cost Allocation (Costs /$1000)**		**2026**		**2027**		**2028**
18	Priority Firm - 7(b) Loads..........	$	6,772,391	$	6,872,378	$	7,089,934
19	Industrial Firm - 7(c) Loads..........	$	10,471	$	9,972	$	9,970
20	New Resources - 7(f) Loads..........	$	658	$	17,724	$	23,109
21	Surplus Firm - SP Loads..........	$	0	$	0	$	0
22	Total Costs Functionalized to Power....	$	6,783,520	$	6,900,073	$	7,123,013
23							
24							
25							
26	REP Cost Functionalized to Transmission	$	291,806	$	292,155	$	293,377
27							
28	Total COSA Revenue Requirement	$	7,075,326	$	7,192,228	$	7,416,390

Cost of Service Analysis
General Revenue Credits
($ 000)

	B		C		D		E
5	**General Revenue Credits ($000))**		**2026**		**2027**		**2028**
6							
7	**FBS**	**$**	**(399,473)**	**$**	**(312,329)**	**$**	**(359,859)**
8	Hydro and Renewable	$	(25,793)	$	(25,793)	$	(25,793)
9	Downstream Benefits and Pumping Power	$	(21,193)	$	(21,193)	$	(21,193)
10	Colville and Spokane Settlements	$	(4,600)	$	(4,600)	$	(4,600)
11	Green Tags (FBS resources)	$	-	$	-	$	-
12	Fish and Wildlife	$	(124,911)	$	(131,117)	$	(132,163)
13	4(h)(10)(c)	$	(124,911)	$	(131,117)	$	(132,163)
14	Tiered Rates Adjustment	$	(239,962)	$	(145,142)	$	(190,764)
15	Tier 2 Adjustment	$	(8,806)	$	(10,276)	$	(11,139)
16	**Contract Obligations**	**$**	**(485)**	**$**	**(476)**	**$**	**(456)**
17	Pre-sub/Hungry Horse	$	-	$	-	$	-
18	Other Locational/Seasonal Exchange	$	-	$	-	$	-
19	Upper Baker	$	(485)	$	(476)	$	(456)
20	**New Resources**	**$**	**-**	**$**	**-**	**$**	**-**
21	Green Tags (New resources)	$	-	$	-	$	-
22	**Conservation**	**$**	**-**	**$**	**-**	**$**	**-**
23	Energy Efficiency Revenues	$	-	$	-	$	-
24	**BPAPrograms**	**$**	**-**	**$**	**-**	**$**	**-**
25	**Transmission**	**$**	**(8,647)**	**$**	**(8,831)**	**$**	**(9,078)**
26	Miscellaneous Credits (incl. GTA)	$	(8,647)	$	(8,831)	$	(9,078)
27							
28	**Other Revenue Credits ($ 000))**		**2026**		**2027**		**2028**
29	Secondary Revenue	**$**	**(523,061)**	**$**	**(484,267)**	**$**	**(466,159)**
30	Incl. Slice	$	(523,061)	$	(484,267)	$	(466,159)
31	Generation Inputs Revenue	**$**	**(133,219)**	**$**	**(133,219)**	**$**	**(133,219)**
32	FPS Real Power Losses (Capacity)	**$**	**(44,745)**	**$**	**(44,745)**	**$**	**(44,745)**
33	FPS Real Power Losses (Energy)	**$**	**-**	**$**	**-**	**$**	**-**
34	PRSC Net Credit (Composite)	**$**	**-**	**$**	**-**	**$**	**-**
35	PRSC Net Credit (Non-Slice)	**$**	**-**	**$**	**-**	**$**	**-**
36	Composite Non-Federal RSS Revenue Debit/(Credit)	**$**	**(1,293)**	**$**	**(3,064)**	**$**	**(3,434)**
37	Non-Slice Non-Federal RSC Revenue Debit/(Credit)	**$**	**457**	**$**	**(2,518)**	**$**	**(1,405)**
38	NR Revenues from ESS (Capacity)	**$**	**(9,502)**	**$**	**(11,522)**	**$**	**(14,047)**
39	NR Revenues from ESS (Energy)	**$**	**-**	**$**	**-**	**$**	**-**
40	PF Load Forecast Deviation Liquidated Damages	$	-	$	-	$	-
41	**Firm Surplus and from Other Long-term Sales**	**$**	**-**	**$**	**-**	**$**	**-**
42	Other Surplus Sales (Non-Slice)	$	-	$	-	$	-
43	Firm Surplus Secondary Sales	$	-	$	-	$	-
44							
45	**Total Revenue Credits**	$	(1,119,966)	$	(1,000,970)	$	(1,032,402)

Table 2.3.7.1

Cost of Service Analysis
Allocation of Revenue Credits
($ 000)

	B		C		D		E
4	**Allocation of Revenue Requirement**		**2026**		**2027**		**2028**
5	Priority Firm - 7(b) Loads	$	6,772,391	$	6,872,378	$	7,089,934
6	Industrial Firm - 7(c) Loads	$	10,471	$	9,972	$	9,970
7	New Resources - 7(f) Loads	$	658	$	17,724	$	23,109
8	Surplus Firm - SP Loads	$	0	$	0	$	0
9	Total	$	6,783,520	$	6,900,073	$	7,123,013
10							
11	**General Revenue Credits ($000))**		**2026**		**2027**		**2028**
12							
13	**FBS**	**$**	**(399,957)**	**$**	**(312,805)**	**$**	**(360,316)**
14	Hydro and Renewable	$	(25,793)	$	(25,793)	$	(25,793)
15	Downstream Benefits and Pumping Power	$	(21,193)	$	(21,193)	$	(21,193)
16	Colville and Spokane Settlements	$	(4,600)	$	(4,600)	$	(4,600)
17	Green Tags (FBS resources)	$	-	$	-	$	-
18	Fish and Wildlife	$	(124,911)	$	(131,117)	$	(132,163)
19	4(h)(10)(c)	$	(124,911)	$	(131,117)	$	(132,163)
20	Tiered Rates Adjustment	$	(239,962)	$	(145,142)	$	(190,764)
21	Tier 2 Adjustment	$	(8,806)	$	(10,276)	$	(11,139)
22	Contract Obligations	$	(485)	$	(476)	$	(456)
23	Pre-sub/Hungry Horse	$	-	$	-	$	-
24	Other Locational/Seasonal Exchange	$	-	$	-	$	-
25	Upper Baker	$	(485)	$	(476)	$	(456)
26							
27	**Federal Base System Allocators**		**2026**		**2027**		**2028**
28	Priority Firm - 7(b) Loads		1.0000		1.0000		1.0000
29	Industrial Firm - 7(c) Loads		0.0000		0.0000		0.0000
30	New Resources - 7(f) Loads		0.0000		0.0000		0.0000
31	Surplus Firm - SP Loads		0.0000		0.0000		0.0000
32	Total		1.0000		1.0000		1.0000
33							
34	**FBS Credit Allocation**		**2026**		**2027**		**2028**
35	Priority Firm - 7(b) Loads	$	(399,957)	$	(312,805)	$	(360,316)
36	Industrial Firm - 7(c) Loads	$	-	$	-	$	-
37	New Resources - 7(f) Loads	$	-	$	-	$	-
38	Surplus Firm - SP Loads	$	-	$	-	$	-
39	Total	$	(399,957)	$	(312,805)	$	(360,316)
40							
41	**Allocation of Revenue Requirement**		**2026**		**2027**		**2028**
42	Priority Firm - 7(b) Loads	$	6,372,434	$	6,559,573	$	6,729,618
43	Industrial Firm - 7(c) Loads	$	10,471	$	9,972	$	9,970
44	New Resources - 7(f) Loads	$	658	$	17,724	$	23,109
45	Surplus Firm - SP Loads	$	0	$	0	$	0
46	Total	$	6,383,563	$	6,587,268	$	6,762,697

Cost of Service Analysis
Allocation of Revenue Credits
($ 000)

	B	C	D	E
41	**Allocation of Revenue Requirement**	**2026**	**2027**	**2028**
42	Priority Firm - 7(b) Loads	$ 6,372,434	$ 6,559,573	$ 6,729,618
43	Industrial Firm - 7(c) Loads	$ 10,471	$ 9,972	$ 9,970
44	New Resources - 7(f) Loads	$ 658	$ 17,724	$ 23,109
45	Surplus Firm - SP Loads	$ 0	$ 0	$ 0
46	Total	$ 6,383,563	$ 6,587,268	$ 6,762,697
47				
48				
49	**General Revenue Credits (/$1000))**	**2026**	**2027**	**2028**
50				
51	**Transmission**	**$ (8,647)**	**$ (8,831)**	**$ (9,078)**
52	Miscellaneous Credits (incl. GTA)	$ (8,647)	$ (8,831)	$ (9,078)
53				
54	**Conservation & General Cost Allocators**	**2026**	**2027**	**2028**
55	Priority Firm - 7(b) Loads	0.9991	0.9976	0.9972
56	Industrial Firm - 7(c) Loads	0.0009	0.0009	0.0009
57	New Resources - 7(f) Loads	0.0001	0.0015	0.0020
58	Surplus Firm - SP Loads	0.0000	0.0000	0.0000
59	Total	1.0000	1.0000	1.0000
60				
61	**Transmission Allocation**	**2026**	**2027**	**2028**
62	Priority Firm - 7(b) Loads	$ (8,639)	$ (8,809)	$ (9,052)
63	Industrial Firm - 7(c) Loads	$ (8)	$ (8)	$ (8)
64	New Resources - 7(f) Loads	$ (0)	$ (14)	$ (18)
65	Surplus Firm - SP Loads	$ (0)	$ (0)	$ (0)
66	Total	$ (8,647)	$ (8,831)	$ (9,078)
67				
68	**Allocation of Revenue Requirement**	**2026**	**2027**	**2028**
69	Priority Firm - 7(b) Loads	$ 6,363,795	$ 6,550,764	$ 6,720,566
70	Industrial Firm - 7(c) Loads	$ 10,464	$ 9,964	$ 9,962
71	New Resources - 7(f) Loads	$ 657	$ 17,710	$ 23,091
72	Surplus Firm - SP Loads	$ 0	$ 0	$ 0
73	Total	$ 6,374,916	$ 6,578,438	$ 6,753,619

Table 2.3.7.3

Cost of Service Analysis
Allocation of Revenue Credits
($ 000)

	B		C		D		E
4	**Allocation of Revenue Requirement**		**2026**		**2027**		**2028**
5	Priority Firm - 7(b) Loads	$	6,363,795	$	6,550,764	$	6,720,566
6	Industrial Firm - 7(c) Loads	$	10,464	$	9,964	$	9,962
7	New Resources - 7(f) Loads	$	657	$	17,710	$	23,091
8	Surplus Firm - SP Loads	$	0	$	0	$	0
9	Total	$	6,374,916	$	6,578,438	$	6,753,619
10							
11							
12	**General Revenue Credits ($000))**		**2026**		**2027**		**2028**
13							
14	**New Resources**	**$**	**-**	**$**	**-**	**$**	**-**
15	Green Tags (New resources)	$	-	$	-	$	-
16							
17							
18	**New Resources Cost Allocators**		**2026**		**2027**		**2028**
19	Priority Firm - 7(b) Loads		0.8336		0.6078		0.4428
20	Industrial Firm - 7(c) Loads		0.1566		0.1412		0.1679
21	New Resources - 7(f) Loads		0.0098		0.2510		0.3893
22	Surplus Firm - SP Loads		0.0000		0.0000		0.0000
23	Total		1.0000		1.0000		1.0000
24							
25	**New Resources Allocation**		**2026**		**2027**		**2028**
26	Priority Firm - 7(b) Loads	$	-	$	-	$	-
27	Industrial Firm - 7(c) Loads	$	-	$	-	$	-
28	New Resources - 7(f) Loads	$	-	$	-	$	-
29	Surplus Firm - SP Loads	$	-	$	-	$	-
30	Total	$	-	$	-	$	-
31							
32	**Allocation of Revenue Requirement**		**2026**		**2027**		**2028**
33	Priority Firm - 7(b) Loads	$	6,363,795	$	6,550,764	$	6,720,566
34	Industrial Firm - 7(c) Loads	$	10,464	$	9,964	$	9,962
35	New Resources - 7(f) Loads	$	657	$	17,710	$	23,091
36	Surplus Firm - SP Loads	$	0	$	0	$	0
37	Total	$	6,374,916	$	6,578,438	$	6,753,619
38							

Table 2.3.7.4

Cost of Service Analysis
Allocation of Revenue
Credits
($ 000)

	B	C		D		E	
32	**Allocation of Revenue Requirement**	**2026**		**2027**		**2028**	
33	Priority Firm - 7(b) Loads	$	6,363,795	$	6,550,764	$	6,720,566
34	Industrial Firm - 7(c) Loads	$	10,464	$	9,964	$	9,962
35	New Resources - 7(f) Loads	$	657	$	17,710	$	23,091
36	Surplus Firm - SP Loads	$	0	$	0	$	0
37	Total	$	6,374,916	$	6,578,438	$	6,753,619
39							
40	**General Revenue Credits (/$1000))**	**2026**		**2027**		**2028**	
41							
42	**Conservation**	**$**	**-**	**$**	**-**	**$**	**-**
43	Energy Efficiency Revenues	$	-	$	-	$	-
44							
45	**Conservation & General Cost Allocators**	**2026**		**2027**		**2028**	
46	Priority Firm - 7(b) Loads		0.9991		0.9976		0.9972
47	Industrial Firm - 7(c) Loads		0.0009		0.0009		0.0009
48	New Resources - 7(f) Loads		0.0001		0.0015		0.0020
49	Surplus Firm - SP Loads		0.0000		0.0000		0.0000
50	Total		1.0000		1.0000		1.0000
51							
52	**Conservation Allocation**	**2026**		**2027**		**2028**	
53	Priority Firm - 7(b) Loads	$	-	$	-	$	-
54	Industrial Firm - 7(c) Loads	$	-	$	-	$	-
55	New Resources - 7(f) Loads	$	-	$	-	$	-
56	Surplus Firm - SP Loads	$	-	$	-	$	-
57	Total	$	-	$	-	$	-
58							
59	**Allocation of Revenue Requirement**	**2026**		**2027**		**2028**	
60	Priority Firm - 7(b) Loads	$	6,363,795	$	6,550,764	$	6,720,566
61	Industrial Firm - 7(c) Loads	$	10,464	$	9,964	$	9,962
62	New Resources - 7(f) Loads	$	657	$	17,710	$	23,091
63	Surplus Firm - SP Loads	$	0	$	0	$	0
64	Total	$	6,374,916	$	6,578,438	$	6,753,619

Cost of Service Analysis
Allocation of Revenue Credits
($ 000)

	B		C		D		E
4	**Allocation of Revenue Requirement**		**2026**		**2027**		**2028**
5	Priority Firm - 7(b) Loads	$	6,363,795	$	6,550,764	$	6,720,566
6	Industrial Firm - 7(c) Loads	$	10,464	$	9,964	$	9,962
7	New Resources - 7(f) Loads	$	657	$	17,710	$	23,091
8	Surplus Firm - SP Loads	$	0	$	0	$	0
9	Total	$	6,374,916	$	6,578,438	$	6,753,619
10							
11	**General Revenue Credits (/$1000))**		**2026**		**2027**		**2028**
12							
13	**Generation Inputs Revenue**	**$**	**(133,219)**	**$**	**(133,219)**	**$**	**(133,219)**
14							
15	**FPS Real Power Losses (Capacity)**	**$**	**(44,745)**	**$**	**(44,745)**	**$**	**(44,745)**
16							
17	**FPS Real Power Losses (Energy)**	**$**	**-**	**$**	**-**	**$**	**-**
18							
19	**PRSC Net Credit (Composite)**	**$**	**-**	**$**	**-**	**$**	**-**
20							
21	**PRSC Net Credit (Non-Slice)**	**$**	**-**	**$**	**-**	**$**	**-**
22							
23	**NR Revenues from ESS (Capacity)**	**$**	**(9,502)**	**$**	**(11,522)**	**$**	**(14,047)**
24							
25	**NR Revenues from ESS (Energy)**	**$**	**-**	**$**	**-**	**$**	**-**
27							
28	**Federal Base System Allocators**		**2026**		**2027**		**2028**
29	Priority Firm - 7(b) Loads		1.0000		1.0000		1.0000
30	Industrial Firm - 7(c) Loads		0.0000		0.0000		0.0000
31	New Resources - 7(f) Loads		0.0000		0.0000		0.0000
32	Surplus Firm - SP Loads		0.0000		0.0000		0.0000
33	Total		1.0000		1.0000		1.0000
34							
35	**Gen Inputs, Real Power Losses & NR Revenue from ESS**		**2026**		**2027**		**2028**
36	Priority Firm - 7(b) Loads	$	(187,465)	$	(189,485)	$	(192,010)
37	Industrial Firm - 7(c) Loads	$	-	$	-	$	-
38	New Resources - 7(f) Loads	$	-	$	-	$	-
39	Surplus Firm - SP Loads	$	-	$	-	$	-
40	Total	$	(187,465)	$	(189,485)	$	(192,010)
41							
42	**Allocation of Revenue Requirement**		**2026**		**2027**		**2028**
43	Priority Firm - 7(b) Loads	$	6,176,329	$	6,361,278	$	6,528,556
44	Industrial Firm - 7(c) Loads	$	10,464	$	9,964	$	9,962
45	New Resources - 7(f) Loads	$	657	$	17,710	$	23,091
46	Surplus Firm - SP Loads	$	0	$	0	$	0
47	Total	$	6,187,451	$	6,388,952	$	6,561,609
48							

Cost of Service Analysis
Allocation of Revenue Credits
($ 000)

	B		C		D		E
42	**Allocation of Revenue Requirement**		**2026**		**2027**		**2028**
43	Priority Firm - 7(b) Loads	$	6,176,329	$	6,361,278	$	6,528,556
44	Industrial Firm - 7(c) Loads	$	10,464	$	9,964	$	9,962
45	New Resources - 7(f) Loads	$	657	$	17,710	$	23,091
46	Surplus Firm - SP Loads	$	0	$	0	$	0
47	Total	$	6,187,451	$	6,388,952	$	6,561,609
49							
50	**Other Revenue Credits**		**2026**		**2027**		**2028**
51	Composite Non-Federal RSS Revenue Debit/(Credit)	$	(1,293)	$	(3,064)	$	(3,434)
52	Non-Slice Non-Federal RSC Revenue Debit/(Credit)	$	457	$	(2,518)	$	(1,405)
53							
54							
55	**Conservation & General Cost Allocators**		**2026**		**2027**		**2028**
56	Priority Firm - 7(b) Loads		0.9991		0.9976		0.9972
57	Industrial Firm - 7(c) Loads		0.0009		0.0009		0.0009
58	New Resources - 7(f) Loads		0.0001		0.0015		0.0020
59	Surplus Firm - SP Loads		0.0000		0.0000		0.0000
60	Total		1.0000		1.0000		1.0000
61							
62	**Non-Federal RSS Revenues**		**2026**		**2027**		**2028**
63	Priority Firm - 7(b) Loads	$	(835)	$	(5,569)	$	(4,825)
64	Industrial Firm - 7(c) Loads	$	(1)	$	(5)	$	(4)
65	New Resources - 7(f) Loads	$	(0)	$	(9)	$	(10)
66	Surplus Firm - SP Loads	$	(0)	$	(0)	$	(0)
67	Total	$	(836)	$	(5,582)	$	(4,839)
68							
69	**Allocation of Revenue Requirement**		**2026**		**2027**		**2028**
70	Priority Firm - 7(b) Loads	$	6,175,494	$	6,355,710	$	6,523,731
71	Industrial Firm - 7(c) Loads	$	10,463	$	9,959	$	9,958
72	New Resources - 7(f) Loads	$	657	$	17,701	$	23,082
73	Surplus Firm - SP Loads	$	0	$	0	$	0
74	Total	$	6,186,615	$	6,383,370	$	6,556,770

Table 2.3.8

Cost of Service Analysis
Calculation and Allocation of
Secondary Revenue Credit
(aMW, $ 000)

	C	D	E	F
4	**General Revenue Credits ($000))**	**2026**	**2027**	**2028**
9				
10	BPA Secondary Sales Post-Slice (aMW)	1729	1738	1758
11				
12	Slice Percentage	11.75%	11.75%	11.75%
13				
14	Secondary Sales Pre-Slice, aMW	1959	1969	1992
15				
16	aMW to GWh Multiplier	8.760	8.760	8.784
17				
18	Secondary Sales Price (Weighted Average, $/MWh)	$ 25.23	$ 23.93	$ 22.83
19				
20	BPA Secondary Sales Post-Slice	$ 382,005	$ 364,275	$ 352,501
21	Adjustments to Secondary Sales (CAISO/Pre-Sold/Secondary Operational Adj per BP-26 Settlement)	$ 71,308	$ 55,367	$ 50,267
22	EIM Benefits Pre-Slice	$ 10,000	$ 9,700	$ 8,200
24	Firm Surplus Sold at Firm Surplus Price	$ -	$ -	$ -
25	Total Firm Surplus Secondary Sales	$ -	$ -	$ -
26				
27	Slice Secondary Sales including EIM Benefits ($000)	$ 60,921	$ 56,064	$ 56,154
28				
29	BPA Secondary Sales Pre-Slice $000 (incl. CAISO Adjust, EIM Benefits excl. Firm Surplus)	$ 523,061	$ 484,267	$ 466,159
30				
35				
36	**Federal Base System Allocators**	**2026**	**2027**	**2028**
37	Priority Firm - 7(b) Loads	1.0000	1.0000	1.0000
38	Industrial Firm - 7(c) Loads	0.0000	0.0000	0.0000
39	New Resources - 7(f) Loads	0.0000	0.0000	0.0000
40	Surplus Firm - SP Loads	0.0000	0.0000	0.0000
41	Total	1.0000	1.0000	1.0000
42				
43				
44	**Allocation of Secondary Revenues Credit**	**2026**	**2027**	**2028**
45	Priority Firm - 7(b) Loads	$ (523,061)	$ (484,267)	$ (466,159)
46	Industrial Firm - 7(c) Loads	$ -	$ -	$ -
47	New Resources - 7(f) Loads	$ -	$ -	$ -
48	Surplus Firm - SP Loads	$ -	$ -	$ -
49	Total	$ (523,061)	$ (484,267)	$ (466,159)
50				
51	**Allocation of Revenue Requirement**	**2026**	**2027**	**2028**
52	Priority Firm - 7(b) Loads	$ 5,652,433	$ 5,871,443	$ 6,057,572
53	Industrial Firm - 7(c) Loads	$ 10,463	$ 9,959	$ 9,958
54	New Resources - 7(f) Loads	$ 657	$ 17,701	$ 23,082
55	Surplus Firm - SP Loads	$ 0	$ 0	$ 0
56	Total	$ 5,663,554	$ 5,899,103	$ 6,090,611

Cost of Service Analysis
Calculation and Allocation of FPS Revenue
Deficiency Delta ($ 000)

	B	C	D	E
5	**Allocation of Revenue Requirement**	2026	2027	2028
6	Priority Firm - 7(b) Loads	$ 5,652,433	$ 5,871,443	$ 6,057,572
7	Industrial Firm - 7(c) Loads	$ 10,463	$ 9,959	$ 9,958
8	New Resources - 7(f) Loads	$ 657	$ 17,701	$ 23,082
9	Surplus Firm - SP Loads	$ 0	$ 0	$ 0
10	Total	$ 5,663,554	$ 5,899,103	$ 6,090,611
11				
12	**Firm Surplus and from Other Long-term Sales**	**$ -**	**$ -**	**$ -**
13	Other Surplus Sales (Non-Slice)	$ -	$ -	$ -
14	Firm Surplus Secondary Sales	$ -	$ -	$ -
15				
16	**Calculation of FPS Revenue Deficiency**	2026	2027	2028
17	Surplus Firm - SP Loads	$ 0	$ 0	$ 0
18				
19	**Deficiency**	**$ 0**	**$ 0**	**$ 0**
20				
21				
22				
23	**Surplus Deficit Cost Allocators**	2026	2027	2028
24	Priority Firm - 7(b) Loads	0.9991	0.9976	0.9972
25	Industrial Firm - 7(c) Loads	0.0009	0.0009	0.0009
26	New Resources - 7(f) Loads	0.0001	0.0015	0.0020
27	Surplus Firm - SP Loads	-1.0000	-1.0000	-1.0000
28	Total	0.0000	0.0000	0.0000
29				
30	**Surplus Deficit Cost Allocation**	2026	2027	2028
31	Priority Firm - 7(b) Loads	$ 0	$ 0	$ 0
32	Industrial Firm - 7(c) Loads	$ 0	$ 0	$ 0
33	New Resources - 7(f) Loads	$ 0	$ 0	$ 0
34	Surplus Firm - SP Loads	$ (0)	$ (0)	$ (0)
35	Total	$ -	$ -	$ -
36				
37				
38	**Initial Allocation of Net Revenue Requirement**	2026	2027	2028
39	Priority Firm - 7(b) Loads	$ 5,652,433	$ 5,871,443	$ 6,057,572
40	Industrial Firm - 7(c) Loads	$ 10,463	$ 9,959	$ 9,958
41	New Resources - 7(f) Loads	$ 657	$ 17,701	$ 23,082
42	Surplus Firm - SP Loads	$ -	$ -	$ -
43	Total	$ 5,663,554	$ 5,899,103	$ 6,090,611

Table 2.3.10

Cost of Service Analysis
Calculation of Initial Allocation
Power Rates
($ 000, aMW, $/MWh)

	B	C	D	E
5	**Initial Allocation of Net Revenue Requirement ($000)**	**2026**	**2027**	**2028**
6	Unbifurcated Priority Firm - 7(b) Loads	$ 5,652,433	$ 5,871,443	$ 6,057,572
7	Industrial Firm - 7(c) Loads	$ 10,463	$ 9,959	$ 9,958
8	New Resources - 7(f) Loads	$ 657	$ 17,701	$ 23,082
9	Surplus Firm - SP Loads	$ -	$ -	$ -
10	Total	$ 5,663,554	$ 5,899,103	$ 6,090,611
11				
12				
13	**Energy Billing Determinants (aMW)**	**2026**	**2027**	**2028**
14				
15	Unbifurcated Priority Firm - 7(b) Loads	12,634	12,714	12,784
16	Industrial Firm - 7(c) Loads	11	11	11
17	New Resources - 7(f) Loads	1	20	25
18				
19				
20	**Average Power Rates ($/MWh)**	**2026**	**2027**	**2028**
21				
22	Unbifurcated Priority Firm - 7(b) Loads	$ 51.07	$ 52.72	$ 53.94
23	Industrial Firm - 7(c) Loads	$ 108.58	$ 103.35	$ 103.06
24	New Resources - 7(f) Loads	$ 108.52	$ 103.34	$ 103.06

Table 2.4.1

Rate Directive Step
Calculation of DSI VOR and Net
Industrial Margin

	B	C	D	E	F	G	H	I
5								
6	Operating Reserves - Supplemental							
8			Embedded Cost $/kW/Mo			$ 4.93		
9								
10	1) Assumed DSI sale					11	aMW	
11	Assumed Wheel Turning Load					0	aMW	
12	Interruptible Load					11		
13	percent of DSI sale that is interruptible					10%		
14	MWs of interruptible load					1	MW	
15								
16	Total value of Operating Reserves per year					$ 65,076	per year	
17	Value converted to $/MWh on total load					$ 0.675	$/MWh	
18								
19					industrial margin	0.966		
20								
21					**net industrial margin**	**$ 0.291**		

Table 2.4.2

Rate Directive Step
Calculation of Annual Energy Rate Scalars for First
IP-PF Link Calculation

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	PQ	R	S	T
6		Load Shaping Rate		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
7			HLH (mills/kWh)	50.63	39.53	47.63	43.56	45.43	29.19	22.33	8.60	15.10	50.98	53.80	60.51				
8			LLH (mills/kWh)	48.85	41.64	48.79	43.80	49.18	34.54	27.09	12.73	16.08	48.06	50.32	59.06				
9			Demand Rate ($/kW/mo)	13.81	10.78	12.99	11.88	12.39	7.97	6.09	2.35	4.12	13.91	14.67	16.51				
10																			
11																			
12		Unbifurcated PF		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep			2026	
13		2026	HLH	5183	5528	6838	6961	5931	5991	5103	4777	4995	5463	5444	4793			Energy (GWH)	110671
14			LLH	3128	4048	4530	4598	3848	4006	3155	3405	2964	3457	3402	3124			Allocated Cost	$ 5,658,260
15			Demand	1307	1226	2293	2376	1897	2153	1949	1132	2007	2119	2509	1608			Rate Scalar	9.01
16		Revenue at marginal Rates		$ 433,229	$ 400,285	$ 576,507	$ 532,864	$ 482,178	$ 330,386	$ 211,285	$ 87,086	$ 131,345	$ 474,128	$ 500,926	$ 501,066		$ 4,661,287		
17				Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep			2027	
18		2027	HLH	5247	5577	6911	6809	5956	6248	5177	4695	5001	5509	5476	4838			Energy (GWH)	111378
19			LLH	3152	4097	4574	4842	3874	3828	3189	3366	2954	3473	3438	3147			Allocated Cost	$ 5,876,613
20			Demand	1357	1343	2352	2431	1991	2311	2054	1222	2053	2153	2634	1686			Rate Scalar	10.51
21		Revenue at marginal Rates		$ 438,382	$ 405,515	$ 582,885	$ 537,558	$ 485,763	$ 333,021	$ 214,510	$ 86,094	$ 131,473	$ 477,727	$ 506,253	$ 506,452		$ 4,705,635		
22				Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep			2028	
23		2028	HLH	5083	5813	6957	6844	6167	6290	4947	5020	5049	5322	5701	4869			Energy (GWH)	112293
24			LLH	3366	3918	4580	4863	3947	3842	3410	3238	2979	3689	3244	3155			Allocated Cost	$ 6,062,611
25			Demand	1484	1429	2408	2618	2113	2470	2267	1262	2120	2145	2751	1794			Rate Scalar	11.68
26		Revenue at marginal Rates		$ 442,261	$ 408,316	$ 586,105	$ 542,231	$ 500,472	$ 335,986	$ 216,644	$ 87,364	$ 132,881	$ 478,456	$ 510,277	$ 510,600		$ 4,751,593		
42																			
43																			
50																			
51			IP Load	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep			2026	
52		2026	HLH	5	4	4	4	4	5	4	4	5	4	5	4			Energy (GWH)	96
53			LLH	4	4	4	4	3	4	3	4	3	4	3	4			Allocated Cost	$ 4,636
54			Demand	0	0	0	0	0	0	0	0	0	0	0	0			Rate Scalar	8.72
55		Revenue at marginal Rates		$ 408	$ 321	$ 394	$ 357	$ 348	$ 257	$ 193	$ 86	$ 123	$ 406	$ 428	$ 474		$ 3,796		
56				Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep			2027	
57		2027	HLH	5	4	4	4	4	5	4	4	5	4	5	4			Energy (GWH)	96
58			LLH	4	4	4	4	3	4	3	4	3	4	3	4			Allocated Cost	$ 4,781
59			Demand	0	0	0	0	0	0	0	0	0	0	0	0			Rate Scalar	10.22
60		Revenue at marginal Rates		$ 408	$ 321	$ 394	$ 357	$ 348	$ 257	$ 193	$ 86	$ 123	$ 406	$ 428	$ 474		$ 3,796		
61				Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep			2028	
62		2028	HLH	5	4	4	4	4	5	4	4	5	4	5	4			Energy (GWH)	97
63			LLH	4	4	4	4	3	4	3	4	3	4	3	4			Allocated Cost	$ 4,909
64			Demand	0	0	0	0	0	0	0	0	0	0	0	0			Rate Scalar	11.38
65		Revenue at marginal Rates		$ 408	$ 321	$ 394	$ 357	$ 360	$ 257	$ 193	$ 86	$ 123	$ 406	$ 428	$ 474		$ 3,809		

Table 2.4.3

Rate Directive Step
Calculation of Monthly Energy Rate Scalars for
First IP-PF Link Calculation ($/MWh)

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	PQR	S
5		**Load Shaping Rate**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
6		HLH (mills/kWh)	50.63	39.53	47.63	43.56	45.43	29.19	22.33	8.60	15.10	50.98	53.80	60.51		
7		LLH (mills/kWh)	48.85	41.64	48.79	43.80	49.18	34.54	27.09	12.73	16.08	48.06	50.32	59.06		
8		Demand Rate ($/kW/mo)	13.81	10.78	12.99	11.88	12.39	7.97	6.09	2.35	4.12	13.91	14.67	16.51		
9																
10																
11		**Unbifurcated PF**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
12	**2026**	HLH	59.64	48.54	56.64	52.57	54.44	38.20	31.34	17.61	24.11	59.99	62.81	69.52		**2026**
13		LLH	57.86	50.65	57.80	52.81	58.19	43.55	36.10	21.74	25.09	57.07	59.33	68.07		**9.01**
14		Demand	13.81	10.78	12.99	11.88	12.39	7.97	6.09	2.35	4.12	13.91	14.67	16.51		**Scalar**
15			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
16	**2027**	HLH	61.14	50.04	58.14	54.07	55.94	39.70	32.84	19.11	25.61	61.49	64.31	71.02		**2027**
17		LLH	59.36	52.15	59.30	54.31	59.69	45.05	37.60	23.24	26.59	58.57	60.83	69.57		**10.51**
18		Demand	13.81	10.78	12.99	11.88	12.39	7.97	6.09	2.35	4.12	13.91	14.67	16.51		**Scalar**
19			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
20	**2028**	HLH	62.31	51.21	59.31	55.24	57.11	40.87	34.01	20.28	26.78	62.66	65.48	72.19		**2028**
21		LLH	60.53	53.32	60.47	55.48	60.86	46.22	38.77	24.41	27.76	59.74	62.00	70.74		**11.68**
22		Demand	13.81	10.78	12.99	11.88	12.39	7.97	6.09	2.35	4.12	13.91	14.67	16.51		**Scalar**
36																
42																
43		**IP**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
44	**2026**	HLH	59.35	48.25	56.35	52.28	54.15	37.91	31.05	17.32	23.82	59.70	62.52	69.23		**2026**
45		LLH	57.57	50.36	57.51	52.52	57.90	43.26	35.81	21.45	24.80	56.78	59.04	67.78		**8.72**
46		Demand	13.81	10.78	12.99	11.88	12.39	7.97	6.09	2.35	4.12	13.91	14.67	16.51		**Scalar**
47			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
48	**2027**	HLH	60.85	49.75	57.85	53.78	55.65	39.41	32.55	18.82	25.32	61.20	64.02	70.73		**2027**
49		LLH	59.07	51.86	59.01	54.02	59.40	44.76	37.31	22.95	26.30	58.28	60.54	69.28		**10.22**
50		Demand	13.81	10.78	12.99	11.88	12.39	7.97	6.09	2.35	4.12	13.91	14.67	16.51		**Scalar**
51			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
52	**2028**	HLH	62.01	50.91	59.01	54.94	56.81	40.57	33.71	19.98	26.48	62.36	65.18	71.89		**2028**
53		LLH	60.23	53.02	60.17	55.18	60.56	45.92	38.47	24.11	27.46	59.44	61.70	70.44		**11.38**
54		Demand	13.81	10.78	12.99	11.88	12.39	7.97	6.09	2.35	4.12	13.91	14.67	16.51		**Scalar**

Table 2.4.4

Rate Directive Step
Calculation of First IP-PF Link Delta
($ 000)

	B	C	D	E
89		**FY 2026**	**FY 2027**	**FY 2028**
90	Average PF Rate	$ 51.07	$ 52.72	$ 53.94
91	Net Industrial Margin	0.291	0.291	0.291
92	Flat DSI Load (GWh)	96	96	97
93	Revenue 1	4,949	5,108	5,240
94				
95	IP Rate	$ 108.58	$ 103.35	$ 103.06
96	Flat DSI Load (GWh)	96	96	97
97	Revenue 2	10,463	9,959	9,958
98				
99	Starting Difference	5,514	4,851	4,718
100				
101	Adjustment (calculated using Goal Seek)	313.31	327.30	331.01
102				
103	Delta	5,827	5,178	5,049

Rate Directive Step
Reallocation of First IP-PF Link Delta and
Recalculation of Rates ($ 000, aMW, $/MWh)

	B	C	D	E
5	**Initial Allocation of Net Revenue Requirement)**	**2026**	**2027**	**2028**
6	Unbifurcated Priority Firm - 7(b) Loads................................	$ 5,652,433	$ 5,871,443	$ 6,057,572
7	Industrial Firm - 7(c) Loads..	$ 10,463	$ 9,959	$ 9,958
8	New Resources - 7(f) Loads..	$ 657	$ 17,701	$ 23,082
9	Surplus Firm - SP Loads..	$ -	$ -	$ -
10	Total...	$ 5,663,554	$ 5,899,103	$ 6,090,611
11				
12				
13	**First IP-PF Link Delta**	**$ 5,827**	**$ 5,178**	**$ 5,049**
14				
15				
16	**7(c)(2) Delta Cost Allocators**	**2026**	**2027**	**2028**
17	Unbifurcated Priority Firm - 7(b) Loads................................	1.000	0.998	0.998
18	Industrial Firm - 7(c) Loads..	-1.000	-1.000	-1.000
19	New Resources - 7(f) Loads..	0.000	0.002	0.002
20				
21	**7(c)(2) Delta Cost Allocation**	**2026**	**2027**	**2028**
22	Unbifurcated Priority Firm - 7(b) Loads................................	$ 5,827	$ 5,170	$ 5,039
23	Industrial Firm - 7(c) Loads..	$ (5,827)	$ (5,178)	$ (5,049)
24	New Resources - 7(f) Loads..	$ 0.319	$ 7.950	$ 10.051
25	Total...	$ 0	$ 0	$ (0)
26				
27	**Cost Allocation After 7c2 Delta ($ 000)**	**2026**	**2027**	**2028**
28	Unbifurcated Priority Firm - 7(b) Loads................................	$ 5,658,260	$ 5,876,613	$ 6,062,611
29	Industrial Firm - 7(c) Loads..	$ 4,636	$ 4,781	$ 4,909
30	New Resources - 7(f) Loads..	$ 658	$ 17,709	$ 23,092
31	Surplus Firm - SP Loads..	$ -	$ -	$ -
32	Total...	$ 5,663,554	$ 5,899,103	$ 6,090,611
33				
34	**Energy Billing Determinants (aMW)**	**2026**	**2027**	**2028**
35	Unbifurcated Priority Firm - 7(b) Loads................................	12,634	12,714	12,784
36	Industrial Firm - 7(c) Loads..	11	11	11
37	New Resources - 7(f) Loads..	1	20	25
38				
39				
40	**Average Power Rates ($/MWh)**	**2026**	**2027**	**2028**
41				
42	Unbifurcated Priority Firm - 7(b) Loads................................	51.13	52.76	53.99
43	Industrial Firm - 7(c) Loads..	48.11	49.62	50.80
44	New Resources - 7(f) Loads..	108.58	103.39	103.11
45				
46				
47	Base PF Exchange Rate w/o Transmission Adder.............	**52.63**		

Table 2.4.6

Rate Directive Step
Calculation of IP Floor Calculation

	B	C	D	E	F	G	H	I	J
10		Industrial Firm Power Floor Rate Calculation							
11				**A**	**B**	**C**	**D**	**E**	**F**
12									
13				**DEMAND**		**ENERGY**		**Customer**	**Total/**
14				**Winter**	**Summer**	**Winter**	**Summer**	**Charge**	**Average**
15				(Dec-Apr)	(May-Nov)	(Sep-Mar)	(Apr-Aug)		
16									
17	1	IP Billing Determinants[1]		162	229	168	121	392	289
18	2	IP-83 Rates		4.62	2.21	14.70	12.20	7.34	
19	3	Revenue		750	507	2,472	1,478	2,875	8,083
20	4	Exchange Adj Clause for OY 1985							
21	5	New ASC Effective Jul 1, 1984							
22	6	Actual Total Exchange Cost (AEC)		938,442					
23	7	Actual Exchange Revenue (AER)		772,029					
24	8	Forecasted Exchange Cost (FEC)		1,088,690					
25	9	Forecasted Exchange Revenue (FER)		809,201					
26	10	Total Under/Over-recovery (TAR)							
27	11	(TAR=(AEC-AER)-(FEC-FER))		(113,076)					
28	12	Exchange Cost Percentage for IP (ECP)		0.521					
29	13	Rebate or Surcharge for IP (CCEA=TAR*ECP)		(58,913)					
30	14	OY 1985 IP Billing Determinants[2]		24,368					
31	15	OY 1985 DSI Transmission Costs[3]		92,960					
32	16	Adjustment for Transmission Costs[4]		(3.81)					
33	17	Adjustment for the Exchange (mills/kWh)[5]		(2.42)					
34	18	Adjustment for the Deferral (mills/kWh)[6]		(0.90)					
35	19	IP-83 Average Rate (mills/kWh)[7]		27.94					
36	20	Floor Rate (mills/kWh)[8]		20.81					
37									
38		<u>Note 1</u> - Demand billing determinants are the test period DSI load expressed in noncoincidental demand MWs.							
39		<u>Note 2</u> - Billing determinants as forecast in the 1983 Rate Case Final Proposal (WP-83-FS-BPA-07, p. 82).							
40		<u>Note 3</u> - Transmission Costs as forecast in the 1983 Rate Case Final Proposal (WP-83-FS-BPA-07, p. 80).							
41		<u>Note 4</u> - Line 15 / Line 14							
42		<u>Note 5</u> - Rebate or Surcharge for IP divided by OY 1985 IP Billing Determinants							
43		<u>Note 6</u> - 1985 Final Rate Proposal (WP-85-FS-BPA-08A, p. 15).							
44		<u>Note 7</u> - Total Revenue Col F, divided by IP Billing Determinants, Col F							
45		<u>Note 8</u> - IP-83 Avg Rate adjusted for the effects of the Exchange and Deferral, Lines 16 + 17 + 18 + 19							

Table 2.4.7

Rate Directive Step IP Floor
Rate Test

	B	C	D	E	F	G	H	I
8								
9								
10								
11		Industrial Firm Power Floor Rate Test						
12						**A**	**B**	**C**
13								
14								
15						**Total**		**Average**
16						**Energy**	**TOTALS**	**Rate**
17								
18								
19	1	IP Billing Determinants				289		
20	2	Floor Rate (mills/kWh)				20.81		
21	3	Value of Reserves Credit (mills/kWh)						
22	4	Revenue at Floor Rate Less VOR Credit				6,021	6,021	20.81
23	5	IP Revenue Under Proposed Rates					9,417	32.55
24	6	Difference[1]					0	
25								
26		Note 1 - Difference is Line 4 - Line 5. If difference is negative, Floor Rate does not trigger and difference is set to zero.						
27								

Table 2.4.8

Rate Directive Step
Calculation of IOU and COU
Base PF Exchange Rates

	B	C	D	E	F	G
9		**Cost Allocation After 7c2 Delta**	**2026**	**2027**	**2028**	Total
10		Unbifurcated Priority Firm - 7(b) Loads	$ 5,658,260	$ 5,876,613	$ 6,062,611	$ 17,597,483
11						
12		Exchange Unbifurcated Costs to 7(b) Loads	$ 2,394,724	$ 2,474,302	$ 2,542,407	$ 7,411,433
13						
14						
15						
16						
17		**Energy Billing Determinants (aMW)**	**2026**	**2027**	**2028**	
18		Unbifurcated Priority Firm - 7(b) Loads	5,347	5,353	5,361	
19						
20						
21		**Average Power Rates**	**2026**	**2027**	**2028**	
22						
23		Unbifurcated Priority Firm - 7(b) Loads	51.13	52.76	53.99	
24						
25						
26			(GWh)			
27		Three Year PF Public Load T1	178,407			
28		Three Year PF Public Load T2	15,110			
29		Three Year IOU PF Exchange Load	128,740			
30		Three Year COU PF Exchange Load	12,085			
31		Total Three-Year Unbifurcated PF Load	334342			
32						
33						
34		T 2 Costs	$ 1,033,334			
35		T 1 Costs	$ 16,564,149			
36		Total	$ 17,597,483			
37						
45		Total PF Costs Minus PF T2 Costs	$ 16,564,149			
46		Total PF Load Minus PF T2 Load	319,232			
47		COU Base PF w/o Transmission	51.89			
48		Exchange Transmission Adder	6.23			
49		**COU Base PFx**	**58.12**			
50						
51						
52		Two Year COU PF Exchange Load	12085			
53		Two Year Base PF Public Exchange T2 Revenue	$ 627,066			
54						
55		Total Exchange Costs minus COU Exchange Costs	$ 6,784,368			
56		Total IOU Exchange Loads	128,740			
57		IOU Base PF w/o Transmission	52.70			
58		Exchange Transmission Adder	6.23			
59		**IOU Base PFx**	**58.93**			
60						

Table 2.4.9

Rate Directive Step
Calculation of IOU REP Benefits in
Rates

	B	C	D	E
8				
9	EOFY 2011 Lookback Amount	($510,030)		
10				
11	Mortgage Payment Variables			
12	PMT Interest Rate	0.0425		
13	Number of Periods	8		
14				
15	Annual Lookback Mortgage Payment	$76,538		
16				
17				
18	IOU Scheduled Amount	$286,100		
19	Refund Amount*	$0		
20	REP Recovery Amount	$286,100		
21				
26				
27				
28		**2026**	**2027**	**2028**
29		($000)	($000)	($000)
30	IOU Unconstrained Benefits	$ 1,085,583	$ 1,085,583	$ 1,088,557
31	REP Recovery Amount	**$ 286,100**	**$ 286,100**	**$ 286,100**
32	Rate Protection Delta	$ 799,483	$ 799,483	$ 802,457
33				
34	**Refund of Initial EOFY2011 Lookback Completed by end of FY 2019*			

Table 2.4.10

Rate Directive Step
Calculation of REP Base Exchange
Benefits

	B	C	D	E	F	G	H	I	J	K	L	M	N	O
5	**IOU Base PFx**	**58.93**												
6	**COU Base PFx**	**58.12**		**ASCs**				**Exchange Loads**				**Unconstrained Benefits**		
7												**(**load * (ASC - Base PFx)		
8				**2026**	**2027**	**2028**		**2026**	**2027**	**2028**		**2026**	**2027**	**2028**
9														
10														
11	Avista Corporation	1		67.29	67.29	67.29		4,201.30	4,201.30	4,212.81		$ 35,141	$ 35,141	$ 35,237
12	Idaho Power Company	1		60.47	60.47	60.47		7,366.28	7,366.28	7,386.47		$ 11,385	$ 11,385	$ 11,416
13	NorthWestern Energy, LLC	1		89.44	89.44	89.44		771.76	771.76	773.87		$ 23,546	$ 23,546	$ 23,610
14	PacifiCorp	1		103.92	103.92	103.92		9,405.61	9,405.61	9,431.38		$ 423,139	$ 423,139	$ 424,298
15	Portland General Electric Company	1		93.89	93.89	93.89		8,571.66	8,571.66	8,595.14		$ 299,675	$ 299,675	$ 300,496
16	Puget Sound Energy, Inc.	1		82.24	82.24	82.24		12,557.46	12,557.46	12,591.86		$ 292,697	$ 292,697	$ 293,499
17	Clark Public Utilities	0		49.61	49.61	49.61		0.00	0.00	0.00		$ -	$ -	$ -
18	Franklin	0		0.00	0.00	0.00		0.00	0.00	0.00		$ -	$ -	$ -
19	Snohomish PUD	1		59.28	59.28	59.28		3,964.78	4,020.84	4,099.49		$ 4,603	$ 4,668	$ 4,760
31	Total											**$1,090,186**	**$1,090,251**	**$1,093,316**
32														
33											IOU	**$1,085,583**	**$1,085,583**	**$1,088,557**

Table 2.4.11

Rate Directive Step
Calculation of Utility Specific PF
Exchange Rates and REP Benefits

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
4	**Initial Allocations**				**FY 2026**	**FY 2027**	**FY 2028**	**Average**				**Interim**	**Refund**	**Interim**	**Interim**	**Interim**
5				**Base**	**Exchange**	**Exchange**	**Exchange**	**Exchange**	**Unconstrained**	**Scheduled**	**Refund**	**Protection**	**Cost**	**7(b)(3)**	**Utility**	**REP**
6			**ASC**	**PFx**	**Load**	**Load**	**Load**	**Load**	**Benefits**	**Amount**	**Amount**	**Allocation**	**Allocation**	**Surcharge**	**PFx**	**Benefits**
7			a	b	c	d	e	e=avg(c,d,e)	f=(a-b)*e	g=contract	h=contract	Σi=Σf - Σh	Σj=h	k=(i+j)/e	l=b+k	m=(a-l)*e
8	Avista Corporation	1	67.29	58.93	4,201	4,201	4,213	4,205	$ 35,173			$ 25,912	$ -	6.16	65.09	$ 9,261
9	Idaho Power Company	1	60.47	58.93	7,366	7,366	7,386	7,373	$ 11,395			$ 8,395	$ -	1.14	60.07	$ 3,000
10	NorthWestern Energy, LLC	1	89.44	58.93	772	772	774	772	$ 23,567			$ 17,362	$ -	22.48	81.40	$ 6,205
11	PacifiCorp	1	103.92	58.93	9,406	9,406	9,431	9,414	$ 423,525			$ 312,009	$ -	33.14	92.07	$ 111,516
12	Portland General Electric Company	1	93.89	58.93	8,572	8,572	8,595	8,579	$ 299,949			$ 220,971	$ -	25.76	84.68	$ 78,978
13	Puget Sound Energy, Inc.	1	82.24	58.93	12,557	12,557	12,592	12,569	$ 292,964			$ 215,825	$ -	17.17	76.10	$ 77,139
14	Clark Public Utilities	0	0.00	0.00	0	0	0	0	$ -			$ -		0.00	0.00	$ -
15	Franklin	0	0.00	0.00	0	0	0	0	$ -			$ -		0.00	0.00	$ -
16	Snohomish PUD	1	59.28	58.12	3,965	4,021	4,099	4,028	$ 4,677			$ 3,445		0.86	58.97	$ 1,231
17	Total				46,839	46,895	47,091	46,942	$ 1,091,251	$286,100	$0	$ 803,919	$0			$ 287,331
18																
19	rounding to	4	places =	-$438				IOU Σ(g)	$ 1,086,574	$286,100	$286,100	$ 800,474	IOU Σ(j)		IOU REP	$ 286,100
20								COU Σ(g)	$ 4,677		$1,231	$ 3,445	COU Σ(j)		COU REP	$ 1,231
21																
22	**IOU Reallocations**															
23			**Interim**				**Final**	**Final**	**Final**	**Final**				**FY 2026**	**FY 2027**	**FY 2028**
24			**REP**	**Annual**	**Reallocation**	**Reallocated**	**Protection**	**7(b)(3)**	**Utility**	**REP**				**REP**	**REP**	**REP**
25			**Benefits**	**Adjustment**	**Adjustment**	**Benefits**	**Allocation**	**Surcharge**	**PFx**	**Benefits**				**Benefits**	**Benefits**	**Benefits**
26			n=m	o=contract	p=below	q=n-o+p	r=f-q	s=r/e	t=b+s	u=(a-t)*e				v=(a-t)*c	w=(a-t)*d	w=(a-t)*d
27	Avista Corporation		$ 9,261	$ -	$ -	$ 9,261	$ 25,912	6.16	65.09030	$ 9,261			Avista	$ 9,253	$ 9,253	$ 9,278
28	Idaho Power Company		$ 3,000	$ -	$ -	$ 3,000	$ 8,395	1.14	60.06700	$ 3,000			Idaho Power	$ 2,997	$ 2,997	$ 3,006
29	NorthWestern Energy, LLC		$ 6,205	$ -	$ -	$ 6,205	$ 17,362	22.48	81.40440	$ 6,205			NorthWestern	$ 6,200	$ 6,200	$ 6,217
30	PacifiCorp		$ 111,516	$ -	$ -	$ 111,516	$ 312,009	33.14	92.07070	$ 111,516			PacifiCorp	$ 111,415	$ 111,415	$ 111,720
31	Portland General Electric Company		$ 78,978	$ -	$ -	$ 78,978	$ 220,971	25.76	84.68410	$ 78,978			Portland	$ 78,906	$ 78,906	$ 79,122
32	Puget Sound Energy, Inc.		$ 77,139	$ -	$ -	$ 77,139	$ 215,825	17.17	76.09970	$ 77,139			Puget Sound	$ 77,068	$ 77,068	$ 77,279
33	Total		$ 286,100	$ -	$ -	$ 286,100	$ 800,474			$ 286,100			IOU REP	$ 285,839	$ 285,839	$ 286,622
34																
35													Clark	$ -	$ -	$ -
36													Franklin	$ -	$ -	$ -
37	**IOU Reallocation Adjustments**												Snohomish	$ 1,212	$ 1,229	$ 1,253
38			Avista	Idaho	NorthWestern	PacifiCorp	Portland	Puget Sound	Total				COU REP	$ 1,212	$ 1,229	$ 1,253
39			$ -	$ -	$ -	$ -	$ -	$ -					Total REP	$ 287,051	$ 287,068	$ 287,875
40			p1=o1*(f/Σf)	p2=o2*(f/Σf)	p3=o3*(f/Σf)	p4=o4*(f/Σf)	p5=o5*(f/Σf)	p6=o6*(f/Σf)	p=Σ(p1...p6)							
41	Avista Corporation			$ -	$ -				$ -				Refund Amt	$ -	$ -	$ -
42	Idaho Power Company								$ -				REP Cost	$ 287,051	$ 287,068	$ 287,875
43	NorthWestern Energy, LLC		$ -	$ -		$ -	$ -	$ -	$ -							
44	PacifiCorp			$ -	$ -				$ -							
45	Portland General Electric Company		$ -	$ -	$ -	$ -			$ -							
46	Puget Sound Energy, Inc.		$ -	$ -	$ -	$ -	$ -		$ -							
47			$ -	$ -	$ -	$ -	$ -	$ -	$ -							

Table 2.4.12

Rate Directive Step
IOU Reallocation Balances

	B	C	D	E	F	G
4	**2012 REP Settlement Agreement Section 6 Reallocations**					
5						
6		**Initital Amount**	**Max Annual**		**Receiving Utilities**	
7	Avista Corporation	$ 22,985,810	$ 2,004,778		NWE, PGE, PSE	
8	Idaho Power Company -- total	$ 45,140,170				
9	Idaho Power Company -- 92%	$ 41,528,956	50% of benefits		AVA, NWE, PAC, PGE, PSE	
10	Idaho Power Company -- 8%	$ 3,611,214	50% of benefits		AVA, PAC, PGE, PSE	
11	NorthWestern Energy, LLC	N/A	N/A		AVA, IDA, PAC, PGE, PSE	
12	PacifiCorp	$ 66,721,315	$ 8,442,636		NWE, PGE, PSE	
13	Portland General Electric Company	$ 4,669,222	$ 1,237,583		NWE, PSE	
14	Puget Sound	N/A	N/A		NWE	
15						
16			**Max Annual**	**Max Annual**		
17	**Section 6.2.4 Adjustment**	**Initital Amount**	**2012–2015**	**2016–2017**	**Paying Utilities**	
18	NorthWestern Energy, LLC	$ (3,830,000)	$ (766,000)	$ (383,000)	AVA, PAC, PGE, PSE	
19						
20		**FY2012 Realloc**	**Accrued Interest**	**FY2013 Realloc**	**Accrued Interest**	**Remain Balance**
21	Avista Corporation	$ 2,004,778	$ 659,503	$ 2,004,778	$ 619,144	$ 20,254,901
22	Idaho Power Company	$ 2,521,193	$ 1,316,387	$ 2,521,193	$ 1,280,243	$ 42,694,414
23	NorthWestern Energy, LLC	$ (766,000)	$ -	$ (766,000)	$ -	$ (2,298,000)
24	PacifiCorp	$ 8,442,636	$ 1,875,000	$ 8,442,636	$ 1,677,971	$ 53,389,014
25	Portland General Electric Company	$ 1,237,583	$ 121,513	$ 1,237,583	$ 88,031	$ 2,403,600
26						
27		**FY2014 Realloc**	**Accrued Interest**	**FY2015 Realloc**	**Accrued Interest**	**Remain Balance**
28	Avista Corporation	$ 2,004,778	$ 577,575	$ 4,287	$ 534,759	$ 17,357,680
29	Idaho Power Company	$ 3,001,474	$ 1,235,810	$ 3,001,474	$ 1,182,840	$ 39,110,117
30	NorthWestern Energy, LLC	$ (766,000)	$ -	$ (766,000)	$ -	$ (766,000)
31	PacifiCorp	$ 8,442,636	$ 1,475,031	$ 8,442,636	$ 1,266,003	$ 39,244,775
32	Portland General Electric Company	$ 1,237,583	$ 53,544	$ 1,237,583	$ 18,023	$ -
33						
34		**FY2016 Realloc**	**Accrued Interest**	**FY2017 Realloc**	**Accrued Interest**	**Remain Balance**
35	Avista Corporation	$ 2,004,778	$ 490,659	$ 2,004,778	$ 445,235	$ 14,284,017
36	Idaho Power Company	$ 10,183,223	$ 1,020,555	$ 10,183,223	$ 745,675	$ 20,509,901
37	NorthWestern Energy, LLC	$ (383,000)	$ -	$ (383,000)	$ -	$ -
38	PacifiCorp	$ 8,442,636	$ 1,050,704	$ 8,442,636	$ 828,946	$ 24,239,153
39	Portland General Electric Company	$ -	$ -	$ -	$ -	$ -
40						
41		**FY2018 Realloc**	**Accrued Interest**	**FY2019 Realloc**	**Accrued Interest**	**Remain Balance**
42	Avista Corporation	$ 2,004,778	$ 398,449	$ 2,004,778	$ 350,259	$ 11,023,169
43	Idaho Power Company	$ 10,254,951	$ 461,473	$ 10,254,951	$ 167,668	$ 629,141
44	NorthWestern Energy, LLC	$ -	$ -	$ -	$ -	$ -
45	PacifiCorp	$ 8,442,636	$ 600,535	$ 8,442,636	$ 365,272	$ 8,319,688
46	Portland General Electric Company	$ -	$ -	$ -	$ -	$ -
47						
48		**FY2020 Realloc**	**Accrued Interest**	**FY2021 Realloc**	**Accrued Interest**	**Remain Balance**
49	Avista Corporation	$ 2,004,778	$ 300,623	$ 2,004,778	$ 249,499	$ 7,563,736
50	Idaho Power Company	$ 314,571	$ 14,156	$ 314,571	$ 5,143	$ -
51	NorthWestern Energy, LLC	$ -	$ -	$ -	$ -	$ -
52	PacifiCorp	$ 4,159,844	$ 187,193	$ 4,159,844	$ 68,013	$ -
53	Portland General Electric Company	$ -	$ -	$ -	$ -	$ -
54						
55		**FY2022 Realloc**	**Accrued Interest**	**FY2023 Realloc**	**Accrued Interest**	**Remain Balance**
56	Avista Corporation	$ 2,004,778	$ 196,840	$ 2,004,778	$ 142,602	$ 3,893,622
57	Idaho Power Company	$ -	$ -	$ -	$ -	$ -
58	NorthWestern Energy, LLC	$ -	$ -	$ -	$ -	$ -
59	PacifiCorp	$ -	$ -	$ -	$ -	$ -
60	Portland General Electric Company	$ -	$ -	$ -	$ -	$ -
61						
62		**FY2024 Realloc**	**Accrued Interest**	**FY2025 Realloc**	**Accrued Interest**	**Remain Balance**
63	Avista Corporation	$ 2,004,778	$ 86,737	$ 2,004,778	$ 29,196	$ (1)
64	Idaho Power Company	$ -	$ -	$ -	$ -	$ -
65	NorthWestern Energy, LLC	$ -	$ -	$ -	$ -	$ -
66	PacifiCorp	$ -	$ -	$ -	$ -	$ -
67	Portland General Electric Company	$ -	$ -	$ -	$ -	$ -

Table 2.4.13

Rate Directive Step
Calculation and Allocation of the Increase in PF Exchange Revenue
Requirement Due to REP Settlement

	B		C		D		E
4	**Cost Allocation After 7c2 Delta**		2026		2027		2028
5	Priority Firm Public - 7(b) Loads	$	3,263,536	$	3,402,311	$	3,520,204
6	Priority Firm Exchange - 7(b) Loads	$	2,394,724	$	2,474,302	$	2,542,407
7	Industrial Firm - 7(c) Loads	$	4,636	$	4,781	$	4,909
8	New Resources - 7(f) Loads	$	658	$	17,709	$	23,092
9	Surplus Firm - SP Loads	$	-	$	-	$	-
10	Total	$	5,663,554	$	5,899,103	$	6,090,611
11							
12							
13	**Calc Rate Protection to PFx Rate**		2026		2027		2028
14	Unconstrained Benefits	$	1,090,186	$	1,090,251	$	1,093,316
15	REP Recovery Amount plus COU Benefits	$	(287,051)	$	(287,068)	$	(287,875)
16	delta	$	803,135	$	803,183	$	805,441
17							
18							
19	**Allocation Factors**		2026		2027		2028
20	Priority Firm Public - 7(b) Loads		-1.000		-1.000		-1.000
21	Priority Firm Exchange - 7(b) Loads		1.000		1.000		1.000
22	Industrial Firm - 7(c) Loads		0.000		0.000		0.000
23	New Resources - 7(f) Loads		0.000		0.000		0.000
24							
25							
26	**Allocation of Rate Protection Cost**		2026		2027		2028
27	Priority Firm Public - 7(b) Loads	$	(803,135)	$	(803,183)	$	(805,441)
28	Priority Firm Exchange - 7(b) Loads	$	803,135	$	803,183	$	805,441
29	Industrial Firm - 7(c) Loads	$	-	$	-	$	-
30	New Resources - 7(f) Loads	$	-	$	-	$	-
31	Total	$	-	$	-	$	-
32							
33							
34	**Cost Allocation After Rate Protection to PFx**		2026		2027		2028
35	Priority Firm Public - 7(b) Loads	$	2,460,400	$	2,599,128	$	2,714,762
36	Priority Firm Exchange - 7(b) Loads	$	3,197,860	$	3,277,485	$	3,347,848
37	Industrial Firm - 7(c) Loads	$	4,636	$	4,781	$	4,909
38	New Resources - 7(f) Loads	$	658	$	17,709	$	23,092
39	Surplus Firm - SP Loads	$	-	$	-	$	-
40	Total	$	5,663,554	$	5,899,103	$	6,090,611
41							
42							
43	**Energy Billing Determinants (aMW)**		2026		2027		2028
44	Priority Firm Public - 7(b) Loads		7,287		7,361		7,423
45	Priority Firm Exchange - 7(b) Loads		5,347		5,353		5,361
46	Industrial Firm - 7(c) Loads		11		11		11
47	New Resources - 7(f) Loads		1		20		25
48							
50							
51	**Average Power Rates**		2026		2027		2028
52	Priority Firm Public - 7(b) Loads	$	38.55	$	40.31	$	41.64
53	Priority Firm Exchange - 7(b) Loads	$	74.50	$	76.12	$	77.32
54	Industrial Firm - 7(c) Loads	$	48.11	$	49.62	$	50.80
55	New Resources - 7(f) Loads	$	108.58	$	103.39	$	103.11

Table 2.4.14

Rate Directive Step
Calculation of PF, IP and NR Rate Contribution to Net REP
Benefit Costs

	B		C		D		E
25			2026		2027		2028
26	WP-10 Average IOU REP Benefits (before Lookback recovery)	$	265,847	$	265,847	$	265,847
27							
28	WP-10 7b3 Supplemental Rate Charge	$	7.38	$	7.38	$	7.38
29	IP/NR REP Surcharge	$	7.97	$	7.97	$	7.99
30	IP Load		96		96		97
31	NR Load		6		171		224
32	REP Surcharge Revenue from IP Rate	$	768	$	768	$	772
33	REP Surcharge Revenue from NR Rate	$	48	$	1,365	$	1,790
34							
35	Amount of REP Recovery remaining after IP/NR REP Surcharge	$	286,234	$	284,935	$	285,313
36	Remaining REP Recovery in PF, IP and NR Rates ($/MWh)	$	4.48	$	4.40	$	4.35
37							
38	Before Reallocation						
39	IP REP Recovery Amount in Rates	$	1,199	$	1,192	$	1,193
40	NR REP Recovery Amount in Rates	$	75	$	2,119	$	2,765
41							
42	After Reallocation						
43	IP REP Recovery Amount in Rates	$	767	$	765	$	768
44	NR REP Recovery Amount in Rates	$	48	$	1,359	$	1,781
45							
46							
47	Reallocation that Should be in Rates		2026		2027		2028
48	Priority Firm Public - 7(b) Loads..	$	285,776	$	283,757	$	283,917
49	Industrial Firm - 7(c) Loads..	$	1,199	$	1,192	$	1,193
50	New Resources - 7(f) Loads...	$	75	$	2,119	$	2,765
51		$	287,051	$	287,068	$	287,875
52							
53	Adjustment Necessary to Achieve Reallocation		2026		2027		2028
54	Priority Firm Public - 7(b) Loads..	$	(815)	$	(2,124)	$	(2,549)
55	Industrial Firm - 7(c) Loads..	$	767	$	765	$	768
56	New Resources - 7(f) Loads...	$	48	$	1,359	$	1,781
57		$	-	$	-	$	-
58							
59			2026		2027		2028
60	PF Contribution to Net REP Benefits $/MWh.................................		4.48		4.40		4.35
61	IP Contribution to Net REP Benefits $/MWh.................................		12.45		12.37		12.35
62	NR Contribution to Net REP Benefits $/MWh................................		12.45		12.37		12.35

Table 2.4.15

Rate Directive Step
Reallocation of Rate Protection Provided by the IP
and NR Rates

	B		C		D		E
4	**Cost Allocation After Rate Protection Provided by PFx**		**2026**		**2027**		**2028**
5	Priority Firm Public - 7(b) Loads	$	2,460,400	$	2,599,128	$	2,714,762
6	Priority Firm Exchange - 7(b) Loads	$	3,197,860	$	3,277,485	$	3,347,848
7	Industrial Firm - 7(c) Loads	$	4,636	$	4,781	$	4,909
8	New Resources - 7(f) Loads	$	658	$	17,709	$	23,092
9	Surplus Firm - SP Loads	$	-	$	-	$	-
10	Total	$	5,663,554	$	5,899,103	$	6,090,611
11							
12							
13							
14	**Allocation of Rate Protection Provided by IP and NR**		**2026**		**2027**		**2028**
15	Priority Firm Public - 7(b) Loads	$	(815)	$	(2,124)	$	(2,549)
16							
17	Industrial Firm - 7(c) Loads	$	767	$	765	$	768
18	New Resources - 7(f) Loads	$	48	$	1,359	$	1,781
19	Total	$	-	$	-	$	-
20							
21							
22	**Cost Allocation After Rate Protection Provided by IP and NR**		**2026**		**2027**		**2028**
23	Priority Firm Public - 7(b) Loads	$	2,459,586	$	2,597,003	$	2,712,213
24	Priority Firm Exchange - 7(b) Loads	$	3,197,860	$	3,277,485	$	3,347,848
25	Industrial Firm - 7(c) Loads	$	5,403	$	5,546	$	5,677
26	New Resources - 7(f) Loads	$	706	$	19,069	$	24,873
27	Surplus Firm - SP Loads	$	-	$	-	$	-
28	Total	$	5,663,554	$	5,899,103	$	6,090,611
29							
30							
31	**Energy Billing Determinants (aMW)**		**2026**		**2027**		**2028**
32	Priority Firm Public - 7(b) Loads		7,287		7,361		7,423
33	Priority Firm Exchange - 7(b) Loads		5,347		5,353		5,361
34	Industrial Firm - 7(c) Loads		11		11		11
35	New Resources - 7(f) Loads		1		20		25
36							
38							
39	**Average Power Rates After Rate Protection Reallocations**		**2026**		**2027**		**2028**
40	Priority Firm Public - 7(b) Loads	$	38.53	$	40.27	$	41.60
41	Priority Firm Exchange - 7(b) Loads	$	74.50	$	76.12	$	77.32
42	Industrial Firm - 7(c) Loads	$	56.07	$	57.55	$	58.75
43	New Resources - 7(f) Loads	$	116.54	$	111.32	$	111.06

Table 2.4.16

Rate Directive Step
Calculation of Annual Energy Rate Scalars for
Second IP-PF Link Calculation

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	PQ	R	S	T
5																		
6		**Load Shaping Rate**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
7		HLH (mills/kWh)	50.63	39.53	47.63	43.56	45.43	29.19	22.33	8.60	15.10	50.98	53.80	60.51				
8		LLH (mills/kWh)	48.85	41.64	48.79	43.80	49.18	34.54	27.09	12.73	16.08	48.06	50.32	59.06				
9		Demand Rate ($/kW/mo)	13.81	10.78	12.99	11.88	12.39	7.97	6.09	2.35	4.12	13.91	14.67	16.51				
10																		
11		**PF**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			**2026**	
12	**2026**	HLH	2989	3188	3944	4015	3421	3455	2943	2755	2881	3151	3140	2764			Energy (GWH)	63832
13		LLH	1804	2335	2613	2652	2219	2310	1820	1964	1709	1994	1962	1802			Allocated Cost	**$2,460,740**
14		Demand	754	707	1323	1370	1094	1242	1124	653	1157	1222	1447	928			Rate Scalar	**-3.57**
15		Revenue at marginal Rates	$ 249,875	$ 230,874	$ 332,514	$ 307,342	$ 278,108	$ 190,558	$ 121,864	$ 50,229	$ 75,757	$ 273,465	$ 288,921	$ 289,002		**$ 2,688,507**		
16			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			**2027**	
17	**2027**	HLH	3038	3229	4001	3942	3448	3618	2997	2718	2895	3190	3170	2801			Energy (GWH)	64483
18		LLH	1825	2372	2648	2803	2243	2216	1846	1949	1710	2011	1990	1822			Allocated Cost	**$2,598,143**
19		Demand	785	777	1362	1408	1153	1338	1189	707	1189	1246	1525	976			Rate Scalar	**-1.96**
20		Revenue at marginal Rates	$ 253,805	$ 234,776	$ 337,466	$ 311,224	$ 281,236	$ 192,805	$ 124,192	$ 49,845	$ 76,118	$ 276,584	$ 293,099	$ 293,214		**$ 2,724,364**		
21			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			**2028**	
22	**2028**	HLH	2951	3375	4040	3974	3581	3652	2873	2915	2932	3090	3310	2827			Energy (GWH)	65202
23		LLH	1954	2275	2659	2824	2292	2231	1980	1880	1730	2142	1883	1832			Allocated Cost	**$2,713,345**
24		Demand	862	830	1398	1520	1227	1434	1316	733	1231	1245	1597	1042			Rate Scalar	**-0.70**
25		Revenue at marginal Rates	$ 256,795	$ 237,085	$ 340,317	$ 314,842	$ 290,595	$ 195,087	$ 125,792	$ 50,727	$ 77,156	$ 277,812	$ 296,288	$ 296,476		**$ 2,758,972**		
26																		
27																		
28		**IP Load**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			**2026**	
29	**2026**	HLH	5	4	4	4	4	5	4	4	5	4	5	4			Energy (GWH)	96
30		LLH	4	4	4	4	3	4	3	4	3	4	3	4			Allocated Cost	**$ 4,248**
31		Demand	0	0	0	0	0	0	0	0	0	0	0	0			Rate Scalar	**4.69**
32		Revenue at marginal Rates	$ 408	$ 321	$ 394	$ 357	$ 348	$ 257	$ 193	$ 86	$ 123	$ 406	$ 428	$ 474		**$ 3,796**		
33			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			**2027**	
34	**2027**	HLH	5	4	4	4	4	5	4	4	5	4	5	4			Energy (GWH)	96
35		LLH	4	4	4	4	3	4	3	4	3	4	3	4			Allocated Cost	**$ 4,403**
36		Demand	0	0	0	0	0	0	0	0	0	0	0	0			Rate Scalar	**6.30**
37		Revenue at marginal Rates	$ 408	$ 321	$ 394	$ 357	$ 348	$ 257	$ 193	$ 86	$ 123	$ 406	$ 428	$ 474		**$ 3,796**		
38			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			**2028**	
39	**2028**	HLH	5	4	4	4	4	5	4	4	5	4	5	4			Energy (GWH)	97
40		LLH	4	4	4	4	3	4	3	4	3	4	3	4			Allocated Cost	**$ 4,541**
41		Demand	0	0	0	0	0	0	0	0	0	0	0	0			Rate Scalar	**7.58**
42		Revenue at marginal Rates	$ 408	$ 321	$ 394	$ 357	$ 360	$ 257	$ 193	$ 86	$ 123	$ 406	$ 428	$ 474		**$ 3,809**		

Table 2.4.17

Rate Directive Step
Calculation of Monthly Energy Rate Scalars for
Second IP-PF Link Rate Calculation

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
5	**Load Shaping Rate**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
6	HLH (mills/kWh)		50.63	39.53	47.63	43.56	45.43	29.19	22.33	8.60	15.10	50.98	53.80	60.51				
7	LLH (mills/kWh)		48.85	41.64	48.79	43.80	49.18	34.54	27.09	12.73	16.08	48.06	50.32	59.06				
8	Demand Rate ($/kW/mo)		13.81	10.78	12.99	11.88	12.39	7.97	6.09	2.35	4.12	13.91	14.67	16.51				
9																		
10																		
11		**PFp**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
12	**2026**	HLH	47.06	35.96	44.06	39.99	41.86	25.62	18.76	5.03	11.53	47.41	50.23	56.94				**2026**
13		LLH	45.28	38.07	45.22	40.23	45.61	30.97	23.52	9.16	12.51	44.49	46.75	55.49				**-3.57**
14		Demand	13.81	10.78	12.99	11.88	12.39	7.97	6.09	2.35	4.12	13.91	14.67	16.51				**Scalar**
15			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
16	**2027**	HLH	48.67	37.57	45.67	41.60	43.47	27.23	20.37	6.64	13.14	49.02	51.84	58.55				**2027**
17		LLH	46.89	39.68	46.83	41.84	47.22	32.58	25.13	10.77	14.12	46.10	48.36	57.10				**-1.96**
18		Demand	13.81	10.78	12.99	11.88	12.39	7.97	6.09	2.35	4.12	13.91	14.67	16.51				**Scalar**
19			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
20	**2028**	HLH	49.93	38.83	46.93	42.86	44.73	28.49	21.63	7.90	14.40	50.28	53.10	59.81				**2028**
21		LLH	48.15	40.94	48.09	43.10	48.48	33.84	26.39	12.03	15.38	47.36	49.62	58.36				**-0.70**
22		Demand	13.81	10.78	12.99	11.88	12.39	7.97	6.09	2.35	4.12	13.91	14.67	16.51				**Scalar**
23																		
24		**IP**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
25	**2026**	HLH	55.32	44.22	52.32	48.25	50.12	33.88	27.02	13.29	19.79	55.67	58.49	65.20				**2026**
26		LLH	53.54	46.33	53.48	48.49	53.87	39.23	31.78	17.42	20.77	52.75	55.01	63.75				**4.69**
27		Demand	13.81	10.78	12.99	11.88	12.39	7.97	6.09	2.35	4.12	13.91	14.67	16.51				**Scalar**
28			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
29	**2027**	HLH	56.93	45.83	53.93	49.86	51.73	35.49	28.63	14.90	21.40	57.28	60.10	66.81				**2027**
30		LLH	55.15	47.94	55.09	50.10	55.48	40.84	33.39	19.03	22.38	54.36	56.62	65.36				**6.30**
31		Demand	13.81	10.78	12.99	11.88	12.39	7.97	6.09	2.35	4.12	13.91	14.67	16.51				**Scalar**
32			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
33	**2028**	HLH	58.21	47.11	55.21	51.14	53.01	36.77	29.91	16.18	22.68	58.56	61.38	68.09				**2028**
34		LLH	56.43	49.22	56.37	51.38	56.76	42.12	34.67	20.31	23.66	55.64	57.90	66.64				**7.58**
35		Demand	13.81	10.78	12.99	11.88	12.39	7.97	6.09	2.35	4.12	13.91	14.67	16.51				**Scalar**

Table 2.4.18

Rate Directive Step
Calculation of Second IP-PF Link Delta

	B	C	D	E
55		**FY 2026**	**FY 2027**	**FY 2028**
56	Average PF Rate	$ 38.53	$ 40.27	$ 41.60
57	Net Industrial Margin	0.291	0.291	0.291
58	Flat DSI Load (GWh)	96	96	97
59	Revenue 1	$ 3,741	$ 3,909	$ 4,047
60				
61	IP Rate	$ 56.07	$ 57.55	$ 58.75
62	Flat DSI Load (GWh)	96	96	97
63	Revenue 2	$ 5,403	$ 5,546	$ 5,677
64				
65	Difference	$ 1,662	$ 1,637	$ 1,630
66				
67	Adjustment (calculated using Goal Seek)	$ (507)	$ (495)	$ (494)
68				
69	Delta	$ 1,155	$ 1,143	$ 1,136

Table 2.4.19

Rate Directive Step
Reallocation of IP-PF Link Delta and
Recalculation of Rates

	B	C	D	E
4	**Cost Allocation After Rate Protection Provided by IP and NR**	**2026**	**2027**	**2028**
5	Priority Firm Public - 7(b) Loads	$ 2,459,586	$ 2,597,003	$ 2,712,213
6	Priority Firm Exchange - 7(b) Loads	$ 3,197,860	$ 3,277,485	$ 3,347,848
7	Industrial Firm - 7(c) Loads	$ 5,403	$ 5,546	$ 5,677
8	New Resources - 7(f) Loads	$ 706	$ 19,069	$ 24,873
9	Surplus Firm - SP Loads	$ -	$ -	$ -
10	Total	$ 5,663,554	$ 5,899,103	$ 6,090,611
11				
12				
13	IP-PF Link Delta	$ 1,155	$ 1,143	$ 1,136
14				
15		**2026**	**2027**	**2028**
16	Priority Firm Public - 7(b) Loads	1.000	0.997	0.997
17	Industrial Firm - 7(c) Loads	(1.000)	(1.000)	(1.000)
18	New Resources - 7(f) Loads	0.000	0.003	0.003
19				
20				
21	**Allocation of Second IP-PF Link Delta**	**2026**	**2027**	**2028**
22	Priority Firm Public - 7(b) Loads	$ 1,155	$ 1,139	$ 1,132
23	Priority Firm Exchange - 7(b) Loads	$ -	$ -	$ -
24	Industrial Firm - 7(c) Loads	$ (1,155)	$ (1,143)	$ (1,136)
25	New Resources - 7(f) Loads	$ 0	$ 3	$ 4
26	Total	$ 0	$ (0)	$ 0
27				
28				
29	**Cost Allocation After Second IP-PF Link**	**2026**	**2027**	**2028**
30	Priority Firm Public - 7(b) Loads	$ 2,460,740	$ 2,598,143	$ 2,713,345
31	Priority Firm Exchange - 7(b) Loads	$ 3,197,860	$ 3,277,485	$ 3,347,848
32	Industrial Firm - 7(c) Loads	$ 4,248	$ 4,403	$ 4,541
33	New Resources - 7(f) Loads	$ 706	$ 19,072	$ 24,877
34	Surplus Firm - SP Loads	$ 0	$ (0)	$ 0
35	Total	$ 5,663,554	$ 5,899,103	$ 6,090,611
36				
37				
38	**Energy Billing Determinants (aMW)**	**2026**	**2027**	**2028**
39	Priority Firm Public - 7(b) Loads	7,287	7,361	7,423
40	Priority Firm Exchange - 7(b) Loads	5,347	5,353	5,361
41	Industrial Firm - 7(c) Loads	11	11	11
42	New Resources - 7(f) Loads	1	20	25
43				
45				
46	**Average Power Rates After Second IP-PF Link**	**2026**	**2027**	**2028**
47	Priority Firm Public - 7(b) Loads	38.55	40.29	41.61
48	Priority Firm Exchange - 7(b) Loads	74.50	76.12	77.32
49	Industrial Firm - 7(c) Loads	44.09	45.70	47.00
50	New Resources - 7(f) Loads	116.55	111.34	111.07

Table 2.4.20

Rate Design Step
REP Benefit
Reconciliation

	B	D	E	F	G	H	I	J	K	L	M
4		**2026**	**2027**	**2028**	**Avg**				**2026**	**2027**	**2028**
5	Resource Costs	3,847,106	3,850,430	3,864,988	3,854,175			PFx Alloc Cost	(3,197,860)	(3,277,485)	(3,347,848)
6	PFx Revenues	(3,489,666)	(3,569,640)	(3,641,226)	(3,566,844)			Exch Tmn Cost	(291,806)	(292,155)	(293,377)
7	REP Benefits	357,441	280,790	223,763	287,331				(3,489,666)	(3,569,640)	(3,641,226)
8											
9	**REP Benefits**							**PFx Revenues**			
10	Avista Corporation	9,253	9,253	9,278				Avista Corporation	313,012	319,803	325,747
11	Idaho Power Company	2,997	2,997	3,006				Idaho Power Company	548,815	560,722	571,145
12	NorthWestern Energy, LLC	6,200	6,200	6,217				NorthWestern Energy, LLC	57,499	58,746	59,838
13	PacifiCorp	111,415	111,415	111,720				PacifiCorp	700,753	715,955	729,264
14	Portland General Electric Company	78,906	78,906	79,122				Portland General Electric Company	638,620	652,475	664,603
15	Puget Sound Energy, Inc.	77,068	77,068	77,279				Puget Sound Energy, Inc.	935,577	955,874	973,642
16	IOU REP	285,839	285,839	286,622	286,100			IOU REP	3,194,275	3,263,574	3,324,240
17											
18	Clark Public Utilities	-	-	-				Clark Public Utilities	-	-	-
19	Franklin	-	-	-				Franklin	-	-	-
20	Snohomish PUD	1,212	1,229	1,253				Snohomish PUD	295,390	306,066	316,986
21	COU REP	1,212	1,229	1,253	1,231			COU REP	295,390	306,066	316,986
22											
23	Refund Amounts	-	-	-				Refund Amounts	-	-	-
24	Total REP	287,051	287,068	287,875	287,331			Total REP	3,489,666	3,569,640	3,641,226
25					(0)				(0)	(0)	0
26											
27	**For Slice True-Up**										
28	IOU REP	285,839	285,839	286,622							
29	COU REP	1,212	1,229	1,253							
30	Refund Amounts	-	-	-							
31	Total REP	287,051	287,068	287,875							

Table 2.5.1

Rate Design Study
Allocated Cost and Unit Cost for
Priority Firm Rates

	C	D	E	F	H	I	J	K
11								
12		**A**	**B**	**C**	**PF Public**		**PF Exchange**	
13		**ALLOCATED**	**UNIT**	**PERCENT**	**ALLOCATED**		**ALLOCATED**	
14		**COSTS**	**COSTS**	**CONTRIBUTION**	**COSTS**		**COSTS**	
15	GENERATION ENERGY	($ Thousands)	(Mills/kWh)	(Percent)				
16								
17	Federal Base System							
18	Hydro	2,751,102	8.228	15.63%	1,592,339	8.228	1,158,763	8.228
19	Fish & Wildlife	1,157,802	3.463	6.58%	670,136	3.463	487,666	3.463
20	Trojan	3,988	0.012	0.02%	2,308	0.012	1,680	0.012
21	WNP #1	192,528	0.576	1.09%	111,435	0.576	81,093	0.576
22	WNP #2	2,327,598	6.962	13.23%	1,347,215	6.962	980,384	6.962
23	WNP #3	231,014	0.691	1.31%	133,711	0.691	97,303	0.691
24	System Augmentation	0	0.000	0.00%	0	0.000	0	0.000
25	Balancing Power Purchases	286,321	0.856	1.63%	165,722	0.856	120,598	0.856
26	Tier 2 Costs	1,033,334	3.091	5.87%	598,094	3.091	435,240	3.091
27	Total Federal Base System	7,983,688	23.879	45.37%	4,620,961	23.879	3,362,727	23.879
28	New Resources	120,701	0.361	0.69%	69,862	0.361	50,839	0.361
29	Gross Residential Exchange	10,686,123	31.962	60.73%	6,185,132	31.962	4,500,992	31.962
30	Conservation	504,527	1.509	2.87%	292,020	1.509	212,506	1.509
31	BPA Programs	617,389	1.847	3.51%	357,345	1.847	260,044	1.847
32	Power Transmission	626,330	1.873	3.56%	362,520	1.873	263,810	1.873
33	TOTAL COSA ALLOCATIONS	20,538,758	61.430	116.71%	11,887,840	61.430	8,650,918	61.430
34			0.000					
35			0.000					
36	Nonfirm Excess Revenue Credit	(1,473,487)	-4.407	-8.37%	(852,855)	-4.407	(620,632)	-4.407
37	Low Density Discount Expense	195,944	0.586	1.11%	113,412	0.586	82,532	0.586
38	Other Revenue Credits	(1,679,768)	-5.024	-9.55%	(972,250)	-5.024	(707,518)	-5.024
39	Irrigation Rate Mitigation Expense		0.000	0.00%	0	0.000	0	0.000
40	SP Revenue Surplus/Dfct Adj.	0	0.000	0.00%	0	0.000	0	0.000
41	7(c)(2) Delta Adjustment	16,054	0.048	0.09%	9,292	0.048	6,762	0.048
42	7(c)(2) Floor Rate Adjustment		0.000	0.00%	0	0.000	0	0.000
43	TOTAL RATE DESIGN ADJUSTMENTS	(2,941,257)	-8.797	-16.71%	(1,702,401)	-8.797	(1,238,856)	-8.797
44			0.000	0.00%				
45	Total Generation	17,597,501	**52.6332**	100.00%	10,185,440	**52.63**	7,412,062	**52.63**
46			0.000					
47		0	0.000					
48	REP Settlement Rate Protection Adjustment		0.000		(2,417,248)	-12.491	2,411,760	2,411,760
49	7(b)(2) - 7(c)(2) Industrial Adjustment	0	0.000		3,426	0.018	0	0.000
50	Total Generation		0.000		**7,771,618**	**40.16**	9,823,821	**69.76**
51						$ 40.16		
52	Total Transmission					$ 0	877,338	6.230
53							10,701,160	**75.99**
54								

Table 2.5.2

Rate Design Study
Allocated Cost and Unit Costs for
Industrial Firm Power Rate

	C	D	E	F
13		**ALLOCATED**	**UNIT**	**PERCENT**
14		**COSTS**	**COSTS**	**CONTRIBUTION**
15	GENERATION ENERGY	($ Thousands)	(Mills/kWh)	(Percent)
16				
17	Federal Base System			
18	Hydro	0	0.000	0.00%
19	Fish & Wildlife	0	0.000	0.00%
20	Trojan	0	0.000	0.00%
21	WNP #1	0	0.000	0.00%
22	WNP #2	0	0.000	0.00%
23	WNP #3	0	0.000	0.00%
24	System Augmentation	0	0.000	0.00%
25	Balancing Power Purchases	0	0.000	
26	Total Federal Base System	0	0.000	0.00%
27	New Resources	29,362	101.480	222.57%
28	Gross Residential Exchange	0	0.000	0.00%
29	Conservation	437	1.510	3.31%
30	BPA Programs	534	1.850	4.06%
31	Power Transmission	79	0.270	0.59%
32	TOTAL COSA ALLOCATIONS	30,413	105.110	230.53%
33			0.000	0.00%
34	Nonfirm Excess Revenue Credit	0	0.000	0.00%
35			0.000	0.00%
36	Other Revenue Credits	(33)	-0.110	-0.24%
37			0.000	0.00%
38	SP Revenue Surplus/Dfct Adj.	0	0.000	0.00%
39	7(c)(2) Delta Adjustment	(16,054)	-55.480	-121.68%
40	7(c)(2) Floor Rate Adjustment	0	0.000	0.00%
41	TOTAL RATE DESIGN ADJSTMTS	(16,087)	-55.600	-121.94%
42	Total Generation	14,326	49.510	108.59%
43			0.000	0.00%
55	Total Allocated & Adjusted Costs	14,326	49.510	108.59%
56			0.000	0.00%
57	Settlement Adjustments		0.000	0.00%
58	REP Settlement Rate Protection Adjustment	2,300	7.950	17.44%
59	7(b)(2) - 7(c)(2) Industrial Adjustment	(3,433)	(11.86)	-26.01%
60		13,193	45.595	100.00%
61			45.595	100.00%
62	Billing Determinants:		*0.0*	
63	Energy (GwH)	289		

Table 2.5.3

Rate Design Study
Allocated Costs and Unit Costs for
New Resources Firm Power Rate

	C	D	E	F
12		**ALLOCATED**	**UNIT**	**PERCENT**
13		**COSTS**	**COSTS**	**CONTRIBUTION**
14	GENERATION ENERGY	($ Thousands)	(Mills/kWh)	(Percent)
15				
16	Federal Base System			
17	Hydro	0	0.000	0.00%
18	Fish & Wildlife	0	0.000	0.00%
19	Trojan	0	0.000	0.00%
20	WNP #1	0	0.000	0.00%
21	WNP #2	0	0.000	0.00%
22	WNP #3	0	0.000	0.00%
23	System Augmentation	0	0.000	
24	Balancing Power Purchases	0	0.000	0.00%
25	Total Federal Base System	0.000	0.000	0.00%
26	New Resources	40,007	99.69	89.59%
27	Gross Residential Exchange	0.0000	0.000	0.00%
28	Conservation	613	1.53	1.37%
29	BPA Programs & Transmission Costs	871	2.17	1.95%
30	GTA costs	0	0.00	0.00%
31	TOTAL COSA ALLOCATIONS	41,491	103.39	92.92%
32			0.000	0.00%
33	Nonfirm Excess Revenue Credit	0.00000	0.000	0.00%
34		0.00000	0.000	0.00%
35	Other Revenue Credits	(50)	-0.125	-0.11%
36			0.000	0.00%
37	SP Revenue Surplus/Dfct Adj.	0.0000	0.000	0.00%
38	7(c)(2) Delta Adjustment	18	0.046	0.04%
39	7(c)(2) Floor Rate Adjustment	0	0.000	0.00%
40	TOTAL RATE DESIGN ADJSTMTS	(32)	-0.080	-0.07%
41	Total Generation Energy	41,459	103.307	92.84%
42			0.000	0.00%
51			0.000	0.00%
52	Total Allocated & Adjusted Costs	41,459	103.307	92.84%
53	Settlement Adjustments		0.000	0.00%
54	REP Settlement Rate Protection Adjustment	3,189	7.946	7.14%
55	7(c)(2) Industrial Adjustment (IP-PF#2)	7	0.018	0.02%
56			0.000	0.00%
57	Total With 7(b)(2) Adjustments	44,654	**111.27**	100.00%
58				100.00%
59	Billing Determinant / Energy (GWh)	401.3		0.00%

Table 2.5.4

Rate Design Study
Resource Cost Percent Contribution to Load Pools

	B	C	D	E	F	G	H	I	J	K
9		**ALLOCATED GENERATION COSTS**					**PERCENTAGES**			
10										
11		**FBS**	**Exchange**	**New**			**FBS**	**Exchange**	**New**	
12		**Resources**	**Resources**	**Resources**	**Total**		**Resources**	**Resources**	**Resources**	**Total**
13										
14	**CLASSES OF SERVICE:**									
15										
16	**Power Rates**									
17	Priority Firm - Public	4,620,961	6,185,132	69,862	10,875,955		42.49%	56.87%	0.64%	100.00%
18	Priority Firm - Exchange	3,362,727	4,500,992	50,839	7,914,557		42.49%	56.87%	0.64%	100.00%
19	Priority Firm Power - Total	7,983,688	10,686,123	120,701	18,790,512		42.49%	56.87%	0.64%	100.00%
20	Industrial Firm Power	0	0	29,362	29,362		0.00%	0.00%	100.00%	100.00%
21	New Resources Firm	0	0	40,007	40,007		0.00%	0.00%	100.00%	100.00%
22	Firm Power Products and Services	0	0	0	0		0.00%	0.00%	100.00%	100.00%
23										
24										
25	**TOTALS**	**7,983,688**	**10,686,123**	**190,070**	**18,859,881**		**42.33%**	**56.66%**	**1.01%**	**100.00%**
26										
27					335,033					
28										
29				Average Cost of Resources	56.29					
30										
31				Average Cost to Serve Load Growth	68.51					

SECTION 3: RATE DESIGN

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Description of Ratemaking Tables

Table 3.1.1
Cost Aggregation under Tiered Rate Methodology (DS 01)

Worksheet aggregates costs and credits to be used in the TRM ratemaking. The TRM specifies a cost allocation methodology different from what is used in the COSA to separate costs into the various TRM cost pools. The mapping of costs to the TRM cost pools includes costs passed from the Power Revenue Requirement Study, credits passed from the revenue forecast, and cost and credit line items internally computed in RAM. For each cost pool under TRM, costs are conveniently grouped according to their COSA classification.

Table 3.1.2
Calculation of Unused RHWM (net) Credit (DS 02)

Worksheet calculates the $/MWh value for unused Rate Period High Water Mark. That value is used to determine the reallocation adjustment to distribute costs between the Composite and Non-Slice cost pools.

Table 3.1.3
Calculation of Slice Return of Network Losses Adjustment (DS 03)

Worksheet calculates the value of power associated with Non-Slice network losses such that these costs can explicitly be included in the Non-Slice cost pool. This leaves only system losses for which all Composite customers pay (regardless of product subscription) in the Composite cost pool, and properly accounts for Customer return of Slice-Resource losses. That value is used to determine the reallocation credit that will shift costs between the Composite and Non-Slice TRM cost pools.

Table 3.1.4
Balancing Augmentation Adjustment for Change to the Equivalent Tier 1 System Firm Critical Output (DS 04)

Worksheet calculates the change in the TISFCO from the RHWM to 7(i) processes, and values the difference at the system augmentation price when the system augmentation amount is greater than zero

Table 3.1.5
Calculation of Load Shaping and Demand Revenues (DS 05)

Worksheet calculates the Load Shaping and Demand revenues under the TRM rate design. These revenues are used as a credit against the costs in the Non-Slice rate pool.

Table 3.1.6
Calculation of PF Public Rates under Tiered Rate Methodology (DS 06)

Worksheet applies the costs, revenue credits and inter-rate-pool reallocations to the Composite, Non-Slice, Slice, and Tier 2 TRM rate pools to produce TRM rates. The TRM rates are in the form of monthly $/percent TOCA.

Table 3.1.7.1
Calculation of Net REP Ratemaking and Recovery Demonstration (DS 07-1)
Worksheet applies all power costs and revenue credits to the PF Public rate pool. The IP revenues are calculated with a macro to arrive at the proper relationship between the PFp rate and the IP rate. The net REP benefits are used in the calculations. The worksheet demonstrates that the PFp rate using the net REP benefits is identical to the PFp calculated with BPA's standard gross REP methodology.

Table 3.1.7.2
TRM PFp Revenues Equal to Non-TRM PFp Revenues (DS 07-2)
Worksheet demonstrates that the TRM revenues from Table 3.1.6 are equal to the non-TRM revenues from Table 3.1.7.1. This table completes the proof process for revenue recovery and cost allocation under the Northwest Power Act, REP Settlement, and the TRM.

Table 3.1.8.1
Calculation of Priority Firm Public Tier 1 Rate Equivalent Components (DS 08-1)
Worksheet calculates the energy and demand components for a PF Public rate that is equivalent to a Tier 1 PF rate. The monthly energy Load Shaping rates are adjusted by a scalar in all periods so that they and the monthly demand rates will recover the Tier 1 PF revenue requirement.

Table 3.1.8.2
Calculation of Priority Firm Public Melded Rate Equivalent Components (DS 08-2)
Worksheet calculates the energy and demand components for a PF Public rate that is equivalent to a melded Tier 1 and Tier 2 PF rate. The monthly energy Load Shaping rates are adjusted by a scalar in all periods so that they and the monthly demand rates will recover the Tier 1 and Tier 2 PF revenue requirement. These monthly energy PF rates are necessary to calculate the Industrial Firm Power rates.

Table 3.1.8.3
Calculation of Industrial Firm Power Rate Components (DS 08-3)
Worksheet calculates the Industrial Firm Power (IP) rate monthly energy and demand components. The IP rate is a formula rate derived from the "applicable wholesale rate." In this rate proceeding, with no NR load, the applicable wholesale rate is the melded PF Public rate. The monthly IP energy rates are set equal to the melded PF rate, plus the DSI value of reserve (VOR), plus the Industrial Margin, plus the Settlement Charge.

Table 3.1.8.4
Calculation of New Resource Rate Components (DS 08-4)
Worksheet calculates the energy and demand components for the New Resources (NR) rate. The monthly energy Load Shaping rates are adjusted by a scalar in all periods so that they and the monthly demand rates will recover the NR revenue requirement.

Table 3.1.8.5
Calculation of the Non-Slice Priority Firm Tier 1 Equivalent and Load Shaping True-Up Rate Components (DS 08-5)
Worksheet calculates the Load Shaping True-up rate by comparing the non-Slice Tier 1 market energy revenue (the non-Slice Tier 1 loads times the market rates) with the non-Slice Tier 1 energy revenue at Tier 1 rates. The difference in the form of a $/MWh is the Load Shaping True-up rate.

Table 3.2
Summary RSS Revenue Credits for Tier 1 Cost Pools
Table summarizes the total revenue credits associated with RSS and related services, delineated by Tier 1 cost pool.

Table 3.3
Tier 2 Purchases Made by BPA
Table lists information pertaining to Mid-C purchases made by BPA to meet Tier 2 rate load obligations.

Table 3.4
Inputs to TSS Monthly Rate and Charge
Table shows costs used as the numerator and the megawatt hours sold as the denominator for the TSS rate. The transaction values are used to calculate the charge cap.

Table 3.5.1
Tier 2 Short-Term Rate Costing Table
Costing table used to calculate the Tier 2 Short-Term rates for each year of the rate period.

Table 3.5.2
Tier 2 Load Growth Rate Costing Table
Costing table used to calculate the Tier 2 Load Growth rates for each year of the rate period.

Table 3.6
Tier 2 Overhead Adder Inputs
Table lists inputs to Tier 2 Overhead Cost Adder.

Table 3.7
Tier 2 Rate Revenues
Table summarizes the Tier 2 rate-related revenues and adjustments to Tier 1 cost pools.

Table 3.8
Total Remarketing Charges and Credits
Table summarizes the sources of power for meeting different Tier 2 loads, including purchases, executed and forecast, remarketed power from other Tier 2 cost pools, and remarketed power from non-Federal resources with DFS.

Table 3.9
Tier 2 Rate Inputs
Table lists Tier 2 rate inputs including Tier 2 purchase prices, executed and forecast, remarketing amounts, and the monthly TSS rate.

Table 3.10
Remarketing Value Inputs and Capacity Adder
Table lists the Aurora firm price under P10 conditions and the capacity adder used to determine the Remarketing Rate.

Table 3.11
Rates and Charges for RSS and Related Services
Table summarizes the RSS model forecast results for the purchaser's grandfathered GMS, SCS, DFS, FORS, and TSS/TCMS. This table also shows who is taking which service, during which year, and for which resource. Table summarizes the revenue credits by customers produced by the RSS model when applying the RSS and related services charges to the identified resources. Also included is the all-in forecast $/MWh equivalent rate for the identified services.

Table 3.12
Calculation of ESS Revenue Forecast
Worksheet calculates the Energy Shaping Services (ESS) revenue forecast.

Table 3.1.1.1

Rate Design Step
Cost Aggregation under Tiered Rate Methodology

	A	B	C	D	E	G	H	I
4						**2026**	**2027**	**2028**
5		**Composite**						
6			Federal Base System					
7				Hydro				
8					Operating Expense	752,238	784,932	810,396
9					Interest	5,233	(10,652)	(9,220)
10					MRNR	106,298	103,634	208,243
11				Fish & Wildlife				
12					Operating Expense	358,977	365,745	374,663
13					Interest	1,139	(1,361)	(1,001)
14					MRNR	23,121	13,242	23,278
15				Trojan		1,300	1,329	1,359
16				WNP #1		68,791	63,976	59,761
17				Columbia Generating Station		702,669	811,473	813,456
18				WNP #3		81,418	76,981	72,615
19				Augmentation		-	-	-
20			Residential Exchange Program					
21				REP Net Cost		287,051	287,068	287,875
22				Program Support		303	312	322
23				Settlement Interest Accrual		-	-	-
24			NewResources					
25				Cowlitz		28,197	33,172	29,922
26				Idaho		-	-	-
27				Tier 1 Aug (Klondike III)		11,347	13,030	4,577
28				Other		20,774	7,174	4,338
29				Other System Augmentation		7,021	17,440	20,974
30			Conservation					
31				Operating Expense		165,059	159,628	180,753
32				Interest		6	-	-
33				MRNR		128	3	-
34			BPAPrograms					
35				Operating Expense		194,454	207,433	214,900
36				Interest		51	(41)	(52)
37				MRNR		1,036	397	503
38			Transmission					
39				Transmission and Ancillary Services		29,096	30,355	32,481
40				General Transfer Agreements		92,013	94,644	96,736
41			Nonslice Interest and MRNR Allocated to Cost Pools					
42				Interest on BPA fund Credit to Nonslice		1,449	1,403	1,950
43				Accrual Revenue (MRNR Adjustment)		-	-	-
44			**Total Composite**			**2,939,169**	**3,061,317**	**3,228,829**

Table 3.1.1.2

Rate Design Step
Cost Aggregation under Tiered Rate Methodology

	A	B	C	D	E	G	H	I
4						**2026**	**2027**	**2028**
45		**Non-Slice**						
46			FBS					
47				Balancing Purchases from Risk Mod		79,624	58,774	74,492
48				Balancing in Revenue Requirement		24,477	24,477	24,477
49				PNRR				
50					Hydro	-	-	-
51					Fish & Wildlife	-	-	-
52			Conservation					
53				PNRR		-	-	-
54			BPAPrograms					
55				Hedging Mitigation		-	-	-
56				RCD Expense Offset Non-Slice		-	-	-
57				PNRR		-	-	-
58			Transmission					
59				Transmission and Ancillary Services		83,653	83,208	84,336
60				Third-party T&A		-	-	-
61			Nonslice Interest and MRNR					
62				BPA Fund		(1,449)	(1,403)	(1,950)
63				Non-Slice MRNR Adjustment		-	-	-
64			**Total Non-Slice**			**186,305**	**165,056**	**181,356**
65		**Slice**						
66			BPAPrograms					
67				Other Slice Costs		-	-	-
68			**Total Slice**			-	-	-
69		**Tier 2**						
70			FBS					
71				Tier 2 Purchase Costs		319,432	329,517	354,163
72				Tier 2 Rate Design Adjustments		8,806	10,276	11,139
73				Tier 2 Other Costs		-	-	-
74			**Total Tier 2**			**328,238**	**339,794**	**365,302**

Table 3.1.1.3

Rate Design Step
Cost Aggregation under Tiered Rate
Methodology

	A	B	C	D	E	G	H	I
4						**2026**	**2027**	**2028**
75		**Rate Direct/Design Adjustments**						
76			Credits Allocated Against Cost Pools					
77				FBS (excluding T2 Adjustment)		(390,666)	(302,052)	(348,720)
78				Contract Obligations		(485)	(476)	(456)
79				New Resources		-	-	-
80				Conservation		-	-	-
81				BPAPrograms		-	-	-
82				Transmission		(8,647)	(8,831)	(9,078)
83								
84			Secondary Energy Credit (includes pre-sale and Slice)			(523,061)	(484,267)	(466,159)
85			Firm Surplus Secondary Sales			-	-	-
86			Generation Inputs Credit			(133,219)	(133,219)	(133,219)
87			Capacity for Delayed 168-hr Loss Returns			-	-	-
88			FPS Real Power Losses (Capacity)			(44,745)	(44,745)	(44,745)
89			FPS Real Power Losses (Energy)			-	-	-
90			PRSC Net Credit (Composite)			-	-	-
91			PRSC Net Credit (Non-Slice)			-	-	-
92			NR Revenues from ESS (Capacity)			(9,502)	(11,522)	(14,047)
93			NR Revenues from ESS (Energy)			-	-	-
94			Composite FPS Revenues (excl. secondary)			-	-	-
95			Non-Slice FPS Revenues (excl. secondary)			-	-	-
96								
97			Low Density Discount			42,155	43,297	44,391
98			Irrigation Rate Mitigation Costs			22,034	22,034	22,034
99								
100			Composite Augmentation RSS Revenue Debit/(Credit)			(1,560)	(1,560)	(1,561)
101			Composite Tier 2 RSS Revenue Debit/(Credit)			(563)	(610)	(651)
102			Composite Tier 2 Rate Design Adjustment Debit/(Credit)			(8,243)	(9,667)	(10,488)
103			Composite Non-Federal RSS Revenue Debit/(Credit)			(1,293)	(3,064)	(3,434)
104			Non-Slice Augmentation RSC Revenue Debit/(Credit)			(1,071)	(1,070)	(1,074)
105			Non-Slice Tier 2 RSC Revenue Debit/(Credit)			-	-	-
106			Non-Slice Tier 2 Rate Design Debit/(Credit)			-	-	-
107			Non-Slice Non-Federal RSC Revenue Debit/(Credit)			457	(2,518)	(1,405)
108								
109			Firm Surplus and Secondary Credit (from unused RHWM)			(94,894)	(73,857)	(60,238)
110			Demand Revenue			141,637	148,212	144,925
111			Load Shaping Revenue			72,093	76,824	74,458
112								

Table 3.1.2

Rate Design Step
Unused RHWM (net) Credit
Computation

	B	C	D	E
4		**2026**	**2027**	**2028**
5	Secondary (aMW)	1,959	1,969	1,992
6	T1SFCO (aMW)	7,033	7,033	7,033
7	RHWM Augmentation (aMW)	76	76	76
8	RP Augmentation (aMW)	-	-	-
9	System Augmentation (aMW)	-	-	-
10	Firm Surplus (aMW)	-	-	-
11	IP and NR Loads contributing to avoided cost	12	31	38
12				
13	Value of Secondary	$ 25.23	$ 23.93	$ 22.83
14	Value of T1SFCO ($/MWh)	$ 38.83	$ 38.83	$ 38.83
15	Value of Augmentation	$ 66.58	$ 63.28	$ 63.54
16	Value of Firm Surplus	0	0	0
17				
18	Secondary (MWh)	17,157,592	17,249,783	17,497,913
19	T1SFCO (MWh)	61,611,515	61,611,515	61,780,314
20	RHWM Augmentation (MWh)	668,160	668,160	669,991
21	IP and NR Loads (MWh)	105,454	275,575	330,114
22	Change in T1SFCO (MWh)	(128,364)	(69,791)	(128,364)
23				
24	Unused RHWM (MWh)	3,177,453	2,921,820	2,721,266
25				
26	Unused Secondary	875,365	809,265	762,470
27	Unused T1SFCO	3,143,364	2,890,473	2,692,071
28	Unused Augmentation	34,089	31,346	29,195
29				
30	Value of Unused	$ 146,401,148	$ 133,576,874	$ 123,785,172
31	Value of System Augmentation not Purchased	$ 51,507,251	$ 59,719,565	$ 63,546,675
32				
33	Net Credit/(Cost)	$ 94,893,897	$ 73,857,309	$ 60,238,496
34				
35	$/MWh value of Unused RHWM	**$ 45.78**		

Table 3.1.3

Rate Design Step
Slice Return of Network Losses
Adjustment

	B	C	D	E
4		**2026**	**2027**	**2028**
5	Non Slice Loads (MWh)	51,820,511	52,198,318	52,424,248
6	Loss Percent Assumption	1.81%	1.81%	1.81%
7	Implied Non Slice Losses	936,775	943,556	947,549
8	Average Slice&Non-Slice Tier 1 Rate	37.98	37.98	37.98
9	Implied Cost/Credit ($1000)	35,579	35,836	35,988

Table 3.1.4

Rate Design Step
Balancing Augmentation Adjustment for Change to the Equivalent Tier 1 System Firm Critical Output

	A	B	C	E	F	G
4				**2026**	**2027**	**2028**
5		**Table 3.1**				
6			Regulated	6,336	6,345	6,354
7			Independent	264	270	265
8		**Table 3.2**				
9			Ashland Solar Project	-	-	-
10			Columbia Generating Station	1,116	994	1,116
11			Condon Wind Project	-	-	-
12			Dworshak/Clearwater Small Hydropower	3	3	3
13			Elwha Hydro	-	-	-
14			Foote Creek 1	-	-	-
15			Foote Creek 2	-	-	-
16			Foote Creek 4	-	-	-
17			Fourmile Hill Geothermal	-	-	-
18			Georgia-Pacific Paper (Wauna)	-	-	-
19			Glines Canyon Hydro	-	-	-
20			Klondike I	-	-	-
21			Stateline Wind Project	21	5	-
22		**Table 3.3**				
23			Canadian Entitlement	84	84	84
24			Libby Coordination	-	-	-
25			BC Hydro Power Purchase	1	1	1
26			Pasadena Capacity	-	-	-
27			Pasadena Seasonal	-	-	-
28			Pasadena Exchange Energy	-	-	-
29			PacifiCorp (So Idaho)	-	-	-
30			Riverside Capacity	-	-	-
31			Riverside Seasonal	-	-	-
32			Riverside Exchange Energy	-	-	-
33			Sierra Pacific (Wells)	-	-	-
34			PacifiCorp	-	-	-
35		**Table 3.4**				
36			USBR Pump Load	192	192	196
37			Canadian Entitlement	305	305	305
38			Non-Treaty Storage	12	13	13
39			Libby Coordination	-	-	-
40			Hungry Horse	-	-	-
41			Riverside Capacity	-	-	-
42			Riverside Seasonal	-	-	-
43			Pasadena Capacity	-	-	-
44			Pasadena Seasonal	-	-	-
45			Sierra Pacific (Wells)	-	-	-
46			Intertie Losses	-	-	-
47			WNP3	-	-	-
48			PacifiCorp	-	-	-
49			PacifiCorp (So Idaho)	-	-	-
50			Upper Baker	1	1	1
51			Dittmer Station Service	9	9	9
52						
53			Federal Power Deliveries			
54			Preference	7,287	7,361	7,423
55			Tier 2	531	577	615
56			Net Preference	6,756	6,785	6,807
57			Industrial	11	11	11
58			New Resource	1	20	25
59			Intraregional Transfer	2	2	2
60			FBS Obligation	520	520	524
61			Seasonal or Capacity Exchange	-	-	-
62			Conservation Augmentation	-	-	-
63			Transmission Losses Before Slice Return	232	235	237
64			Slice Return of Losses	17	17	17
65			Transmission Losses After Slice Return	215	218	220
66						
67		**Annual T1SFCO**		7,090	6,963	7,079
68		**RHWM Process T1SFCO (annual)**		7,075	6,955	7,069
69		**Difference**		15	8	10
70		**Augmentation Price (zero if no incremental Augmentation)**		$ -	$ -	$ -
71		**Hours**		8,760	8,760	8,784
72		**Credit/Cost to Balancing Augmentation**		$ -	$ -	$ -

Table 3.1.5

Rate Design Step
Calculation of Load Shaping and Demand Revenues

	B	E	F	G	H	I	J	K	L
5	**2026**	Demand (kW)	Demand Rate ($/kW/mo.)	**Demand**	Load Shaping HLH (MWh)	Load Shaping LLH (MWh)	Load Shaping HLH Rate ($/MWh)	Load Shaping LLH Rate ($/MWh)	**Load Shaping**
6	Oct-25	753,867	$ 13.81	$ 10,410,909	301,811	158,183	$ 50.63	$ 48.85	$ 23,007,922
7	Nov-25	706,916	$ 10.78	$ 7,620,557	(51,491)	156,660	$ 39.53	$ 41.64	$ 4,487,893
8	Dec-25	1,322,782	$ 12.99	$ 17,182,941	55,250	389,854	$ 47.63	$ 48.79	$ 21,652,530
9	Jan-26	1,370,293	$ 11.88	$ 16,279,086	(25,454)	257,587	$ 43.56	$ 43.80	$ 10,173,529
10	Feb-26	1,094,310	$ 12.39	$ 13,558,506	149,330	313,747	$ 45.43	$ 49.18	$ 22,214,138
11	Mar-26	1,242,030	$ 7.97	$ 9,898,976	(171,562)	278,770	$ 29.19	$ 34.54	$ 4,620,826
12	Apr-26	1,123,925	$ 6.09	$ 6,844,704	210,073	100,189	$ 22.33	$ 27.09	$ 7,405,051
13	May-26	652,755	$ 2.35	$ 1,533,973	(669,782)	(319,842)	$ 8.60	$ 12.73	$ (9,831,715)
14	Jun-26	1,157,404	$ 4.12	$ 4,768,504	(860,980)	(333,985)	$ 15.10	$ 16.08	$ (18,371,262)
15	Jul-26	1,221,947	$ 13.91	$ 16,997,280	(117,807)	66,863	$ 50.98	$ 48.06	$ (2,792,377)
16	Aug-26	1,447,094	$ 14.67	$ 21,228,865	(348,486)	132,518	$ 53.80	$ 50.32	$ (12,080,227)
17	Sep-26	927,509	$ 16.51	$ 15,313,181	171,840	189,785	$ 60.51	$ 59.06	$ 21,606,689
18	**Total**			**$ 141,637,483**		33,071			**$ 72,092,997**
19									
20	**2027**	Demand (kW)	Demand Rate ($/kW/mo.)	**Demand**	Load Shaping HLH (MWh)	Load Shaping LLH (MWh)	Load Shaping HLH Rate ($/MWh)	Load Shaping LLH Rate ($/MWh)	**Load Shaping**
21	Oct-26	785,366	$ 13.81	$ 10,845,898	311,576	153,036	$ 50.63	$ 48.85	$ 23,250,898
22	Nov-26	777,265	$ 10.78	$ 8,378,917	(44,690)	172,041	$ 39.53	$ 41.64	$ 5,397,222
23	Dec-26	1,361,649	$ 12.99	$ 17,687,818	74,690	392,573	$ 47.63	$ 48.79	$ 22,711,157
24	Jan-27	1,407,518	$ 11.88	$ 16,721,315	(105,543)	356,226	$ 43.56	$ 43.80	$ 11,005,213
25	Feb-27	1,152,969	$ 12.39	$ 14,285,285	160,160	322,028	$ 45.43	$ 49.18	$ 23,113,418
26	Mar-27	1,337,722	$ 7.97	$ 10,661,647	(76,077)	198,224	$ 29.19	$ 34.54	$ 4,625,974
27	Apr-27	1,189,464	$ 6.09	$ 7,243,838	217,531	98,622	$ 22.33	$ 27.09	$ 7,529,151
28	May-27	707,390	$ 2.35	$ 1,662,367	(675,757)	(319,147)	$ 8.60	$ 12.73	$ (9,874,245)
29	Jun-27	1,188,706	$ 4.12	$ 4,897,470	(862,558)	(340,884)	$ 15.10	$ 16.08	$ (18,506,034)
30	Jul-27	1,246,354	$ 13.91	$ 17,336,786	(108,821)	60,586	$ 50.98	$ 48.06	$ (2,635,891)
31	Aug-27	1,525,151	$ 14.67	$ 22,373,958	(351,458)	138,557	$ 53.80	$ 50.32	$ (11,936,226)
32	Sep-27	976,174	$ 16.51	$ 16,116,629	181,634	188,831	$ 60.51	$ 59.06	$ 22,143,053
33	**Total**			**$ 148,211,929**		141,384			**$ 76,823,690**
34									
35	**2028**	Demand (kW)	Demand Rate ($/kW/mo.)	**Demand**	Load Shaping HLH (MWh)	Load Shaping LLH (MWh)	Load Shaping HLH Rate ($/MWh)	Load Shaping LLH Rate ($/MWh)	**Load Shaping**
36	Oct-27	861,790	$ 13.81	$ 11,901,324	231,085	249,006	$ 50.63	$ 48.85	$ 23,863,781
37	Nov-27	829,623	$ 10.78	$ 8,943,341	54,023	78,356	$ 39.53	$ 41.64	$ 5,398,268
38	Dec-27	1,398,109	$ 12.99	$ 18,161,437	85,684	384,144	$ 47.63	$ 48.79	$ 22,823,489
39	Jan-28	1,520,318	$ 11.88	$ 18,061,377	(102,604)	355,662	$ 43.56	$ 43.80	$ 11,108,554
40	Feb-28	1,227,186	$ 12.39	$ 15,204,829	132,893	289,974	$ 45.43	$ 49.18	$ 20,298,277
41	Mar-28	1,434,379	$ 7.97	$ 11,431,998	(72,176)	194,122	$ 29.19	$ 34.54	$ 4,598,153
42	Apr-28	1,316,169	$ 6.09	$ 8,015,469	115,862	193,099	$ 22.33	$ 27.09	$ 7,818,262
43	May-28	732,563	$ 2.35	$ 1,721,524	(592,125)	(422,765)	$ 8.60	$ 12.73	$ (10,474,064)
44	Jun-28	1,230,684	$ 4.12	$ 5,070,416	(869,719)	(355,013)	$ 15.10	$ 16.08	$ (18,841,372)
45	Jul-28	1,245,490	$ 13.91	$ 17,324,764	(209,221)	148,677	$ 50.98	$ 48.06	$ (3,520,686)
46	Aug-28	1,597,272	$ 14.67	$ 23,431,988	(262,392)	37,680	$ 53.80	$ 50.32	$ (12,220,624)
47	Sep-28	1,041,740	$ 16.51	$ 17,199,121	185,490	180,289	$ 60.51	$ 59.06	$ 21,871,878
48	**Total**			**$ 156,467,588**		30,032			**$ 72,723,916**

Table 3.1.6.1

Rate Design Step
Calculation of PF Preference Rates under
Tiered Rate Methodology

	B	C	D	E	F
5	**Costs ($000)**	**2026**	**2027**	**2028**	**Rate Period (total)**
6	**Composite**	$ 2,939,169	$ 3,061,317	$ 3,228,829	$ 9,229,315
7	**Non-Slice**	$ 186,305	$ 165,056	$ 181,356	$ 532,716
8	**Slice**	$ -	$ -	$ -	$ -
9	**Tier 2**	$ 328,238	$ 339,794	$ 365,302	$ 1,033,334
13					
14	**Revenues from Rate Pools to Composite Cost Pool**	**2026**	**2027**	**2028**	**Rate Period (total)**
15	DSI Revenue Credit	$ (4,393)	$ (4,393)	$ (4,405)	$ (13,192)
16	Exchange Revenues	$ -	$ -	$ -	$ -
17	New Resource Revenues	$ (706)	$ (19,072)	$ (24,877)	$ (44,654)
18	FPS Revenues	$ -	$ -	$ -	$ -
19	Non-Federal RSS Revenues	$ (1,293)	$ (3,064)	$ (3,434)	$ (7,791)
20	Other Credits	$ (533,016)	$ (444,577)	$ (491,473)	$ (1,469,067)
21	NR Revenues from ESS (Capacity)	$ (9,502)	$ (11,522)	$ (14,047)	$ (35,071)
22	FPS Real Power Losses (Capacity)	$ (44,745)	$ (44,745)	$ (44,745)	$ (134,235)
23	Tiered Rate Elements				
24	Unused RHWM Credit Reallocation	$ (94,894)	$ (73,857)	$ (60,238)	$ (228,990)
25	Balancing Augmentation Adjustment Reallocation	$ (834)	$ (3,383)	$ (686)	$ (4,903)
26	Composite Augmentation RSS Revenue Debit/(Credit)	$ (1,560)	$ (1,560)	$ (1,561)	$ (4,681)
27	Composite Tier 2 RSS Revenue Debit/(Credit)	$ (563)	$ (610)	$ (651)	$ (1,824)
28	Composite Tier 2 Rate Design Adjustment Debit/(Credit)	$ (8,243)	$ (9,667)	$ (10,488)	$ (28,397)
29	Transmission Losses Adjustment Reallocation	$ (35,579)	$ (35,836)	$ (35,988)	$ (107,403)
30	Total	$ (735,329)	$ (652,287)	$ (692,593)	$ (2,080,208)
31					
32	**Rate Discount Costs Applied to Composite Pool**	**2026**	**2027**	**2028**	**Rate Period (total)**
33	Irigation Rate Discout Costs	$ 22,034	$ 22,034	$ 22,034	$ 66,101
34	Low Density Discount Costs	$ 42,155	$ 43,297	$ 44,391	$ 129,843
35	Total	$ 64,189	$ 65,330	$ 66,424	$ 195,944
36					
37		**2026**	**2027**	**2028**	**Rate Period (total)**
38	**Composite**	$ 2,268,029	$ 2,474,361	$ 2,602,661	$ 7,345,051

Table 3.1.6.2

Rate Design Step
Calculation of PF Preference Rates under
Tiered Rate Methodology

	B	C	D	E	F
5	**Costs ($000)**	**2026**	**2027**	**2028**	**Rate Period (total)**
6	**Composite**	$ 2,939,169	$ 3,061,317	$ 3,228,829	$ 9,229,315
7	**Non-Slice**	$ 186,305	$ 165,056	$ 181,356	$ 532,716
8	**Slice**	$ -	$ -	$ -	$ -
9	**Tier 2**	$ 328,238	$ 339,794	$ 365,302	$ 1,033,334
39					
40	**Non-Slice Revenues, Credits, and Costs**	**2026**	**2027**	**2028**	**Rate Period (total)**
41	Secondary Revenue	$ (462,139)	$ (428,203)	$ (410,005)	$ (1,300,347)
42	Unused RHWM Credit Reallocation	$ 94,894	$ 73,857	$ 60,238	$ 228,990
43	Other Long Term Contract Revenues	$ -	$ -	$ -	$ -
44	Non-federal RSC Revenues	$ 457	$ (2,518)	$ (1,405)	$ (3,466)
45	Load Shaping Revenue	$ (72,093)	$ (76,824)	$ (72,724)	$ (221,641)
46	Balancing Augmentation Adjustment Reallocation	$ 834	$ 3,383	$ 686	$ 4,903
47	Demand Revenue	$ (141,637)	$ (148,212)	$ (156,468)	$ (446,317)
48	Non-Slice Augmentation RSC Revenue Debit/(Credit)	$ (1,071)	$ (1,070)	$ (1,074)	$ (3,215)
49	Non-Slice Tier 2 RSC Revenue Debit/(Credit)	$ -	$ -	$ -	$ -
50	Non-Slice Tier 2 Rate Design Debit/(Credit)	$ -	$ -	$ -	$ -
51	FPS Real Power Losses (Energy)	$ -	$ -	$ -	$ -
52	NR Revenues from ESS (Energy)	$ -	$ -	$ -	$ -
53	PRSC Net Credit (Non-Slice)	$ -	$ -	$ -	$ -
54	Transmission Losses Adjustment Reallocation	$ 35,579	$ 35,836	$ 35,988	$ 107,403
55	Total	$ (545,177)	$ (543,750)	$ (544,764)	$ (1,633,690)
56					
57		**2026**	**2027**	**2028**	**Rate Period (total)**
58	**Non-Slice**	$ (358,872)	$ (378,694)	$ (363,408)	$ (1,100,974)

Table 3.1.6.3

Rate Design Step
Calculation of PF Preference Rates
under Tiered Rate Methodology

	B	C	D	E	F
5	**Costs ($000)**	**2026**	**2027**	**2028**	**Rate Period (total)**
6	**Composite**	$ 2,939,169	$ 3,061,317	$ 3,228,829	$ 9,229,315
7	**Non-Slice**	$ 186,305	$ 165,056	$ 181,356	$ 532,716
8	**Slice**	$ -	$ -	$ -	$ -
9	**Tier 2**	$ 328,238	$ 339,794	$ 365,302	$ 1,033,334
59					
60	**TRM Costs after Adjustments**	**2026**	**2027**	**2028**	**Rate Period (total)**
61	**Composite**	$ 2,268,029	$ 2,474,361	$ 2,602,661	$ 7,345,051
62	**Non-Slice**	$ (358,872)	$ (378,694)	$ (363,408)	$ (1,100,974)
63	**Slice**	$ -	$ -	$ -	$ -
64	**Tier 2**	$ 328,238	$ 339,794	$ 365,302	$ 1,033,334
65	**Total Costs**	$ 2,237,396	$ 2,435,461	$ 2,604,555	$ 7,277,411
66					
67	**Billing Determinants**	**2026**	**2027**	**2028**	**Rate Period (Avg)**
68	**TOCA**	94.8981	95.3086	95.6425	95.2831
69	**Non-slice TOCA**	83.1530	83.5635	83.8975	83.5380
70	**Slice Percentage**	11.7451	11.7451	11.7451	11.7451
71					
72	**Annual TRM Rates ($000/percent)**	**2026**	**2027**	**2028**	**Rate Period (Avg)**
73	**Composite**	$ 23,900	$ 25,962	$ 27,212	$ 25,696
74	**Non-Slice**	$ (4,316)	$ (4,532)	$ (4,332)	$ (4,393)
75	**Slice**	$ -	$ -	$ -	$ -
76					
77	**Monthly TRM Rates ($/percent)**	**2026**	**2027**	**2028**	**Rate Period (Avg)**
78	**Composite**	1,991,636	2,163,465	2,267,699	2,141,296
79	**Non-Slice**	(359,650)	(377,651)	(360,965)	(366,092)
80	**Slice**	-	-	-	-
81					
82	**Tier 2 Rates ($/MWh)**	**2026**	**2027**	**2028**	**Rate Period (Avg)**
83	**Tier 2 Short Term**	$ 70.66	$ 67.40	$ 67.70	$ 68.51
84	**Tier 2 Load Growth**	$ 70.66	$ 67.40	$ 67.70	$ 68.59

Table 3.1.7.1

Rate Design Step
Calculation of Net REP Ratemaking and Recovery Demonstration
($ 000, $/MWh)

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
11			2026	2027	2028		PF p	IP	NR	FPS				PF p	IP	NR
12	GENERATION ENERGY															
13														193,517	289	401.3155197
14	Federal Base System															
15	Hydro		863,769	877,914	1,009,419		2,751,102	0.0	(0.0)	0				14.22	0.00	0.00
16	Fish & Wildlife		383,237	377,626	396,940		1,157,802	0.0	0.0	0				5.98	0.00	0.00
17	Trojan		1,300	1,329	1,359		3,988	0.0	0.0	0				0.02	0.00	0.00
18	WNP #1		68,791	63,976	59,761		192,528	0.0	0.0	0				1.00	0.00	0.00
19	WNP #2		702,669	811,473	813,456		2,327,598	0.0	0.0	0				12.03	0.00	0.00
20	WNP #3		81,418	76,981	72,615		231,014	0.0	0.0	0				1.19	0.00	0.00
21	System Augmentation		0	0	0		0	0.0	0.0	0				0.00	0.00	0.00
22	Balancing Power Purchases		104,101	83,251	98,969		286,321	0.0	0.0	0				1.48	0.00	0.00
23	Tier 2 Costs		328,238	339,794	365,302		1,033,334	0.0	0.0	0				5.34	0.00	0.00
24	Total Federal Base System		2,533,523	2,632,344	2,817,821		7,983,688	0.0	0.0	0.0				41.26	0.00	0.00
25																
26	New Resources		64,709	68,185	57,177		190,070	0.0	0.0	0		PFx Revenue		0.98	0.00	0.00
27	Residential Exchange		3,555,603	3,558,587	3,571,933		862,930	0.0	0.0	0		9,823,193		4.46	0.00	0.00
28	Conservation		165,193	159,631	180,753		505,577	0.0	0.0	0				2.61	0.00	0.00
29	BPA Programs & Transmission		400,302	415,996	428,905		1,245,204	0.0	0.0	0		NR Revenue		6.44	0.00	0.00
30	TOTAL COSA ALLOCATIONS		6,719,331	6,834,742	7,056,588		10,787,469	0	0	0		44,654		55.75	0.00	0.00
31																
32																
33	Nonfirm Excess Revenue Credit		(523,061)	(484,267)	(466,159)		(1,473,487)	0.0	0.0	0.0				-7.61	0.00	0.00
34	LDD/IRD Expense		64,189	65,330	66,424		195,944	0.0						1.01	0.00	0.00
35	Other Revenue Credits		(596,905)	(516,703)	(566,243)		(1,679,851)	0.0	0.0	0.0				-8.68	0.00	0.00
36														0.00	0.00	0.00
37	SP Revenue Surplus/Dfct Adj.		0	0	0		0	0	0.0	0				0.00	0.00	0.00
38	NR Rate Revenue						(44,654.4)		44,654					-0.23	0.00	111.27
39	IP Rate Revenue		0	0	0		(13,193)	13,193						-0.07	45.60	0.00
40																
41	TOTAL RATE DESIGN ADJUSTMENTS		(1,055,777)	(935,639)	(965,977)		(3,015,242)	13,193	44,654	0				-15.58	45.60	111.27
42																
43	Total Generation		5,663,554	5,899,103	6,090,611							**7,830,075**		**40.17**	**45.60**	**111.27**
44					**PFp Revenue Recovery**		**7,772,227**	13,193	44,654	0						

Table 3.1.7.2

Rate Design Step
Demonstration that TRM PFp Rates Collect the Same Revenue Requirement as the Non-TRM PFp Rate

	B	C	D	E	F	G
4						
5						
6		**Proof: TRM PF Revenues = Non-TRM PF Revenues**				
7						
8			2026	2027	2028	
9		Composite Revenue....................................	$ 2,438,459	$ 2,449,006	$ 2,457,587	
10		Non-Slice Revenue.....................................	$ (365,300)	$ (367,103)	$ (368,571)	
11		Slice Revenue..	$ -	$ -	$ -	
12		Tier 2..	$ 328,238	$ 339,794	$ 365,302	
13		Load Shaping Revenue.............................	$ 72,093	$ 76,824	$ 72,724	
14		Demand Revenue..	$ 141,637	$ 148,212	$ 156,468	
15		Total TRM PF Revenue	$ 2,615,127	$ 2,646,732	$ 2,683,510	
16						
17		Slice Portion of Secondary Revenue....	$ (60,921)	$ (56,064)	$ (56,154)	
18		Total Net TRM PF Revenue	$ 2,554,206	$ 2,590,667	$ 2,627,356	
19						
20					PF Rate	
21		Total TRM PF Revenue Analogous to w/ Slice PF		$ 7,772,229	40.16	
22						
23		w/ Slice PF Public Rate Revenue from "Net REP" Table		$ 7,772,227	40.16	
24			delta	$ (2)		
25						
26						

Table 3.1.8.1

Rate Design Step
Calculation of Priority Firm Tier 1
Equivalent Rate Components

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26		
15	HLH (mills/kWh)	50.63	39.53	47.63	43.56	45.43	29.19	22.33	8.60	15.10	50.98	53.80	60.51		
16	LLH (mills/kWh)	48.85	41.64	48.79	43.80	49.18	34.54	27.09	12.73	16.08	48.06	50.32	59.06		
17	Demand Rate ($/kW/mo)	13.81	10.78	12.99	11.88	12.39	7.97	6.09	2.35	4.12	13.91	14.67	16.51		
18															
19															**Totals**
20	Classic Billing Determinants	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Tier 1 Energy (GWh)
21	HLH (GWh)	8,245	9,121	11,269	11,234	9,777	9,989	8,107	7,689	7,989	8,722	8,892	7,705		178,407
22	LLH (GWh)	5,037	6,411	7,357	7,695	6,253	6,213	5,112	5,209	4,625	5,571	5,279	4,906		Tier 1 Demand (MW/mo)
23	Demand (MW)	2,401	2,314	4,083	4,298	3,474	4,014	3,630	2,093	3,577	3,714	4,570	2,945		41,112
24															
25															
26															
27	Revenue @ Mkt Rates	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Mkt Energy Revenue ($000)
28	HLH ($000)	$ 417,459	$ 360,557	$ 536,762	$ 489,349	$ 444,193	$ 291,558	$ 181,034	$ 66,096	$ 120,640	$ 444,617	$ 478,382	$ 466,252		$ 7,130,325
29	LLH ($000)	$ 246,049	$ 266,956	$ 358,942	$ 337,062	$ 307,502	$ 214,589	$ 138,497	$ 66,314	$ 74,365	$ 267,725	$ 265,664	$ 289,758		Demand Revenue ($000)
30	Demand ($000)	$ 33,158	$ 24,943	$ 53,032	$ 51,062	$ 43,049	$ 31,993	$ 22,104	$ 4,918	$ 14,736	$ 51,659	$ 67,035	$ 48,629		$ 446,317
31															$ 7,576,642
32															Tier 1 Revenue Requirement (RR) ($000)
33															$ 6,775,957
34															Tier 1 RR less Demand Revenue ($000)
35															$ 6,329,640
36	Slice&Non-Slice Tier 1 Equivalent	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Market Energy Delta (mills/kWh)
37	HLH (mills/kWh)	46.14	35.04	43.14	39.07	40.94	24.70	17.84	4.11	10.61	46.49	49.31	56.02		4.49
38	LLH (mills/kWh)	44.36	37.15	44.30	39.31	44.69	30.05	22.60	8.24	11.59	43.57	45.83	54.57		
39	Demand ($/kW/mo)	13.81	10.78	12.99	11.88	12.39	7.97	6.09	2.35	4.12	13.91	14.67	16.51		
40															
41															
42															
43	Classic Rate Design Revenues	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Allocated Cost Energy ($000)
44	HLH ($000)	$ 380,438	$ 319,601	$ 486,150	$ 438,910	$ 400,285	$ 246,716	$ 144,625	$ 31,600	$ 84,763	$ 405,478	$ 438,475	$ 431,653		$ 6,329,308
45	LLH ($000)	$ 223,434	$ 238,171	$ 325,910	$ 302,510	$ 279,428	$ 186,694	$ 115,542	$ 42,925	$ 53,600	$ 242,713	$ 241,959	$ 267,729		Allocated Cost Demand ($000)
46	Demand ($000)	$ 33,158	$ 24,943	$ 53,032	$ 51,062	$ 43,049	$ 31,993	$ 22,104	$ 4,918	$ 14,736	$ 51,659	$ 67,035	$ 48,629		$ 446,317
47															$ 6,775,625
48	Average Slice&Non-Slice Tier 1 Rate														
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 6,329,308	35.48												
51	Allocated Cost Demand	$ 446,317	2.50												
52	Total Allocated Costs	$ 6,775,625	37.98												
53															
54	Tier 1 Energy (GWh)		178,407												
55	Market Energy Delta (mills/kWh)		4.49												

Table 3.1.8.2

Rate Design Step
Calculation of Priority Firm Public
Melded Rate Equivalent
Components

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26		
15	HLH (mills/kWh)	50.63	39.53	47.63	43.56	45.43	29.19	22.33	8.60	15.10	50.98	53.80	60.51		
16	LLH (mills/kWh)	48.85	41.64	48.79	43.80	49.18	34.54	27.09	12.73	16.08	48.06	50.32	59.06		
17	Demand Rate ($/kW/mo)	13.81	10.78	12.99	11.88	12.39	7.97	6.09	2.35	4.12	13.91	14.67	16.51		
18															
19															**Totals**
20	Classic Billing Determinants	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Tier 1&2 Energy (GWh)
21	HLH (GWh)	8,978	9,792	11,984	11,931	10,449	10,725	8,813	8,388	8,708	9,431	9,621	8,392		193,517
22	LLH (GWh)	5,583	6,982	7,921	8,279	6,754	6,757	5,646	5,793	5,150	6,147	5,836	5,456		Tier 1 Demand (MW/mo)
23	Demand (MW)	2,401	2,314	4,083	4,298	3,474	4,014	3,630	2,093	3,577	3,714	4,570	2,945		41,112
24															
25															
26															
27	Revenue @ Mkt Rates	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Mkt Energy Revenue ($000)
28	HLH ($000)	$ 454,575	$ 387,085	$ 570,829	$ 519,710	$ 474,729	$ 313,052	$ 196,810	$ 72,112	$ 131,491	$ 480,748	$ 517,573	$ 507,829		$ 7,725,492
29	LLH ($000)	$ 272,741	$ 290,711	$ 386,450	$ 362,634	$ 332,169	$ 233,399	$ 152,945	$ 73,742	$ 82,809	$ 295,430	$ 293,679	$ 322,237		Demand Revenue ($000)
30	Demand ($000)	$ 33,158	$ 24,943	$ 53,032	$ 51,062	$ 43,049	$ 31,993	$ 22,104	$ 4,918	$ 14,736	$ 51,659	$ 67,035	$ 48,629		$ 446,317
31															$ 8,171,809
32															Tier 1&2 Revenue Requirement (RR) ($000)
33															$ 7,772,228
34															T1&2RR less Demand Revenue ($000)
35															$ 7,325,911
36	PF Melded Rate Equivalent	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		PF Melded Equivalent Energy Scalar (mills/kWh)
37	HLH (mills/kWh)	48.57	37.47	45.57	41.49	43.37	27.12	20.27	6.53	13.04	48.91	51.73	58.45		2.07
38	LLH (mills/kWh)	46.79	39.58	46.73	41.74	47.12	32.48	25.03	10.67	14.02	46.00	48.26	57.00		
39	Demand ($/kW/mo)	13.81	10.78	12.99	11.88	12.39	7.97	6.09	2.35	4.12	13.91	14.67	16.51		
40															
41															
42															
43	Classic Rate Design Revenues	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Allocated Cost Energy ($000)
44	HLH ($000)	$ 436,080	$ 366,910	$ 546,126	$ 495,015	$ 453,195	$ 290,858	$ 178,644	$ 54,777	$ 113,547	$ 461,250	$ 497,680	$ 490,537		$ 7,326,380
45	LLH ($000)	$ 261,240	$ 276,329	$ 370,134	$ 345,578	$ 318,256	$ 219,479	$ 141,314	$ 61,809	$ 72,201	$ 282,767	$ 281,657	$ 310,997		Allocated Cost Demand ($000)
46	Demand ($000)	$ 33,158	$ 24,943	$ 53,032	$ 51,062	$ 43,049	$ 31,993	$ 22,104	$ 4,918	$ 14,736	$ 51,659	$ 67,035	$ 48,629		$ 446,317
47															$ 7,772,697
48	Average Slice&Non-Slice Tier 1&2 Rate														
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 7,326,380	37.86												
51	Allocated Cost Demand	$ 446,317	2.31												
52	Total Allocated Costs	$ 7,772,697	40.17												
53															
54	Tier 1&2 Energy (GWh)		193,517												
55	PF Melded Equivalent Energy Scalar (mills/kWh)		2.07												

Table 3.1.8.3

Rate Design Step
Calculation of Industrial Firm Power Rate Components

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
11																
12																
13																
14		PF Melded Equiv Rate	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26		
15		HLH (mills/kWh)	48.57	37.47	45.57	41.49	43.37	27.12	20.27	6.53	13.04	48.91	51.73	58.45		
16		LLH (mills/kWh)	46.79	39.58	46.73	41.74	47.12	32.48	25.03	10.67	14.02	46.00	48.26	57.00		
17		Demand Rate ($/kW/mo)	13.81	10.78	12.99	11.88	12.39	7.97	6.09	2.35	4.12	13.91	14.67	16.51		
18																
19																**Totals**
20		IP Billing Determinants	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		IP Energy (GWh)
21		HLH (GWh)	14	13	13	13	13	14	13	13	14	13	14	13		289.344
22		LLH (GWh)	11	11	11	11	10	11	10	11	10	11	10	11		
23		Demand (MW)	-	-	-	-	-	-	-	-	-	-	-	-		
24																
25																
26																
27		Revenue @ PF Melded Rates	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Energy Rev & Tier1&2 ($000)
28		HLH ($000)	$ 679	$ 489	$ 603	$ 551	$ 547	$ 379	$ 272	$ 88	$ 177	$ 649	$ 730	$ 735		$ 10,804
29		LLH ($000)	$ 495	$ 425	$ 529	$ 471	$ 463	$ 343	$ 258	$ 119	$ 143	$ 519	$ 504	$ 638		Demand Rev ($000)
30		Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
31																$ 10,804
32																
33																VOR
34																(0.675)
35																Industrial Margin (mills/kWh)
36		IP Rate	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		0.966
37		HLH (mills/kWh)	56.84	45.74	53.84	49.76	51.64	35.39	28.54	14.80	21.31	57.18	60.00	66.72		Net industrial Margin
38		LLH (mills/kWh)	55.06	47.85	55.00	50.01	55.39	40.75	33.30	18.94	22.29	54.27	56.53	65.27		0.291
39		Demand ($/kW/mo)	13.81	10.78	12.99	11.88	12.39	7.97	6.09	2.35	4.12	13.91	14.67	16.51		Settlement Charge
40																7.976
41																
42																
43		Revenues @ Posted IP Rate	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Allocated Cost Energy ($000)
44		HLH ($000)	$ 795	$ 597	$ 712	$ 660	$ 651	$ 494	$ 383	$ 199	$ 289	$ 758	$ 846	$ 839		$ 13,197
45		LLH ($000)	$ 582	$ 514	$ 623	$ 564	$ 544	$ 430	$ 344	$ 211	$ 227	$ 613	$ 590	$ 731		Allocated Cost Demand ($000)
46		Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
47																$ 13,197
48			Average IP Rate													
49			($000)	(mills/kWh)												
50		Allocated Cost Energy	$ 13,197	45.61												
51		Allocated Cost Demand	$ -	-												
52		Total Allocated Costs	$ 13,197	45.61												
53																
54			IP Energy (GWh)	289.3												
55			Industrial Margin (mills/kWh)	0.966												
56			VOR	(0.675)												
57			Settlement Charge	7.976												

Table 3.1.8.4 DS 08-4

Rate Design Step
Calculation of New Resource Rate Components

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26		
15	HLH (mills/kWh)	50.63	39.53	47.63	43.56	45.43	29.19	22.33	8.60	15.10	50.98	53.80	60.51		
16	LLH (mills/kWh)	48.85	41.64	48.79	43.80	49.18	34.54	27.09	12.73	16.08	48.06	50.32	59.06		
17	Demand Rate ($/kW/mo)	13.81	10.78	12.99	11.88	12.39	7.97	6.09	2.35	4.12	13.91	14.67	16.51		
18															
19															**Totals**
20	NR Determinants	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		NR Energy (GWh)
21	HLH (GWh)	18	12	17	17	17	23	22	18	18	18	16	28		401
22	LLH (GWh)	14	10	14	14	13	17	17	15	13	15	12	22		Demand (MW/mo)
23	Demand (MW)	0	0	-	-	0	0	-	-	0	0	0	0		0
24															
25															
26															
27	Revenue @ Mkt Rates	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Mkt Energy Revenue ($000)
28	HLH ($000)	$ 916	$ 479	$ 831	$ 733	$ 783	$ 684	$ 495	$ 154	$ 275	$ 914	$ 876	$ 1,673		$ 15,927
29	LLH ($000)	$ 685	$ 425	$ 671	$ 634	$ 631	$ 583	$ 457	$ 186	$ 214	$ 717	$ 605	$ 1,306		Demand Revenue ($000)
30	Demand ($000)	$ 0	$ 0	$ -	$ -	$ 0	$ 0	$ -	$ -	$ 0	$ 0	$ 0	$ 0		$ 0
31															$ 15,927
32															NR Revenue Requirement (RR) ($000)
33															$ 44,654
34															NR RR less Demand Revenue ($000)
35															$ 44,654
36	NR Rates	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Market Energy Delta (mills/kWh)
37	HLH (mills/kWh)	122.21	111.11	119.21	115.14	117.01	100.77	93.91	80.18	86.68	122.56	125.38	132.09		(71.58)
38	LLH (mills/kWh)	120.43	113.22	120.37	115.38	120.76	106.12	98.67	84.31	87.66	119.64	121.90	130.64		
39	Demand ($/kW/mo)	13.81	10.78	12.99	11.88	12.39	7.97	6.09	2.35	4.12	13.91	14.67	16.51		
40															
41															
42															
43	Revenues @ Posted NR Rate	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Allocated Cost Energy ($000)
44	HLH ($000)	$ 2,211	$ 1,347	$ 2,081	$ 1,936	$ 2,015	$ 2,361	$ 2,080	$ 1,436	$ 1,580	$ 2,197	$ 2,041	$ 3,652		$ 44,653
45	LLH ($000)	$ 1,689	$ 1,156	$ 1,656	$ 1,669	$ 1,549	$ 1,790	$ 1,666	$ 1,233	$ 1,167	$ 1,785	$ 1,466	$ 2,890		Allocated Cost Demand ($000)
46	Demand ($000)	$ 0	$ 0	$ -	$ -	$ 0	$ 0	$ -	$ -	$ 0	$ 0	$ 0	$ 0		$ 0
47															$ 44,653
48		Average NR Rate													
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 44,653	111.27												
51	Allocated Cost Demand	$ 0	0.00												
52	Total Allocated Costs	$ 44,653	111.27												
53															
54		NR Energy (GWh)	401												
55															

Table 3.1.8.5

Rate Design Step
Calculation of the Non-Slice Priority Firm Tier 1 Equivalent and Load Shaping True-Up Rate Components

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26		
15	HLH (mills/kWh)	50.63	39.53	47.63	43.56	45.43	29.19	22.33	8.60	15.10	50.98	53.80	60.51		
16	LLH (mills/kWh)	48.85	41.64	48.79	43.80	49.18	34.54	27.09	12.73	16.08	48.06	50.32	59.06		
17	Demand Rate ($/kW/mo)	13.81	10.78	12.99	11.88	12.39	7.97	6.09	2.35	4.12	13.91	14.67	16.51		
18															
19															**Totals**
20	Classic Billing Determinants	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Tier 1 Energy (GWh) [FAT1L]
21	HLH (GWh) [FMDT1L]	7,334	7,992	9,907	9,820	8,627	8,718	7,174	6,502	6,685	7,593	7,677	6,822		156,443
22	LLH (GWh) [FMDT1L]	4,486	5,671	6,594	6,866	5,596	5,530	4,531	4,436	3,928	4,918	4,667	4,370		Tier 1 Demand (MW/mo)
23	Demand (MW)	2,401	2,314	4,083	4,298	3,474	4,014	3,630	2,093	3,577	3,714	4,570	2,945		41,112
24															
25															
26															
27	Revenue @ Mkt Rates	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Mkt Energy Revenue ($000) [MktR]
28	HLH ($000)	$ 371,325	$ 315,908	$ 471,864	$ 427,775	$ 391,920	$ 254,468	$ 160,215	$ 55,896	$ 100,942	$ 387,073	$ 413,033	$ 412,800	$	6,278,817
29	LLH ($000)	$ 219,125	$ 236,139	$ 321,713	$ 300,749	$ 275,211	$ 190,995	$ 122,734	$ 56,474	$ 63,157	$ 236,360	$ 234,832	$ 258,110		Demand Revenue ($000)
30	Demand ($000)	$ 33,158	$ 24,943	$ 53,032	$ 51,062	$ 43,049	$ 31,993	$ 22,104	$ 4,918	$ 14,736	$ 51,659	$ 67,035	$ 48,629	$	446,317
31														$	6,725,134
32															Tier 1 Non-Slice PF Public RR minus Tier 2 Costs
33														**$**	**6,006,648**
34															Tier 1 RR less Demand Revenue ($000) [BLFRnD]
35														$	5,560,331
36	Non-Slice Tier 1 PF Rate Equivalent	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Load Shaping True-up Rate (mills/kWh) [LSTUR]
37	HLH (mills/kWh)	46.04	34.94	43.04	38.97	40.84	24.60	17.74	4.01	10.51	46.39	49.21	55.92		4.59
38	LLH (mills/kWh)	44.26	37.05	44.20	39.21	44.59	29.95	22.50	8.14	11.49	43.47	45.73	54.47		
39	Demand ($/kW/mo)	13.81	10.78	12.99	11.88	12.39	7.97	6.09	2.35	4.12	13.91	14.67	16.51		
40															
41															
42															
43	Classic Rate Design Revenues	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Allocated Cost Energy ($000)
44	HLH ($000)	$ 337,662	$ 279,224	$ 426,381	$ 382,701	$ 352,316	$ 214,459	$ 127,276	$ 26,073	$ 70,255	$ 352,240	$ 377,810	$ 381,484	$	5,560,771
45	LLH ($000)	$ 198,536	$ 210,109	$ 291,448	$ 269,232	$ 249,526	$ 165,614	$ 101,938	$ 36,112	$ 45,129	$ 213,786	$ 213,412	$ 238,050		Allocated Cost Demand ($000)
46	Demand ($000)	$ 33,158	$ 24,943	$ 53,032	$ 51,062	$ 43,049	$ 31,993	$ 22,104	$ 4,918	$ 14,736	$ 51,659	$ 67,035	$ 48,629	$	446,317
47														$	6,007,088

	Average Non-Slice Tier 1 Rate		
48			
49		($000)	(mills/kWh)
50	Allocated Cost Energy	$ 5,560,771	35.55
51	Allocated Cost Demand	$ 446,317	2.85
52	Total Allocated Costs	$ 6,007,088	38.40
53			
54	Tier 1 Energy (GWh) [FAT1L]		156,443
55	Load Shaping True-up Rate (mills/kWh) [LSTUR]		4.59

Table 3.2
Summary of RSS Revenue Credits for Tier 1 Cost Pools

	A	B	C	D	E	F	G
1	TRM	COSA	AggregationKey	Category	FY2026	FY2027	FY2028
2	C	RDS	CNTA	Augmentation RSS & RSC Adder	$ 2,631	$ 2,631	$ 2,635
3	C	RDS	CD2RCF	Composite Augmentation RSS Revenue Debit/(Credit)	$ (1,560)	$ (1,560)	$ (1,561)
4	2.0	RDS	2D2RCF	Composite Tier 2 RSS Revenue Debit/(Credit)	$ -	$ -	$ -
5	C	RDS	CD2RCN	Composite Non-Federal RSS Revenue Debit/(Credit)	$ (1,293)	$ (3,064)	$ (3,434)
6	N	RDS	ND2RNF	Non-Slice Augmentation RSC Revenue Debit/(Credit)	$ (1,071)	$ (1,070)	$ (1,074)
7	2.0	RDS	2D2RNF	Non-Slice Tier 2 RSC Revenue Debit/(Credit)	$ -	$ -	$ -
8	N	RDS	ND2RNN	Non-Slice Non-Federal RSC Revenue Debit/(Credit)	$ 457	$ (2,518)	$ (1,405)

Table 3.3
Tier 2 Purchases Made by BPA

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1	**Start_ Date**	**Maturity_ Date**	**Trade_ Date**	**Internal_ Portfolio**	**Tran_ Status**	**Hours**	**Price**	**Revenue**	**Position**	**Choice**	**Product**	**Term**	**Description**	**Reference**	**Buy_ Sell**	**Pt_of_ Receipt**
2	No FY 2026, FY 2027 and FY 2028 Tier 2 purchases as of November 1, 2024.															

Table 3.4
Inputs to TSS Monthly Rate and Charge

	A	B	B	C	D	D	E	F	F
1	FY2026 PTK + PTFR Scheduling Costs	FY2027 PTK + PTFR Scheduling Costs	FY2028 PTK + PTFR Scheduling Costs	FY2021 Scheduled (MWh)	FY2022 Scheduled (MWh)	FY2023 Scheduled (MWh)	FY2021 Number of Transactions	FY2022 Number of Transactions	FY2023 Number of Transactions
2	$3,899,631	$4,032,118	$4,167,216	35,789,630	36,444,506	28,989,084	112,833	124,328	112,432

Table 3.5.1
Tier 2 Short-Term Rate Costing Table

	A	B	C	B
1		ST.4.2025_2028	ST.4.2025_2028	ST.4.2025_2028
2	Hours	8760	8760	8784
3	Fiscal Year	FY2026	FY2027	FY2028
4	Rate Period	BP-26		
5	Total Forecast Expected Cost	$ 321,834,152	$ 331,679,609	$ 355,834,167
6	Base Power Purchase Cost (Provided by PTL)	$ -	$ -	$ -
7	Power Purchase Cost	$ -	$ -	$ -
8	Transmission	$ -	$ -	$ -
9	Third Party PTP	$ -	$ -	$ -
10	Ancillary Services	$ -	$ -	$ -
11	Scheduling, System Control, Dispatch Services			
12	Operating Reserves (Spinning and Non-Spinning)			
13	Within Hour Balancing			
14	Other BA Losses	$ -	$ -	$ -
15	Rate Design Components	$ 8,544,944	$ 9,952,527	$ 10,787,936
16	Resource Support Services	$ 546,546	$ 590,537	$ 630,745
17	Diurnal Flattening Service	$ -	$ -	$ -
18	DFS Energy (Variable)	$ -	$ -	$ -
19	DFS Capacity (Fixed)	$ -	$ -	$ -
20	Forced Outage Reserve	$ -	$ -	$ -
21	Forced Outage Reserve Capacity (Fixed)	$ -	$ -	$ -
22	Transmission Scheduling Services	$ 546,546	$ 590,537	$ 630,745
23	Transmission Curtailment Management Service Capacity (Fixed)	$ -	$ -	$ -
24	Transmission Curtailment Management Service Energy (Variable)	$ -	$ -	$ -
25	Alternative Transmission Path Costs	$ -	$ -	$ -
26	Generation Imbalance	$ -	$ -	$ -
27	TSS - Overhead	$ 546,546	$ 590,537	$ 630,745
28	Resource Shaping Charge	$ -	$ -	$ -
29	Tier 2 Overhead	$ 7,998,398	$ 9,361,991	$ 10,157,191
30	Risk Adder	$ -	$ -	$ -
31	Carbon Costs Pass Through	$ -	$ -	$ -
32	Renewable Energy Credits (MWh)	0	0	0
33	Quantity Purchased (MWh)	0	0	0
34	Tier 2 Obligation w/o losses (Billing Determinant)	4,554,551	4,921,140	5,256,212
35	Tier 2 Obligation w losses	4,705,600	5,084,348	5,430,532
36	Energy (Short)/Long (MWh)	-4,705,600	-5,084,348	-5,430,532
37	Composite Cost Pool Augmentation (MWh) - BP12 Only			
38	Energy Short (MWh)	-4,705,600	-5,084,348	-5,430,532
39	Energy to be Remarketed (MWh)	0	0	0
40	Remarketing Available (MWh)	51,544	42,355	33,341
41	Total Tier 2 Pool Shortfall (MWh)	-4,849,413	-5,249,815	-5,607,354
42	Augmentation Price ($/MWh)	52	49	49
43	Flat Block RSC ($/MWh)	0	0	0
44	Remarketing Value ($/MWh)	67	63	64
45	Remarketed Purchase (MWh)	50,015	41,020	32,289
46	Remarketed Purchase Cost	3,329,914	2,595,638	2,051,598
47	Remaining Shortfall (MWh)	-4,655,585	-5,043,328	-5,398,243
48	Remaining Shortfall Cost	309,959,294	319,131,443	342,994,633
49	Tier 2 Balancing Adjustment Debit/(Credit) - BP12 Only			
50	Remarketing Treatment (Remove From Rate) (Yes or No)	No	No	No
51	Additional Remarketing (MWh)			
52	Total Fixed Costs	$ 321,834,152	$ 331,679,609	$ 355,834,167
53	Billing Components			
54	ShortTerm ($/MWh)	$ 32.13	$ 30.73	$ 67.70
55	Remarketing Credit	$ 1.03	$ 0.99	$ -
56	Remarketing Charge	$ -	$ -	$ -
57	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (7,998,398)	$ (9,361,991)	$ (10,157,191)
58	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -	$ -
59	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (546,546)	$ (590,537)	$ (630,745)

Table 3.5.2
Tier 2 Load Growth Rate Costing Table

	A			
1		LG.1.2012_2028	LG.1.2012_2028	LG.1.2012_2028
2	Hours	8,760	8,760	8,784
3	Fiscal Year	FY2026	FY2027	FY2028
4	Rate Period		BP-26	
5	Total Forecast Expected Cost	$ 9,835,920	$ 10,794,352	$ 11,586,209
6	Base Power Purchase Cost (Provided by PTL)	$ -	$ -	$ -
7	Power Purchase Cost	$ -	$ -	$ -
8	Transmission	$ -	$ -	$ -
9	Third Party PTP	$ -	$ -	$ -
10	Ancillary Services	$ -	$ -	$ -
11	Scheduling, System Control, Dispatch Services	$ -	$ -	$ -
12	Operating Reserves (Spinning and Non-Spinning)	$ -	$ -	$ -
13	Within Hour Balancing	$ -	$ -	$ -
14	Other BA Losses	$ -	$ -	$ -
15	Rate Design Components	$ 261,151	$ 323,900	$ 351,263
16	Resource Support Services	$ 16,704	$ 19,219	$ 20,538
17	Diurnal Flattening Service	$ -	$ -	$ -
18	DFS Energy (Variable)	$ -	$ -	$ -
19	DFS Capacity (Fixed)	$ -	$ -	$ -
20	Forced Outage Reserve	$ -	$ -	$ -
21	Forced Outage Reserve Capacity (Fixed)	$ -	$ -	$ -
22	Transmission Scheduling Services	$ 16,704	$ 19,219	$ 20,538
23	Transmission Curtailment Management Service Capacity (Fixed)	$ -	$ -	$ -
24	Transmission Curtailment Management Service Energy (Variable)	$ -	$ -	$ -
25	Alternative Transmission Path Costs	$ -	$ -	$ -
26	Generation Imbalance	$ -	$ -	$ -
27	TSS - Overhead	$ 16,704	$ 19,219	$ 20,538
28	Resource Shaping Charge	$ -	$ -	$ -
29	Tier 2 Overhead	$ 244,448	$ 304,681	$ 330,725
30	Risk Adder	$ -	$ -	$ -
31	Carbon Costs Pass Through	$ -	$ -	$ -
32	Renewable Energy Credits (MWh)	0	0	0
33	Quantity Purchased (MWh)			
34	Tier 2 Obligation w/o losses (Billing Determinant)			
35	Tier 2 Obligation w losses			
36	Energy (Short)/Long (MWh)			
37	Composite Cost Pool Augmentation (MWh) - BP12 Only			
38	Energy Short (MWh)	-143,813	-165,468	-176,822
39	Energy to be Remarketed (MWh)	0	0	0
40	Remarketing Available (MWh)	51,544	42,355	33,341
41	Total Tier 2 Pool Shortfall (MWh)	-4,849,413	-5,249,815	-5,607,354
42	Augmentation Price ($/MWh)	$ 52.03	$ 48.73	$ 49.03
43	Flat Block RSC ($/MWh)	$ -	$ -	$ -
44	Remarketing value ($/MWh)	$ 66.58	$ 63.28	$ 63.54
45	Remarketed Purchase (MWh)	1,529	1,335	1,051
46	Remarketed Purchase Cost	101,769	84,474	66,801
47	Remaining Shortfall (MWh)	-142,284	-164,133	-175,771
48	Remaining Shortfall Cost	$ 9,473,000	$ 10,385,978	$ 11,168,144
49	Tier 2 Balancing Adjustment Debit/(Credit) - BP12 Only	$ -	$ -	$ -
50	Remarketing Treatment (Remove From Rate) (Yes or No)	No	No	No
51	Additional Remarketing - Vintage Only (MWh)	0	0	0
52	Total Fixed Costs	$ 9,835,920	$ 10,794,352	$ 11,586,209
53	Billing Components			
54	LoadGrowth ($/MWh)	$ 70.66	$ 67.40	$ 67.70
55	Remarketing Credit	$ -	$ -	$ -
56	Remarketing Charge	$ -	$ -	$ -
57	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (244,448)	$ (304,681)	$ (330,725)
58	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -	$ -
59	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (16,704)	$ (19,219)	$ (20,538)

Table 3.6
Tier 2 Overhead Adder Inputs

	A	B	C	D	E	B	C
1		**BP-26**					
2		**FY2026**		**FY2027**		**FY2028**	
3	**Line Item**	**FY2026**	**Total Forecast Sales (MWh)**	**FY2027**	**Total Forecast Sales (MWh)**	**FY2028**	**Total Forecast Sales (MWh)**
4	Generation Project Coordination	$ 4,500,604	82,723,766	$ 4,615,255	82,258,029	$ 4,732,001	83,962,545
5	Sales & Support	$ 14,504,106		$ 15,022,436		$ 15,566,940	
6	Power Internal Support	$ 23,019,606		$ 23,701,336		$ 24,425,275	
7	Strategy, Finance & Risk Mgmt	$ 4,385,207		$ 6,495,503		$ 6,364,334	
8	Agency Services G&A	$ 98,864,431		$ 106,653,367		$ 111,162,046	
9	Total Costs	$ 145,273,954		$ 156,487,898		$ 162,250,596	
10	**Total Costs Divided by Total Sales**		$ 1.76		$ 1.90		$ 1.93

Table 3.7
Tier 2 Rate Revenues

	A	B	C	B
1	Hours	8,760	8,760	8,784
2	Fiscal Year	FY2026	FY2027	FY2028
3	Rate Period		BP-26	
4	ShortTerm Rate $/MWh	$ 70.66	$ 67.40	$ 67.70
5	LoadGrowth Rate $/MWh	$ 70.66	$ 67.40	$ 67.70
6	Vintage Rate $/MWh	$ -	$ -	$ -
7				
8	**ShortTerm**			
9	Portfolio Purchased aMW	0.000	0.000	0.000
10	Portfolio Purchased MWh	0	0	0
11	Portfolio Obligation w/ Losses aMW	537	580	618
12	Portfolio Obligation w/ Losses MWh	4,705,600	5,084,348	5,430,532
13	Portfolio Billing Determinant aMW	520	562	598
14	Portfolio Billing Determinant MWh	4,554,551	4,921,140	5,256,212
15	RECs MWh	0	0	0
16	Base Power Purchase Cost	$ -	$ -	$ -
17	Rate Design Components	$ 8,544,944	$ 9,952,527	$ 10,787,936
18	Other Costs	$ -	$ -	$ -
19	Rate $/MWh	$ 70.66	$ 67.40	$ 67.70
20	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (7,998,398)	$ (9,361,991)	$ (10,157,191)
21	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -	$ -
22	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (546,546)	$ (590,537)	$ (630,745)
23	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -	$ -
24	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -	$ -
25	Total Short Term Rate Revenue	$ 321,824,550	$ 331,684,852	$ 355,845,568
26	Remarketing Credit	$ -	$ -	$ -
27	Remarketing Charge	$ -	$ -	$ -
28	Forecast Power Purchase Costs	$ 309,959,294	$ 319,131,443	$ 342,994,633
29				
30	**LoadGrowth**			
31	Portfolio Purchased aMW	0.000	0.000	0.000
32	Portfolio Purchased MWh	0	0	0
33	Portfolio Obligation /w Losses aMW	16.417	18.889	20.130
34	Portfolio Obligation /w Losses MWh	143,813	165,468	176,822
35	Portfolio Billing Determinant aMW	15.890	18.283	19.484
36	Portfolio Billing Determinant MWh	139,197	160,156	171,146
37	RECs MWh	0	0	0
38	Base Power Purchase Cost	$ -	$ -	$ -
39	Rate Design Components	$ 261,151	$ 323,900	$ 351,263
40	Other Costs	$ -	$ -	$ -
41	Rate $/MWh	$ 70.66	$ 67.40	$ 67.70
42	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (244,448)	$ (304,681)	$ (330,725)
43	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -	$ -
44	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (16,704)	$ (19,219)	$ (20,538)
45	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -	$ -
46	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -	$ -
47	Total Load Growth Rate Revenue	$ 9,835,626	$ 10,794,523	$ 11,586,580
48	Remarketing Credit	$ -	$ -	$ -
49	Remarketing Charge	$ -	$ -	$ -
50	Forecast Power Purchase Costs	$ 9,473,000	$ 10,385,978	$ 11,168,144
51				
52	**Total Costs**			
53	Total Base Power Purchase Cost	$ -	$ -	$ -
54	Total Rate Design Components	$ 8,806,095	$ 10,276,428	$ 11,139,199

Table 3.7 Continued
Tier 2 Rate Revenues

55	Total Other Costs	$ -	$ -	$ -
56	Forecast Power Purchase Costs	$ 319,432,294	$ 329,517,422	$ 354,162,778
57	Total Cost	$ 328,238,389	$ 339,793,849	$ 365,301,976
58				
59	**Total Revenue**			
60	Total Tier 2 Rate Revenue Collection	$ 331,660,177	$ 342,479,375	$ 367,432,148
61	Total Tier 2 Remarketing Charge	$ -	$ -	$ -
62	Total Tier 2 Remarketing Credit	$ -	$ -	$ -
63	Non-Federal Remarketing Credit	$ (3,431,683)	$ (2,680,112)	$ (2,118,399)
64	Total Revenue	$ 328,228,494	$ 339,799,263	$ 365,313,749
65	Value of BPA Purchased Remarketing	$ -	$ -	$ -
66	Total Tier 2 Revenue and Value of BPA Purchased Remarketing	$ 328,228,494	$ 339,799,263	$ 365,313,749
67				
68	Total Tier 2 Adjustments and Credits*			
69	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (244,448)	$ (304,681)	$ (330,725)
70	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -	$ -
71	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (16,704)	$ (19,219)	$ (20,538)
72	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -	$ -
73	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -	$ -
74				
75	*This amount is in addition to any RSS credits that result from the RSS model			

Table 3.8
Total Remarketing Charges and Credits

	A	B	C	D
1	Rate Period	BP-26		
2	Fiscal Year	FY2026	FY2027	FY2028
3	ShortTerm Remarket (MWh)	0	0	0
4	LoadGrowth Remarket (MWh)	0	0	0
5	Vintage Remarket (MWh)			
6	Non-Federal Remarket (MWh)	51,544	42,355	33,341
7	Total	51,544	42,355	33,341
8				
9	ShortTerm Purchase of Remarket (MWh)	50,015	41,020	32,289
10	LoadGrowth Purchase of Remarket (MWh)	1,529	1,335	1,051
11	Vintage Purchase of Remarket (MWh)			
12	BPA Purchase of Remarket (MWh)	0	0	0
13	Total	51,544	42,355	33,341
14				
15	ShortTerm Remarket Credit	$ -	$ -	$ -
16	ShortTerm Remarket Charge	$ -	$ -	$ -
17	LoadGrowth Remarket Credit	$ -	$ -	$ -
18	LoadGrowth Remarket Charge	$ -	$ -	$ -
19	Vintage Remarket Credit			
20	Vintage Remarket Charge			
21	Non-Federal Resource Remarketing Credit	$ 3,431,683	$ 2,680,112	$ 2,118,399
22				
23	ShortTerm Open Position (MWh)	4,655,585	5,043,328	5,398,243
24	LoadGrowth Open Position (MWh)	142,284	164,133	175,771
25	Vintage Opern Position (MWh)			
26	BPA Purchase of Remarket (MWh)	0	0	0
27	Total Open Position (MWh)	4,797,870	5,207,461	5,574,014

Table 3.9
Tier 2 Rate Inputs

	A	B	C	D	E	F
1	**Fiscal Year**	**TSS Rate ($/MWh)**	**Aurora P10 Price ($/MWh)**	**Capacity Price ($/MWh)**	**Remarketing Value ($/MWh)**	**Available Non-Federal Resource Remarketing (MWh)**
2	FY 2026	$ 0.12	$ 52.03	$ 14.55	$ 66.58	51,544
3	FY 2027	$ 0.12	$ 48.73	$ 14.55	$ 63.28	42,355
4	FY 2028	$ 0.12	$ 49.03	$ 14.51	$ 63.54	33,341

Table 3.10
Remarketing Value Inputs

	A	B	C	D
	Fiscal Year	**Aurora P10 Price ($/MWh)**	**Capacity Price ($/MWh)**	**Remarketing Value ($/MWh)**
1	FY 2026	52.03	14.55	66.58
2	FY 2027	48.73	14.55	63.28
3	FY 2028	49.03	14.51	63.54

Table 3.11.1
RSS and Related Charges

	A	B	C	D	E	F	G	H
1	**Purchaser**	**Resource Name**	**Services & RSC**	**Applicable Year(s)**	**"ResourceInput" Tab Adj. for Schedule Annual aMW**	**Exh. A FY2026 Annual aMW**	**Exh. A FY2027 Annual aMW**	**Exh. A FY2028 Annual aMW**
2	Tier 1	Klondike 3 (07PB-11860)	DFS TSS TCMS RSC	FY2026&FY2028	13.349	13.944	13.944	$ 13.94
3	City of Bonners Ferry	Moyie	GMS	FY2026&FY2028	N/A	1.881	1.881	$ 1.88
4	City of Centralia	Yelm Hydro	GMS	FY2026&FY2028	N/A	7.114	7.114	$ 7.13
5	City of Forest Grove	Priest Rapids	SCS	FY2026&FY2028	N/A	1.577	1.577	$ 1.58
6	City of Forest Grove	Wanapum	SCS	FY2026&FY2028	N/A	1.600	1.600	$ 1.60
7	The City of McMinnville, a municipal corporation of the State of Oregon, acting by and through its Water and Light Commission	Priest Rapids	SCS	FY2026&FY2028	N/A	1.577	1.577	$ 1.58
8	The City of McMinnville, a municipal corporation of the State of Oregon, acting by and through its Water and Light Commission	Wanapum	SCS	FY2026&FY2028	N/A	1.600	1.600	$ 1.60
9	The City of McMinnville, a municipal corporation of the State of Oregon, acting by and through its Water and Light Commission	Riverbend Biogas	DFS FOR RSC	FY2026&FY2028	3.222	3.253	3.019	$ 2.80
10	City of Milton-Freewater	Priest Rapids	SCS	FY2026&FY2028	N/A	1.577	1.577	$ 1.58
11	City of Milton-Freewater	Wanapum	SCS	FY2026&FY2028	N/A	1.600	1.600	$ 1.60
12	Public Utility District No. 1 of Clallam County	Packwood	DFS FOR TSS TCMS RSC	FY2026&FY2028	0.806	0.460	0.460	$ 0.46
13	Columbia REA	Walla Walla Hydro	DFS FOR RSC	FY2026&FY2028	0.896	1.231	1.231	$ 1.23
14	PNGC	Flathead LFGTE	DFS FOR RSC	FY2026&FY2028	1.858	1.077	1.077	$ 1.08
15	PNGC	Stoltze Lumber	DFS FOR RSC	FY2026&FY2028	1.931	2.500	2.500	$ 2.51
16	PNGC	Lake Creek	SCS	FY2026&FY2028	N/A	1.530	1.530	$ 1.53
17	PNGC	Chester Hydro	DFS FOR RSC	FY2026&FY2028	0.893	0.967	0.967	$ 0.97
18	PNGC	Island Park	SCS	FY2026&FY2028	N/A	0.992	0.992	$ 0.99
19	Richland	Horn Rapids Solar	DFS TSS TCMS RSC	FY2026&FY2028	0.632	0.582	0.582	$ 0.58
20	Public Utility District No. 3 of Mason County	Packwood	SCS TSS TCMS	FY2026&FY2028	N/A	0.656	0.656	$ 0.66
21	Public Utility District No. 3 of Mason County	Nine Canyon Wind	DFS TSS TCMS RSC	FY2026&FY2028	0.705	0.717	0.717	$ 0.72
22	Public Utility District No. 3 of Mason County	White Creek Wind	DFS TSS TCMS RSC	FY2026&FY2028	0.963	0.920	0.920	$ 0.11
23	Public Utility District No. 1 of Kittitas County	Priest Rapids	SCS	FY2026&FY2028	N/A	0.526	0.526	$ 0.53
24	Public Utility District No. 1 of Kittitas County	Wanapum	SCS	FY2026&FY2028	N/A	0.533	0.533	$ 0.53
25	Northern Wasco County People's Utility District	NLSL Unspecified Resource Amounts	TSS TCMS	FY2026&FY2028	N/A	170.821	194.303	$ 216.67
26	Northern Wasco County People's Utility District	Unspecified Resource Amounts	TSS TCMS	FY2026&FY2028	N/A	16.000	16.000	$ 16.00
27	Northern Wasco County People's Utility District	McNary Fishway	GMS TSS	FY2026&FY2028	N/A	4.404	4.404	$ 4.42
28	Klickitat	McNary Fishway	SCS TSS TCMS	FY2026&FY2028	N/A	4.222	4.222	$ 4.23
29	Klickitat	Packwood	SCS TSS TCMS	FY2026&FY2028	N/A	0.197	0.197	$ 0.20
30	Benton PUD	Packwood	SCS TSS	FY2026&FY2028	N/A	0.919	0.919	$ 0.92
31	Mission Valley Power	Kerr Dam	TSS	FY2026&FY2028	N/A	2.189	2.189	$ 2.19
32	Snohomish PUD	Jackson	SCS	FY2026&FY2028	N/A	29.478	29.478	$ 29.49
33	Snohomish PUD	Packwood	SCS TSS	FY2026&FY2028	N/A	1.313	1.313	$ 1.31
34	Snohomish PUD	Youngs Creek	DFS FOR RSC	FY2026&FY2028	1.932	1.369	1.368	$ 1.37
35	Harney County PUD	Harney Solar	DFS TSS TCMS RSC	FY2028	1.310	0.000	1.360	$ 1.36
36	PNGC	Stateline Wind FY2028	DFS TSS TCMS RSC	FY2028	19.440	0.000	20.850	$ 20.85
37	Emerald	Short Mountain	DFS FOR RSC	FY2026	2.616	2.549	2.549	$ -

Table 3.11.2

RSS and Related Charges

	A	I	J	K	L	M	N	O	P	Q	R	S	T
1	**Purchaser**	**DFS Energy Rate $/MWh**	**DFS Capacity Charge $/mo**	**DFS Capacity $/MWh Equiv.**	**RSC $/mo**	**RSC $/MWh Equiv.**	**FOR Capacity $/mo**	**FOR Capacity $/MWh Equiv.**	**TSS $/mo**	**TSS $/MWh Equiv.**	**TCMS $/mo**	**TCMS $/MWh Equiv.**	**SCS $/mo**
2	Tier 1	$ 4.25	$ 129,018	$ 13.24	$ 48,123	$ 4.94	$ -	$ -	$ 1,023	$ 0.11	$ -	$ -	$ -
3	City of Bonners Ferry	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	City of Centralia	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	City of Forest Grove	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 852
6	City of Forest Grove	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 861
7	The City of McMinnville, a municipal corporation of the State of Oregon, acting by and through its Water and Light Commission	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 852
8	The City of McMinnville, a municipal corporation of the State of Oregon, acting by and through its Water and Light Commission	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 861
9	The City of McMinnville, a municipal corporation of the State of Oregon, acting by and through its Water and Light Commission	$ 0.15	$ 6,543	$ 2.78	$ (7,028)	$ (2.99)	$ 1,930	$ 0.82	$ -	$ -	$ -	$ -	$ -
10	City of Milton-Freewater	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 852
11	City of Milton-Freewater	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 861
12	Public Utility District No. 1 of Clallam County	$ 1.51	$ 4,481	$ 7.61	$ (9,517)	$ (16.17)	$ 153	$ 0.26	$ 40	$ 0.07	$ -	$ -	$ -
13	Columbia REA	$ 0.75	$ 2,795	$ 4.28	$ 9,307	$ 14.24	$ 347	$ 0.53	$ -	$ -	$ -	$ -	$ -
14	PNGC	$ 0.48	$ 7,741	$ 5.71	$ (24,254)	$ (17.88)	$ 825	$ 0.61	$ -	$ -	$ -	$ -	$ -
15	PNGC	$ 0.32	$ 9,302	$ 6.60	$ 4,327	$ 3.07	$ 1,073	$ 0.76	$ -	$ -	$ -	$ -	$ -
16	PNGC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 585
17	PNGC	$ 0.43	$ 2,491	$ 3.82	$ 2,900	$ 4.45	$ 310	$ 0.48	$ -	$ -	$ -	$ -	$ -
18	PNGC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 459
19	Richland	$ 4.48	$ 6,717	$ 14.55	$ (9)	$ (0.02)	$ -	$ -	$ 51	$ 0.11	$ -	$ -	$ -
20	Public Utility District No. 3 of Mason County	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 58	$ 0.12	$ -	$ -	$ 311
21	Public Utility District No. 3 of Mason County	$ 4.68	$ 6,841	$ 13.30	$ 1,713	$ 3.33	$ -	$ -	$ 63	$ 0.12	$ -	$ -	$ -
22	Public Utility District No. 3 of Mason County	$ 4.23	$ 9,237	$ 13.14	$ (10,874)	$ (15.46)	$ -	$ -	$ 45	$ 0.06	$ -	$ -	$ -
23	Public Utility District No. 1 of Kittitas County	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 284
24	Public Utility District No. 1 of Kittitas County	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 287
25	Northern Wasco County People's Utility District	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,023	$ 0.01	$ -	$ -	$ -
26	Northern Wasco County People's Utility District	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,404	$ 0.12	$ -	$ -	$ -
27	Northern Wasco County People's Utility District	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 386	$ 0.12	$ -	$ -	$ -
28	Klickitat	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 370	$ 0.12	$ -	$ -	$ 2,233
29	Klickitat	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 21	$ 0.15	$ -	$ -	$ 93
30	Benton PUD	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 81	$ 0.12	$ -	$ -	$ 435
31	Mission Valley Power	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 192	$ 0.12	$ -	$ -	$ -
32	Snohomish PUD	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
33	Snohomish PUD	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 115	$ 0.12	$ -	$ -	$ -
34	Snohomish PUD	$ 2.79	$ 17,613	$ 12.49	$ (25,720)	$ (18.23)	$ 74	$ 0.05	$ -	$ -	$ -	$ -	$ -
35	Harney County PUD	$ 4.66	$ 13,918	$ 14.55	$ 2,447	$ 2.56	$ -	$ -	$ 119	$ 0.12	$ -	$ -	$ -
36	PNGC	$ 5.03	$ 171,784	$ 12.11	$ 85,116	$ 6.00	$ -	$ -	$ 1,023	$ 0.07	$ -	$ -	$ -
37	Emerald	$ 0.30	$ 7,248	$ 3.79	$ (1,003)	$ (0.53)	$ 1,399	$ 0.73	$ -	$ -	$ -	$ -	$ -

Table 3.11.3

RSS and Related Charges

	A	U	V	W	X	Y	Z	AA	AB	AC	AD
1	**Purchaser**	**SCS $/MWh Equiv.**	**GMS $/mo**	**GMS $/MWh Equiv.**	**Revenue Credit to Composite Cost Pool FY2026**	**Revenue Credit to Non-Slice Cost Pool FY2026**	**Revenue Credit to Composite Cost Pool FY2027**	**Revenue Credit to Non-Slice Cost Pool FY2027**	**Revenue Credit to Composite Cost Pool FY2028**	**Revenue Credit to Non-Slice Cost Pool FY2028**	**Forecast Total $/MWh Equivalent Rate**
2	Tier 1	$ -	$ -	$ -	$ 1,560,492	$ 1,074,380	$ 1,560,266	$ 1,066,870	$ 1,560,492	$ 1,074,380	$ 22.54
3	City of Bonners Ferry	$ -	$ 774	$ 0.56	$ 9,285	$ -	$ 9,285	$ -	$ 9,285	$ -	$ 0.56
4	City of Centralia	$ -	$ 3,901	$ 0.75	$ 46,808	$ -	$ 46,807	$ -	$ 46,808	$ -	$ 0.75
5	City of Forest Grove	$ 0.74	$ -	$ -	$ 10,220	$ -	$ 10,222	$ -	$ 10,220	$ -	$ 0.74
6	City of Forest Grove	$ 0.74	$ -	$ -	$ 10,331	$ -	$ 10,332	$ -	$ 10,331	$ -	$ 0.74
7	The City of McMinnville, a municipal corporation of the State of Oregon, acting by and through its Water and Light Commission	$ 0.74	$ -	$ -	$ 10,220	$ -	$ 10,222	$ -	$ 10,220	$ -	$ 0.74
8	The City of McMinnville, a municipal corporation of the State of Oregon, acting by and through its Water and Light Commission	$ 0.74	$ -	$ -	$ 10,331	$ -	$ 10,332	$ -	$ 10,331	$ -	$ 0.74
9	The City of McMinnville, a municipal corporation of the State of Oregon, acting by and through its Water and Light Commission	$ -	$ -	$ -	$ 101,682	$ (80,062)	$ 101,682	$ (44,189)	$ 101,682	$ (80,062)	$ 0.76
10	City of Milton-Freewater	$ 0.74	$ -	$ -	$ 10,220	$ -	$ 10,222	$ -	$ 10,220	$ -	$ 0.74
11	City of Milton-Freewater	$ 0.74	$ -	$ -	$ 10,331	$ -	$ 10,332	$ -	$ 10,331	$ -	$ 0.74
12	Public Utility District No. 1 of Clallam County	$ -	$ -	$ -	$ 56,086	$ (103,526)	$ 56,045	$ (103,953)	$ 56,086	$ (103,526)	$ (6.72)
13	Columbia REA	$ -	$ -	$ -	$ 37,704	$ 117,597	$ 37,704	$ 116,401	$ 37,704	$ 117,597	$ 19.80
14	PNGC	$ -	$ -	$ -	$ 102,793	$ (283,207)	$ 102,793	$ (284,300)	$ 102,793	$ (283,207)	$ (11.08)
15	PNGC	$ -	$ -	$ -	$ 124,500	$ 57,273	$ 124,500	$ 54,880	$ 124,500	$ 57,273	$ 10.75
16	PNGC	$ 0.52	$ -	$ -	$ 7,020	$ -	$ 7,020	$ -	$ 7,020	$ -	$ 0.52
17	PNGC	$ -	$ -	$ -	$ 33,612	$ 38,158	$ 33,612	$ 37,322	$ 33,612	$ 38,158	$ 9.18
18	PNGC	$ 0.63	$ -	$ -	$ 5,505	$ -	$ 5,505	$ -	$ 5,505	$ -	$ 0.63
19	Richland	$ -	$ -	$ -	$ 81,217	$ 24,706	$ 81,165	$ 24,195	$ 81,217	$ 24,706	$ 19.12
20	Public Utility District No. 3 of Mason County	$ 0.65	$ -	$ -	$ 4,421	$ -	$ 4,361	$ -	$ 4,421	$ -	$ 0.77
21	Public Utility District No. 3 of Mason County	$ -	$ -	$ -	$ 82,847	$ 49,449	$ 82,783	$ 48,708	$ 82,847	$ 49,449	$ 21.43
22	Public Utility District No. 3 of Mason County	$ -	$ -	$ -	$ 111,386	$ (94,759)	$ 111,730	$ 44,509	$ 111,386	$ (94,759)	$ 1.97
23	Public Utility District No. 1 of Kittitas County	$ 0.74	$ -	$ -	$ 3,406	$ -	$ 3,407	$ -	$ 3,406	$ -	$ 0.74
24	Public Utility District No. 1 of Kittitas County	$ 0.74	$ -	$ -	$ 3,444	$ -	$ 3,445	$ -	$ 3,444	$ -	$ 0.74
25	Northern Wasco County People's Utility District	$ -	$ -	$ -	$ 12,276	$ -	$ 12,050	$ -	$ 12,276	$ -	$ 0.01
26	Northern Wasco County People's Utility District	$ -	$ -	$ -	$ 16,842	$ -	$ 15,418	$ -	$ 16,842	$ -	$ 0.12
27	Northern Wasco County People's Utility District	$ -	$ 2,329	$ 0.72	$ 32,590	$ -	$ 32,197	$ -	$ 32,590	$ -	$ 0.84
28	Klickitat	$ 0.72	$ -	$ -	$ 31,242	$ -	$ 30,868	$ -	$ 31,242	$ -	$ 0.84
29	Klickitat	$ 0.65	$ -	$ -	$ 1,424	$ -	$ 1,405	$ -	$ 1,324	$ -	$ 0.80
30	Benton PUD	$ 0.65	$ -	$ -	$ 6,190	$ -	$ 6,109	$ -	$ 6,190	$ -	$ 0.77
31	Mission Valley Power	$ -	$ -	$ -	$ 2,301	$ -	$ 2,109	$ -	$ 2,301	$ -	$ -
32	Snohomish PUD	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
33	Snohomish PUD	$ -	$ -	$ -	$ 1,382	$ -	$ 2,109	$ -	$ 1,382	$ -	$ 0.12
34	Snohomish PUD	$ -	$ -	$ -	$ 212,248	$ (261,378)	$ 212,248	$ (262,114)	$ 212,248	$ (261,378)	$ (2.90)
35	Harney County PUD	$ -	$ -	$ -	$ -	$ -	$ 169,125	$ 81,358	$ 168,450	$ 82,821	$ 21.89
36	PNGC	$ -	$ -	$ -	$ -	$ -	$ 1,595,685	$ 2,913,795	$ 2,073,684	$ 1,878,797	$ 23.21
37	Emerald	$ -	$ -	$ -	$ 103,761	$ (5,148)	$ 103,761	$ (5,252)	$ -	$ -	$ 4.29

Table 3.12
Calculation of ESS Revenue Forecast

	B	C	D	E	F	G	H
5		**Demand Rate**	**NLSL Peak**	**Election**	**Capacity**	**Capacity BD**	**Revenue**
6		*$ per kW-mo*	*MW*	*Average %*	*MW*	*kW*	*$1000s*
7	Oct-25	$ 13.81	1,518.15	5%	75.91	75,907	$ 1,048
8	Nov-25	$ 10.78	1,512.02	5%	75.60	75,601	$ 815
9	Dec-25	$ 12.99	1,418.42	5%	70.92	70,921	$ 921
10	Jan-26	$ 11.88	1,362.38	5%	68.12	68,119	$ 809
11	Feb-26	$ 12.39	1,403.55	5%	70.18	70,177	$ 869
12	Mar-26	$ 7.97	1,380.02	5%	69.00	69,001	$ 550
13	Apr-26	$ 6.09	1,412.79	5%	70.64	70,639	$ 430
14	May-26	$ 2.35	1,521.16	5%	76.06	76,058	$ 179
15	Jun-26	$ 4.12	1,577.81	5%	78.89	78,891	$ 325
16	Jul-26	$ 13.91	1,640.55	5%	82.03	82,028	$ 1,141
17	Aug-26	$ 14.67	1,573.07	5%	78.65	78,654	$ 1,154
18	Sep-26	$ 16.51	1,526.55	5%	76.33	76,327	$ 1,260
19	FY 2026						$ 9,502
20							
21		**Demand Rate**	**NLSL Peak**	**Election**	**Capacity**	**Capacity BD**	**Revenue**
22		*$ per kW-mo*	*MW*	*Average %*	*MW*	*kW*	*$1000s*
23	Oct-26	$ 13.81	1,879.82	5%	93.99	93,991	$ 1,298
24	Nov-26	$ 10.78	1,871.02	5%	93.55	93,551	$ 1,008
25	Dec-26	$ 12.99	1,753.49	5%	87.67	87,674	$ 1,139
26	Jan-27	$ 11.88	1,669.79	5%	83.49	83,490	$ 992
27	Feb-27	$ 12.39	1,711.57	5%	85.58	85,578	$ 1,060
28	Mar-27	$ 7.97	1,662.73	5%	83.14	83,137	$ 663
29	Apr-27	$ 6.09	1,702.24	5%	85.11	85,112	$ 518
30	May-27	$ 2.35	1,823.12	5%	91.16	91,156	$ 214
31	Jun-27	$ 4.12	1,889.75	5%	94.49	94,487	$ 389
32	Jul-27	$ 13.91	1,961.34	5%	98.07	98,067	$ 1,364
33	Aug-27	$ 14.67	1,874.13	5%	93.71	93,706	$ 1,375
34	Sep-27	$ 16.51	1,818.06	5%	90.90	90,903	$ 1,501
35	FY 2027						$ 11,522
36							
37		**Demand Rate**	**NLSL Peak**	**Election**	**Capacity**	**Capacity BD**	**Revenue**
38		*$ per kW-mo*	*MW*	*Average %*	*MW*	*kW*	*$1000s*
39	Oct-27	$ 13.81	2,296.64	5%	114.83	114,832	$ 1,586
40	Nov-27	$ 10.78	2,293.00	5%	114.65	114,650	$ 1,236
41	Dec-27	$ 12.99	2,136.53	5%	106.83	106,826	$ 1,388
42	Jan-28	$ 11.88	2,020.31	5%	101.02	101,016	$ 1,200
43	Feb-28	$ 12.39	2,099.07	5%	104.95	104,954	$ 1,300
44	Mar-28	$ 7.97	2,023.54	5%	101.18	101,177	$ 806
45	Apr-28	$ 6.09	2,082.15	5%	104.11	104,107	$ 634
46	May-28	$ 2.35	2,223.13	5%	111.16	111,156	$ 261
47	Jun-28	$ 4.12	2,308.78	5%	115.44	115,439	$ 476
48	Jul-28	$ 13.91	2,396.42	5%	119.82	119,821	$ 1,667
49	Aug-28	$ 14.67	2,275.76	5%	113.79	113,788	$ 1,669
50	Sep-28	$ 16.51	2,209.70	5%	110.49	110,485	$ 1,824
51	FY 2028						$ 14,047

SECTION 4: RATE SCHEDULES

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Table Descriptions

Table 4.1
Tier 1 Demand Rates
Table shows calculation of the Tier 1 Demand rate.

Table 4.2
Load Shaping Rates
Table shows calculation of the Load Shaping rates and the flat annual block AURORA market price forecast with negative prices removed.

Table 4.3
Tier 2 Load Obligations
Table lists Tier 2 load obligation by Tier 2 rate and year. Also includes load obligation after accounting for transmission losses incurred when delivering Tier 2-priced power to loads.

Table 4.4
FPS Real Power Losses Capacity Costs
Table shows calculation of capacity cost for FPS Real Power Losses.

Table 4.1
Demand Rates

Row	A	B	C
2	Start Year of Operation (FY)	2026	
3	Cost of Debt	3.79%	/1
4			
5	Inflation Rate	3.18%	
6	Insurance Rate	0.25%	/2
7			
8	Debt Finance Period (years)	30	/2
9	Plant Lifecycle (years)	30	/2
10			
11	Lifetime Average Heat Rate Btu/kWh	8,797	/2
12			
13	Eastside Fixed Fuel $/kW/yr with 8797 Heat Rate 2016$	$ 16.67	/2
14	Westside Fixed Fuel $/kW/yr with 8797 Heat Rate 2016$	$ 22.68	/2
15	Average Eastside and Westside 2016$	$ 19.67	
16			
17	All-in Capital Cost Recip $/kW 2026$	$ 1,797.60	/3
18	Fixed O&M $/kW/yr 2026$	$ 6.83	/4
19	Fixed Fuel $/kW/yr 2026$	$ 26.90	

Row	D: Calendar Year	E: Chained GDP IPD	F	G: Month	H: BP-26 Load Shaping Rate HLH $/MWh	I: Demand Shaping Factor	J: Monthly Demand Rate $/kW/mo
2	2016	98.241		Oct	50.63	10.83%	$ 13.81
3	2017	100.000		Nov	39.53	8.46%	$ 10.78
4	2018	102.291		Dec	47.63	10.19%	$ 12.99
5	2019	104.008		Jan	43.56	9.32%	$ 11.88
6	2020	105.381		Feb	45.43	9.72%	$ 12.39
7	2021	110.213		Mar	29.19	6.25%	$ 7.97
8	2022	117.973		Apr	22.33	4.78%	$ 6.09
9	2023	122.273		May	8.60	1.84%	$ 2.35
10		103.18%	7-year Avg.	Jun	15.10	3.23%	$ 4.12
11				Jul	50.98	10.91%	$ 13.91
12				Aug	53.80	11.51%	$ 14.67
13				Sep	60.51	12.95%	$ 16.51
14					**Average $/kW/mo**		**$ 10.62**

Chained GDP IPD from BEA -- Table 1.1.9. Implicit Price Deflators for Gross Domestic Product (2017 Base year) - Last Revised September 26, 2024

Row	End of Fiscal Year	Midyear Assessed Value	Debt Payment	Fixed O&M	Insurance	Fixed Fuel	Cash Expense Each Year
18	2026	$ 1,767.64	$101.32	$ 6.83	$ 4.42	$ 26.90	$ 139.47
19	2027	$ 1,707.72	$101.32	$ 7.05	$ 4.27	$ 27.75	$ 140.39
20	2028	$ 1,647.80	$101.32	$ 7.27	$ 4.12	$ 28.64	$ 141.35
21				**Rate Period Average Expense $/kW/year**			**$ 140.40**

Row		
23	Historical BP-24 Average $/kW/mo	$ 9.54
24	Historical BP-24 Rate Period Average Expense $/kW/year	$ 114.54
26	Modeled BP-26 Average $/kW/mo	$ 11.70
27	Modeled BP-26 Rate Period Average Expense $/kW/year	$ 140.40
29	Dampened results for BP-26 $/kW/mo	$ 10.62
30	Dampened results for BP-26 $/kW/year	$ 127.47

23 /1 Source BPA FY 2024 Third-Party Tax-Exempt Borrowing Rate Forecast 30-year
24 /2 Source NWPCC 2021 Power Plan Microfin Model and Fixed Fuel Workbook
25 /3 Source NWPCC Microfin Model assumption of $1315/kW in 2016$
26 /4 Source NWPCC Microfin Model assumption of $5/kW/yr in 2016$

Table 4.2
Load Shaping Rates

	A	B	C	D	E	F	G
3	**Aurora Market Prices with Negative Prices Removed**				**Load Shaping Rates**		
4		HLH - $/MWh	LLH - $/MWh			HLH - $/MWh	LLH - $/MWh
5	Oct-25	51.74	51.07		October	$ 50.63	$ 48.85
6	Nov-25	40.36	43.56		November	$ 39.53	$ 41.64
7	Dec-25	48.10	50.64		December	$ 47.63	$ 48.79
8	Jan-26	45.60	45.43		January	$ 43.56	$ 43.80
9	Feb-26	49.40	51.47		February	$ 45.43	$ 49.18
10	Mar-26	34.14	38.43		March	$ 29.19	$ 34.54
11	Apr-26	25.12	31.32		April	$ 22.33	$ 27.09
12	May-26	9.55	13.70		May	$ 8.60	$ 12.73
13	Jun-26	14.71	15.79		June	$ 15.10	$ 16.08
14	Jul-26	52.93	48.47		July	$ 50.98	$ 48.06
15	Aug-26	57.47	54.06		August	$ 53.80	$ 50.32
16	Sep-26	61.93	58.99		September	$ 60.51	$ 59.06
17	Oct-26	51.12	48.62				
18	Nov-26	40.65	42.92		**Aurora Flat Annual Block with Negative Prices Removed ($/MWh)**		
19	Dec-26	47.80	48.49				
20	Jan-27	43.84	43.72				
21	Feb-27	45.96	52.47		**2026**	41.34	
22	Mar-27	25.85	30.68		**2027**	37.94	
23	Apr-27	20.02	23.47		**2028**	38.91	
24	May-27	9.76	13.43				
25	Jun-27	17.09	16.57				
26	Jul-27	47.25	44.02				
27	Aug-27	48.31	44.20				
28	Sep-27	54.22	52.23				
29	Oct-27	49.04	46.88				
30	Nov-27	37.59	38.43				
31	Dec-27	46.99	47.24				
32	Jan-28	41.24	42.24				
33	Feb-28	40.93	43.61				
34	Mar-28	27.58	34.51				
35	Apr-28	21.85	26.48				
36	May-28	6.48	11.08				
37	Jun-28	13.51	15.88				
38	Jul-28	52.76	51.70				
39	Aug-28	55.61	52.71				
40	Sep-28	65.39	65.97				

Table 4.3
Tier 2 Load Obligations

	A	B	C	D	E
1	**Sorting Key**	**Rate Pool**	**Fiscal Year**	**aMW Quantity w/o Losses**	**aMW Quantity w/ Losses (1)**
10	LG.1.2012_2028_FY2026	LG.1.2012_2028	FY2026	15.890	16.417
11	LG.1.2012_2028_FY2027	LG.1.2012_2028	FY2027	18.283	18.889
12	LG.1.2012_2028_FY2028	LG.1.2012_2028	FY2028	19.484	20.130
27	ST.4.2025_2028_FY2026	ST.4.2025_2028	FY2026	519.926	537.169
28	ST.4.2025_2028_FY2027	ST.4.2025_2028	FY2027	561.774	580.405
29	ST.4.2025_2028_FY2028	ST.4.2025_2028	FY2028	598.385	618.230
6					
7	*Notes*				
8	(1) Based on a loss factor of 3.21%				

Table 4.4
FPS Real Power Losses Capacity Cost

	A	B	C	D	E	F	G	H	I	J
1	**Capacity Cost Component 1:**						**Capacity Cost Component 2:**			
2		Maximum Hourly Amount (kW)						AveMinMonth	AveHrsMonth	
3		FY 2019	FY 2020	FY 2021	Average			kW	Hours	
4	October	422,000	412,000	468,000	434,000		October	193,000	744	
5	November	407,000	413,000	493,000	437,667		November	220,667	721	
6	December	436,000	523,000	463,000	474,000		December	236,000	744	
7	January	474,000	476,000	467,000	472,333		January	257,000	744	
8	February	469,000	510,000	531,000	503,333		February	230,667	680	
9	March	413,000	511,000	460,000	461,333		March	220,333	743	
10	April	430,000	468,000	428,000	442,000		April	215,000	720	
11	May	439,000	499,000	461,000	466,333		May	238,333	744	
12	June	472,000	491,000	542,000	501,667		June	244,333	720	
13	July	512,000	531,000	525,000	522,667		July	263,667	744	
14	August	528,000	555,000	558,000	547,000		August	281,667	744	
15	September	517,000	505,000	535,000	519,000		September	246,667	720	
16										
17		Minimum Hourly Amount (kW)					Average Annual Power (kWh)		2,081,413,667	
18		FY 2019	FY 2020	FY 2021	Average		Capacity Cost $Comp_2$		$30,280,292	
19	October	171,000	202,000	206,000	193,000					
20	November	203,000	229,000	230,000	220,667		**Capacity Cost of Real Power Losses:**			
21	December	213,000	234,000	261,000	236,000		Sum of Capacity Cost $Comp_1$ and $Comp_2$			$44,744,912
22	January	256,000	260,000	255,000	257,000		Average Annual Amount of Losses (MWh)			3,049,987
23	February	193,000	282,000	217,000	230,667		FPS Real Power Losses Capacity Rate $/MWh			$14.67
24	March	198,000	234,000	229,000	220,333					
25	April	235,000	213,000	197,000	215,000					
26	May	243,000	269,000	203,000	238,333					
27	June	212,000	268,000	253,000	244,333					
28	July	249,000	313,000	229,000	263,667					
29	August	274,000	325,000	246,000	281,667					
30	September	291,000	232,000	217,000	246,667					
31										
32	Annual Sum of Monthly $Capacity_{inc}$				2,934,000					
33	Capacity Cost $Comp_1$				$14,464,620					

SECTION 5: GENERAL RATE SCHEDULE PROVISIONS

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Table Descriptions

Table 5.1
Weighted LDD for IRD-Eligible Utilities
Table shows the weighted LDD calculation for all IRD-eligible utilities using the irrigation rate mitigation eligible load amounts from Exhibit D of the customers' Regional Dialogue contracts.

Table 5.2
Customers Receiving Remarketing Credits for Non-Federal Resources with DFS
List of customers with remarketed non-Federal resources with DFS and their associated credits.

Table 5.1
Weighted LDD for IRD Eligible Utilties

	A	B	C	D	E	F	G	H	I	J
1			Irrigation Rate Mitigation Amounts from Exhibit D of the Regional Dialogue Contracts (in MWh)						Calculation of Weighted LDD	
2	BES ID	Customer Name	May	June	July	August	September	TOTAL	Eligible LDD	Total IRD MWh * LDD %
3	10024	Benton PUD	53,115.401	75,243.324	89,003.560	62,842.958	32,033.957	312,239.200	0.00%	0.000
4	10183	Benton REA	11,147.270	18,681.537	24,281.424	19,190.846	9,599.780	82,900.857	5.50%	4,559.547
5	10231	Big Bend	32,097.789	47,948.108	50,352.318	47,379.798	31,891.527	209,669.540	7.00%	14,676.868
6	10286	Central Elec	4,687.388	8,675.756	9,539.100	10,094.599	8,088.614	41,085.457	6.50%	2,670.555
7	10025	Columbia Basin	4,185.302	5,469.756	4,513.543	3,665.441	3,266.293	21,100.335	7.00%	1,477.023
8	10027	Columbia Power	706.641	866.742	1,530.227	1,432.169	691.870	5,227.649	7.00%	365.935
9	10391	Columbia REA	21,258.914	30,832.646	36,368.973	29,431.678	16,763.751	134,655.962	7.00%	9,425.917
10	10046	East End	1,061.340	1,353.162	1,240.237	1,171.183	943.562	5,769.484	3.50%	201.932
11	10109	Fall River	721.884	12,605.402	20,135.316	9,028.407	1,818.987	44,309.996	7.00%	3,101.700
12	10111	Franklin PUD	13,084.284	22,897.496	23,715.264	22,079.728	12,630.475	94,407.247	0.00%	0.000
13	10113	Harney	19,540.495	20,142.982	26,028.119	22,023.182	12,164.427	99,899.205	7.00%	6,992.944
14	10173	Inland	10,963.601	14,641.767	12,471.610	11,584.325	10,451.398	60,112.701	7.00%	4,207.889
15	10197	Klickitat	3,082.499	4,137.060	5,575.639	4,578.816	4,258.715	21,632.729	7.00%	1,514.291
16	10209	Lost River	3,725.641	9,902.214	10,705.288	8,479.424	4,746.327	37,558.894	7.00%	2,629.123
17	10242	Midstate	7,679.733	8,829.777	11,222.582	9,712.913	4,044.309	41,489.314	6.50%	2,696.805
18	10256	Mission Valley	1,857.275	3,714.550	6,500.462	5,571.825	742.910	18,387.022	5.00%	919.351
19	10273	Nespelem	1,216.565	1,778.549	2,517.152	2,274.786	1,734.973	9,522.025	7.00%	666.542
20	10291	Okanogan PUD	7,203.742	10,441.534	14,718.217	12,876.538	10,168.120	55,408.151	5.00%	2,770.408
21	10331	OTEC	4,715.415	7,780.401	10,076.149	7,938.224	5,750.412	36,260.601	5.00%	1,813.030
22	10142	Raft River	23,443.131	30,794.718	32,636.209	27,344.114	18,868.686	133,086.858	7.00%	9,316.080
23	10338	Riverside	528.123	986.578	1,167.444	906.478	566.587	4,155.210	2.50%	103.880
24	10360	Salmon River	1,257.157	2,671.504	2,659.622	2,533.409	1,383.969	10,505.661	7.00%	735.396
25	10343	Southside	2,180.245	5,429.243	5,273.390	4,387.577	2,738.885	20,009.340	5.50%	1,100.514
26	10369	Surprise Valley	6,464.252	9,066.424	11,421.596	11,671.642	7,586.987	46,210.901	7.00%	3,234.763
27	10388	Umatilla	39,288.078	52,679.345	55,478.176	49,073.469	32,253.359	228,772.427	3.00%	6,863.173
28	10442	United	5,273.820	10,806.706	12,770.236	9,182.704	6,236.687	44,270.153	3.00%	1,328.105
29	10446	Vigilante	5,362.005	10,090.787	11,936.481	8,014.268	3,459.717	38,863.258	7.00%	2,720.428
30	10502	Wasco	1,883.529	2,101.872	2,215.155	1,766.387	1,766.387	9,733.330	7.00%	681.333
31	10436	Wells	846.538	1,717.671	1,928.492	1,812.765	865.874	7,171.340	7.00%	501.994
32	10258	Yakama Power	1,463.062	1,175.985	1,228.497	1,619.426	1,702.727	7,189.697	7.00%	503.279
33								**Wt. LDD**	**4.70%**	

Table 5.2
Customers Receiving Remarketing Credits for Non-Federal Resources with DFS

	A	B	C	D	E	F
1	**FY 2026**					
2	**Customers receiving remarketing credits for non-Federal resource(s) with DFS**	**Remarketing Amount (aMW)**	**Remarketing Amount (MWh)**	**Remarketing Value ($/MWh)**	**Annual Remarketing Credit**	**Monthly Remarketing Credit**
3	Flathead Electric Coop.		0	66.58	$0	$0
4	McMinnville, City of	3.253	28,496	66.58	$1,897,224	$158,102
5	Mason County PUD #3	1.637	14,340	66.58	$954,736	$79,561
6	Total	4.890	42,836		$2,851,959	$237,663
7	**FY 2027**					
8	**Customers receiving remarketing credits for non-Federal resource(s) with DFS**	**Remarketing Amount (aMW)**	**Remarketing Amount (MWh)**	**Remarketing Value ($/MWh)**	**Annual Remarketing Credit**	**Monthly Remarketing Credit**
9	Flathead Electric Coop.		0	63.28	$0	$0
10	McMinnville, City of	3.019	26,446	63.28	$1,673,476	$139,456
11	Mason County PUD #3	1.637	14,340	63.28	$907,413	$75,618
12	Total	4.656	40,787		$1,673,476	$139,456
13	**FY 2028**					
14	**Customers receiving remarketing credits for non-Federal resource(s) with DFS**	**Remarketing Amount (aMW)**	**Remarketing Amount (MWh)**	**Remarketing Value ($/MWh)**	**Annual Remarketing Credit**	**Monthly Remarketing Credit**
15	Flathead Electric Coop.		0	63.54	$0	$0
16	McMinnville, City of	2.802	24,546	63.54	$1,559,578	$129,965
17	Mason County PUD #3	0.831	7,280	63.54	$462,530	$38,544
18	Total	3.633	31,825		$1,559,578	$129,965

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SECTION 6: TRANSFER SERVICE

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Table Descriptions

Table 6.1

Transfer Service Costs and Rates

Table shows the calculation of revenue credits associated with Transfer Service charges, including charges for holding reserves, regulation and frequency response and WECC fees.

Table 6.1

Transfer Service Costs and Rates

Rate Inputs

BPAT Loss Factor	1.81%	
Schedule 5 & 6	0.0150	
BPAT Spin Reserve Rate	0.0096	kWh
BPAT Supp Reserve Rate	0.0049	kWh
BPAT Reg & Freq Rate	0.00043	kWh

Regulation and Operating Reserves Charges

Transfer Loads Forecast (MWh)	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
FY 2026	930,820	1,031,434	1,260,467	1,261,486	1,115,076	1,051,215	955,363	967,259	1,012,895	1,122,725	1,088,307	944,739
FY 2027	956,722	1,048,820	1,295,859	1,299,258	1,121,842	1,074,172	988,442	988,488	1,039,755	1,149,279	1,110,664	950,306
FY 2028	984,588	1,079,368	1,333,602	1,337,100	1,154,517	1,105,458	1,017,232	1,017,279	1,070,039	1,182,753	1,143,013	977,984
Total	2,872,131	3,159,622	3,889,928	3,897,844	3,391,435	3,230,846	2,961,037	2,973,026	3,122,688	3,454,758	3,341,984	2,873,029

2026 recovery ($1000s)	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
Spin	136	151	185	185	163	154	140	142	148	164	159	138	1,866
Supp	70	78	95	95	84	79	72	73	76	85	82	71	959
Reg & Freq	400	444	542	542	479	452	411	416	436	483	468	406	5,479
WECC Fee	29	29	29	29	29	29	29	29	29	29	29	29	342
Total	635	701	850	851	755	714	651	659	689	760	738	644	8,647

2027 recovery ($1000s)	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
Spin	140	154	190	190	164	157	145	145	152	168	163	139	1,907
Supp	72	79	98	98	84	81	74	74	78	87	84	72	981
Reg & Freq	411	451	557	559	482	462	425	425	447	494	478	409	5,600
WECC Fee	29	29	29	29	29	29	29	29	29	29	29	29	342
Total	652	712	873	875	760	729	673	673	706	778	752	648	8,831

2028 recovery ($1000s)	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
Spin	144	158	195	196	169	162	149	149	157	173	167	143	1,963
Supp	74	81	100	101	87	83	77	77	81	89	86	74	1,009
Reg & Freq	423	464	573	575	496	475	437	437	460	509	491	421	5,763
WECC Fee	29	29	29	29	29	29	29	29	29	29	29	29	342
Total	670	732	898	900	781	749	692	692	726	799	773	666	9,078

Delivery Charge

Distribution and Low Voltage Costs	-	$
BPA Customer System Peak	2,262,194	Peak kW
Proposed Rate	$ -	Per kW

SECTION 7: SLICE

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SECTION 8: AVERAGE SYSTEM COSTS

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Table Descriptions

Table 8.1
Forecast Average System Costs (ASCs)

Table lists the Fiscal Year Forecast ASCs in $/MWh as determined through the ASC review process.

Table 8.2
IOUs' Exchange Loads and COUs' Forecast Exchange Loads (MWh)

Table lists the monthly two-year average IOU Exchange Loads based on actual loads as submitted by Exchanging Utilities, and the monthly Forecast COU Exchange Loads.

Table 8.1

Forecast Average System Costs (ASCs)
($/MWh)

	A	B	C	D
1		**FY 2026**	**FY 2027**	**FY 2028**
2	Avista	$ 67.29	$ 67.29	$ 67.29
3	Idaho Power	$ 60.47	$ 60.47	$ 60.47
4	NorthWestern	$ 89.44	$ 89.44	$ 89.44
5	PacifiCorp	$ 103.92	$ 103.92	$ 103.92
6	PGE	$ 93.89	$ 93.89	$ 93.89
7	Puget Sound Energy	$ 82.24	$ 82.24	$ 82.24
8	Clark	$ 49.61	$ 49.61	$ 49.61
9	Snohomish	$ 59.28	$ 59.28	$ 59.28
10				
11	Note: Rate Period ASCs are determined through the ASC review process			

Table 8.2
IOU Residential Loads and COU Forecast
Exchange Loads
(MWh)

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1		**Oct-25**	**Nov-25**	**Dec-25**	**Jan-26**	**Feb-26**	**Mar-26**	**Apr-26**	**May-26**	**Jun-26**	**Jul-26**	**Aug-26**	**Sep-26**	**FY 2026**
2	Avista	248,113	330,334	415,845	508,089	424,264	420,669	326,211	283,013	267,953	324,026	357,357	295,492	**4,201,365**
3	Idaho Power	471,434	461,385	594,173	691,938	649,447	604,545	513,824	516,547	589,074	746,777	848,392	678,434	**7,365,970**
4	NorthWestern	48,232	57,802	71,621	86,421	80,456	74,578	63,358	54,465	53,041	57,312	65,960	58,707	**771,953**
5	PacifiCorp	575,613	732,161	928,002	1,052,987	928,063	875,552	724,735	619,917	650,450	787,431	842,495	687,933	**9,405,337**
6	PGE	530,681	628,736	817,299	963,597	841,922	798,646	688,579	596,376	591,498	687,649	747,701	678,725	**8,571,409**
7	Puget Sound Energy	783,254	1,018,127	1,309,072	1,423,091	1,303,028	1,286,357	1,120,195	928,665	826,874	841,809	879,308	837,375	**12,557,155**
8														
9		**Oct-26**	**Nov-26**	**Dec-26**	**Jan-27**	**Feb-27**	**Mar-27**	**Apr-27**	**May-27**	**Jun-27**	**Jul-27**	**Aug-27**	**Sep-27**	**FY 2027**
10	Avista	248,113	330,334	415,845	508,089	424,264	420,669	326,211	283,013	267,953	324,026	357,357	295,492	**4,201,365**
11	Idaho Power	471,434	461,385	594,173	691,938	649,447	604,545	513,824	516,547	589,074	746,777	848,392	678,434	**7,365,970**
12	NorthWestern	48,232	57,802	71,621	86,421	80,456	74,578	63,358	54,465	53,041	57,312	65,960	58,707	**771,953**
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16														
17		**Oct-27**	**Nov-27**	**Dec-27**	**Jan-28**	**Feb-28**	**Mar-28**	**Apr-28**	**May-28**	**Jun-28**	**Jul-28**	**Aug-28**	**Sep-28**	**FY 2028**
18	Avista	248,113	330,334	415,845	508,089	424,264	420,669	326,211	283,013	267,953	324,026	357,357	295,492	**4,201,365**
19	Idaho Power	471,434	461,385	594,173	691,938	649,447	604,545	513,824	516,547	589,074	746,777	848,392	678,434	**7,365,970**
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21	PacifiCorp	575,613	732,161	928,002	1,052,987	928,063	875,552	724,735	619,917	650,450	787,431	842,495	687,933	**9,405,337**
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23	Puget Sound Energy	783,254	1,018,127	1,309,072	1,423,091	1,303,028	1,286,357	1,120,195	928,665	826,874	841,809	879,308	837,375	**12,557,155**
24														
25														
26							COUs FY 2026 - 2028 Forecast Exchange Loads							
27							(MWh)							
28														
29		**Oct-25**	**Nov-25**	**Dec-25**	**Jan-26**	**Feb-26**	**Mar-26**	**Apr-26**	**May-26**	**Jun-26**	**Jul-26**	**Aug-26**	**Sep-26**	**FY 2026**
30	Clark	195,136	236,848	312,014	295,459	248,689	247,292	194,367	176,964	167,030	191,397	193,109	154,231	**2,612,536**
31	Snohomish	263,972	314,541	416,318	523,893	400,107	459,382	309,078	288,729	255,956	239,084	252,132	241,962	**3,965,153**
32														
33		**Oct-26**	**Nov-26**	**Dec-26**	**Jan-27**	**Feb-27**	**Mar-27**	**Apr-27**	**May-27**	**Jun-27**	**Jul-27**	**Aug-27**	**Sep-27**	**FY 2027**
34	Clark	197,264	239,841	316,529	297,954	250,657	248,822	195,012	177,216	167,344	192,122	193,984	154,509	**2,631,253**
35	Snohomish	267,001	318,150	421,095	531,778	406,129	466,296	313,730	293,074	259,808	242,683	255,927	245,603	**4,021,275**
36														
37		**Oct-27**	**Nov-27**	**Dec-27**	**Jan-28**	**Feb-28**	**Mar-28**	**Apr-28**	**May-28**	**Jun-28**	**Jul-28**	**Aug-28**	**Sep-28**	**FY 2028**
38	Clark	197,903	241,314	319,383	303,897	255,659	253,719	198,610	180,491	170,472	195,853	197,777	157,366	**2,672,443**
39	Snohomish	271,019	322,939	427,433	540,980	413,157	474,365	319,159	298,146	264,304	246,882	260,355	249,853	**4,088,593**

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SECTION 9: REVENUE FORECAST

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Table Descriptions

Table 9.1
Revenue at Current Rates
Table provides breakdown of revenue and power purchases at current rates.

Table 9.2
Revenue at Proposed Rates
Table provides breakdown of revenue and power purchases at proposed rates.

Table 9.3.1.1
Inter-Business Line Allocations
The forecast revenue Power Services receives from Transmission Services for providing balancing reserve capacity, operating reserve capacity, and the other generation inputs included in the Settlement.

Table 9.3.1.2
FCRPS 1-Hour Peaking Capacity for FY 2026, FY 2027, and FY2028
The forecasted 14 period (10 calendar months and two periods each for April and August) 1-hour peaking capacity of the Federal Columbia River Power System using the monthly P10 water conditions from the most recent 30 water year data.

Table 9.3.1.3
Capacity Costs
Forecasted BPA Power costs allocated to capacity for the rate period. Includes capital related costs, fish and wildlife costs, power purchase costs and two cost adjustments.

Table 9.3.1.4
Embedded Cost Calculation
Table provides inputs and assumptions to calculate the unit embedded cost of system capacity.

Table 9.3.1.5
Variable Fuel Costs of Regulation Balancing Reserves and Operating Reserves
Table provides a rate period annual average forecast of energy shift and net generation costs associated with holding regulation balancing reserves as well as holding operating reserves.

Table 9.3.1.6
7HA.02 SCCT Frame Annual Costs
Table provides forecast of annual costs for the General Electric 7HA.02 combustion turbine.

Table 9.3.1.7
Balancing Reserve Capacity Requirement - Proportions for Rate Design
Table provides the proportions that reflect the balancing area needs between Regulation and Non-Regulation Balancing Reserve capacity. This ratio is used to design rates for the FCRPS quantities of balancing capacity.

Table 9.3.1.8
Costs Allocated to Balancing Reserve and Operating Reserve Capacity
Table provides forecast of annual costs that are allocated to incremental Balancing Reserve Capacity and Operating Reserve capacity.

Table 9.3.1.9
Cost of Capacity Calculation
Table provides inputs and assumptions for calculating annual average of the rate period capacity costs by reserve type. Both embedded and variable costs are included.

Table 9.3.1.10
Balancing and Operating Reserve Revenue Forecast
Table provides forecast of rate period annual average balancing and operating reserve revenue forecast by reserve type.

Table 9.3.2.1
Synchronous Condenser Projected Motoring Hours, Hourly Energy Consumption and Energy Costs
Table provides historical condensing hours and a forecast of annual energy consumption and cost by generating project.

Table 9.3.2.2
Determination of Synchronous Condenser Plant Modification Costs
Table provides costs for plant modifications at John Day and The Dalles to enable synchronous condenser operation for the rate period. These costs are allocated to the Southern Intertie segment.

Table 9.3.2.3
Summary of Synchronous Condenser Costs
Table provides a summary synchronous condensing cost and includes information from Tables 9.3.2.1 and 9.3.2.2.

Table 9.3.3.1
Estimated Costs of "Generation Drop" of Unit 22, 23, or 24 at the Grand Coulee Third Powerhouse
Table provides an annual total Generation Dropping cost. Provides total costs per drop for each equipment type including 550kV circuit breaker, main power transformer, generator, turbine, and 500kV cable.

Table 9.3.4.1
Redispatch Costs
Historical and forecasted, for the rate period, redispatch costs that will be transferred as revenue to Power Services from Transmission Services for the provision of redispatch.

Table 9.3.5.1
Load Factor calculation for Station Service Energy Use Analysis
Calculated load factor is the historical average monthly use divided by installed transformation divided by 730 average hours in the month.

Table 9.3.5.2
Calculation of Station Service Use and Cost
Table provides inputs and assumptions to calculate annual costs allocation for station service.

Table 9.3.1.9
Cost of Capacity Calculation
Table provides inputs and assumptions for calculating annual average of the rate period capacity costs by reserve type. Both embedded and variable costs are included.

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Table provides forecast of rate period annual average balancing and operating reserve revenue forecast by reserve type.

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Table provides inputs and assumptions to calculate annual costs allocation for station service.

Table 9.1

Revenue at Current Rates

	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	**Table 9.1 -Revenue at Current Rates**													**2025**	
2	**Category**	**202410**	**202411**	**202412**	**202501**	**202502**	**202503**	**202504**	**202505**	**202506**	**202507**	**202508**	**202509**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 197,392	$ 197,392	$ 197,392	$ 197,392	$ 197,392	$ 197,839	$ 197,839	$ 197,839	$ 197,839	$ 197,839	$ 197,839	$ 197,839	$ 2,371,835	5,323
4	Non-Slice Revenue	$ (27,488)	$ (27,488)	$ (27,488)	$ (27,488)	$ (27,488)	$ (27,566)	$ (27,566)	$ (27,566)	$ (27,566)	$ (27,566)	$ (27,566)	$ (27,566)	$ (330,400)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	1,403
6	Load Shaping Revenue	$ 11,505	$ 997	$ 16,155	$ 20,321	$ 28,389	$ (3,053)	$ 2,595	$ (15,566)	$ (16,340)	$ 603	$ 6,695	$ 8,481	$ 60,782	24
7	Demand Revenue	$ 3,702	$ 1,217	$ 5,472	$ 8,260	$ 13,355	$ 4,111	$ 2,835	$ 1,794	$ 2,250	$ 9,065	$ 10,424	$ 6,175	$ 68,661	-
8	Irrigation Rate Discount	$ -	$ 33	$ -	$ -	$ -	$ -	$ -	$ (3,356)	$ (5,015)	$ (5,776)	$ (4,740)	$ (2,883)	$ (21,737)	-
9	Low Density Discount	$ (3,174)	$ (2,719)	$ (3,050)	$ (3,484)	$ (3,895)	$ (1,867)	$ (2,212)	$ (2,085)	$ (2,142)	$ (3,074)	$ (3,219)	$ (2,569)	$ (33,490)	-
10	Tier 2	$ 17,066	$ 16,525	$ 17,066	$ 17,066	$ 15,394	$ 16,865	$ 16,341	$ 16,897	$ 16,344	$ 16,903	$ 16,898	$ 16,364	$ 199,730	391
11	RSS (Non-Federal) and Other	$ 127	$ (46)	$ (130)	$ (262)	$ (58)	$ 84	$ 84	$ 84	$ 84	$ 84	$ 84	$84	$ 221	-
12	**PF customers (TRM) sub-total**	**$ 199,130**	**$ 185,912**	**$ 205,417**	**$ 211,807**	**$ 223,089**	**$ 186,414**	**$ 189,917**	**$ 168,042**	**$ 165,454**	**$ 188,080**	**$ 196,415**	**$ 195,924**	**$ 2,315,602**	**7,140**
13	**NR sub-total**	**$ (994)**	**$ (794)**	**$ (672)**	**$ (1,039)**	**$ (420)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ (3,919)**	**-**
14	**DSIs sub-total**	**$ 377**	**$ 308**	**$ 468**	**$ 366**	**$ 397**	**$ 371**	**$ 196**	**$ 171**	**$ 141**	**$ 439**	**$ 565**	**$ 467**	**$ 4,266**	**8**
15	**FPS sub-total**	**$ 518**	**$ 1,078**	**$ 1,542**	**$ 1,438**	**$ 1,284**	**$ 764**	**$ 741**	**$ 741**	**$ 755**	**$ 785**	**$ 774**	**$ 731**	**$ 11,150**	**-**
16	**Short-term market sales sub-total**	**$ 50,304**	**$ 44,783**	**$ 47,529**	**$ 69,398**	**$ 61,886**	**$ 38,310**	**$ 46,919**	**$ 34,410**	**$ 49,560**	**$ 68,453**	**$ 49,830**	**$ 26,831**	**$ 588,214**	**1,482**
17	**Long Term Contractual Obligations sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**462**
19	**Other Sales sub-total**	**$ 2**	**$ 2**	**$ 3**	**$ 6**	**$ 0**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ (33,273)**	**$ (33,259)**	**-**
20	**Gross Sales**	**$ 249,337**	**$ 231,291**	**$ 254,288**	**$ 281,976**	**$ 286,237**	**$ 225,859**	**$ 237,773**	**$ 203,364**	**$ 215,910**	**$ 257,756**	**$ 247,585**	**$ 190,679**	**$ 2,882,054**	**9,093**
21	Transfer Service Delivery charge	$ 234	$ 260	$ 282	$ 343	$ 367	$ 248	$ 222	$ 233	$ 243	$ 264	$ 258	$ 233	$ 3,186	-
22	Irrigation Pumping Power	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102	$ 1,225	15
23	Reserve Energy	$ 869	$ 869	$ 869	$ 869	$ 869	$ 869	$ 886	$ 886	$ 886	$ 886	$ 886	$ 886	$ 10,532	160
24	USBR Owyhee Wheeling Project	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 133	$ 133	$ 133	$ 133	$ 133	$ 133	$ 1,629	-
25	Downstream Benefits	$ 723	$ 660	$ 660	$ 1,497	$ 3,177	$ 640	$ 640	$ 619	$ 619	$ 619	$ 619	$ 619	$ 11,093	-
26	Upper Baker Revenues	$ -	$ 105	$ 150	$ 129	$ 127	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 510	-
27	**Miscellaneous Revenue**	**$ 2,066**	**$ 2,135**	**$ 2,201**	**$ 3,077**	**$ 4,779**	**$ 1,997**	**$ 1,984**	**$ 1,974**	**$ 1,984**	**$ 2,005**	**$ 1,999**	**$ 1,974**	**$ 28,175**	**175**
28	Balancing Reserve Capacity	$ 4,933	$ 4,933	$ 4,933	$ 4,944	$ 4,944	$ 4,944	$ 4,944	$ 4,944	$ 4,944	$ 4,944	$ 4,944	$ 4,944	$ 59,300	-
29	ACS Risk Share	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
30	Risk Mitigation Tool	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
31	Imbalance Adjustment for Third-Party Deployed Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
32	Operating Reserve - Spinning	$ 1,616	$ 1,964	$ 2,088	$ 2,217	$ 2,111	$ 1,862	$ 2,060	$ 2,263	$ 2,469	$ 2,123	$ 1,954	$ 1,725	$ 24,451	-
33	Operating Reserve - Supplemental	$ 992	$ 1,206	$ 1,282	$ 1,361	$ 1,297	$ 1,144	$ 1,265	$ 1,390	$ 1,516	$ 1,304	$ 1,200	$ 1,059	$ 15,016	-
34	Operating Reserve - Spinning Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
35	Operating Reserve - Supplemental Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
36	Operating Reserve - Energy	$ 33	$ -	$ 41	$ 11	$ 13	$ 34	$ 27	$ 25	$ 35	$ 74	$ 65	$ 54	$ 411	-
37	Synchronous Condensing	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 1,292	-
38	Generation Dropping	$ -	$ 92	$ 50	$ 50	$ 50	$ 50	$ 50	$ 50	$ 50	$ 50	$ 50	$ 50	$ 595	-
39	Redispatch	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 332	-
40	Segmentation of COE/Reclamation Network and Delivery Facilities	$ 680	$ 680	$ 680	$ 680	$ 680	$ 680	$ 680	$ 680	$ 680	$ 680	$ 680	$ 680	$ 8,161	-
41	Station Service	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 3,307	9
42	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
43	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
44	Energy Imbalance Persistent Deviation	$ 17	$ (22)	$ 4	$ 269	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 267	-
45	Generation Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	Invalid Loss Return Penalty	$ 6	$ 5	$ 3	$ 3	$ 7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 24	-
47	Real Power Losses Imbalance Settlement	$ (10)	$ 8	$ 7	$ 12	$ (6)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11	-
48	**Generation Inputs / Inter-business line**	**$ 8,678**	**$ 9,276**	**$ 9,500**	**$ 9,959**	**$ 9,507**	**$ 9,125**	**$ 9,437**	**$ 9,764**	**$ 10,107**	**$ 9,587**	**$ 9,304**	**$ 8,924**	**$ 113,167**	**9**
49	4(h)(10)(c)	$ 13,494	$ 15,123	$ 12,778	$ 21,342	$ 17,762	$ 15,486	$ 9,181	$ 8,492	$ 6,672	$ 6,761	$ 6,349	$ 13,300	$ 146,741	-
50	Colville Settlement	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
51	**Treasury Credits**	**$ 13,877**	**$ 15,506**	**$ 13,161**	**$ 21,725**	**$ 18,146**	**$ 15,869**	**$ 9,565**	**$ 8,875**	**$ 7,056**	**$ 7,145**	**$ 6,732**	**$ 13,684**	**$ 151,341**	**-**
52	Augmentation Power Purchase sub-total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
53	Balancing Power Purchase sub-total	$ 51,821	$ 27,933	$ 30,869	$ 81,477	$ 105,012	$ 25,618	$ 56,785	$ 19,153	$ 10	$ 10,409	$ 16,000	$ 29,002	$ 454,090	1,129
54	Tier 2 Augmentation total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
55	Other Augmentation total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
56	**Power Purchases**	**$ 51,821**	**$ 27,933**	**$ 30,869**	**$ 81,477**	**$ 105,012**	**$ 25,618**	**$ 56,785**	**$ 19,153**	**$ 10**	**$ 10,409**	**$ 16,000**	**$ 29,002**	**$ 454,090**	**1,129**

Table 9.1 (continued)

Revenue at Current Rates

	A B C D	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF
1	**Table 9.1 -Revenue at Current Rates**													**2026**	
2	**Category**	**202510**	**202511**	**202512**	**202601**	**202602**	**202603**	**202604**	**202605**	**202606**	**202607**	**202608**	**202609**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 196,999	$ 196,999	$ 196,999	$ 196,999	$ 196,999	$ 196,999	$ 196,999	$ 196,999	$ 196,999	$ 196,999	$ 196,999	$ 196,999	$ 2,363,988	5,916
4	Non-Slice Revenue	$ (30,340)	$ (30,340)	$ (30,340)	$ (30,340)	$ (30,340)	$ (30,340)	$ (30,340)	$ (30,340)	$ (30,340)	$ (30,340)	$ (30,340)	$ (30,340)	$ (364,084)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	840
6	Load Shaping Revenue	$ 19,605	$ 2,842	$ 23,946	$ 8,192	$ 20,695	$ 3,974	$ 6,461	$ (17,423)	$ (18,836)	$ (4,082)	$ (18,440)	$ 18,472	$ 45,408	4
7	Demand Revenue	$ 7,818	$ 6,186	$ 17,712	$ 14,854	$ 11,961	$ 9,464	$ 4,979	$ 2,578	$ 4,491	$ 14,761	$ 22,488	$ 11,826	$ 129,117	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,356)	$ (5,015)	$ (5,776)	$ (4,740)	$ (2,883)	$ (21,770)	-
9	Low Density Discount	$ (3,176)	$ (3,176)	$ (3,176)	$ (3,176)	$ (3,176)	$ (3,176)	$ (3,176)	$ (3,176)	$ (3,176)	$ (3,176)	$ (3,176)	$ (3,176)	$ (38,116)	-
10	Tier 2	$ 25,334	$ 24,551	$ 25,334	$ 25,334	$ 22,882	$ 25,300	$ 24,517	$ 25,334	$ 24,517	$ 25,334	$ 25,334	$ 24,517	$ 298,286	538
11	RSS (Non-Federal) and Other	$ 88	$ 88	$ 88	$ 88	$ 88	$ 88	$ 88	$ 88	$ 88	$ 88	$ 88	$ 88	$ 1,056	-
12	**PF customers (TRM) sub-total**	**$ 216,327**	**$ 197,149**	**$ 230,563**	**$ 211,950**	**$ 219,108**	**$ 202,309**	**$ 199,527**	**$ 170,704**	**$ 168,727**	**$ 193,808**	**$ 188,213**	**$ 215,501**	**$ 2,413,884**	**7,298**
13	**NR sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**1**
14	**DSIs sub-total**	**$ 353**	**$ 302**	**$ 485**	**$ 373**	**$ 358**	**$ 304**	**$ 180**	**$ 157**	**$ 130**	**$ 399**	**$ 521**	**$ 425**	**$ 3,987**	**11**
15	**FPS sub-total**	**$ 723**	**$ 798**	**$ 969**	**$ 970**	**$ 861**	**$ 813**	**$ 742**	**$ 750**	**$ 785**	**$ 866**	**$ 841**	**$ 734**	**$ 9,852**	**-**
16	**Short-term market sales sub-total**	**$ 29,731**	**$ 44,576**	**$ 72,344**	**$ 87,012**	**$ 78,647**	**$ 60,074**	**$ 46,251**	**$ 47,374**	**$ 62,237**	**$ 100,526**	**$ 84,274**	**$ 33,799**	**$ 746,846**	**1,729**
17	**Long Term Contractual Obligations sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**462**
19	**Other Sales sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
20	**Gross Sales**	**$ 247,134**	**$ 242,825**	**$ 304,361**	**$ 300,305**	**$ 298,974**	**$ 263,500**	**$ 246,699**	**$ 218,985**	**$ 231,879**	**$ 295,600**	**$ 273,848**	**$ 250,459**	**$ 3,174,570**	**9,501**
21	Transfer Service Delivery charge	$ 217	$ 222	$ 315	$ 346	$ 300	$ 248	$ 222	$ 233	$ 243	$ 264	$ 258	$ 233	$ 3,100	-
22	Irrigation Pumping Power	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 1,207	15
23	Reserve Energy	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 10,482	160
24	USBR Owyhee Wheeling Project	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 1,732	-
25	Downstream Benefits	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 7,772	-
26	Upper Baker Revenues	$ -	$ 107	$ 131	$ 122	$ 125	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 485	-
27	**Miscellaneous Revenue**	**$ 1,983**	**$ 2,095**	**$ 2,212**	**$ 2,234**	**$ 2,191**	**$ 2,014**	**$ 1,988**	**$ 1,999**	**$ 2,009**	**$ 2,030**	**$ 2,024**	**$ 1,999**	**$ 24,778**	**175**
28	Balancing Reserve Capacity	$ 4,916	$ 4,916	$ 4,931	$ 4,969	$ 4,969	$ 4,984	$ 4,984	$ 5,023	$ 5,023	$ 5,023	$ 5,023	$ 5,023	$ 59,785	-
29	ACS Risk Share	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
30	Risk Mitigation Tool	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
31	Imbalance Adjustment for Third-Party Deployed Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
32	Operating Reserve - Spinning	$ 1,867	$ 2,132	$ 2,395	$ 2,397	$ 2,422	$ 2,412	$ 2,428	$ 2,508	$ 2,643	$ 2,396	$ 2,193	$ 1,897	$ 27,690	-
33	Operating Reserve - Supplemental	$ 960	$ 1,096	$ 1,231	$ 1,232	$ 1,245	$ 1,240	$ 1,248	$ 1,290	$ 1,359	$ 1,232	$ 1,128	$ 975	$ 14,235	-
34	Operating Reserve - Spinning Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
35	Operating Reserve - Supplemental Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
36	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
37	Synchronous Condensing	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 1,637	-
38	Generation Dropping	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 714	-
39	Redispatch	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 245	-
40	Segmentation of COE/Reclamation Network and Delivery Facilities	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 7,696	-
41	Station Service	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 3,265	9
42	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
43	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
44	Energy Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
45	Generation Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	Invalid Loss Return Penalty	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	Real Power Losses Imbalance Settlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
48	**Generation Inputs / Inter-business line**	**$ 8,872**	**$ 9,273**	**$ 9,686**	**$ 9,728**	**$ 9,766**	**$ 9,766**	**$ 9,790**	**$ 9,951**	**$ 10,154**	**$ 9,781**	**$ 9,474**	**$ 9,025**	**$ 115,267**	**9**
49	4(h)(10)(c)	$ 20,138	$ 11,184	$ 9,923	$ 10,430	$ 9,432	$ 8,892	$ 9,394	$ 7,556	$ 6,949	$ 8,254	$ 6,216	$ 16,541	$ 124,911	-
50	Colville Settlement	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
51	**Treasury Credits**	**$ 20,522**	**$ 11,568**	**$ 10,306**	**$ 10,813**	**$ 9,815**	**$ 9,275**	**$ 9,778**	**$ 7,939**	**$ 7,332**	**$ 8,638**	**$ 6,600**	**$ 16,925**	**$ 129,511**	**-**
52	Augmentation Power Purchase sub-total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
53	Balancing Power Purchase sub-total	$ 21,569	$ 6,309	$ 13,038	$ 12,313	$ 16,218	$ 6,981	$ 6,753	$ 21	$ 22	$ 3,970	$ 3,325	$ 13,582	$ 104,101	211
54	Tier 2 Augmentation total	$ 26,619	$ 26,619	$ 26,619	$ 26,619	$ 26,619	$ 26,619	$ 26,619	$ 26,619	$ 26,619	$ 26,619	$ 26,619	$ 26,619	$ 319,432	554
55	Other Augmentation total	$ 585	$ 585	$ 585	$ 585	$ 585	$ 585	$ 585	$ 585	$ 585	$ 585	$ 585	$ 585	$ 7,021	12
56	**Power Purchases**	**$ 48,773**	**$ 33,513**	**$ 40,242**	**$ 39,517**	**$ 43,422**	**$ 34,185**	**$ 33,958**	**$ 27,225**	**$ 27,227**	**$ 31,175**	**$ 30,530**	**$ 40,786**	**$ 430,554**	**777**

Table 9.1 (continued)

Revenue at Current Rates

	A B C D	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT
1	**Table 9.1 -Revenue at Current Rates**													**2027**	
2	**Category**	**202610**	**202611**	**202612**	**202701**	**202702**	**202703**	**202704**	**202705**	**202706**	**202707**	**202708**	**202709**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 197,851	$ 197,851	$ 197,851	$ 197,851	$ 197,851	$ 197,851	$ 197,851	$ 197,851	$ 197,851	$ 197,851	$ 197,851	$ 197,851	$ 2,374,213	6,776
4	Non-Slice Revenue	$ (30,490)	$ (30,490)	$ (30,490)	$ (30,490)	$ (30,490)	$ (30,490)	$ (30,490)	$ (30,490)	$ (30,490)	$ (30,490)	$ (30,490)	$ (30,490)	$ (365,881)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	826
6	Load Shaping Revenue	$ 19,902	$ 3,599	$ 25,288	$ 7,820	$ 21,588	$ 4,436	$ 6,579	$ (17,520)	$ (18,935)	$ (3,814)	$ (18,357)	$ 19,004	$ 49,590	16
7	Demand Revenue	$ 8,144	$ 6,801	$ 18,232	$ 15,257	$ 12,602	$ 10,193	$ 5,269	$ 2,794	$ 4,612	$ 15,056	$ 23,701	$ 12,446	$ 135,109	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,356)	$ (5,015)	$ (5,776)	$ (4,740)	$ (2,883)	$ (21,770)	-
9	Low Density Discount	$ (3,176)	$ (3,176)	$ (3,176)	$ (3,176)	$ (3,176)	$ (3,176)	$ (3,176)	$ (3,176)	$ (3,176)	$ (3,176)	$ (3,176)	$ (3,176)	$ (38,116)	-
10	Tier 2	$ 25,898	$ 25,098	$ 25,898	$ 25,898	$ 23,392	$ 25,863	$ 25,063	$ 25,898	$ 25,063	$ 25,898	$ 25,898	$ 25,063	$ 304,931	588
11	RSS (Non-Federal) and Other	$ 86	$ 86	$ 86	$ 86	$ 86	$ 86	$ 86	$ 86	$ 86	$ 86	$ 86	$ 86	$ 1,036	-
12	**PF customers (TRM) sub-total**	**$ 218,215**	**$ 199,769**	**$ 233,690**	**$ 213,246**	**$ 221,853**	**$ 204,764**	**$ 201,182**	**$ 172,087**	**$ 169,996**	**$ 195,636**	**$ 190,774**	**$ 217,901**	**$ 2,439,112**	**8,206**
13	**NR sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**20**
14	**DSIs sub-total**	**$ 353**	**$ 302**	**$ 485**	**$ 373**	**$ 358**	**$ 304**	**$ 180**	**$ 157**	**$ 130**	**$ 399**	**$ 521**	**$ 425**	**$ 3,987**	**11**
15	**FPS sub-total**	**$ 743**	**$ 811**	**$ 996**	**$ 998**	**$ 866**	**$ 830**	**$ 766**	**$ 766**	**$ 805**	**$ 886**	**$ 857**	**$ 738**	**$ 10,063**	**-**
16	**Short-term market sales sub-total**	**$ 21,309**	**$ 38,034**	**$ 64,651**	**$ 77,474**	**$ 63,434**	**$ 46,700**	**$ 34,727**	**$ 31,323**	**$ 53,088**	**$ 91,103**	**$ 70,783**	**$ 25,463**	**$ 618,090**	**1,738**
17	**Long Term Contractual Obligations sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**462**
19	**Other Sales sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
20	**Gross Sales**	**$ 240,620**	**$ 238,916**	**$ 299,821**	**$ 292,092**	**$ 286,510**	**$ 252,599**	**$ 236,856**	**$ 204,333**	**$ 224,018**	**$ 288,024**	**$ 262,935**	**$ 244,527**	**$ 3,071,251**	**10,437**
21	Transfer Service Delivery charge	$ 217	$ 222	$ 315	$ 346	$ 300	$ 248	$ 222	$ 233	$ 243	$ 264	$ 258	$ 233	$ 3,100	-
22	Irrigation Pumping Power	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 1,207	15
23	Reserve Energy	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 10,482	160
24	USBR Owyhee Wheeling Project	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 1,732	-
25	Downstream Benefits	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 7,772	-
26	Upper Baker Revenues	$ -	$ 107	$ 130	$ 119	$ 119	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 476	-
27	**Miscellaneous Revenue**	**$ 1,983**	**$ 2,096**	**$ 2,211**	**$ 2,231**	**$ 2,185**	**$ 2,014**	**$ 1,988**	**$ 1,999**	**$ 2,009**	**$ 2,030**	**$ 2,024**	**$ 1,999**	**$ 24,769**	**175**
28	Balancing Reserve Capacity	$ 5,555	$ 5,555	$ 5,957	$ 6,132	$ 6,420	$ 6,420	$ 6,580	$ 6,619	$ 6,741	$ 6,741	$ 6,741	$ 6,741	$ 76,201	-
29	ACS Risk Share	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
30	Risk Mitigation Tool	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
31	Imbalance Adjustment for Third-Party Deployed Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
32	Operating Reserve - Spinning	$ 1,973	$ 2,227	$ 2,513	$ 2,535	$ 2,565	$ 2,597	$ 2,533	$ 2,612	$ 2,833	$ 2,600	$ 2,140	$ 2,028	$ 29,156	-
33	Operating Reserve - Supplemental	$ 1,015	$ 1,145	$ 1,292	$ 1,303	$ 1,318	$ 1,335	$ 1,302	$ 1,343	$ 1,456	$ 1,337	$ 1,100	$ 1,043	$ 14,989	-
34	Operating Reserve - Spinning Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
35	Operating Reserve - Supplemental Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
36	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
37	Synchronous Condensing	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 1,637	-
38	Generation Dropping	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 714	-
39	Redispatch	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 245	-
40	Segmentation of COE/Reclamation Network and Delivery Facilities	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 7,696	-
41	Station Service	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 3,265	9
42	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
43	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
44	Energy Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
45	Generation Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	Invalid Loss Return Penalty	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	Real Power Losses Imbalance Settlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
48	**Generation Inputs / Inter-business line**	**$ 9,672**	**$ 10,056**	**$ 10,891**	**$ 11,101**	**$ 11,433**	**$ 11,482**	**$ 11,545**	**$ 11,704**	**$ 12,159**	**$ 11,808**	**$ 11,111**	**$ 10,941**	**$ 133,903**	**9**
49	4(h)(10)(c)	$ 20,477	$ 17,924	$ 12,644	$ 10,429	$ 11,080	$ 9,401	$ 8,221	$ 9,011	$ 9,168	$ 8,273	$ 7,733	$ 6,756	$ 131,117	-
50	Colville Settlement	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
51	**Treasury Credits**	**$ 20,860**	**$ 18,308**	**$ 13,028**	**$ 10,813**	**$ 11,464**	**$ 9,784**	**$ 8,604**	**$ 9,394**	**$ 9,551**	**$ 8,656**	**$ 8,117**	**$ 7,139**	**$ 135,717**	**-**
52	Augmentation Power Purchase sub-total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
53	Balancing Power Purchase sub-total	$ 17,221	$ 5,658	$ 11,311	$ 10,531	$ 15,539	$ 5,383	$ 4,145	$ 151	$ 39	$ 2,330	$ 1,888	$ 9,055	$ 83,251	178
54	Tier 2 Augmentation total	$ 27,460	$ 27,460	$ 27,460	$ 27,460	$ 27,460	$ 27,460	$ 27,460	$ 27,460	$ 27,460	$ 27,460	$ 27,460	$ 27,460	$ 329,517	599
55	Other Augmentation total	$ 1,453	$ 1,453	$ 1,453	$ 1,453	$ 1,453	$ 1,453	$ 1,453	$ 1,453	$ 1,453	$ 1,453	$ 1,453	$ 1,453	$ 17,440	31
56	**Power Purchases**	**$ 46,134**	**$ 34,571**	**$ 40,224**	**$ 39,444**	**$ 44,452**	**$ 34,296**	**$ 33,058**	**$ 29,064**	**$ 28,952**	**$ 31,243**	**$ 30,801**	**$ 37,968**	**$ 430,208**	**809**

Table 9.1 (continued)

Revenue at Current Rates

	A B C D	AU	AV	AW	AX	AY	AZ	BA	BB	BC	BD	BE	BF	BG	BH
1	**Table 9.1 -Revenue at Current Rates**													**2028**	
2	**Category**	**202710**	**202711**	**202712**	**202801**	**202802**	**202803**	**202804**	**202805**	**202806**	**202807**	**202808**	**202809**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 198,544	$ 198,544	$ 198,544	$ 198,544	$ 198,544	$ 198,544	$ 198,544	$ 198,544	$ 198,544	$ 198,544	$ 198,544	$ 198,544	$ 2,382,532	6,800
4	Non-Slice Revenue	$ (30,612)	$ (30,612)	$ (30,612)	$ (30,612)	$ (30,612)	$ (30,612)	$ (30,612)	$ (30,612)	$ (30,612)	$ (30,612)	$ (30,612)	$ (30,612)	$ (367,343)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	842
6	Load Shaping Revenue	$ 19,220	$ 4,637	$ 25,521	$ 7,946	$ 18,869	$ 4,426	$ 6,550	$ (17,691)	$ (19,209)	$ (6,144)	$ (16,923)	$ 18,853	$ 46,056	3
7	Demand Revenue	$ 8,937	$ 7,259	$ 18,721	$ 16,480	$ 13,413	$ 10,930	$ 5,831	$ 2,894	$ 4,775	$ 15,046	$ 24,822	$ 13,282	$ 142,389	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,356)	$ (5,015)	$ (5,776)	$ (4,740)	$ (2,883)	$ (21,770)	-
9	Low Density Discount	$ (3,176)	$ (3,176)	$ (3,176)	$ (3,176)	$ (3,176)	$ (3,176)	$ (3,176)	$ (3,176)	$ (3,176)	$ (3,176)	$ (3,176)	$ (3,176)	$ (38,116)	-
10	Tier 2	$ 28,415	$ 27,536	$ 28,415	$ 28,415	$ 26,582	$ 28,377	$ 27,498	$ 28,415	$ 27,498	$ 28,415	$ 28,415	$ 27,498	$ 335,477	627
11	RSS (Non-Federal) and Other	$ 87	$ 87	$ 87	$ 87	$ 87	$ 87	$ 87	$ 87	$ 87	$ 87	$ 87	$ 87	$ 1,046	-
12	**PF customers (TRM) sub-total**	**$ 221,415**	**$ 204,275**	**$ 237,500**	**$ 217,684**	**$ 223,707**	**$ 208,576**	**$ 204,722**	**$ 175,105**	**$ 172,892**	**$ 196,384**	**$ 196,417**	**$ 221,593**	**$ 2,480,271**	**8,272**
13	**NR sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**25**
14	**DSIs sub-total**	**$ 353**	**$ 302**	**$ 485**	**$ 373**	**$ 371**	**$ 304**	**$ 180**	**$ 157**	**$ 130**	**$ 399**	**$ 521**	**$ 425**	**$ 3,999**	**11**
15	**FPS sub-total**	**$ 763**	**$ 834**	**$ 1,024**	**$ 1,026**	**$ 890**	**$ 854**	**$ 788**	**$ 788**	**$ 827**	**$ 911**	**$ 882**	**$ 758**	**$ 10,346**	**-**
16	**Short-term market sales sub-total**	**$ 23,539**	**$ 37,113**	**$ 63,436**	**$ 74,668**	**$ 67,195**	**$ 47,248**	**$ 38,081**	**$ 35,311**	**$ 54,852**	**$ 98,268**	**$ 77,084**	**$ 28,718**	**$ 645,514**	**1,758**
17	**Long Term Contractual Obligations sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**461**
19	**Other Sales sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
20	**Gross Sales**	**$ 246,070**	**$ 242,525**	**$ 302,444**	**$ 293,752**	**$ 292,163**	**$ 256,982**	**$ 243,771**	**$ 211,360**	**$ 228,701**	**$ 295,962**	**$ 274,904**	**$ 251,495**	**$ 3,140,130**	**10,528**
21	Transfer Service Delivery charge	$ 217	$ 222	$ 315	$ 346	$ 300	$ 248	$ 222	$ 233	$ 243	$ 264	$ 258	$ 233	$ 3,100	-
22	Irrigation Pumping Power	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 1,207	-
23	Reserve Energy	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 10,482	-
24	USBR Owyhee Wheeling Project	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 1,732	-
25	Downstream Benefits	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 7,772	-
26	Upper Baker Revenues	$ -	$ 102	$ 129	$ 115	$ 111	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 456	-
27	**Miscellaneous Revenue**	**$ 1,983**	**$ 2,090**	**$ 2,210**	**$ 2,227**	**$ 2,176**	**$ 2,014**	**$ 1,988**	**$ 1,999**	**$ 2,009**	**$ 2,030**	**$ 2,024**	**$ 1,999**	**$ 24,749**	**175**
28	Balancing Reserve Capacity	$ 7,235	$ 7,235	$ 7,470	$ 7,470	$ 7,470	$ 7,740	$ 7,740	$ 7,763	$ 7,763	$ 7,763	$ 7,763	$ 7,763	$ 91,177	-
29	ACS Risk Share	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
30	Risk Mitigation Tool	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
31	Imbalance Adjustment for Third-Party Deployed Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
32	Operating Reserve - Spinning	$ 2,041	$ 2,312	$ 2,581	$ 2,582	$ 2,625	$ 2,638	$ 2,660	$ 2,773	$ 2,941	$ 2,697	$ 2,248	$ 2,137	$ 30,235	-
33	Operating Reserve - Supplemental	$ 1,049	$ 1,188	$ 1,327	$ 1,327	$ 1,349	$ 1,356	$ 1,368	$ 1,426	$ 1,512	$ 1,386	$ 1,155	$ 1,099	$ 15,543	-
34	Operating Reserve - Spinning Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
35	Operating Reserve - Supplemental Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
36	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
37	Synchronous Condensing	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 1,637	-
38	Generation Dropping	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 714	-
39	Redispatch	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 245	-
40	Segmentation of COE/Reclamation Network and Delivery Facilities	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 7,696	-
41	Station Service	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 3,265	9
42	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
43	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
44	Energy Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
45	Generation Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	Invalid Loss Return Penalty	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	Real Power Losses Imbalance Settlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
48	**Generation Inputs / Inter-business line**	**$ 11,455**	**$ 11,865**	**$ 12,508**	**$ 12,509**	**$ 12,574**	**$ 12,864**	**$ 12,897**	**$ 13,092**	**$ 13,347**	**$ 12,977**	**$ 12,296**	**$ 12,129**	**$ 150,512**	**9**
49	4(h)(10)(c)	$ 20,041	$ 11,691	$ 10,649	$ 11,085	$ 9,948	$ 9,428	$ 9,941	$ 8,168	$ 7,786	$ 9,096	$ 6,917	$ 17,415	$ 132,163	-
50	Colville Settlement	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
51	**Treasury Credits**	**$ 20,424**	**$ 12,074**	**$ 11,032**	**$ 11,469**	**$ 10,331**	**$ 9,811**	**$ 10,324**	**$ 8,552**	**$ 8,169**	**$ 9,479**	**$ 7,300**	**$ 17,798**	**$ 136,763**	**-**
52	Augmentation Power Purchase sub-total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
53	Balancing Power Purchase sub-total	$ 21,225	$ 6,572	$ 12,133	$ 11,306	$ 13,791	$ 6,959	$ 5,808	$ 21	$ 20	$ 3,764	$ 3,457	$ 13,913	$ 98,969	209
54	Tier 2 Augmentation total	$ 29,514	$ 29,514	$ 29,514	$ 29,514	$ 29,514	$ 29,514	$ 29,514	$ 29,514	$ 29,514	$ 29,514	$ 29,514	$ 29,514	$ 354,163	638
55	Other Augmentation total	$ 1,748	$ 1,748	$ 1,748	$ 1,748	$ 1,748	$ 1,748	$ 1,748	$ 1,748	$ 1,748	$ 1,748	$ 1,748	$ 1,748	$ 20,974	38
56	**Power Purchases**	**$ 52,487**	**$ 37,833**	**$ 43,395**	**$ 42,567**	**$ 45,052**	**$ 38,221**	**$ 37,069**	**$ 31,282**	**$ 31,282**	**$ 35,025**	**$ 34,719**	**$ 45,174**	**$ 474,106**	**885**

Table 9.2

Revenue at Proposed Rates

	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	**Table 9.2 -Revenue at Proposed Rates**													**2025**	
2	**Category**	**202410**	**202411**	**202412**	**202501**	**202502**	**202503**	**202504**	**202505**	**202506**	**202507**	**202508**	**202509**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 197,392	$ 197,392	$ 197,392	$ 197,392	$ 197,392	$ 197,839	$ 197,839	$ 197,839	$ 197,839	$ 197,839	$ 197,839	$ 197,839	$ 2,371,835	5,323
4	Non-Slice Revenue	$ (27,488)	$ (27,488)	$ (27,488)	$ (27,488)	$ (27,488)	$ (27,566)	$ (27,566)	$ (27,566)	$ (27,566)	$ (27,566)	$ (27,566)	$ (27,566)	$ (330,400)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	1,403
6	Load Shaping Revenue	$ 11,505	$ 997	$ 16,155	$ 20,321	$ 28,389	$ (3,053)	$ 2,595	$ (15,566)	$ (16,340)	$ 603	$ 6,695	$ 8,481	$ 60,782	24
7	Demand Revenue	$ 3,702	$ 1,217	$ 5,472	$ 8,260	$ 13,355	$ 4,111	$ 2,835	$ 1,794	$ 2,250	$ 9,065	$ 10,424	$ 6,175	$ 68,661	-
8	Irrigation Rate Discount	$ -	$ 33	$ -	$ -	$ -	$ -	$ -	$ (3,356)	$ (5,015)	$ (5,776)	$ (4,740)	$ (2,883)	$ (21,737)	-
9	Low Density Discount	$ (3,174)	$ (2,719)	$ (3,050)	$ (3,484)	$ (3,895)	$ (1,867)	$ (2,212)	$ (2,085)	$ (2,142)	$ (3,074)	$ (3,219)	$ (2,569)	$ (33,490)	-
10	Tier 2	$ 17,066	$ 16,525	$ 17,066	$ 17,066	$ 15,394	$ 16,865	$ 16,341	$ 16,897	$ 16,344	$ 16,903	$ 16,898	$ 16,364	$ 199,730	391
11	RSS (Non-Federal) and Other	$ 127	$ (46)	$ (130)	$ (262)	$ (58)	$ 84	$ 84	$ 84	$ 84	$ 84	$ 84	$84	$ 221	-
12	**PF customers (TRM) sub-total**	**$ 199,130**	**$ 185,912**	**$ 205,417**	**$ 211,807**	**$ 223,089**	**$ 186,414**	**$ 189,917**	**$ 168,042**	**$ 165,454**	**$ 188,080**	**$ 196,415**	**$ 195,924**	**$ 2,315,602**	**7,140**
13	**NR sub-total**	**$ (994)**	**$ (794)**	**$ (672)**	**$ (1,039)**	**$ (420)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ (3,919)**	**-**
14	**DSIs sub-total**	**$ 377**	**$ 308**	**$ 468**	**$ 366**	**$ 397**	**$ 371**	**$ 196**	**$ 171**	**$ 141**	**$ 439**	**$ 565**	**$ 467**	**$ 4,266**	**8**
15	**FPS sub-total**	**$ 518**	**$ 1,078**	**$ 1,542**	**$ 1,438**	**$ 1,284**	**$ 764**	**$ 741**	**$ 741**	**$ 755**	**$ 785**	**$ 774**	**$ 731**	**$ 11,150**	**-**
16	**Short-term market sales sub-total**	**$ 50,304**	**$ 44,783**	**$ 47,529**	**$ 69,398**	**$ 61,886**	**$ 38,310**	**$ 46,919**	**$ 34,410**	**$ 49,560**	**$ 68,453**	**$ 49,830**	**$ 26,831**	**$ 588,214**	**1,482**
17	**Long Term Contractual Obligations sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**462**
19	**Other Sales sub-total**	**$ 2**	**$ 2**	**$ 3**	**$ 6**	**$ 0**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ (33,273)**	**$ (33,259)**	**-**
20	**Gross Sales**	**$ 249,337**	**$ 231,291**	**$ 254,288**	**$ 281,976**	**$ 286,237**	**$ 225,859**	**$ 237,773**	**$ 203,364**	**$ 215,910**	**$ 257,756**	**$ 247,585**	**$ 190,679**	**$ 2,882,054**	**9,093**
21	Transfer Service Delivery charge	$ 234	$ 260	$ 282	$ 343	$ 367	$ 248	$ 222	$ 233	$ 243	$ 264	$ 258	$ 233	$ 3,186	-
22	Irrigation Pumping Power	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102	$ 1,225	15
23	Reserve Energy	$ 869	$ 869	$ 869	$ 869	$ 869	$ 869	$ 886	$ 886	$ 886	$ 886	$ 886	$ 886	$ 10,532	160
24	USBR Owyhee Wheeling Project	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 133	$ 133	$ 133	$ 133	$ 133	$ 133	$ 1,629	-
25	Downstream Benefits	$ 723	$ 660	$ 660	$ 1,497	$ 3,177	$ 640	$ 640	$ 619	$ 619	$ 619	$ 619	$ 619	$ 11,093	-
26	Upper Baker Revenues	$ -	$ 105	$ 150	$ 129	$ 127	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 510	-
27	**Miscellaneous Revenue**	**$ 2,066**	**$ 2,135**	**$ 2,201**	**$ 3,077**	**$ 4,779**	**$ 1,997**	**$ 1,984**	**$ 1,974**	**$ 1,984**	**$ 2,005**	**$ 1,999**	**$ 1,974**	**$ 28,175**	**175**
28	Balancing Reserve Capacity	$ 4,933	$ 4,933	$ 4,933	$ 4,944	$ 4,944	$ 4,944	$ 4,944	$ 4,944	$ 4,944	$ 4,944	$ 4,944	$ 4,944	$ 59,300	-
29	ACS Risk Share	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
30	Risk Mitigation Tool	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
31	Imbalance Adjustment for Third-Party Deployed Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
32	Operating Reserve - Spinning	$ 1,616	$ 1,964	$ 2,088	$ 2,217	$ 2,111	$ 1,862	$ 2,060	$ 2,263	$ 2,469	$ 2,123	$ 1,954	$ 1,725	$ 24,451	-
33	Operating Reserve - Supplemental	$ 992	$ 1,206	$ 1,282	$ 1,361	$ 1,297	$ 1,144	$ 1,265	$ 1,390	$ 1,516	$ 1,304	$ 1,200	$ 1,059	$ 15,016	-
34	Operating Reserve - Spinning Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
35	Operating Reserve - Supplemental Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
36	Operating Reserve - Energy	$ 33	$ -	$ 41	$ 11	$ 13	$ 34	$ 27	$ 25	$ 35	$ 74	$ 65	$ 54	$ 411	-
37	Synchronous Condensing	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 1,292	-
38	Generation Dropping	$ -	$ 92	$ 50	$ 50	$ 50	$ 50	$ 50	$ 50	$ 50	$ 50	$ 50	$ 50	$ 595	-
39	Redispatch	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 332	-
40	Segmentation of COE/Reclamation Network and Delivery Facilities	$ 680	$ 680	$ 680	$ 680	$ 680	$ 680	$ 680	$ 680	$ 680	$ 680	$ 680	$ 680	$ 8,161	-
41	Station Service	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 3,307	9
42	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
43	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
44	Energy Imbalance Persistent Deviation	$ 17	$ (22)	$ 4	$ 269	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 267	-
45	Generation Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	Invalid Loss Return Penalty	$ 6	$ 5	$ 3	$ 3	$ 7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 24	-
47	Real Power Losses Imbalance Settlement	$ (10)	$ 8	$ 7	$ 12	$ (6)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11	-
48	**Generation Inputs / Inter-business line**	**$ 8,678**	**$ 9,276**	**$ 9,500**	**$ 9,959**	**$ 9,507**	**$ 9,125**	**$ 9,437**	**$ 9,764**	**$ 10,107**	**$ 9,587**	**$ 9,304**	**$ 8,924**	**$ 113,167**	**9**
49	4(h)(10)(c)	$ 13,494	$ 15,123	$ 12,778	$ 21,342	$ 17,762	$ 15,486	$ 9,181	$ 8,492	$ 6,672	$ 6,761	$ 6,349	$ 13,300	$ 146,741	-
50	Colville Settlement	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
51	**Treasury Credits**	**$ 13,877**	**$ 15,506**	**$ 13,161**	**$ 21,725**	**$ 18,146**	**$ 15,869**	**$ 9,565**	**$ 8,875**	**$ 7,056**	**$ 7,145**	**$ 6,732**	**$ 13,684**	**$ 151,341**	**-**
52	Augmentation Power Purchase sub-total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
53	Balancing Power Purchase sub-total	$ 51,821	$ 27,933	$ 30,869	$ 81,477	$ 105,012	$ 25,618	$ 56,785	$ 19,153	$ 10	$ 10,409	$ 16,000	$ 29,002	$ 454,090	1,129
54	Tier 2 Augmentation total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
55	Other Augmentation total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
56	**Power Purchases**	**$ 51,821**	**$ 27,933**	**$ 30,869**	**$ 81,477**	**$ 105,012**	**$ 25,618**	**$ 56,785**	**$ 19,153**	**$ 10**	**$ 10,409**	**$ 16,000**	**$ 29,002**	**$ 454,090**	**1,129**

Table 9.2 (continued)

Revenue at Proposed Rates

	A B C D	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF
1	**Table 9.2 -Revenue at Proposed Rates**													**2026**	
2	**Category**	**202510**	**202511**	**202512**	**202601**	**202602**	**202603**	**202604**	**202605**	**202606**	**202607**	**202608**	**202609**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 203,205	$ 203,205	$ 203,205	$ 203,205	$ 203,205	$ 203,205	$ 203,205	$ 203,205	$ 203,205	$ 203,205	$ 203,205	$ 203,205	$ 2,438,459	5,916
4	Non-Slice Revenue	$ (30,442)	$ (30,442)	$ (30,442)	$ (30,442)	$ (30,442)	$ (30,442)	$ (30,442)	$ (30,442)	$ (30,442)	$ (30,442)	$ (30,442)	$ (30,442)	$ (365,300)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	840
6	Load Shaping Revenue	$ 23,008	$ 4,488	$ 21,653	$ 10,174	$ 22,214	$ 4,621	$ 7,405	$ (9,832)	$ (18,371)	$ (2,792)	$ (12,080)	$ 21,607	$ 72,093	4
7	Demand Revenue	$ 10,411	$ 7,621	$ 17,183	$ 16,279	$ 13,559	$ 9,899	$ 6,845	$ 1,534	$ 4,769	$ 16,997	$ 21,229	$ 15,313	$ 141,637	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,396)	$ (5,076)	$ (5,846)	$ (4,797)	$ (2,918)	$ (22,034)	-
9	Low Density Discount	$ (3,714)	$ (3,033)	$ (3,849)	$ (3,561)	$ (3,549)	$ (3,211)	$ (3,444)	$ (2,946)	$ (3,004)	$ (4,146)	$ (3,891)	$ (3,805)	$ (42,155)	-
10	Tier 2	$ 27,353	$ 27,353	$ 27,353	$ 27,353	$ 27,353	$ 27,353	$ 27,353	$ 27,353	$ 27,353	$ 27,353	$ 27,353	$ 27,353	$ 328,238	538
11	RSS (Non-Federal) and Other	$ 70	$ 70	$ 70	$ 70	$ 70	$ 70	$ 70	$ 70	$ 70	$ 70	$ 70	$ 70	$ 836	-
12	**PF customers (TRM) sub-total**	**$ 229,891**	**$ 209,261**	**$ 235,172**	**$ 223,078**	**$ 232,410**	**$ 211,494**	**$ 210,991**	**$ 185,546**	**$ 178,503**	**$ 204,399**	**$ 200,646**	**$ 230,382**	**$ 2,551,774**	**7,298**
13	**NR sub-total**	**$ 1,048**	**$ 815**	**$ 921**	**$ 809**	**$ 869**	**$ 550**	**$ 430**	**$ 179**	**$ 325**	**$ 1,141**	**$ 1,154**	**$ 1,966**	**$ 10,208**	**1**
14	**DSIs sub-total**	**$ 459**	**$ 370**	**$ 445**	**$ 408**	**$ 394**	**$ 308**	**$ 242**	**$ 136**	**$ 172**	**$ 457**	**$ 479**	**$ 523**	**$ 4,394**	**11**
15	**FPS sub-total**	**$ 723**	**$ 798**	**$ 969**	**$ 970**	**$ 861**	**$ 813**	**$ 742**	**$ 750**	**$ 785**	**$ 866**	**$ 841**	**$ 734**	**$ 9,852**	**-**
16	**Short-term market sales sub-total**	**$ 29,731**	**$ 44,576**	**$ 72,344**	**$ 87,012**	**$ 78,647**	**$ 60,074**	**$ 46,251**	**$ 47,374**	**$ 62,237**	**$ 100,526**	**$ 84,274**	**$ 33,799**	**$ 746,846**	**1,729**
17	**Long Term Contractual Obligations sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**462**
19	**Other Sales sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
20	**Gross Sales**	**$ 261,852**	**$ 255,821**	**$ 309,852**	**$ 312,277**	**$ 313,181**	**$ 273,239**	**$ 258,657**	**$ 233,986**	**$ 242,022**	**$ 307,390**	**$ 287,394**	**$ 267,405**	**$ 3,323,075**	**9,501**
21	Transfer Service Delivery charge	$ 217	$ 222	$ 315	$ 346	$ 300	$ 248	$ 222	$ 233	$ 243	$ 264	$ 258	$ 233	$ 3,100	-
22	Irrigation Pumping Power	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 1,207	15
23	Reserve Energy	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 10,482	160
24	USBR Owyhee Wheeling Project	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 1,732	-
25	Downstream Benefits	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 7,772	-
26	Upper Baker Revenues	$ -	$ 107	$ 131	$ 122	$ 125	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 485	-
27	**Miscellaneous Revenue**	**$ 1,983**	**$ 2,095**	**$ 2,212**	**$ 2,234**	**$ 2,191**	**$ 2,014**	**$ 1,988**	**$ 1,999**	**$ 2,009**	**$ 2,030**	**$ 2,024**	**$ 1,999**	**$ 24,778**	**175**
28	Balancing Reserve Capacity	$ 4,916	$ 4,916	$ 4,931	$ 4,969	$ 4,969	$ 4,984	$ 4,984	$ 5,023	$ 5,023	$ 5,023	$ 5,023	$ 5,023	$ 59,785	-
29	ACS Risk Share	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
30	Risk Mitigation Tool	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
31	Imbalance Adjustment for Third-Party Deployed Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
32	Operating Reserve - Spinning	$ 1,867	$ 2,132	$ 2,395	$ 2,397	$ 2,422	$ 2,412	$ 2,428	$ 2,508	$ 2,643	$ 2,396	$ 2,193	$ 1,897	$ 27,690	-
33	Operating Reserve - Supplemental	$ 960	$ 1,096	$ 1,231	$ 1,232	$ 1,245	$ 1,240	$ 1,248	$ 1,290	$ 1,359	$ 1,232	$ 1,128	$ 975	$ 14,235	-
34	Operating Reserve - Spinning Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
35	Operating Reserve - Supplemental Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
36	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
37	Synchronous Condensing	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 1,637	-
38	Generation Dropping	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 714	-
39	Redispatch	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 245	-
40	Segmentation of COE/Reclamation Network and Delivery Facilities	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 7,696	-
41	Station Service	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 3,265	9
42	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
43	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
44	Energy Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
45	Generation Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	Invalid Loss Return Penalty	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	Real Power Losses Imbalance Settlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
48	**Generation Inputs / Inter-business line**	**$ 8,872**	**$ 9,273**	**$ 9,686**	**$ 9,728**	**$ 9,766**	**$ 9,766**	**$ 9,790**	**$ 9,951**	**$ 10,154**	**$ 9,781**	**$ 9,474**	**$ 9,025**	**$ 115,267**	**9**
49	4(h)(10)(c)	$ 20,138	$ 11,184	$ 9,923	$ 10,430	$ 9,432	$ 8,892	$ 9,394	$ 7,556	$ 6,949	$ 8,254	$ 6,216	$ 16,541	$ 124,911	-
50	Colville Settlement	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
51	**Treasury Credits**	**$ 20,522**	**$ 11,568**	**$ 10,306**	**$ 10,813**	**$ 9,815**	**$ 9,275**	**$ 9,778**	**$ 7,939**	**$ 7,332**	**$ 8,638**	**$ 6,600**	**$ 16,925**	**$ 129,511**	**-**
52	Augmentation Power Purchase sub-total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
53	Balancing Power Purchase sub-total	$ 21,569	$ 6,309	$ 13,038	$ 12,313	$ 16,218	$ 6,981	$ 6,753	$ 21	$ 22	$ 3,970	$ 3,325	$ 13,582	$ 104,101	211
54	Tier 2 Augmentation total	$ 26,619	$ 26,619	$ 26,619	$ 26,619	$ 26,619	$ 26,619	$ 26,619	$ 26,619	$ 26,619	$ 26,619	$ 26,619	$ 26,619	$ 319,432	554
55	Other Augmentation total	$ 585	$ 585	$ 585	$ 585	$ 585	$ 585	$ 585	$ 585	$ 585	$ 585	$ 585	$ 585	$ 7,021	12
56	**Power Purchases**	**$ 48,773**	**$ 33,513**	**$ 40,242**	**$ 39,517**	**$ 43,422**	**$ 34,185**	**$ 33,958**	**$ 27,225**	**$ 27,227**	**$ 31,175**	**$ 30,530**	**$ 40,786**	**$ 430,554**	**777**

Table 9.2 (continued)

Revenue at Proposed Rates

	A B C D	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT
1	**Table 9.2 -Revenue at Proposed Rates**													**2027**	
2	**Category**	**202610**	**202611**	**202612**	**202701**	**202702**	**202703**	**202704**	**202705**	**202706**	**202707**	**202708**	**202709**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 204,084	$ 204,084	$ 204,084	$ 204,084	$ 204,084	$ 204,084	$ 204,084	$ 204,084	$ 204,084	$ 204,084	$ 204,084	$ 204,084	$ 2,449,006	6,776
4	Non-Slice Revenue	$ (30,592)	$ (30,592)	$ (30,592)	$ (30,592)	$ (30,592)	$ (30,592)	$ (30,592)	$ (30,592)	$ (30,592)	$ (30,592)	$ (30,592)	$ (30,592)	$ (367,103)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	826
6	Load Shaping Revenue	$ 23,251	$ 5,397	$ 22,711	$ 11,005	$ 23,113	$ 4,626	$ 7,529	$ (9,874)	$ (18,506)	$ (2,636)	$ (11,936)	$ 22,143	$ 76,824	16
7	Demand Revenue	$ 10,846	$ 8,379	$ 17,688	$ 16,721	$ 14,285	$ 10,662	$ 7,244	$ 1,662	$ 4,897	$ 17,337	$ 22,374	$ 16,117	$ 148,212	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,396)	$ (5,076)	$ (5,846)	$ (4,797)	$ (2,918)	$ (22,034)	-
9	Low Density Discount	$ (3,827)	$ (3,161)	$ (3,958)	$ (3,727)	$ (3,649)	$ (3,261)	$ (3,522)	$ (3,009)	$ (3,061)	$ (4,216)	$ (4,006)	$ (3,900)	$ (43,297)	-
10	Tier 2	$ 28,316	$ 28,316	$ 28,316	$ 28,316	$ 28,316	$ 28,316	$ 28,316	$ 28,316	$ 28,316	$ 28,316	$ 28,316	$ 28,316	$ 339,794	588
11	RSS (Non-Federal) and Other	$ 465	$ 465	$ 465	$ 465	$ 465	$ 465	$ 465	$ 465	$ 465	$ 465	$ 465	$ 465	$ 5,582	-
12	**PF customers (TRM) sub-total**	**$ 232,543**	**$ 212,889**	**$ 238,714**	**$ 226,272**	**$ 236,023**	**$ 214,300**	**$ 213,524**	**$ 187,656**	**$ 180,528**	**$ 206,913**	**$ 203,907**	**$ 233,715**	**$ 2,586,983**	**8,206**
13	**NR sub-total**	**$ 2,057**	**$ 2,362**	**$ 2,915**	**$ 2,643**	**$ 2,680**	**$ 2,958**	**$ 2,535**	**$ 1,305**	**$ 1,466**	**$ 2,874**	**$ 2,279**	**$ 4,520**	**$ 30,593**	**20**
14	**DSIs sub-total**	**$ 459**	**$ 370**	**$ 445**	**$ 408**	**$ 394**	**$ 308**	**$ 242**	**$ 136**	**$ 172**	**$ 457**	**$ 479**	**$ 523**	**$ 4,394**	**11**
15	**FPS sub-total**	**$ 743**	**$ 811**	**$ 996**	**$ 998**	**$ 866**	**$ 830**	**$ 766**	**$ 766**	**$ 805**	**$ 886**	**$ 857**	**$ 738**	**$ 10,063**	**-**
16	**Short-term market sales sub-total**	**$ 21,309**	**$ 38,034**	**$ 64,651**	**$ 77,474**	**$ 63,434**	**$ 46,700**	**$ 34,727**	**$ 31,323**	**$ 53,088**	**$ 91,103**	**$ 70,783**	**$ 25,463**	**$ 618,090**	**1,738**
17	**Long Term Contractual Obligations sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**462**
19	**Other Sales sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
20	**Gross Sales**	**$ 257,111**	**$ 254,466**	**$ 307,720**	**$ 307,795**	**$ 303,396**	**$ 265,097**	**$ 251,795**	**$ 221,187**	**$ 236,058**	**$ 302,233**	**$ 278,305**	**$ 264,959**	**$ 3,250,123**	**10,437**
21	Transfer Service Delivery charge	$ 217	$ 222	$ 315	$ 346	$ 300	$ 248	$ 222	$ 233	$ 243	$ 264	$ 258	$ 233	$ 3,100	-
22	Irrigation Pumping Power	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 1,207	15
23	Reserve Energy	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 10,482	160
24	USBR Owyhee Wheeling Project	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 1,732	-
25	Downstream Benefits	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 7,772	-
26	Upper Baker Revenues	$ -	$ 107	$ 130	$ 119	$ 119	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 476	-
27	**Miscellaneous Revenue**	**$ 1,983**	**$ 2,096**	**$ 2,211**	**$ 2,231**	**$ 2,185**	**$ 2,014**	**$ 1,988**	**$ 1,999**	**$ 2,009**	**$ 2,030**	**$ 2,024**	**$ 1,999**	**$ 24,769**	**175**
28	Balancing Reserve Capacity	$ 5,555	$ 5,555	$ 5,957	$ 6,132	$ 6,420	$ 6,420	$ 6,580	$ 6,619	$ 6,741	$ 6,741	$ 6,741	$ 6,741	$ 76,201	-
29	ACS Risk Share	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
30	Risk Mitigation Tool	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
31	Imbalance Adjustment for Third-Party Deployed Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
32	Operating Reserve - Spinning	$ 1,973	$ 2,227	$ 2,513	$ 2,535	$ 2,565	$ 2,597	$ 2,533	$ 2,612	$ 2,833	$ 2,600	$ 2,140	$ 2,028	$ 29,156	-
33	Operating Reserve - Supplemental	$ 1,015	$ 1,145	$ 1,292	$ 1,303	$ 1,318	$ 1,335	$ 1,302	$ 1,343	$ 1,456	$ 1,337	$ 1,100	$ 1,043	$ 14,989	-
34	Operating Reserve - Spinning Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
35	Operating Reserve - Supplemental Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
36	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
37	Synchronous Condensing	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 1,637	-
38	Generation Dropping	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 714	-
39	Redispatch	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 245	-
40	Segmentation of COE/Reclamation Network and Delivery Facilities	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 7,696	-
41	Station Service	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 3,265	9
42	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
43	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
44	Energy Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
45	Generation Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	Invalid Loss Return Penalty	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	Real Power Losses Imbalance Settlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
48	**Generation Inputs / Inter-business line**	**$ 9,672**	**$ 10,056**	**$ 10,891**	**$ 11,101**	**$ 11,433**	**$ 11,482**	**$ 11,545**	**$ 11,704**	**$ 12,159**	**$ 11,808**	**$ 11,111**	**$ 10,941**	**$ 133,903**	**9**
49	4(h)(10)(c)	$ 20,477	$ 17,924	$ 12,644	$ 10,429	$ 11,080	$ 9,401	$ 8,221	$ 9,011	$ 9,168	$ 8,273	$ 7,733	$ 6,756	$ 131,117	-
50	Colville Settlement	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
51	**Treasury Credits**	**$ 20,860**	**$ 18,308**	**$ 13,028**	**$ 10,813**	**$ 11,464**	**$ 9,784**	**$ 8,604**	**$ 9,394**	**$ 9,551**	**$ 8,656**	**$ 8,117**	**$ 7,139**	**$ 135,717**	**-**
52	Augmentation Power Purchase sub-total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
53	Balancing Power Purchase sub-total	$ 17,221	$ 5,658	$ 11,311	$ 10,531	$ 15,539	$ 5,383	$ 4,145	$ 151	$ 39	$ 2,330	$ 1,888	$ 9,055	$ 83,251	178
54	Tier 2 Augmentation total	$ 27,460	$ 27,460	$ 27,460	$ 27,460	$ 27,460	$ 27,460	$ 27,460	$ 27,460	$ 27,460	$ 27,460	$ 27,460	$ 27,460	$ 329,517	599
55	Other Augmentation total	$ 1,453	$ 1,453	$ 1,453	$ 1,453	$ 1,453	$ 1,453	$ 1,453	$ 1,453	$ 1,453	$ 1,453	$ 1,453	$ 1,453	$ 17,440	31
56	**Power Purchases**	**$ 46,134**	**$ 34,571**	**$ 40,224**	**$ 39,444**	**$ 44,452**	**$ 34,296**	**$ 33,058**	**$ 29,064**	**$ 28,952**	**$ 31,243**	**$ 30,801**	**$ 37,968**	**$ 430,208**	**809**

Table 9.2 (continued)

Revenue at Proposed Rates

	A B C D	AU	AV	AW	AX	AY	AZ	BA	BB	BC	BD	BE	BF	BG	BH
1	**Table 9.2 -Revenue at Proposed Rates**													**2028**	
2	**Category**	**202710**	**202711**	**202712**	**202801**	**202802**	**202803**	**202804**	**202805**	**202806**	**202807**	**202808**	**202809**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 204,799	$ 204,799	$ 204,799	$ 204,799	$ 204,799	$ 204,799	$ 204,799	$ 204,799	$ 204,799	$ 204,799	$ 204,799	$ 204,799	$ 2,457,587	6,800
4	Non-Slice Revenue	$ (30,714)	$ (30,714)	$ (30,714)	$ (30,714)	$ (30,714)	$ (30,714)	$ (30,714)	$ (30,714)	$ (30,714)	$ (30,714)	$ (30,714)	$ (30,714)	$ (368,571)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	842
6	Load Shaping Revenue	$ 23,864	$ 5,398	$ 22,823	$ 11,109	$ 20,298	$ 4,598	$ 7,818	$ (10,474)	$ (18,841)	$ (3,521)	$ (12,221)	$ 21,872	$ 72,724	3
7	Demand Revenue	$ 11,901	$ 8,943	$ 18,161	$ 18,061	$ 15,205	$ 11,432	$ 8,015	$ 1,722	$ 5,070	$ 17,325	$ 23,432	$ 17,199	$ 156,468	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,396)	$ (5,076)	$ (5,846)	$ (4,797)	$ (2,918)	$ (22,034)	-
9	Low Density Discount	$ (4,029)	$ (3,181)	$ (4,047)	$ (3,877)	$ (3,716)	$ (3,359)	$ (3,680)	$ (3,019)	$ (3,111)	$ (4,294)	$ (4,068)	$ (4,011)	$ (44,391)	-
10	Tier 2	$ 30,442	$ 30,442	$ 30,442	$ 30,442	$ 30,442	$ 30,442	$ 30,442	$ 30,442	$ 30,442	$ 30,442	$ 30,442	$ 30,442	$ 365,302	627
11	RSS (Non-Federal) and Other	$ 403	$ 403	$ 403	$ 403	$ 403	$ 403	$ 403	$ 403	$ 403	$ 403	$ 403	$403	$ 4,839	-
12	**PF customers (TRM) sub-total**	**$ 236,666**	**$ 216,091**	**$ 241,868**	**$ 230,222**	**$ 236,717**	**$ 217,601**	**$ 217,084**	**$ 189,761**	**$ 182,972**	**$ 208,594**	**$ 207,276**	**$ 237,072**	**$ 2,621,924**	**8,272**
13	**NR sub-total**	**$ 4,724**	**$ 2,394**	**$ 3,359**	**$ 3,163**	**$ 3,253**	**$ 2,675**	**$ 2,375**	**$ 1,844**	**$ 2,151**	**$ 4,144**	**$ 4,273**	**$ 4,569**	**$ 38,924**	**25**
14	**DSIs sub-total**	**$ 459**	**$ 370**	**$ 445**	**$ 408**	**$ 408**	**$ 308**	**$ 242**	**$ 136**	**$ 172**	**$ 457**	**$ 479**	**$ 523**	**$ 4,406**	**11**
15	**FPS sub-total**	**$ 763**	**$ 834**	**$ 1,024**	**$ 1,026**	**$ 890**	**$ 854**	**$ 788**	**$ 788**	**$ 827**	**$ 911**	**$ 882**	**$ 758**	**$ 10,346**	**-**
16	**Short-term market sales sub-total**	**$ 23,539**	**$ 37,113**	**$ 63,436**	**$ 74,668**	**$ 67,195**	**$ 47,248**	**$ 38,081**	**$ 35,311**	**$ 54,852**	**$ 98,268**	**$ 77,084**	**$ 28,718**	**$ 645,514**	**1,758**
17	**Long Term Contractual Obligations sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**461**
19	**Other Sales sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
20	**Gross Sales**	**$266,152**	**$ 256,802**	**$ 310,131**	**$ 309,488**	**$ 308,463**	**$ 268,686**	**$ 258,570**	**$ 227,840**	**$ 240,973**	**$ 312,375**	**$ 289,993**	**$ 271,640**	**$ 3,321,114**	**10,528**
21	Transfer Service Delivery charge	$ 217	$ 222	$ 315	$ 346	$ 300	$ 248	$ 222	$ 233	$ 243	$ 264	$ 258	$ 233	$ 3,100	-
22	Irrigation Pumping Power	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 1,207	15
23	Reserve Energy	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 874	$ 10,482	159
24	USBR Owyhee Wheeling Project	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 144	$ 1,732	-
25	Downstream Benefits	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 648	$ 7,772	-
26	Upper Baker Revenues	$ -	$ 102	$ 129	$ 115	$ 111	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 456	-
27	**Miscellaneous Revenue**	**$1,983**	**$ 2,090**	**$ 2,210**	**$ 2,227**	**$ 2,176**	**$ 2,014**	**$ 1,988**	**$ 1,999**	**$ 2,009**	**$ 2,030**	**$ 2,024**	**$ 1,999**	**$ 24,749**	**175**
28	Balancing Reserve Capacity	$ 7,235	$ 7,235	$ 7,470	$ 7,470	$ 7,470	$ 7,740	$ 7,740	$ 7,763	$ 7,763	$ 7,763	$ 7,763	$ 7,763	$ 91,177	-
29	ACS Risk Share	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
30	Risk Mitigation Tool	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
31	Imbalance Adjustment for Third-Party Deployed Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
32	Operating Reserve - Spinning	$ 2,041	$ 2,312	$ 2,581	$ 2,582	$ 2,625	$ 2,638	$ 2,660	$ 2,773	$ 2,941	$ 2,697	$ 2,248	$ 2,137	$ 30,235	-
33	Operating Reserve - Supplemental	$ 1,049	$ 1,188	$ 1,327	$ 1,327	$ 1,349	$ 1,356	$ 1,368	$ 1,426	$ 1,512	$ 1,386	$ 1,155	$ 1,099	$ 15,543	-
34	Operating Reserve - Spinning Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
35	Operating Reserve - Supplemental Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
36	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
37	Synchronous Condensing	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 136	$ 1,637	-
38	Generation Dropping	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 60	$ 714	-
39	Redispatch	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 20	$ 245	-
40	Segmentation of COE/Reclamation Network and Delivery Facilities	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 641	$ 7,696	-
41	Station Service	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 272	$ 3,265	9
42	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
43	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
44	Energy Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
45	Generation Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	Invalid Loss Return Penalty	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	Real Power Losses Imbalance Settlement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
48	**Generation Inputs / Inter-business line**	**$ 11,455**	**$ 11,865**	**$ 12,508**	**$ 12,509**	**$ 12,574**	**$ 12,864**	**$ 12,897**	**$ 13,092**	**$ 13,347**	**$ 12,977**	**$ 12,296**	**$ 12,129**	**$ 150,512**	**9**
49	4(h)(10)(c)	$ 20,041	$ 11,691	$ 10,649	$ 11,085	$ 9,948	$ 9,428	$ 9,941	$ 8,168	$ 7,786	$ 9,096	$ 6,917	$ 17,415	$ 132,163	-
50	Colville Settlement	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
51	**Treasury Credits**	**$ 20,424**	**$ 12,074**	**$ 11,032**	**$ 11,469**	**$ 10,331**	**$ 9,811**	**$ 10,324**	**$ 8,552**	**$ 8,169**	**$ 9,479**	**$ 7,300**	**$ 17,798**	**$ 136,763**	**-**
52	Augmentation Power Purchase sub-total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
53	Balancing Power Purchase sub-total	$ 21,225	$ 6,572	$ 12,133	$ 11,306	$ 13,791	$ 6,959	$ 5,808	$ 21	$ 20	$ 3,764	$ 3,457	$ 13,913	$ 98,969	209
54	Tier 2 Augmentation total	$ 29,514	$ 29,514	$ 29,514	$ 29,514	$ 29,514	$ 29,514	$ 29,514	$ 29,514	$ 29,514	$ 29,514	$ 29,514	$ 29,514	$ 354,163	638
55	Other Augmentation total	$ 1,748	$ 1,748	$ 1,748	$ 1,748	$ 1,748	$ 1,748	$ 1,748	$ 1,748	$ 1,748	$ 1,748	$ 1,748	$ 1,748	$ 20,974	38
56	**Power Purchases**	**$ 52,487**	**$ 37,833**	**$ 43,395**	**$ 42,567**	**$ 45,052**	**$ 38,221**	**$ 37,069**	**$ 31,282**	**$ 31,282**	**$ 35,025**	**$ 34,719**	**$ 45,174**	**$ 474,106**	**885**

Table 9.3.1.1

Inter-Business Line Allocations
Annual Average for FY 2026-2028

	A	B
	Generation Inputs	Revenue Forecast ($)
1	Reserve Forecast	
2	Balancing Reserves	$ 75,712,200
3	Operating Reserves	$ 43,949,278
4	Operating Reserves - Spinning	$ 29,027,106
5	Operating Reserves - Supplemental	$ 14,922,172
6	Reserves Total (lines 2+3)	$ 119,661,478
7		
8	Other Forecasts	
9	Synchronous Condensing	$ 1,636,876
10	Generation Dropping	$ 714,375
11	Redispatch	$ 244,883
12	Segmentation of COE/BOR	$ 7,696,000
13	Station Service	$ 3,264,936
14	Other Total (lines 9-13)	$ 13,557,070
15		
16	Total Generation Inputs Credit Forecast (lines 6+14)	$ 133,218,548

Table 9.3.1.2
FCRPS 1-Hour Peaking Capacity for FY 2026, FY 2027, and FY2028
Adjusted for Transmission Losses Monthly P10 Water Conditions

	A	B	C	D	E	F	G	H	I	J	K	L	N	N	O	P
		Annual Average	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**1-Apr**	**16-Apr**	**May**	**Jun**	**Jul**	**1-Aug**	**16-Aug**	**Sep**
1	**FY 2026 Federal Resources**															
2	Regulated Hydro	**15,179.7**	14,160.9	16,303.5	16,864.4	16,972.7	16,497.4	16,549.1	15,604.5	11,699.5	12,852.4	15,624.4	14,422.8	14,268.9	12,986.7	14,721.0
3	Independent Hydro	**288.2**	162.7	426.9	235.8	388.0	267.6	161.8	198.9	151.0	305.5	418.2	331.2	212.8	209.1	382.0
4	Small Hydro	**4.2**	4.1	4.5	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.1	3.2	3.5	3.5	3.0
5	Large Thermal (Columbia Generation Station)	**1,170.9**	1,181.0	1,179.0	1,180.0	1,178.0	1,175.0	1,177.0	1,166.0	1,166.0	1,151.0	1,154.0	1,168.0	1,163.0	1,163.0	1,179.0
6	Renewable Resources	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Augmentation Purchases	**134.9**	134.9	134.9	134.9	134.9	134.9	134.9	134.9	134.9	134.9	134.9	134.9	134.9	134.9	134.9
8	Augmentation Purchases (to serve Tier 2 Load)	**18.4**	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
9	**FY 2027 Federal Resources**	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Regulated Hydro	**15,470.0**	14,428.3	15,834.8	16,693.3	17,680.3	17,232.8	16,917.8	15,232.5	11,434.9	13,219.4	15,289.1	15,337.2	14,685.6	13,723.0	15,596.3
11	Independent Hydro	**288.0**	162.7	224.6	235.8	296.3	375.7	124.1	413.6	200.9	439.7	349.2	312.5	274.8	209.1	399.8
12	Small Hydro	**4.2**	4.1	4.5	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.1	3.2	3.5	3.5	3.0
13	Large Thermal (Columbia Generation Station)	**1,170.9**	1,181.0	1,179.0	1,180.0	1,178.0	1,175.0	1,177.0	1,166.0	1,166.0	1,151.0	1,154.0	1,168.0	1,163.0	1,163.0	1,179.0
14	Renewable Resources	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Augmentation Purchases	**336.6**	336.6	336.6	336.6	336.6	336.6	336.6	336.6	336.6	336.6	336.6	336.6	336.6	336.6	336.6
16	Augmentation Purchases (to serve Tier 2 Load)	**30.6**	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6	30.6
17	**FY 2028 Federal Resources**	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Regulated Hydro	**15,457.0**	14,195.0	16,639.0	16,177.2	17,010.7	17,161.8	16,956.7	15,250.1	11,386.2	12,723.6	15,167.4	16,387.1	14,990.5	13,795.9	15,442.9
19	Independent Hydro	**272.7**	155.2	308.6	154.8	267.6	267.6	108.6	480.3	200.9	332.2	349.2	359.5	280.8	209.1	394.1
20	Small Hydro	**4.2**	4.1	4.5	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.1	3.2	3.5	3.5	3.0
21	Large Thermal (Columbia Generation Station)	**1,170.9**	1,181.0	1,179.0	1,180.0	1,178.0	1,175.0	1,177.0	1,166.0	1,166.0	1,151.0	1,154.0	1,168.0	1,163.0	1,163.0	1,179.0
22	Renewable Resources	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Augmentation Purchases	**295.8**	295.8	295.8	295.8	295.8	295.8	295.8	295.8	295.8	295.8	295.8	295.8	295.8	295.8	295.8
24	Augmentation Purchases (to serve Tier 2 Load)	**37.7**	37.7	37.7	37.7	37.7	37.7	37.7	37.7	37.7	37.7	37.7	37.7	37.7	37.7	37.7
25	**Rate Period Average After Losses**	**-**														
26	Regulated Hydro	**14,883.5**														
27	Independent Hydro	**274.0**														
28	Small Hydro	**4.0**														
29	Large Thermal (Columbia Generation Station)	**1,133.9**														
30	Renewable Resources	**-**														
31	Augmentation Purchases	**247.6**														
32	Augmentation Purchases (to serve Tier 2 Load)	**28.0**														
33	1-Hour Capacity Adjusted for Transmission Losses	**16,571.0**														

	Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**1-Apr**	**16-Apr**	**May**	**Jun**	**Jul**	**1-Aug**	**16-Aug**	**Sep**
2026	31	30	31	31	28	31	15	15	31	30	31	15	16	30

	Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**1-Apr**	**16-Apr**	**May**	**Jun**	**Jul**	**1-Aug**	**16-Aug**	**Sep**
2027	31	30	31	31	28	31	15	15	31	30	31	15	16	30

	Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**1-Apr**	**16-Apr**	**May**	**Jun**	**Jul**	**1-Aug**	**16-Aug**	**Sep**
2028	31	30	31	31	29	31	15	15	31	30	31	15	16	30

Table 9.3.1.3

Capacity Costs
($ in thousands)

	A	B FY 2026	C FY 2027	D FY 2028	Capacity Classification (%)	E Annual Average for FY 2026-FY 2028 Classified to Capacity
1	**Capital Related Costs**					
2	Depreciation	$ 148,559	$ 152,451	$ 156,446	100%	$ 152,486
3	Amortization	$ 368,549	$ 401,713	$ 429,362	100%	$ 399,875
4	Interest Expense	$ 199,685	$ 181,242	$ 181,106	100%	$ 187,344
5	Minimum Required Net Revenues	$ 130,583	$ 117,276	$ 232,024	100%	$ 159,961
6	Decommissioning Costs	$ 2,700	$ 2,760	$ 2,822	100%	$ 2,761
7	**Subtotal**	**$ 850,076**	**$ 855,441**	**$ 1,001,761**		**$ 902,426**
8						
9	**Fish & Wildlife Costs**					
10	Fish & Wildlife (Other than Planning Council)	$ 354,396	$ 362,402	$ 371,787	100%	$ 362,862
11	Fish & Wildlife - Planning Council	$ 12,041	$ 11,876	$ 12,052	50%	$ 5,995
12	**Subtotal**	**$ 366,437**	**$ 374,278**	**$ 383,839**		**$ 368,857**
13						
14	**Power Purchase Costs**					
15	Clearwater Hatchery Generation	$ 1,600	$ 1,636	$ 1,673	60%	$ 990
16	Non-Tier 2 Augmentation Power Purchases	$ 10,809	$ 17,045	$ 21,197	50%	$ 8,175
17	Tier 2 Augmentation Power Purchases	$ 83,990	$ 191,875	$ 169,536	50%	$ 74,233
18	**Subtotal**	**$ 96,399**	**$ 210,555**	**$ 192,406**		**$ 83,398**
19						
20	**Cost Adjustments**					
21	4h10C	$ (124,911)	$ (131,117)	$ (132,163)	65%	$ (84,754)
22	Synchronous Condensing	$ (1,637)	$ (1,637)	$ (1,637)	12%	$ (189)
23	**Subtotal**	**$ (126,548)**	**$ (132,754)**	**$ (133,800)**		**$ (84,943)**
24	**Total Allocated Costs**					**$ 1,269,738**

Table 9.3.1.4

Embedded Cost Calculation
($ in Thousands)

	A	B
		Annual Average FY2026-FY2028
1	**Forecast of Total Capacity of Federal System Resources:**	
2	Total Capacity of Federal System Resources	16,571
3		
4	**Revenue Requirement:**	
5	Capacity Costs	$ 1,269,738
6	Hydro Projects Capacity System Uses (Line 2)	16,571
7	Total kW/month/year Hydro Project Capacity System Uses (Line 6 * 12 months * 1000 kW/MW)	198,851,806
8	**Unit Cost Allocation of Capacity System Uses $/kW/month (Line 5 / Line 7)**	$ 6.39

Table 9.3.1.5
Variable Fuel Costs of Regulation Balancing Reserves and Operating Reserves

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
	Month	Year	DEC Shift (MWh)	DEC Net Gen (MWh)	INC Shift (MWh)	INC Net Gen (MWh)	High Price ($/MWh)	Low Price ($/MWh)	Mean Price ($/MWh)	High-low Spread ($/MWh)	DEC Shift Cost ($)	DEC Net Gen Cost ($)	DEC Total Cost ($)	INC Shift Cost ($)	INC Net Gen Cost ($)	INC Total Cost ($)
1	10	2025	15590	1136	771	-31	$ 51.74	$ 51.07	$ 51.45	$ 0.67	$ 10,484	$ 59,622	$ 70,106	$ 569	$ (2,276)	$ (1,707)
2	11	2025	13780	722	9696	3141	$ 43.56	$ 40.35	$ 41.73	$ 3.20	$ 44,166	$ 29,999	$ 74,165	$ 31,750	$ 125,322	$ 157,072
3	12	2025	12611	83	29829	20324	$ 50.63	$ 48.09	$ 49.18	$ 2.53	$ 32,204	$ 3,396	$ 35,599	$ 75,304	$ 949,179	$ 1,024,483
4	1	2026	10857	-51	36197	30260	$ 45.61	$ 45.16	$ 45.41	$ 0.45	$ 4,716	$ (1,786)	$ 2,929	$ 13,825	$ 1,436,917	$ 1,450,742
5	2	2026	9838	392	27202	33740	$ 51.27	$ 49.31	$ 50.15	$ 1.96	$ 19,104	$ 19,181	$ 38,284	$ 51,036	$ 1,721,569	$ 1,772,606
6	3	2026	10836	0	28315	32379	$ 37.61	$ 33.31	$ 35.15	$ 4.29	$ 46,273	$ 5	$ 46,277	$ 123,972	$ 1,202,959	$ 1,326,932
7	4	2026	358	510	13360	25997	$ 30.99	$ 24.49	$ 27.28	$ 6.50	$ 2,335	$ 13,962	$ 16,296	$ 87,893	$ 712,762	$ 800,655
8	5	2026	636	438	31371	49640	$ 11.60	$ 6.92	$ 8.93	$ 4.67	$ 2,958	$ 4,339	$ 7,296	$ 149,813	$ 424,324	$ 574,138
9	6	2026	306	626	39631	86381	$ 13.12	$ 12.67	$ 12.87	$ 0.45	$ 148	$ 8,126	$ 8,274	$ 17,817	$ 1,121,791	$ 1,139,608
10	7	2026	12870	1383	24944	59271	$ 52.85	$ 48.23	$ 50.87	$ 4.62	$ 59,669	$ 69,334	$ 129,003	$ 114,153	$ 3,035,199	$ 3,149,352
11	8	2026	10801	2886	27713	6399	$ 57.47	$ 54.06	$ 56.01	$ 3.41	$ 36,443	$ 161,648	$ 198,091	$ 98,958	$ 353,707	$ 452,665
12	9	2026	20661	-1850	4778	1177	$ 61.93	$ 58.99	$ 60.67	$ 2.94	$ 60,831	$ (109,501)	$ (48,670)	$ 14,100	$ 70,617	$ 84,717
13	10	2026	21800	2181	540	-156	$ 51.12	$ 48.62	$ 50.05	$ 2.51	$ 54,622	$ 108,518	$ 163,140	$ 1,474	$ (7,416)	$ (5,942)
14	11	2026	21303	1009	12322	3911	$ 42.92	$ 40.64	$ 41.62	$ 2.28	$ 48,634	$ 41,616	$ 90,250	$ 26,174	$ 165,435	$ 191,609
15	12	2026	21730	512	47620	33309	$ 48.48	$ 47.80	$ 48.09	$ 0.67	$ 15,053	$ 24,997	$ 40,050	$ 30,443	$ 1,629,186	$ 1,659,629
16	1	2027	16378	967	49396	37631	$ 43.90	$ 43.53	$ 43.73	$ 0.37	$ 5,747	$ 42,755	$ 48,502	$ 20,687	$ 1,734,009	$ 1,754,697
17	2	2027	18677	958	40637	38886	$ 52.40	$ 45.90	$ 48.69	$ 6.50	$ 121,675	$ 48,747	$ 170,421	$ 261,536	$ 1,998,292	$ 2,259,828
18	3	2027	18542	894	40382	44973	$ 29.85	$ 24.86	$ 27.00	$ 5.00	$ 91,050	$ 24,873	$ 115,923	$ 202,644	$ 1,301,057	$ 1,503,700
19	4	2027	18105	5164	19700	47727	$ 23.02	$ 19.13	$ 20.79	$ 3.90	$ 70,846	$ 107,882	$ 178,729	$ 77,336	$ 1,039,346	$ 1,116,682
20	5	2027	8911	5337	35208	52691	$ 11.96	$ 7.69	$ 9.52	$ 4.27	$ 37,704	$ 50,347	$ 88,051	$ 145,454	$ 550,833	$ 696,287
21	6	2027	7296	4677	50961	104184	$ 16.22	$ 15.27	$ 15.81	$ 0.96	$ 6,651	$ 73,591	$ 80,242	$ 50,602	$ 1,675,419	$ 1,726,021
22	7	2027	26474	4419	33195	83372	$ 47.22	$ 43.92	$ 45.81	$ 3.30	$ 87,308	$ 203,059	$ 290,367	$ 109,564	$ 3,773,462	$ 3,883,027
23	8	2027	26760	6411	33099	11529	$ 48.31	$ 44.20	$ 46.55	$ 4.11	$ 109,101	$ 298,195	$ 407,296	$ 141,493	$ 535,716	$ 677,210
24	9	2027	39135	-2740	2020	-296	$ 54.22	$ 52.23	$ 53.36	$ 1.99	$ 77,778	$ (151,184)	$ (73,406)	$ 4,105	$ (15,551)	$ (11,446)
25	10	2027	37599	3061	1469	-693	$ 49.04	$ 46.88	$ 48.12	$ 2.16	$ 81,353	$ 148,886	$ 230,239	$ 2,846	$ (33,053)	$ (30,207)
26	11	2027	33408	1801	12578	4291	$ 38.43	$ 37.59	$ 37.95	$ 0.84	$ 28,411	$ 67,841	$ 96,252	$ 9,831	$ 167,019	$ 176,850
27	12	2027	30045	205	55360	50807	$ 47.29	$ 46.94	$ 47.10	$ 0.34	$ 10,530	$ 9,855	$ 20,385	$ 19,787	$ 2,428,320	$ 2,448,107
28	1	2028	24873	-257	59584	50770	$ 42.19	$ 41.22	$ 41.63	$ 0.97	$ 23,582	$ (10,078)	$ 13,505	$ 58,247	$ 2,157,866	$ 2,216,112
29	2	2028	21967	1258	42239	42992	$ 43.45	$ 40.79	$ 41.93	$ 2.66	$ 59,350	$ 53,993	$ 113,343	$ 106,442	$ 1,872,412	$ 1,978,853
30	3	2028	21023	1613	39715	47014	$ 33.95	$ 26.66	$ 29.78	$ 7.29	$ 154,738	$ 47,533	$ 202,271	$ 283,106	$ 1,415,733	$ 1,698,839
31	4	2028	23091	6194	15360	24264	$ 26.11	$ 21.00	$ 23.19	$ 5.11	$ 116,398	$ 144,044	$ 260,442	$ 79,881	$ 577,665	$ 657,547
32	5	2028	8393	5156	40033	62414	$ 8.80	$ 2.94	$ 5.45	$ 5.86	$ 48,312	$ 27,624	$ 75,936	$ 233,171	$ 405,101	$ 638,272
33	6	2028	7204	3965	58966	123377	$ 14.00	$ 11.64	$ 12.65	$ 2.36	$ 17,406	$ 49,724	$ 67,131	$ 135,489	$ 1,604,490	$ 1,739,979
34	7	2028	29083	5949	34871	76339	$ 52.75	$ 51.61	$ 52.26	$ 1.14	$ 33,098	$ 311,239	$ 344,337	$ 38,202	$ 3,913,620	$ 3,951,823
35	8	2028	28987	6293	34251	8777	$ 55.61	$ 52.71	$ 54.36	$ 2.90	$ 83,997	$ 341,177	$ 425,174	$ 98,370	$ 463,528	$ 561,898
36	9	2028	42100	-1295	2228	-35	$ 65.98	$ 65.38	$ 65.64	$ 0.59	$ 25,195	$ (81,534)	$ (56,338)	$ 1,213	$ (2,683)	$ (1,470)
37	**Rate Period Total:**		**672028**	**70005**	**1035541**	**1296752**	**$ 40.43**	**$ 37.55**	**$ 38.91**	**$ 2.88**	**$ 1,727,870**	**$ 2,242,026**	**$ 3,969,895**	**$ 2,917,289**	**$ 40,501,878**	**$ 43,419,167**
38	**Annual Average:**		**224009**	**23335**	**345180**	**432251**	**$ 40.43**	**$ 37.55**	**$ 38.91**	**$ 2.88**	**$ 575,957**	**$ 747,342**	**$ 1,323,298**	**$ 972,430**	**$ 13,500,626**	**$ 14,473,056**

Table 9.3.1.6

7HA.02 SCCT Frame Annual Costs

A	B	C
Start Year of Operation (FY)	2026	
Cost of Debt	3.79%	[1]
Inflation Rate	3.18%	
Insurance Rate	0.25%	[2]
Debt Finance Period (years)	30	[2]
Plant Lifecycle (years)	30	[2]
Lifetime Average Heat Rate Btu/kWh	9,566	[2]
Eastside Fixed Fuel $/kW/yr with 9566 Heat Rate 2016$	$ 18.13	[2]
Westside Fixed Fuel $/kW/yr with 9566 Heat Rate 2016$	$ 24.66	[2]
Average Eastside and Westside 2016$	$ 21.39	
All-in Capital Cost Frame $/kW 2026$	$ 792.86	[3]
Fixed O&M $/kW/yr 2026$	7.52	[4]
Fixed Fuel $/kW/yr 2026$	29.24	

D Calendar Year	E Chained GDP IPD	F	G Month	H BP-26 Load Shaping Rate HLH $/MWh	I Demand Shaping Factor	J Monthly Demand Rate $/kW/mo
2016	98.241		Oct	50.63	10.83%	$ 9.15
2017	100.000		Nov	39.53	8.46%	$ 7.15
2018	102.291		Dec	47.63	10.19%	$ 8.61
2019	104.008		Jan	43.56	9.32%	$ 7.88
2020	105.381		Feb	45.43	9.72%	$ 8.21
2021	110.213		Mar	29.19	6.25%	$ 5.28
2022	117.973		Apr	22.33	4.78%	$ 4.04
2023	122.273		May	8.60	1.84%	$ 1.55
	103.18%	7-year Avg.	Jun	15.10	3.23%	$ 2.73
			Jul	50.98	10.91%	$ 9.22
			Aug	53.80	11.51%	$ 9.73
			Sep	60.51	12.95%	$ 10.94
				Average $/kW/mo		**$ 7.04**

Chained GDP IPD from BEA -- Table 1.1.9. Implicit Price Deflators for Gross Domestic Product (2017 Base year) - Last Revised September 26, 2024

End of Fiscal Year	Midyear Assessed Value	Debt Payment	Fixed O&M	Insurance	Fixed Fuel	Cash Expense Each Year
2026	$ 779.65	$44.69	$ 7.52	$ 1.95	$ 29.24	$ 83.40
2027	$ 753.22	$44.69	$ 7.76	$ 1.88	$ 30.17	$ 84.50
2028	$ 726.79	$44.69	$ 8.01	$ 1.82	$ 31.13	$ 85.64
			Rate Period Average Expense $/kW/year			**$ 84.51**

Wartsila 18V50SG Average Expense $/kW/mo[5]	$11.70
7HA.02 SCCT Frame Average Expense $/kW/mo	$7.04
Expense Delta	$4.66

[1] Source BPA FY 2024 Third-Party Tax-Exempt Borrowing Rate Forecast 30-year
[2] Source NWPCC 2021 Power Plan Microfin Model and Fixed Fuel Workbook
[3] Source NWPCC Microfin Model assumption of $580/kW in 2016$
[4] Source NWPCC Microfin Model assumption of $5.50/kW/yr in 2016$
[5] Source Power Rates Study Documentation BP-26-FS-BPA-01A Table 4.1

Table 9.3.1.7
Balancing Reserve Capacity Requirement -
Proportions for Rate Design
Rate Period Average

	A	B	C
1	**Proportions Represented by Balancing Area Needs**		
2			
3	**Increment:**	**MW Capacity**	**Proportion**
4	Regulation Increment	577	52%
5	Non-Regulation Increment	538	48%
6	Total Increment (Line 8+9)	1115	100%
7			
8	**Decrement:**	**MW Capacity**	**Proportion**
9	Regulation Decrement	609	51%
10	Non-Regulation Decrement	584	49%
11	Total Decrement (Line 13+14)	1193	100%
12			
13	**Proportions applied to FCRPS Available Quantities**		
14			
15	**Increment:**	**MW Capacity**	**Proportion**
16	Regulation Increment	440	52%
17	Non-Regulation Increment	411	48%
18	Total Increment (Line 20+21)	851	100%
19			
20	**Decrement:**	**MW Capacity**	**Proportion**
21	Regulation Decrement	516	51%
22	Non-Regulation Decrement	494	49%
23	Total Decrement (Line 25+26)	1010	100%

Federal Generation Balancing Quantities are included in the Balancing Reserve Capacity.

The quantities on this table were established based on the studies published in the Initial Proposal. They are used here, without change, due to their role as an input to the settled rates for the Final Proposal.

Table 9.3.1.8

Costs Allocated to Balancing Reserve and Operating Reserve Capacity
Rate Period Average

	A	B	C
1	**Balancing Reserve Capacity ***		
2		Quantity (MW)	Base Unit Cost ($/kW/mo)
3	Regulation Increment	434	7.26
4	Non-Regulation Increment	404	7.26
5			
6	**Total Cost (Column B * Column C * 12 months * 1000) :**		$ 73,006,56
7			
8			
9	**Operating Reserve Capacity**		
10			
11	Spinning	252	7.26
12	Supplemental	252	7.26
13			
14	**Total Cost (Column B * Column C * 12 months * 1000) :**		$ 43,949,27

*Federal Generation Balancing Quantities are included in the Balancing Reserve Capacity.

Table 9.3.1.9

Cost of Capacity Calculation

	A	B Annual Average FY2026-FY2028 ($/kW/mo)
1	**Assumptions for Calculation:**	
2	Embedded Unit Cost of Capacity	6.39
3		
4	**Variable Costs:**	
5	Regulation inc	0.87
6	Regulation dec	0.21
7	Non-regulation inc	0.87
8	Non-regulation dec	0.00
9	Operating Reserves	0.87
10		
11	**Base Cost of Capacity by Reserve Type**	
12	Regulation inc (Line 2 + 5)	7.26
13	Regulation dec (Line 6)	0.21
14	Non-regulation inc (Line 2 + 7)	7.26
15	Non-regulation dec (Line 8)	0.00
16	Operating Reserves - Spinning and Supplemental (Line 2 + 9)	7.26
18		
19	**Rate Design Delta:**	
20	Inc value delta	4.66
21	Regulation inc weighted value delta	2.25
22	Non-regulation inc weighted value delta	-2.41
23	Operating Reserves - Spinning value delta	2.33
24	Operating Reserves - Non Spinning value delta	-2.33
25		
26	**Total Cost of Capacity by Reserve Type:**	
27	Regulation inc (Line 12 + 21)	9.51
28	Regulation dec (Line 13)	0.21
29	Non-regulation inc (Line 14 + 22)	4.85
30	Non-regulation dec (Line 15)	0.00
31	Operating Reserves - Spinning (Line 16 + 23)	9.59
32	Operating Reserves - Supplemental (Line 16 + 24)	4.93

Table 9.3.1.10

Generation Inputs Revenue Forecast

	A	B
1	**Cost of Capacity by Reserve Type (See Table 4.4)**	**$ / kW/mo**
2	Regulation inc	$9.51
3	Regulation dec	$0.21
4	Non-regulation inc	$4.85
5	Non-regulation dec	$0.00
6	Operating Reserves - Spinning	$9.59
7	Operating Reserves - Supplemental	$4.93
8		
9	**Operating Reserve Quantity**	**MW**
10	Operating Reserves Spinning	252
11	Operating Reserves Supplemental	252
12		
13	**Balancing Reserve Quantity** (excludes Federal Generation Balancing Reserves)	**MW**
14	Regulation Reserves inc	482
15	Regulation Reserves dec	503
16	Non-regulation Reserves inc	334
17	Non-regulation Reserves dec	466
18		
19	**Revenue Forecast**	**$ in Thousands**
20	(Cost from A1 * Quantity from A9 or A13 * 12)	
21	Balancing Reserves - Regulation inc	$55,006
22	Balancing Reserves - Regulation dec	$1,268
23	Balancing Reserves - Non-regulation inc	$19,439
24	Balancing Reserves - Non-regulation dec	$0
25	**Balancing Reserves - Total**	$75,712
26		
27	Operating Reserves Spinning	$29,027
28	Operating Reserves Supplemental	$14,922
29	**Operating Reserves - Total**	$43,949
30		
31	**Total Revenue Forecast (B25 + B29)**	$119,661
32		
33		$/kW/mo
34	**Average Cost of Balancing Reserves (B25/((B14+B16)*12)**	$7.73
35	**Average Cost of Operating Reserves (B29/((B10+B11)*12)**	$7.26

*Federal Generation Balancing Costs are not included in the Total Revenue Forecast becaus these costs are paid for by Power Customers

Table 9.3.2.1
Synchronous Condenser Projected Motoring Hours, Hourly Energy Consumption and Energy Costs

	A	B	C	D	E	F	G	H	I	J
	Generating Project	**Nameplate rating (MW/unit)**	**Motoring power consumption (MW/unit)**	**Projected Units to be used**	**Condensing Hours FY 2021**	**Condensing Hours FY 2022**	**Condensing Hours FY 2023**	**Average Annual Condensing hours/year [(E+F+G)/3]**	**Energy Consumption MWhrs/year [H * C]**	**Total Cost of Energy [I * Market Price Forecast of energy]**
1	**John Day, units 11-14**	155	3.0	units 11-14	5,315	1,738	5,706	4,253	12,759	$ 496,453
2	**The Dalles, units 15-20**	99	1.5	units 15-20	4,524	2,215	5,179	3,973	5,959	$ 231,865
3								**SUBTOTAL - SOUTHERN INTERTIE***	**18,718**	**$ 728,317**
4	**Grand Coulee, units 19-24**	690 (units 19-21) 805 (units 22-24)	11.0	units 19-21	1,712	1,008	1,672	1,464	16,104	$ 626,607
5	**Dworshak (small units)**	103	4.0	units 1-2	0	0	8	3	11	$ 415
6	**Dworshak (big unit)**	259	8.0	unit 3	0	52	75	42	339	$ 13,178
7	**Palisades, units 1-4**	44	0.6	units 1-4	3,890	3,478	2,787	3,385	2,031	$ 79,026
8	**Detroit, units 1-2**	58	2.0	units 1-2	NA	NA	NA	0	0	$ -
9	**Green Peter, units 1-2**	46	1.2	units 1-2	NA	NA	NA	0	0	$ -
10	**Lookout Point, units 1-3**	46	1.1	units 1-3	NA	NA	NA	0	0	$ -
11	**Hungry Horse, units 1-4**	107	2.5	units 1-4	0	0	0	0	0	$ -
12								**SUBTOTAL - NETWORK***	**18,484**	**$ 719,225**
13								**TOTAL ENERGY COST**	**37,202**	**$ 1,447,543**
14	**Market Price Forecast of energy ($/MWh)**	**$ 38.91**								

***Synchronous condensing costs for the John Day and The Dalles projects are allocated to the Southern Intertie segment. Costs of all other projects are allocated to the Network segment.**

Table 9.3.2.2 Determination of Synchronous Condenser Plant Modification Costs* ($ thousands)					
	A	B	C	D	E
		FY 2026	FY 2027	FY 2028	Annual Average of FY 2026 - FY2028
1	**Synchronous Condensers Net Plant**	$ 4,980	$ 4,877	$ 4,774	$ 4,877
2	Total Corps/Reclamation Average Net Plant	$ 6,268,277	$ 6,436,381	$ 6,626,520	$ 6,443,726
3	**percent**	0.08%	0.08%	0.07%	0.08%
4	Corps/Reclamation Net Interest	$ (15,032)	$ (20,422)	$ (21,485)	$ (18,979)
5	**Sync Cond Net Interest**	$ (12)	$ (15)	$ (15)	$ (14)
6	Corps/Reclamation MRNR	$ 115,565	$ 97,622	$ 187,774	$ 133,654
7	**Sync Cond MRNR**	$ 92	$ 74	$ 135	$ 100
8	**Sync Cond Depreciation**	$ 103	$ 103	$ 103	$ 103
9	**Total Sync Cond Plant Modification Costs**	$ 183	$ 162	$ 223	$ 189

* These are costs for plant modifications at John Day and The Dalles to enable synchronous condenser operation. These costs are allocated to the Southern Intertie segment.

Table 9.3.2.3
Summary of Synchronous Condenser Costs
($)

	A	B	C	D	E
		FY 2026	**FY 2027**	**FY 2028**	**Annual Average of FY2026 - FY2028**
1	Modifications at John Day and The Dalles*	$ 183,000	$ 162,000	$ 223,000	$ 189,333
2	**Energy Consumption - John Day and The Dalles**	$ 728,317	$ 728,317	$ 728,317	$ 728,317
3	**Subtotal - Southern Intertie**	**$ 911,317**	**$ 890,317**	**$ 951,317**	**$ 917,651**
4	**Energy Consumption - Network**	$ 719,225	$ 719,225	$ 719,225	$ 719,225
5	**Total Synchronous Condenser Costs**	**$ 1,630,543**	**$ 1,609,543**	**$ 1,670,543**	**$ 1,636,876**

* These are costs for plant modifications at John Day and The Dalles to enable synchronous condenser operation
These costs are allocated to the Southern Intertie segment.

Table 9.3.3.1
ESTIMATED COSTS OF "GENERATION DROP" OF UNIT 22, 23, OR 24 AT THE GRAND COULEE THIRD POWERHOUSE

	Equipment	Incremental Equipment Deterioration, Replacement or Overhaul Costs			Incremental Routine Operation and Maintenance Costs			Incremental Lost Revenue In The Event of Replacement or Overhaul				Total Cost Per Drop
		% Life Reduction Per Drop	Cost of Major Overhaul (1)	Cost/Drop	% Increase O&M Per Drop	Annual O&M Cost	Cost/Drop	Probability of Failure	Months of Downtime	Downtime Cost (2)	Cost/Drop	
	A	B	C	D	E	F	G	H	I	J	K	L
1	550kV Circuit Breaker (50% of replacement)	0.04%	$ 1,175,000	$ 470	0.04%	$ 5,629	$ 2	0.04%	1	$ 3,537,885	$ 1,415	**$ 1,887**
2	Main Power Transformer (equal to replacement)	0.015%	$ 13,411,215	$ 2,012	0.015%	$ 64,900	$ 10	0.018%	1	$ 3,537,885	$ 637	**$ 2,658**
3	Generator (rewinding)	0.71%	$ 29,845,000	$ 211,900	0.71%	$ 511,657	$ 3,633	0.71%	18	$ 63,681,935	$ 452,142	**$ 667,674**
4	Turbine (refurbished)	0.24%	$ 2,350,000	$ 5,640	0.24%	$ 511,657	$ 1,228	0.05%	16	$ 56,606,164	$ 28,303	**$ 35,171**
5	500 kV Cable (replacement)	0.055%	$ 8,840,700	$ 4,862	0.055%	$ 320,387	$ 176	0.055%	1	$ 3,537,885	$ 1,946	**$ 6,984**
6	**Total Cost Per Drop**			**$ 224,884**			**$ 5,049**				**$ 484,443**	**$ 714,375**
7	**Total Generation Dropping Cost per year** (3)			**$ 714,375**								

(1) Updated to FY 2026-FY 2028 from original Harza Engineering Company study using the Handy-Whitman Index to calculate cost multiplier:
2.35
(2) Downtime costs calculate the marginal outage cost by assuming a base unit availability at Grand Coulee and then the loss of an additional big unit. The current marginal outage cost is adjusted to forecasted average market price for energy ($38.91) during the FY 2026-2028 rate period.
(3) Drops per year 1.

Table 9.3.4.1
Redispatch Costs FY 2020 to August 2024

	A	B	C	D	E	F	G
	Fiscal Year	Discretionary	Transmission Purchases: Redispatch	NT Redispatch: FCRPS Redispatch (INC/DEC)	Emergency	Transmission Purchases: Stranded Load	Total
	A	B	C	D	E	F	G
1	2020	$ -	$ 253,226.20	$ 9,100.00	$ -	$ 71,778.73	$ 334,104.93
2	2021	$ -	$ 87,437.49	$ -	$ -	$ 208,360.96	$ 295,798.45
3	2022	$ 43,565.00	$ 97,538.53	$ -	$ -	$ 203,617.52	$ 344,721.06
4	2023	$ -	$ 51,051.47	$ 441.00	$ -	$ 36,559.81	$ 88,052.27
5	2024	$ 12,500.00	$ 30,414.02	$ -	$ -	$ 96,783.89	$ 139,697.91
6	Total FY2020-2024:	$ 56,065.00	$ 519,667.71	$ 9,541.00	$ -	$ 617,100.91	$ 1,202,374.61
7	FY Average (FY26-28 Forecast):	$ 11,418.53	$ 105,838.64	$ 1,943.18	$ -	$ 125,682.47	$ 244,882.81

Table 9.3.5.1
Load Factor Calculation for Station Service Energy Use Analysis

	Substation Name	Installed Transformation (kVA)	Historical Average Monthly Use (kWh)	Calculated Load Factor
	A	B	C	D
1	**Large**			
2	Alvey	2,267	96,923	
3	Bell	2,250	149,000	
4	Snohomish	1,250	78,000	
5	Olympia	1,100	132,738	
6	Covington	946	108,333	
7	Pearl	875	28,067	
8	Longview	825	38,317	
9	McNary	800	108,717	
10	Chemawa	725	18,140	
11	Anaconda	600	42,910	
12	Columbia	600	18,292	
13	John Day	500	65,896	
14	Santiam	400	25,740	
15	St. Johns	310	15,858	
16	Port Angeles	300	49,920	
17	Valhalla	300	17,592	
18	Fairview	300	12,560	
19	**Subtotal**	14,348	1,007,003	
20	**Medium**			
21	Oregon City	225	13,663	
22	Walla Walla	150	6,919	
23	LaGrande	150	5,663	
24	Ellensburg	100	3,897	
25	Roundup	75	5,708	
26	Boardman	75	1,595	
27	Drain	65	1,654	
28	Reedsport	55	3,922	
29	**Subtotal**	895	43,021	
30	**Small**			
31	Sappho	45	2,363	
32	Lookout Point	40	3,387	
33	The Dalles	38	2,657	
34	Bandon	25	1,746	
35	Gardiner	25	1,402	
36	Creston	15	1,122	
37	Hauser	10	1,525	
38	Duckabush	10	1,192	
39	Ione	5	1,028	
40	**Subtotal**	213	16,422	
41	**TOTAL**	**15,456**	**1,066,446**	**9.452%**

Calculated Load Factor is the Historical Average Monthly Use divided by Installed Transformation divided by 730 average hours in the month.
D = C / B / 730.

Table 9.3.5.2
Calculation of Station Service Use and Cost

	Facility Type	Installed Transformation (kVA)	Average Monthly Use[1] (kWh)	Annual Station Service Use[2] (MWh)	Transmission Losses[3] (MWh)	Annual Average Market Price Forecast ($/MWh)	Real Power Losses Capacity Charge ($/MWh)	Cost Allocation for Station Service per Year[4] ($)
	A	B	C	D	E	F	G	H
1	Large	39,403	2,718,791					
2	Medium	5,943	410,065					
3	Small	1,438	99,221					
4	Big Eddy/Celilo Complex		1,822,937					
5	Ross Complex		1,749,300					
6	**Total**	**46,784**	**6,800,314**	**81,604**	**1,673**	**$38.91**	**$5.52**	**$ 3,249,529**

1/ For Large, Medium and Small substations, the calculated average monthly use is installed transformation times 9.452% average calculated load factor times 730 average hours in month (B * 0.09452% * 730). Historical usage is metered for Big Eddy/Celilo and Ross Complexes.

2/ Annual Station Service Use is the Average Monthly Use times 12 months divided by 1000 to convert from kWh to MWh.

3/ Transmission Losses associated with Annual Station Service is based on the BPA Transmission Network Loss Factor of 2.05% (D * 0.0205)

4/ Cost Allocation for Station Service per Year is the sum of (i) the amount of Annual Station Service Use plus Transmission Losses multiplied by the Annual Average Market Price Forecast ((D+E)*F); and (ii) Transmission Losses multiplied by the Real Power Losses Capacity Rate (E*G).

BONNEVILLE POWER ADMINISTRATION
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