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-24 Rate Proceeding

Final Proposal

Power Rates Study Documentation

BP-24-FS-BPA-01A

July 2023

POWER RATES STUDY DOCUMENTATION

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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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BP-24 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 (RAM2024). RAM2024 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 RAM2024 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 2024–2025, and at current rates for the fiscal year immediately preceding the two-year rate period, FY 2023.

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-24-E-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 for FY 2024-2025.

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-24-E-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-24-E-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-24-E-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 res urces 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-24-E-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-24-E-BPA-05)

The Power and Transmission Risk Study demonst ates 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-24 rate case (RAM2024).

Results Provided for Input into RAM2024 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 P10 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. It also computes augmentation costs based on hydro generation data and AURORA© prices under

P10 hydro conditions. As described in the Power Rates Study below, RAM2024 and the Power Services Revenue Forecast both use the secondary energy revenues, firm surplus energy revenues, and balancing and augmentation power purchase expenses calculated in 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-24-E-BPA-01)

Rate Analysis Model (RAM2024)

RAM2024 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), residential exchange, 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 RAM2024 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 RAM2024 using unique database keys.

RAM2024 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. RAM2024 designs rates for each rate pool.

Resource Support Services Module of RAM2024

The Resource Support Services (RSS) module of RAM2024, 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 RAM2024); 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 RAM2024

The Tier 2 module of RAM2024, 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 RAM2024. 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 2024-2025 Average System Cost (ASC) Forecasts

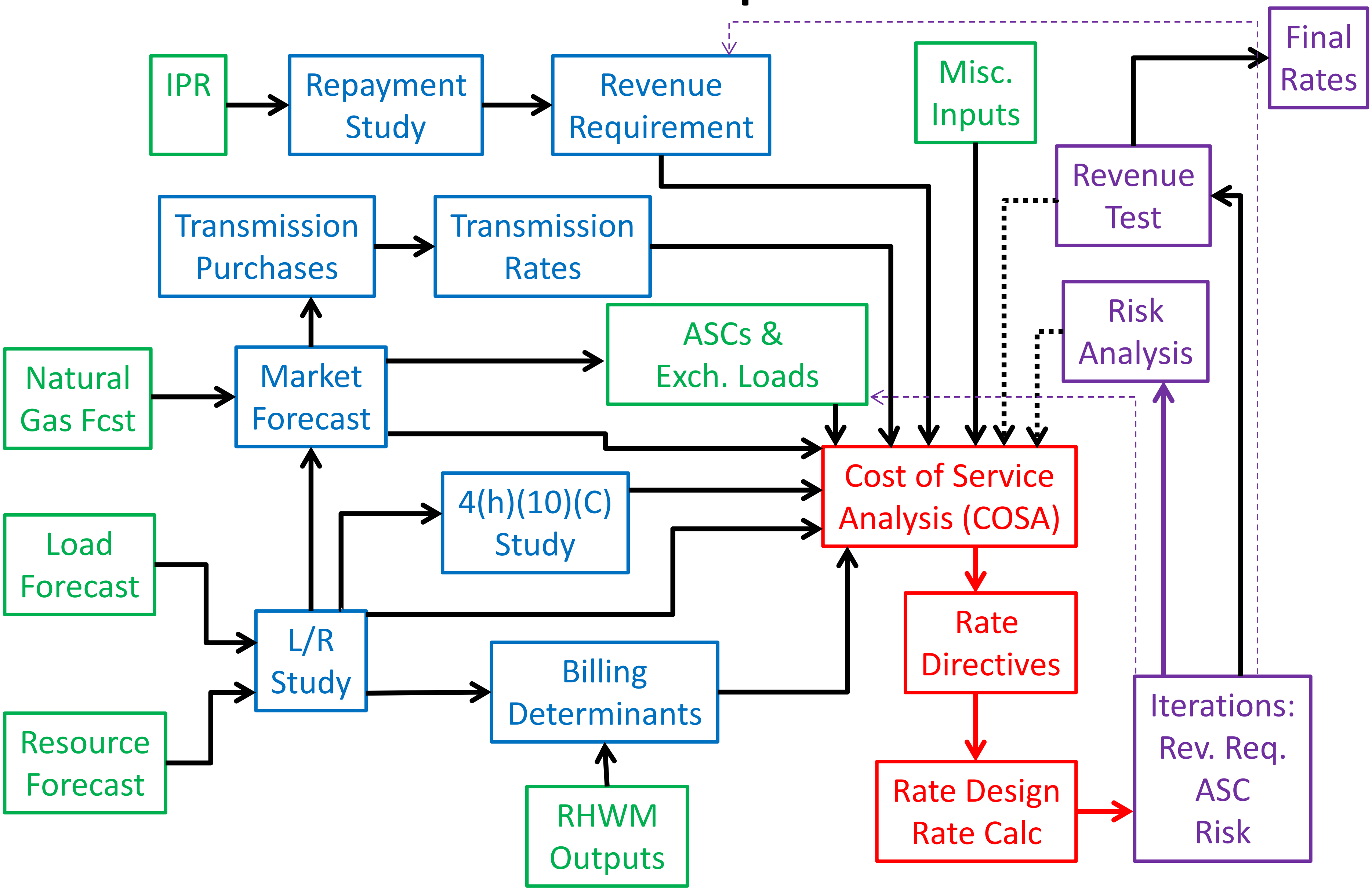
ASCs are used in determining the forecast of Residential Exchange Program (REP) benefits that exchanging utilities are entitled to during the rate period. For purposes of the BP-24 rates, BPA is using the ASC Reports published by BPA on October 28th, 2022

Revenue and Power Purchase Expense Forecast

The Revenue Forecast presents BPA's expected level of revenue and power purchase expense for FY 2023-2025, FY 2023 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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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

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Table 2.1.1

Rate Data Input
Disaggregated Loads
Test Period October 2023 - September
2025 (MWh)

	A	B	C	E	F
4				2024	2025
5	Preference			61,127,528	62,837,586
6		Block		4,680,019	4,649,142
7		Slice Block		10,827,953	11,067,431
8		Slice		12,307,663	12,154,961
9		Load Following		31,516,146	31,552,569
10		Tier 2		1,795,748	3,413,483
11	Industrial			96,624	96,360
12		Smelter		0	0
13		Other Industrial		96,624	96,360
14	New Resource			10	10
15	Firm Power and Services			5,883,098	5,873,661
16		Intraregional Transfer		98,653	98,426
17			WNP#3 Settlement	0	0
18			Dittmer Station Service	82,895	82,668
19			Transfer Gen Losses	15,758	15,758
27		FBS Obligation		5,784,445	5,775,235
28			Canadian Entitlement	3,990,570	3,979,667
29			USBR Pump Load	1,648,915	1,648,483
30			Hungry Horse	0	0
31			Upper Baker	11,340	11,228
32			Non-Treaty Storage	133,620	135,857
33			Libby Coordination	0	0
38		Seasonal or Capacity Exchange		0	0
39			Riverside Capacity	0	0
40			Riverside Seasonal	0	0
41			Pasadena Capacity	0	0
42			Pasadena Seasonal	0	0
43			PG&E	0	0
44			Intertie Losses	0	0
45			PacifiCorp	0	0
49	Firm Surplus Sale			0	0
50	Presale of Secondary			0	0
51	Conservation			0	0
52					
53					
54	Loss Percentage			3.223%	3.223%

Table 2.1.2

Rate Data Input
Disaggregated Resources
Test Period October 2023 - September 2025 (MWh)

	A	B	C	E	F
5				2024	2025
6	Hydro			59,668,002	59,903,561
7		Regulated		55,516,890	55,701,272
8		Independent		2,976,300	3,026,198
9			Cowlitz Falls	212,697	243,489
10			Idaho Falls	0	0
11			PreAct	2,763,603	2,782,709
19		Hydro Other		1,174,812	1,176,092
20			Canadian Entitlement	1,174,812	1,176,092
21			Libby Coordination	0	0
22			Other	0	0
30	Non Hydro			10,012,230	8,913,646
31		Water		23,102	23,039
32			Dworshak/Clearwater Small Hydropower	23,102	23,039
33			Elwha Hydro	0	0
34			Glines Canyon Hydro	0	0
42		Thermal		9,802,944	8,704,800
43			Columbia Generating Station	9,802,944	8,704,800
53		Wind		186,184	185,808
54			Foote Creek 1	0	0
55			Foote Creek 2	0	0
56			Foote Creek 4	0	0
57			Stateline Wind Project	186,184	185,808
58			Condon Wind Project	0	0
59			Klondike I	0	0
64		Renewable		0	0
65			Georgia-Pacific Paper (Wauna)	0	0
66			Fourmile Hill Geothermal	0	0
67			Ashland Solar Project	0	0
75	Contracts			812,530	812,219
76		Imports		812,530	812,219
77			Riverside Exchange Energy	0	0
78			Pasadena Exchange Energy	0	0
79			BC Hydro Power Purchase	8,784	8,760
80			Slice Return of Losses	249,546	251,859
81			Southeast Idaho Load Service	554,200	551,600
87		Seasonal or Capacity Exchange		0	0
88			Riverside Capacity	0	0
89			Riverside Seasonal	0	0
90			Pasadena Capacity	0	0
91			Pasadena Seasonal	0	0
92			PG&E Shaping	0	0
93			PacifiCorp Shaping	0	0
109	Augmentation and Balancing			105,714	105,505
110		Tier 1 Resources		105,714	105,505
111			Klondike III	103,511	103,302
112			Rocky Brook	2,203	2,203
113					
114	Transmission Losses			(2,219,219)	(2,230,092)

Rate Data Input
Exchange ASCs, Loads, and Gross Costs
Test Period October 2023 - September 2025

	B	D		E	
7	**Exchange ASCs ($/MWh)**		**2024**		**2025**
8					
9	Avista Corporation	$	70.61	$	70.61
10	Idaho Power Company	$	66.03	$	66.03
11	NorthWestern Energy, LLC	$	83.73	$	83.73
12	PacifiCorp	$	84.08	$	84.08
13	Portland General Electric Company	$	80.83	$	80.83
14	Puget Sound Energy, Inc.	$	81.53	$	81.53
15	Clark Public Utilities	$	-	$	-
17	Snohomish PUD	$	54.13	$	54.13
18					
19	**Exchange Loads (GWh)**		**2024**		**2025**
20					
21	Avista Corporation		4,129		4,129
22	Idaho Power Company		7,165		7,165
23	NorthWestern Energy, LLC		746		746
24	PacifiCorp		9,419		9,419
25	Portland General Electric Company		8,661		8,661
26	Puget Sound Energy, Inc.		12,503		12,503
27	Clark Public Utilities		0		0
29	Snohomish PUD		3,663		3,634
30			46,286		46,257
31					
32	**Exchange Resource Cost ($000)**		**2024**		**2025**
33					
34	Avista Corporation	$	291,540	$	291,540
35	Idaho Power Company	$	473,077	$	473,077
36	NorthWestern Energy, LLC	$	62,491	$	62,491
37	PacifiCorp	$	791,963	$	791,963
38	Portland General Electric Company	$	700,069	$	700,069
39	Puget Sound Energy, Inc.	$	1,019,333	$	1,019,333
40	Clark Public Utilities	$	-	$	-
42	Snohomish PUD	$	198,293	$	196,713
43		$	3,536,766	$	3,535,185

Table 2.2.1.1

Energy Allocation Factor
Power Sales and Resources
Test Period October 2023 - September 2025
(aMW)

	A	B	C	E	F
5				2024	2025
6	Hydro			59,668,002	59,903,561
7		Regulated		55,516,890	55,701,272
8		Independent		2,976,300	3,026,198
9			Cowlitz Falls	212,697	243,489
10			Idaho Falls	0	0
11			PreAct	2,763,603	2,782,709
19		Hydro Other		1,174,812	1,176,092
20			Canadian Entitlement	1,174,812	1,176,092
21			Libby Coordination	0	0
22			Other	0	0
30	Non Hydro			10,012,230	8,913,646
31		Water		23,102	23,039
32			Dworshak/Clearwater Small Hydropower	23,102	23,039
33			Elwha Hydro	0	0
34			Glines Canyon Hydro	0	0
42		Thermal		9,802,944	8,704,800
43			Columbia Generating Station	9,802,944	8,704,800
53		Wind		186,184	185,808
54			Foote Creek 1	0	0
55			Foote Creek 2	0	0
56			Foote Creek 4	0	0
57			Stateline Wind Project	186,184	185,808
58			Condon Wind Project	0	0
59			Klondike I	0	0
64		Renewable		0	0
65			Georgia-Pacific Paper (Wauna)	0	0
66			Fourmile Hill Geothermal	0	0
67			Ashland Solar Project	0	0
75	Contracts			812,530	812,219
76		Imports		812,530	812,219
77			Riverside Exchange Energy	0	0
78			Pasadena Exchange Energy	0	0
79			BC Hydro Power Purchase	8,784	8,760
80			Slice Return of Losses	249,546	251,859
81			Southeast Idaho Load Service	554,200	551,600
87		Seasonal or Capacity Exchange		0	0
88			Riverside Capacity	0	0
89			Riverside Seasonal	0	0
90			Pasadena Capacity	0	0
91			Pasadena Seasonal	0	0
92			PG&E Shaping	0	0
93			PacifiCorp Shaping	0	0
109	Augmentation and Balancing			105,714	105,505
110		Tier 1 Resources		105,714	105,505
111			Klondike III	103,511	103,302
112			Rocky Brook	2,203	2,203
113					
114	Transmission Losses			(2,219,219)	(2,230,092)

Table 2.2.1.2

Energy Allocation Factor
Power Sales and Resources
Test Period October 2023 - September 2025
(aMW)

	B	C	E	F
4			**2024**	**2025**
46	Combustion Turbines			
47	Renewables			
48		Foote Creek 1	0	0
49		Foote Creek 2	0	0
50		Foote Creek 4	0	0
51		Stateline Wind Project	21	21
52		Condon Wind Project	0	0
53		Klondike I	0	0
54		Georgia-Pacific Paper (Wauna)	0	0
55		Klondike III	12	12
56		Fourmile Hill Geothermal	0	0
57		Ashland Solar Project	0	0
58		White Bluffs Solar	0	0
59	Cogeneration			
60	Imports			
61		Riverside Exchange Energy	0	0
62		Pasadena Exchange Energy	0	0
63		BC Hydro Power Purchase	1	1
64		Riverside Capacity	0	0
65		Riverside Seasonal	0	0
66		Pasadena Capacity	0	0
67		Pasadena Seasonal	0	0
68		Slice Losses Return	28	29
69	Regional Transfers (In)			
70		Southeast Idaho Load Purchase	63	63
71		PacifiCorp	0	0
72	Large Thermal		1,116	994
73	Non-Utility Generation			
74		Dworshak/Clearwater Small Hydropower	3	3
75		Elwha Hydro	0	0
76		Glines Canyon Hydro	0	0
77		Rocky Brook	0	0
78	Tier 2 Purchases		204	390
79	Federal Trans. Losses		(251)	(253)
80	Total Net Resources		**7,991**	**8,097**
81				
82	Total Firm Surplus/Deficit		**351**	**243**

Table 2.2.2.1

Energy Allocation Factor
Aggregated Loads and Resources
Test Period October 2023 - September 2025
(aMW)

	B	C	E	F
4			**2024**	**2025**
7	**Loads**			
8	Priority Firm - 7(b) Loads			
9		Block	1,822	1,852
10		Load Following	3,704	3,718
11		Slice (output energy)	1,446	1,432
12		Tier 2	211	402
14		5(c) Exchange	5,439	5,451
15	Industrial Firm - 7(c) Loads			
16		Direct Service Industries	11	11
17	New Resources - 7(f) Loads			
18		NR	0	0
19	Surplus Firm - SP Loads			
20		Firm Surplus Sale	0	0
21		Dittmer/Substation Sale	10	10
22	Total Loads		**12,643**	**12,876**
23				
24	**Resources**			
25	Federal Base System			
26		Hydro	6,769	6,811
27		Other Resources		
28		Small Thermal & Misc.		
29		Combustion Turbines		
30		Renewables	0	0
31		Cogeneration		
32		Imports	1	1
33		Regional Transfers (In)	63	63
34		Large Thermal	1,116	994
35		Non-Utility Generation	0	0
36		Slice Loss Return	28	29
37		Augmentation Purchases	0	0
38		Tier 2 Purchases	211	402

Energy Allocation Factor
Aggregated Loads and Resources
Test Period October 2023 - September 2025
(aMW)

	B	C	E	F
4			**2024**	**2025**
39	less: FBS Obligations			
40		BC Hydro (Cdn Entitlement)	(469)	(469)
41		Non-Treaty Storage	(16)	(16)
42		Libby Coordination	0	0
43		Hungry Horse	0	0
44		Upper Baker	(1)	(1)
45		USBR Pump Load	(194)	(194)
46	less: FBS Uses			
47		Pasadena	0	0
48		Riverside	0	0
49		PacifiCorp	0	0
50		PG&E	0	0
51		Federal Generation Transmission Losses	(2)	(2)
52		Intertie Losses	0	0
53	Exchange Resources			
54		5(c) Exchange	5,439	5,451
55	New Resources			
56		Cowlitz Falls	24	28
57		Idaho Falls	0	0
58		Foote Creek 1	0	0
59		Foote Creek 2	0	0
60		Foote Creek 4	0	0
61		Stateline Wind Project	21	21
62		Condon Wind Project	0	0
63		Klondike I	0	0
64		Klondike III	12	12
65		Georgia-Pacific Paper (Wauna)	0	0
66		Fourmile Hill Geothermal	0	0
67		Ashland Solar Project	0	0
68		White Bluffs Solar	0	0
69		Dworshak/Clearwater Small Hydropower	3	3
70		Elwha Hydro	0	0
71		Glines Canyon Hydro	0	0
72		Rocky Brook	0	0
73	Total Resources		**13,006**	**13,131**

Table 2.2.3.1

Energy Allocation Factor
Calculation of Energy Allocation Factors
Test Period October 2023 - September 2025

	B	C	D
4		**2024**	**2025**
5			
6	**Loads (after adjustments)**		
7	Public	7,183	7,404
8	Exchange	5,439	5,451
9	DSI	11	11
10	NR	0.001	0.001
11	FPS	372	265
12			
13	Load Pools -- Program Case		
14	Priority Firm - 7(b) Loads	12,622	12,855
15	Industrial Firm - 7(c) Loads	11	11
16	New Resources - 7(f) Loads	0.001	0.001
17	Surplus Firm - SP Loads	372	265
18	Total Firm Loads	13,006	13,131
19	Secondary	2,017	1,975
20	Surplus Firm - SP Loads (for rate protection)	372	265
21			
22	**Resources (after adjustments)**		
23	Federal Base System	7,506	7,617
24	Exchange Resources	5,439	5,451
25	New Resources	60	64
26	Total Firm Resources	13,006	13,131
27			
28	Allocators -- Program Case		
29	Federal Base System		
30	Priority Firm - 7(b) Loads	7,506	7,617
31	Industrial Firm - 7(c) Loads	0	0
32	New Resources - 7(f) Loads	0	0
33	Surplus Firm - SP Loads	0	0
34	Exchange Resources		
35	Priority Firm - 7(b) Loads	5,116	5,238
36	Industrial Firm - 7(c) Loads	10	9
37	New Resources - 7(f) Loads	0.0010	0.0009
38	Surplus Firm - SP Loads	314	204
39	New Resources		
40	Priority Firm - 7(b) Loads	0	0
41	Industrial Firm - 7(c) Loads	2	3
42	New Resources - 7(f) Loads	0	0
43	Surplus Firm - SP Loads	58	61

Energy Allocation Factor
Calculation of Energy Allocation Factors
Test Period October 2023 - September 2025

	B	C	D
4		**2024**	**2025**
44			
45	**Allocation Factors -- Program Case with Exchange**		
46	Federal Base System + NR		
47	Priority Firm - 7(b) Loads	0.9921	0.9917
48	Industrial Firm - 7(c) Loads	0.0002	0.0003
49	New Resources - 7(f) Loads	0.0000	0.0000
50	Surplus Firm - SP Loads	0.0077	0.0080
51	Federal Base System		
52	Priority Firm - 7(b) Loads	1.0000	1.0000
53	Industrial Firm - 7(c) Loads	0.0000	0.0000
54	New Resources - 7(f) Loads	0.0000	0.0000
55	Surplus Firm - SP Loads	0.0000	0.0000
56	Exchange Resources		
57	Priority Firm - 7(b) Loads	0.9406	0.9610
58	Industrial Firm - 7(c) Loads	0.0018	0.0016
59	New Resources - 7(f) Loads	0.0000	0.0000
60	Surplus Firm - SP Loads	0.0577	0.0374
61	New Resources		
62	Priority Firm - 7(b) Loads	0.0000	0.0000
63	Industrial Firm - 7(c) Loads	0.0296	0.0411
64	New Resources - 7(f) Loads	0.0000	0.0000
65	Surplus Firm - SP Loads	0.9704	0.9589
66	Conservation & General		
67	Priority Firm - 7(b) Loads	0.9705	0.9790
68	Industrial Firm - 7(c) Loads	0.0009	0.0009
69	New Resources - 7(f) Loads	0.0000	0.0000
70	Surplus Firm - SP Loads	0.0286	0.0202
81	Surplus Deficit		
82	Priority Firm - 7(b) Loads	0.9991	0.9991
83	Industrial Firm - 7(c) Loads	0.0009	0.0009
84	New Resources - 7(f) Loads	0.0000	0.0000
85	Surplus Firm - SP Loads	-1.0000	-1.0000
89	Rate Protection		
90	PF Exchange	0.6938	0.7077
91	Industrial Firm - 7(c) Loads	0.0014	0.0015
92	New Resources - 7(f) Loads	0.0000	0.0000
93	Secondary Sales	0.3047	0.2908

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2023 -
September 2025 ($ 000)

	B	D	E
4		**2024**	**2025**
5	**Power System Generation Resources**		
6	**Operating Generation**		
7	Columbia Generating Station (WNP-2)	296,477	351,133
8	Bureau of Reclamation	154,364	157,218
9	Corps of Engineers	265,146	275,147
10	CRFM Studies	9,349	6,051
11	Billing Credits Generation	5,300	5,300
12	Cowlitz Falls O&M	8,600	9,600
13	Clearwater Hatchery Generation	1,368	1,410
14	New Resources Integration Wheeling	768	813
15			
16	**Operating Generation Settlement Payment**		
17	Operating Generation Settlement Payment (Colville)	22,000	22,000
18	Operating Generation Settlement Payment (Spokane)	5,749	5,500
19			
20	**Non-Operating Generation**		
21	Trojan Decomissioning	1,200	1,200
22	WNP-1&3 Decomissioning	1,141	1,175
23			
24	**Contracted and Augmentation Power Purchases**		
25	Augmentation Power Purchases	-	-
26	Balancing Purchases	55,078	45,875
27	PNCA Headwater Benefits	3,100	3,100
28	Tier 1 Augmentation Resources (Klondike III)	8,158	9,335
29	Hedging/Mitigation	25,191	24,594
30	Other Committed Purchase (excl. Hedging)	332	332
31	Bookout Adj to Contracted Power Purchases	-	-
32			
33	**Exchanges and Settlements**		
34	Residential Exchange (IOU)	273,600	273,600
35	Residential Exchange (COU)	623	618
36	Residential Exchange (Refund)	-	-
37	Residential Exchange Program Support	554	602
38	Residential Exchange Interest Accrual	-	-
39			
40	**Renewable and Conservation Generation**		
41	Renewables R&D	1,011	1,011
42	Renewable Generation	17,809	17,432
43	Conservation Infrastructure	26,044	26,106
44	Generation Conservation R&D	657	657
45	DR & Smart Grid	215	215
46	Conservation Acquisition	69,027	69,027
47	Low Income Energy Efficiency	6,005	6,005
48	Reimbursable Energy Efficiency Development	-	-
49	Legacy Conservation	590	590
50	Market Transformation	11,800	11,800

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2023 -
September 2025 ($ 000)

	B	D	E
4		**2024**	**2025**
51			
52	**Transmission Acquisition and Ancillary Services**		
53	Trans & Ancillary Svcs (non-slice)	65,246	64,334
54	Trans & Ancillary Svcs (sys oblig)	29,703	29,700
55	Third Party GTA Wheeling	91,278	92,598
56	Power 3rd Party Trans & Ancillary Svcs (Non-Slice Cost)	-	-
57	Power 3rd Party Trans & Ancillary Svcs (Composite Cost)	3,300	3,300
58	Trans Acq Generation Integration	19,894	20,194
59	Power Telemetering/Equipment Replacement	-	-
60	EESC Charges (Composite)	-	-
61	EESC Charges (Non-Slice)	-	-
62			
63	**Power Non-Generation Operations**		
64	Efficiencies Program	-	-
65	Information Technology	2,376	2,473
66	Generation Project Coordination	4,443	4,571
67	Slice costs Charged to Slice Customers	-	-
68	Slice Implementation	608	632
69			
70	**PS Scheduling**		
71	Operations Scheduling	9,505	9,945
72	Operations Planning	9,739	10,102
73			
74	**PS Marketing and Business Support**		
75	Sales and Support	17,871	18,429
76	Strategy, Finance & Risk Mgmt	-	-
77	Executive and Administrative Svcs	-	-
78	Conservation Support	7,045	7,309
79	Power R&D	1,870	1,870
80	Grid Mod	-	-
81	Power Internal Support	27,856	27,210
82	KSI Commercial Operations Expense	-	-
83	EIM Support Costs	-	-
84			
85	**Fish and Wildlife/USF&W/Planning Council/Env Req.**		
86	Fish and Wildlife	269,235	268,865
87	USF&W Lower Snake Hatcheries	32,765	32,765
88	Planning Council	11,942	11,942
89			
90	**BPA Internal Support**		
91	Additional Post-Retirement Contribution	19,310	19,844
92	Agency Svs for Power for Rev Req schedule	62,518	64,557
93	F&W Corporate Support - G&A	16,086	16,577
94	Agency Svs for Energy Efficiency for Rev Req schedule	14,980	15,356
95			
96	**Bad Debt Expense/Other**		
97	Bad Debt Expense (composite)	-	-
98	Bad Debt Expense (non-slice)	-	-
99	Other Income & Expense (composite) - Decommissioning	-	-

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2023 -
September 2025 ($ 000)

	B	D	E
4		**2024**	**2025**
103			
104	**Depreciation and Amortization**		
105	**Depreciation**		
106	Depreciation - BPA	2,573	2,708
107	Depreciation - Corps	108,009	110,397
108	Depreciation - Bureau	29,121	30,495
109			
110	**Amortization**		
111	Amortization - Legacy Conservation	-	-
112	Amortization - Conservation Acquisitions	22,255	16,422
113	Amortization - CRFM	19,891	19,891
114	Amortization - Fish & Widlife	36,802	37,613
115	Amortization -- CGS	155,454	164,056
116	Accretion -- CGS Decomm Trust liability	40,043	41,798
117	Amortization -- WNP1	32,755	32,755
118	Amortization -- WNP3	37,637	37,637
119	Amortization -- Cowlitz Falls	5,706	5,706
120	Amortization -- N. Wasco	1,987	1,987
121			
122	**Interest Expense**		
123	**Net Interest**		
124	Interest On Appropriated Funds	34,236	23,203
125	Capitalization Adjustment	(45,937)	(45,937)
126	Interest On Treasury Bonds	39,728	43,660
127	Non Federal Interest (Prepay)	5,694	4,539
128	Non Federal Interest (CGS)	141,095	140,046
129	Non Federal Interest (WNP 1)	39,574	39,631
130	Non Federal Interest (WNP 3)	45,426	43,901
131	Non Federal Interest (N Wasco)	108	16
132	Non Federal Interest (Lewis County)	2,646	2,402
133	Premiums/Discounts	11,090	605
134	Amortization of Refinancing Premiums/Discounts	(34,767)	(38,006)
135	Amortization of Cost of Issuance	500	500
136	Gains/losses on Extinguishment	-	-
137	AFUDC	(17,821)	(18,137)
138	Interest Income on Decommissioning Trust	(11,469)	(12,191)
139	Other Expense and (Income) (Gains/Losses on Decomm Tr	(4,335)	(4,608)
140	Interest Earned on BPA Fund for Power (composite)	(2,274)	(3,199)
141	Interest Earned on BPA Fund for Power (non-slice)	(1,165)	(2,665)
142			
143	**Net Interest into Cost Pools**		
144	Power Net Interest - Hydro Allocation	18,918	1,767
145	Power Net Interest - Fish & Wildlife Allocation	3,843	262
146	Power Net Interest - Conservation Allocation	389	10
147	Power Net Interest - BPA Programs Allocation	401	29
148			

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2023 -
September 2025 ($ 000)

	B	D	E
4		**2024**	**2025**
149	**Net Interest into Cost Pools 7b2**		
150	Power Net Interest Hydro 7b2 Allocation	18,918	1,767
151	Power Net Interest Fish & Wildlife 7b2 Allocation	3,843	262
152	Power Net Interest BPA Programs 7b2 Allocation	790	39
153			
154	**Net Revenue**		
155	**Minimum Required Net Revenue**		
156	Repayment of Treasury Borrowings	181,200	236,863
157	Payment of Irrigation Assistance	8,067	14,006
158	Depreciation (MRNR - Reverse sign)	(139,703)	(143,600)
159	Amortization (MRNR - Reverse sign)	(352,530)	(357,864)
160	Non Federal Interest (Prepay) (MRNR - Reverse Sign)	(5,694)	(4,539)
161	Capitalization Adjustment (MRNR - Reverse Sign)	45,937	45,937
162	Amortization of Refinancing Premiums/Discounts (MRNR	34,767	38,006
163	Amortization of Cost of Issuance (MRNR-reverse sign)	(500)	(500)
164	Gains/Losses on Extinguishment	-	-
165	Repayment of Federal Appropriations	278,799	209,137
166	Accrual Revenues (MRNR Adjustment - Reverse Sign)	-	-
167	Prepay Revenue Credits (MRNR - Reverse Sign)	30,600	30,600
168	Non-Cash Expenses	-	-
169	Repayment of NF Obligations (LOC)	-	-
170	Repayment of NF Obligations (CGS)	20,081	18,160
171	Repayment of NF Obligations (WNP 1)	365	(2,961)
172	Repayment of NF Obligations (WNP 3)	226	679
173	Repayment of NF Obligations (N Wasco)	1,840	315
174	Repayment of NF Obligations (Cowlitz Falls)	4,655	4,900
175	Cash freed up by DSR refinancing	(17,600)	-
176	Cash Contribution to CGS Decomm Trust	15,100	15,100
177	Interest Income on Decommissioning Trust (MRNR - Reve	11,469	12,191
178	Other Expense and (Income) (Gains/Losses on Decomm Tr	4,335	4,608
179	Revenue Financing Requirement	33,743	34,290
180	Depreciation Exceeds Cash Expense	(155,158)	(155,327)
181			
182	**Minimum Net Revenue into Cost Pools**		
183	Power MNetRev - Hydro Allocation	124,636	132,736
184	Power MNetRev - Fish & Wildlife Allocation	25,319	19,667
185	Power MNetRev - Conservation Allocation	2,560	728
186	Power MNetRev - BPA Programs Allocation	2,643	2,195
187			
188	**Minimum Net Revenue into Cost Pools 7b2**		
189	Power MNetRev - Hydro 7b2 Allocation	124,636	132,736
190	Power MNetRev - Fish & Wildlife 7b2 Allocation	25,319	19,667
191	Power MNetRev - PBA Programs 7b2 Allocation	5,203	2,924
192			
193	**Planned Net Revenues for Risk into Cost Pools**		
194	Power PNetRev - Hydro Allocation	103,623	110,238
195	Power PNetRev - Fish & Wildlife Allocation	21,051	16,333
196	Power PNetRev - Conservation Allocation	2,128	605
197	Power PNetRev - BPA Programs Allocation	2,197	1,823
198			
199	**Planned Net Revenues for Risk into Cost Pools 7b2**		
200	Power PNetRev - Hydro 7b2 Allocation	103,623	110,238
201	Power PNetRev - Fish & Wildlife 7b2 Allocation	21,051	16,333
202	Power PNetRev - BPA Programs 7b2 Allocation	4,325	2,429

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2023 -
September 2025 ($ 000)

	B	D	E
4		**2024**	**2025**
203			
204	**Internally Computed Line Items**		
205	Augmentation Power Purchases	-	-
206	Balancing Purchases	80,269	70,470
207	Secondary Energy Credit	(638,013)	(575,152)
208	Low Density Discount Costs	37,701	38,532
209	Irrigation Rate Mitigation Costs	21,770	21,770
210	**Charges/Credits to Tiered Rate Pools**		
211	Firm Surplus and Secondary Credit (from unused RHWM	(98,789)	(86,644)
212	Balancing Augmentation	(2,358)	(5,792)
213	Transmission Loss Adjustment	(33,464)	(33,639)
214	Demand Revenue	60,247	62,636
215	Load Shaping Revenue	57,931	63,975
216	**Tier 2 and RSS Charges/Credits to Tiered Rate Pools**		
217	Augmentation RSS & RSC Adder	2,790	2,790
218	Tier 2 Purchase Costs	111,871	200,414
219	Tier 2 Rate Design Adjustments (Cost)	2,916	5,378
220	Tier 2 Other Costs	-	-
221			
222	**Revenue Credits / Rate Design Adjustments**		
223	Downstream Benefits and Pumping Power	(20,607)	(20,607)
224	Generation Inputs Revenue	(112,085)	(112,085)
225	Capacity for Delayed 168-hr Loss Returns	-	-
226	FPS Real Power Losses	-	-
227	4(h)(10)(C)	(111,288)	(111,456)
228	PRSC Net Credit (Composite)	-	-
229	PRSC Net Credit (Non-Slice)	-	-
230	Colville and Spokane Settlements	(4,600)	(4,600)
231	Green Tags (FBS resources)	-	-
232	Green Tags (New resources)	-	-
233	Energy Efficiency Revenues	-	-
234	Miscellaneous Credits (incl. GTA)	(12,104)	(12,306)
235	Pre-sub/Hungry Horse	-	-
236	Other Locational/Seasonal Exchange	-	-
237	Upper Baker	(523)	(510)
238	Other Surplus Sales (Non-Slice)	-	-
239	PF Load Forecast Deviation Liquidated Damages	-	-
240	NR Revenues from ESS energy and capacity charges	-	-
241	**Tier 2**		
242	Composite Augmentation RSS Revenue Debit/(Credit)	(1,947)	(1,947)
243	Composite Tier 2 RSS Revenue Debit/(Credit)	(203)	(380)
244	Composite Tier 2 Rate Design Adjustment Debit/(Credit)	(2,713)	(4,998)
245	Composite Non-Federal RSS Revenue Debit/(Credit)	(964)	(944)
246	Non-Slice Augmentation RSC Revenue Debit/(Credit)	(842)	(842)
247	Non-Slice Tier 2 RSC Revenue Debit/(Credit)	-	-
248	Non-Slice Tier 2 Rate Design Debit/(Credit)	-	-
249	Non-Slice Non-Federal RSC Revenue Debit/(Credit)	(92)	(92)

Table 2.3.2

Cost of Service Analysis
Cost Pool Aggregation
Test Period October 2023 - September 2025 ($ 000)

	B		D	E
3			**2024**	**2025**
4				
5	**Federal Base System**		**2,217,068**	**2,354,186**
6	Hydro		896,671	907,305
7		Operating Expense	649,494	662,564
8		Net Interest	18,918	1,767
9		PNRR	103,623	110,238
10		MRNR	124,636	132,736
11	BPA Fish and Wildlife Program		384,278	371,260
12		Operating Expense	334,065	334,997
13		Net Interest	3,843	262
14		PNRR	21,051	16,333
15		MRNR	25,319	19,667
16	Trojan		1,200	1,200
17	WNP #1		73,470	73,561
18	WNP #2		582,998	642,729
19	WNP #3		83,064	81,539
20	System Augmentation		-	-
21	Balancing		80,601	70,802
22	Tier 2 Costs		114,787	205,792
23				
24	**New Resources**		**48,161**	**49,711**
25	Idaho Falls		-	-
26	Tier 1 Aug (Klondike III)		8,158	9,335
27	Cowlitz Falls		14,414	15,322
28	Other NR		25,589	25,055
29				
30	**Residential Exchange**		**3,537,320**	**3,535,787**
31				
32	**Conservation**		**168,995**	**160,131**
33		Operating Expense	163,917	158,788
34		Net Interest	389	10
35		PNRR	2,128	605
36		MRNR	2,560	728
37				
38	**BPA Programs**		**163,909**	**166,389**
39		Operating Expense	158,668	162,341
40		Net Interest	401	29
41		PNRR	2,197	1,823
42		MRNR	2,643	2,195
43				
44				
45	**Transmission**		**209,422**	**210,126**
46	TBL Transmission/Ancillary Services		118,143	117,528
47	3Rd Party Trans/Ancillary Services		-	-
48	General Transfer Agreements		91,278	92,598
49				
50	**Total PBL Revenue Requirement**		**6,344,874**	**6,476,331**
51				

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

	B	D	E	F	G	H
18	**Program Totals**	**2024**	**2025**			
19	**Low Density Discount Expenses........................**	**$ 37,701**	**$ 38,532**			
20	**Irrigation Rate Discount...................................**	**$ 21,770**	**$ 21,770**			
21						
22						
23	**TRM Costs after Adjustments**	**2024**	**2025**			
24	**Composite..**	$ 2,376,037	$ 2,385,737			
25	**Non-Slice..**	$ (331,138)	$ (332,843)			
26	**Slice...**	$ -	$ -			
27	**Tier 2..**	$ 114,787	$ 205,792			
28	**Total Costs**	$ 2,159,685	$ 2,258,686			
29						
30	**Low Density Discount**					
31	**Customer Charge LDD**	**2024**	**2025**			
32	**TOCA LDD Offest %..**	1.68%	1.70%			
33	**LDD Customer Charge ($000).........................**	$ 34,259	$ 34,808			
34						
35	**Irrigation Rate Discount**					
36	**IRD Percentage..**	37.06%				
37	**Total Irrigation Load (MWh)..........................**	1,881,605				
38	**RT1SC...**	7,063				
39	**Irrigation Load Weighted LDD.......................**	4.6%				
40						
41		**2024**	**2025**			
42	**Hours...**	8784	8760			
43	**IRD TOCA..**	3.03266%	3.04097%			
44	**Composite Revenue...**	$ 75,547,668	$ 75,754,682			
45	**Non-Slice Revenue..**	$ (13,276,627)	$ (13,313,007)			
46	**Load Shaping Revenue.......................................**	$ (777,674)	$ (738,300)			
47	**Total after LDD...**	$ 58,664,673	$ 58,865,020			
48						
49	**Irrigation Rate Discount...................................**	**11.57**				
50						
51						

Cost of Service Analysis
Computation of Low Density and Irrigation Rate Discount Costs
Test Period October 2019 - September 2021
($ 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-23	11,003	3,166	$ 10.37	$ 47.71	$ 265,174
54	Oct-23	-	(592)	$ 10.37	$ 32.91	$ (19,487)
55	Nov-23	14,743	(7,205)	$ 8.75	$ 40.30	$ (161,385)
56	Nov-23	-	(2,713)	$ 8.75	$ 31.39	$ (85,167)
57	Dec-23	21,700	1,340	$ 13.39	$ 61.63	$ 373,125
58	Dec-23	-	4,664	$ 13.39	$ 52.69	$ 245,755
59	Jan-24	20,854	(1,828)	$ 10.84	$ 49.88	$ 134,892
60	Jan-24	-	3,600	$ 10.84	$ 36.73	$ 132,254
61	Feb-24	17,154	(3,350)	$ 10.93	$ 50.32	$ 18,915
62	Feb-24	-	2,528	$ 10.93	$ 42.01	$ 106,206
63	Mar-24	18,629	(6,832)	$ 7.62	$ 35.07	$ (97,665)
64	Mar-24	-	(4,568)	$ 7.62	$ 35.84	$ (163,707)
65	Apr-24	20,147	17	$ 4.43	$ 20.42	$ 89,607
66	Apr-24	-	1,415	$ 4.43	$ 21.67	$ 30,655
67	May-24	14,133	(7,305)	$ 3.95	$ 18.21	$ (77,189)
68	May-24	-	(3,738)	$ 3.95	$ 16.34	$ (61,067)
69	Jun-24	17,786	(4,596)	$ 3.88	$ 17.87	$ (13,116)
70	Jun-24	-	(3,849)	$ 3.88	$ 10.33	$ (39,743)
71	Jul-24	22,606	6,399	$ 12.08	$ 55.60	$ 628,835
72	Jul-24	-	9,153	$ 12.08	$ 36.92	$ 337,883
73	Aug-24	26,164	9,322	$ 15.54	$ 71.52	$ 1,073,352
74	Aug-24	-	5,243	$ 15.54	$ 48.93	$ 256,549
75	Sep-24	13,940	4,054	$ 12.75	$ 58.70	$ 415,672
76	Sep-24	-	1,160	$ 12.75	$ 44.18	$ 51,249
77	**Total**					**$ 3,441,597**

Table 2.3.3.3

Cost of Service Analysis
Computation of Low Density and Irrigation Rate Discount Costs
Test Period October 2019 - September 2021
($ 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-24	17,747	2,387	$ 10.37	$ 47.71	$ 297,955
80	Oct-24	-	(87)	$ 10.37	$ 32.91	$ (2,875)
81	Nov-24	15,423	(7,405)	$ 8.75	$ 40.30	$ (163,488)
82	Nov-24	-	(2,875)	$ 8.75	$ 31.39	$ (90,224)
83	Dec-24	21,876	1,257	$ 13.39	$ 61.63	$ 370,405
84	Dec-24	-	4,568	$ 13.39	$ 52.69	$ 240,675
85	Jan-25	21,583	(1,774)	$ 10.84	$ 49.88	$ 145,467
86	Jan-25	-	3,716	$ 10.84	$ 36.73	$ 136,491
87	Feb-25	17,206	(2,109)	$ 10.93	$ 50.32	$ 81,941
88	Feb-25	-	2,928	$ 10.93	$ 42.01	$ 122,992
89	Mar-25	18,955	(6,799)	$ 7.62	$ 35.07	$ (94,014)
90	Mar-25	-	(4,634)	$ 7.62	$ 35.84	$ (166,077)
91	Apr-25	23,192	80	$ 4.43	$ 20.42	$ 104,382
92	Apr-25	-	1,506	$ 4.43	$ 21.67	$ 32,640
93	May-25	15,880	(7,439)	$ 3.95	$ 18.21	$ (72,723)
94	May-25	-	(3,865)	$ 3.95	$ 16.34	$ (63,153)
95	Jun-25	18,121	(4,397)	$ 3.88	$ 17.87	$ (8,260)
96	Jun-25	-	(3,966)	$ 3.88	$ 10.33	$ (40,955)
97	Jul-25	28,857	6,484	$ 12.08	$ 55.60	$ 709,111
98	Jul-25	-	9,300	$ 12.08	$ 36.92	$ 343,300
99	Aug-25	23,445	10,825	$ 15.54	$ 71.52	$ 1,138,554
100	Aug-25	-	4,068	$ 15.54	$ 48.93	$ 199,025
101	Sep-25	17,173	2,999	$ 12.75	$ 58.70	$ 394,973
102	Sep-25	-	2,444	$ 12.75	$ 44.18	$ 107,996
103	**Total**					**$ 3,724,136**

Cost of Service Analysis
Allocation of Costs
Test Period October 2023 - September 2025 ($ 000)

	B	C	D
4	**Costs ($000)**	**2024**	**2025**
5	**FBS...**	$ 2,217,068	$ 2,354,186
6	**New Resources......................................**	$ 48,161	$ 49,711
7	**Residential Exchange...........................**	$ 3,537,320	$ 3,535,787
8	**Conservation..**	$ 168,995	$ 160,131
9	**BPAPrograms.......................................**	$ 163,909	$ 166,389
10	**Transmission..**	$ 209,422	$ 210,126
11	**Irrigation/Low Density Discounts.......**	$ 59,471	$ 60,302
12	Total..	$ 6,404,345	$ 6,536,633
13			
14	**Cost Allocation**		
15			
16	**FBS...**	$ 2,217,068	$ 2,354,186
17			
18	**Federal Base System Allocators...........**	**2024**	**2025**
19	Priority Firm - 7(b) Loads......................	1.0000	1.0000
20	Industrial Firm - 7(c) Loads...................	0.0000	0.0000
21	New Resources - 7(f) Loads...................	0.0000	0.0000
22	Surplus Firm - SP Loads........................	0.0000	0.0000
23	Total..	1.0000	1.0000
24			
25	**FBS Cost Allocation............................**	**2024**	**2025**
26	Priority Firm - 7(b) Loads......................	$ 2,217,068	$ 2,354,186
27	Industrial Firm - 7(c) Loads...................	$ -	$ -
28	New Resources - 7(f) Loads...................	$ -	$ -
29	Surplus Firm - SP Loads........................	$ -	$ -
30	Total..	$ 2,217,068	$ 2,354,186
31			
32			
33	**Irrigation/Low Density Discounts.......**	$ 59,471	$ 60,302
34			
35	**Irrigation/LDD Allocators...................**	**2024**	**2025**
36	Priority Firm - 7(b) Loads......................	1.0000	1.0000
37	Industrial Firm - 7(c) Loads...................	0.0000	0.0000
38	New Resources - 7(f) Loads...................	0.0000	0.0000
39	Surplus Firm - SP Loads........................	0.0000	0.0000
40	Total..	1.0000	1.0000
41			
42	**Irrigation/LDD Cost Allocation...........**	**2024**	**2025**
43	Priority Firm - 7(b) Loads......................	$ 59,471	$ 60,302
44	Industrial Firm - 7(c) Loads...................	$ -	$ -
45	New Resources - 7(f) Loads...................	$ -	$ -
46	Surplus Firm - SP Loads........................	$ -	$ -
47	Total..	$ 59,471	$ 60,302

Cost of Service Analysis
Allocation of Costs
Test Period October 2023 - September 2025 ($ 000)

	B	C		D	
4	**Costs ($000)**		**2024**		**2025**
5	**FBS...**	$	2,217,068	$	2,354,186
6	**New Resources......................................**	$	48,161	$	49,711
7	**Residential Exchange............................**	$	3,537,320	$	3,535,787
8	**Conservation...**	$	168,995	$	160,131
9	**BPAPrograms.......................................**	$	163,909	$	166,389
10	**Transmission...**	$	209,422	$	210,126
11	**Irrigation/Low Density Discounts.........**	$	59,471	$	60,302
12	Total...	$	6,404,345	$	6,536,633
13					
14	**Cost Allocation (continued)**				
15					
16	**New Resources......................................**	$	48,161	$	49,711
17					
18	**New Resources Allocators**		**2024**		**2025**
19	Priority Firm - 7(b) Loads......................		0.0000		0.0000
20	Industrial Firm - 7(c) Loads....................		0.0296		0.0411
21	New Resources - 7(f) Loads...................		0.00000302		0.00000419
22	Surplus Firm - SP Loads.........................		0.9704		0.9589
23	Total...		1.0000		1.0000
24					
25	**New Resources Cost Allocation...........**		**2024**		**2025**
26	Priority Firm - 7(b) Loads......................	$	-	$	-
27	Industrial Firm - 7(c) Loads....................	$	1,426	$	2,045
28	New Resources - 7(f) Loads...................	$	0.1455	$	0.2085
29	Surplus Firm - SP Loads.........................	$	46,734	$	47,666
30	Total...	$	48,161	$	49,711
31					
32					
33	**Residential Exchange............................**	$	3,537,320	$	3,535,787
34	Costs Functionalized to Transmission.....	$	(256,423)	$	(256,261)
35	Costs Functionalized to Generation.........	$	3,280,897	$	3,279,525
36					
37	**Residential Exchange Allocators**		**2024**		**2025**
38	Priority Firm - 7(b) Loads......................		0.9406		0.9610
39	Industrial Firm - 7(c) Loads....................		0.0018		0.0016
40	New Resources - 7(f) Loads...................		0.00000018		0.00000016
41	Surplus Firm - SP Loads.........................		0.0577		0.0374
42	Total...		1.0000		1.0000
43					
44	**Residential Exchange Cost Allocation**		**2024**		**2025**
45	Priority Firm - 7(b) Loads......................	$	3,085,887	$	3,151,754
46	Industrial Firm - 7(c) Loads....................	$	5,776	$	5,256
47	New Resources - 7(f) Loads...................	$	0.589	$	0.536
48	Surplus Firm - SP Loads.........................	$	189,233	$	122,515
49	Total...	$	3,280,897	$	3,279,525

Cost of Service Analysis
Allocation of Costs
Test Period October 2023 - September
2025 ($ 000)

	B	C		D	
4	**Costs ($000)**		**2024**		**2025**
5	**FBS..**	$	2,217,068	$	2,354,186
6	**New Resources.................................**	$	48,161	$	49,711
7	**Residential Exchange.......................**	$	3,537,320	$	3,535,787
8	**Conservation....................................**	$	168,995	$	160,131
9	**BPAPrograms...................................**	$	163,909	$	166,389
10	**Transmission...................................**	$	209,422	$	210,126
11	**Irrigation/Low Density Discounts...**	$	59,471	$	60,302
12	Total..	$	6,404,345	$	6,536,633
13					
14	**Cost Allocation (continued)**				
15					
16	**Conservation....................................**	$	168,995	$	160,131
17					
18	**BPAPrograms...................................**	$	163,909	$	166,389
19					
20	**Transmission...................................**	$	209,422	$	210,126
21					
22					
23	**Conservation & General Allocators**		**2024**		**2025**
24	Priority Firm - 7(b) Loads.................		0.9705		0.9790
25	Industrial Firm - 7(c) Loads..............		0.0009		0.0009
26	New Resources - 7(f) Loads..............		0.0000		0.0000
27	Surplus Firm - SP Loads...................		0.0286		0.0202
28	Total..		1.0000		1.0000
29					
30	**Conservation Cost Allocation..........**		**2024**		**2025**
31	Priority Firm - 7(b) Loads.................	$	164,013	$	156,765
32	Industrial Firm - 7(c) Loads..............	$	148	$	138
33	New Resources - 7(f) Loads..............	$	0	$	0
34	Surplus Firm - SP Loads...................	$	4,834	$	3,228
35	Total..	$	168,995	$	160,131
36					
37	**BPA Programs Cost Allocation.......**		**2024**		**2025**
38	Priority Firm - 7(b) Loads.................	$	159,078	$	162,891
39	Industrial Firm - 7(c) Loads..............	$	143	$	144
40	New Resources - 7(f) Loads..............	$	0	$	0
41	Surplus Firm - SP Loads...................	$	4,688	$	3,354
42	Total..	$	163,909	$	166,389
43					
44	**Transmission Cost Allocation..........**		**2024**		**2025**
45	Priority Firm - 7(b) Loads.................	$	203,249	$	205,709
46	Industrial Firm - 7(c) Loads..............	$	183	$	182
47	New Resources - 7(f) Loads..............	$	0	$	0
48	Surplus Firm - SP Loads...................	$	5,990	$	4,235
49	Total..	$	209,422	$	210,126

Cost of Service Analysis
Allocation of Costs Summary
Test Period October 2023 - September
2025 ($ 000)

	B	C		D	
4	**Costs ($000)**		**2024**		**2025**
5	**FBS...**	$	2,217,068	$	2,354,186
6	**New Resources.......................................**	$	48,161	$	49,711
7	**Residential Exchange............................**	$	3,537,320	$	3,535,787
8	**Conservation..**	$	168,995	$	160,131
9	**BPAPrograms...**	$	163,909	$	166,389
10	**Transmission..**	$	209,422	$	210,126
11	**Irrigation/Low Density Discounts........**	$	59,471	$	60,302
12	Total..	$	6,404,345	$	6,536,633
13					
14	**Cost Allocation (continued)**				
15					
16					
17	**Initial Cost Allocation (Costs /$1000)**		**2024**		**2025**
18	Priority Firm - 7(b) Loads.......................	$	5,888,766	$	6,091,608
19	Industrial Firm - 7(c) Loads....................	$	7,676	$	7,765
20	New Resources - 7(f) Loads....................	$	0.78	$	0.79
21	Surplus Firm - SP Loads.........................	$	251,480	$	180,998
22	Total Costs Functionalized to Power......	$	6,147,922	$	6,280,371
23					
24					
25					
26	REP Cost Functionalized to Transmission	$	256,423	$	256,261
27					
28	Total COSA Revenue Requirement	$	6,404,345	$	6,536,633

Cost of Service Analysis
General Revenue Credits
Test Period October 2019 - September
2021 ($ 000)

	B	C		D	
5	**General Revenue Credits ($000))**		**2024**		**2025**
6					
7	**FBS....**	**$**	**(139,411)**	**$**	**(142,041)**
8	Hydro and Renewable....	$	(25,207)	$	(25,207)
9	Downstream Benefits and Pumping Power....	$	(20,607)	$	(20,607)
10	Colville and Spokane Settlements....	$	(4,600)	$	(4,600)
11	Green Tags (FBS resources)....	$	-	$	-
12	Fish and Wildlife....	$	(111,288)	$	(111,456)
13	4(h)(10)(c)....	$	(111,288)	$	(111,456)
14	Tier 2 Adjustment....	$	(2,916)	$	(5,378)
15	**Contract Obligations....**	**$**	**(523)**	**$**	**(510)**
16	Pre-sub/Hungry Horse....	$	-	$	-
17	Other Locational/Seasonal Exchange....	$	-	$	-
18	Upper Baker....	$	(523)	$	(510)
19	**New Resources....**	**$**	**-**	**$**	**-**
20	Green Tags (New resources)....	$	-	$	-
21	**Conservation....**	**$**	**-**	**$**	**-**
22	Energy Efficiency Revenues....	$	-	$	-
23	**BPAPrograms....**	**$**	**-**	**$**	**-**
24	**Transmission....**	**$**	**(12,104)**	**$**	**(12,306)**
25	Miscellaneous Credits (incl. GTA)....	$	(12,104)	$	(12,306)
26					
27	**Other Revenue Credits ($ 000))**		**2024**		**2025**
28	Secondary Revenue....	**$**	**(563,160)**	**$**	**(565,741)**
29	Incl. Slice....	$	(563,160)	$	(565,741)
30	Generation Inputs Revenue....	**$**	**(112,085)**	**$**	**(112,085)**
31	Real Power Losses (Non-Slice)....	**$**	**-**	**$**	**-**
32	PRSC Net Credit (Composite)....	**$**	**-**	**$**	**-**
33	PRSC Net Credit (Non-Slice)....	**$**	**-**	**$**	**-**
34	Composite Non-Federal RSS Revenue Debit/(Credit)....	**$**	**(964)**	**$**	**(944)**
35	Non-Slice Non-Federal RSC Revenue Debit/(Credit)....	**$**	**(92)**	**$**	**(92)**
36	NR Revenues from ESS energy and capacity charges....	**$**	**-**	**$**	**-**
37	PF Load Forecast Deviation Liquidated Damages....	$	-	$	-
38	**Firm Surplus and from Other Long-term Sales....**	**$**	**(185,966)**	**$**	**(120,921)**
39	Other Surplus Sales (Non-Slice)....	$	-	$	-
40	Firm Surplus Secondary Sales....	$	(185,966)	$	(120,921)
41					
42	**Total Revenue Credits**	$	(1,014,306)	$	(954,642)

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2019 - September
2021 ($ 000)

	B		C		D
4	**Allocation of Revenue Requirement**		**2024**		**2025**
5	Priority Firm - 7(b) Loads.......................................	$	5,888,766	$	6,091,608
6	Industrial Firm - 7(c) Loads....................................	$	7,676	$	7,765
7	New Resources - 7(f) Loads....................................	$	1	$	1
8	Surplus Firm - SP Loads...	$	251,480	$	180,998
9	Total..	$	6,147,922	$	6,280,371
10					
11	**General Revenue Credits ($000))**		**2024**		**2025**
12					
13	**FBS..**	**$**	**(139,934)**	**$**	**(142,551)**
14	Hydro and Renewable.......................................	$	(25,207)	$	(25,207)
15	Downstream Benefits and Pumping Power..	$	(20,607)	$	(20,607)
16	Colville and Spokane Settlements................	$	(4,600)	$	(4,600)
17	Green Tags (FBS resources)........................	$	-	$	-
18	Fish and Wildlife...	$	(111,288)	$	(111,456)
19	4(h)(10)(c)...	$	(111,288)	$	(111,456)
20	Tier 2 Adjustment...	$	(2,916)	$	(5,378)
21	Contract Obligations...	$	(523)	$	(510)
22	Pre-sub/Hungry Horse.................................	$	-	$	-
23	Other Locational/Seasonal Exchange...........	$	-	$	-
24	Upper Baker..	$	(523)	$	(510)
25					
26	**Federal Base System Allocators**		**2024**		**2025**
27	Priority Firm - 7(b) Loads.......................................		1.0000		1.0000
28	Industrial Firm - 7(c) Loads....................................		0.0000		0.0000
29	New Resources - 7(f) Loads....................................		0.0000		0.0000
30	Surplus Firm - SP Loads...		0.0000		0.0000
31	Total..		1.0000		1.0000
32					
33	**FBS Credit Allocation**		**2024**		**2025**
34	Priority Firm - 7(b) Loads.......................................	$	(139,934)	$	(142,551)
35	Industrial Firm - 7(c) Loads....................................	$	-	$	-
36	New Resources - 7(f) Loads....................................	$	-	$	-
37	Surplus Firm - SP Loads...	$	-	$	-
38	Total..	$	(139,934)	$	(142,551)
39					
40	**Allocation of Revenue Requirement**		**2024**		**2025**
41	Priority Firm - 7(b) Loads.......................................	$	5,748,832	$	5,949,056
42	Industrial Firm - 7(c) Loads....................................	$	7,676	$	7,765
43	New Resources - 7(f) Loads....................................	$	1	$	1
44	Surplus Firm - SP Loads...	$	251,480	$	180,998
45	Total..	$	6,007,988	$	6,137,820

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2019 - September 2021
($ 000)

	B		C		D
40	**Allocation of Revenue Requirement**		**2024**		**2025**
41	Priority Firm - 7(b) Loads.......................................	$	5,748,832	$	5,949,056
42	Industrial Firm - 7(c) Loads....................................	$	7,676	$	7,765
43	New Resources - 7(f) Loads....................................	$	1	$	1
44	Surplus Firm - SP Loads...	$	251,480	$	180,998
45	Total..	$	6,007,988	$	6,137,820
46					
47					
48	**General Revenue Credits (/$1000))**		**2024**		**2025**
49					
50	**Transmission...**	**$**	**(12,104)**	**$**	**(12,306)**
51	Miscellaneous Credits (incl. GTA)...................	$	(12,104)	$	(12,306)
52					
53	**Conservation & General Cost Allocators**		**2024**		**2025**
54	Priority Firm - 7(b) Loads.......................................		0.9705		0.9790
55	Industrial Firm - 7(c) Loads....................................		0.0009		0.0009
56	New Resources - 7(f) Loads....................................		0.0000		0.0000
57	Surplus Firm - SP Loads...		0.0286		0.0202
58	Total..		1.0000		1.0000
59					
60	**Transmission Allocation**		**2024**		**2025**
61	Priority Firm - 7(b) Loads.......................................	$	(11,747)	$	(12,047)
62	Industrial Firm - 7(c) Loads....................................	$	(11)	$	(11)
63	New Resources - 7(f) Loads....................................	$	(0)	$	(0)
64	Surplus Firm - SP Loads...	$	(346)	$	(248)
65	Total..	$	(12,104)	$	(12,306)
66					
67	**Allocation of Revenue Requirement**		**2024**		**2025**
68	Priority Firm - 7(b) Loads.......................................	$	5,737,085	$	5,937,009
69	Industrial Firm - 7(c) Loads....................................	$	7,665	$	7,754
70	New Resources - 7(f) Loads....................................	$	1	$	1
71	Surplus Firm - SP Loads...	$	251,133	$	180,750
72	Total..	$	5,995,884	$	6,125,514

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2019 - September 2021
($ 000)

	B		C		D
4	**Allocation of Revenue Requirement**		**2024**		**2025**
5	Priority Firm - 7(b) Loads................................	$	5,737,085	$	5,937,009
6	Industrial Firm - 7(c) Loads.............................	$	7,665	$	7,754
7	New Resources - 7(f) Loads............................	$	1	$	1
8	Surplus Firm - SP Loads..................................	$	251,133	$	180,750
9	Total..	$	5,995,884	$	6,125,514
10					
11					
12	**General Revenue Credits ($000))**		**2024**		**2025**
13					
14	**New Resources..**	**$**	**-**	**$**	**-**
15	Green Tags (New resources)......................	$	-	$	-
16					
17					
18	**New Resources Cost Allocators**		**2024**		**2025**
19	Priority Firm - 7(b) Loads................................		0.0000		0.0000
20	Industrial Firm - 7(c) Loads.............................		0.0296		0.0411
21	New Resources - 7(f) Loads............................		0.000003		0.000004
22	Surplus Firm - SP Loads..................................		0.9704		0.9589
23	Total..		1.0000		1.0000
24					
25	**New Resources Allocation**		**2024**		**2025**
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**		**2024**		**2025**
33	Priority Firm - 7(b) Loads................................	$	5,737,085	$	5,937,009
34	Industrial Firm - 7(c) Loads.............................	$	7,665	$	7,754
35	New Resources - 7(f) Loads............................	$	0.782	$	0.791
36	Surplus Firm - SP Loads..................................	$	251,133	$	180,750
37	Total..	$	5,995,884	$	6,125,514
38					

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2019 - September 2021
($ 000)

	B	C		D	
32	**Allocation of Revenue Requirement**		**2024**		**2025**
33	Priority Firm - 7(b) Loads................................	$	5,737,085	$	5,937,009
34	Industrial Firm - 7(c) Loads.............................	$	7,665	$	7,754
35	New Resources - 7(f) Loads............................	$	0.782	$	0.791
36	Surplus Firm - SP Loads..................................	$	251,133	$	180,750
37	Total...	$	5,995,884	$	6,125,514
39					
40	**General Revenue Credits (/$1000))**		**2024**		**2025**
41					
42	**Conservation...**	**$**	**-**	**$**	**-**
43	Energy Efficiency Revenues.......................	$	-	$	-
44					
45	**Conservation & General Cost Allocators**		**2024**		**2025**
46	Priority Firm - 7(b) Loads................................		0.9705		0.9790
47	Industrial Firm - 7(c) Loads.............................		0.0009		0.0009
48	New Resources - 7(f) Loads............................		0.0000001		0.0000001
49	Surplus Firm - SP Loads..................................		0.0286		0.0202
50	Total...		1.0000		1.0000
51					
52	**Conservation Allocation**		**2024**		**2025**
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**		**2024**		**2025**
60	Priority Firm - 7(b) Loads................................	$	5,737,085	$	5,937,009
61	Industrial Firm - 7(c) Loads.............................	$	7,665	$	7,754
62	New Resources - 7(f) Loads............................	$	0.782	$	0.791
63	Surplus Firm - SP Loads..................................	$	251,133	$	180,750
64	Total...	$	5,995,884	$	6,125,514

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2023 - September
2025 ($ 000)

	B		C		D
4	**Allocation of Revenue Requirement**		**2024**		**2025**
5	Priority Firm - 7(b) Loads..	$	5,737,085	$	5,937,009
6	Industrial Firm - 7(c) Loads...	$	7,665	$	7,754
7	New Resources - 7(f) Loads..	$	0.7819	$	0.7905
8	Surplus Firm - SP Loads..	$	251,133	$	180,750
9	Total...	$	5,995,884	$	6,125,514
10					
11	**General Revenue Credits (/$1000))**		**2024**		**2025**
12					
13	**Generation Inputs Revenue..**	**$**	**(112,085)**	**$**	**(112,085)**
14					
15	**Real Power Losses (Non-Slice)...**	**$**	**-**	**$**	**-**
16					
17	**PRSC Net Credit (Composite)...**	**$**	**-**	**$**	**-**
18					
19	**PRSC Net Credit (Non-Slice)..**	**$**	**-**	**$**	**-**
20					
21	**NR Revenues from ESS energy and capacity charges.....................**	**$**	**-**	**$**	**-**
22					
23	**PF Load Forecast Deviation Liquidated Damages...........................**	**$**	**-**	**$**	**-**
25					
26	**Conservation & General Cost Allocators**		**2024**		**2025**
27	Priority Firm - 7(b) Loads..		0.9705		0.9790
28	Industrial Firm - 7(c) Loads...		0.0009		0.0009
29	New Resources - 7(f) Loads..		0.0000001		0.0000001
30	Surplus Firm - SP Loads..		0.0286		0.0202
31	Total...		1.0000		1.0000
32					
33	**Gen Inputs & Wind Integration Credit Allocation**		**2024**		**2025**
34	Priority Firm - 7(b) Loads..	$	(108,781)	$	(109,729)
35	Industrial Firm - 7(c) Loads...	$	(98)	$	(97)
36	New Resources - 7(f) Loads..	$	(0)	$	(0)
37	Surplus Firm - SP Loads..	$	(3,206)	$	(2,259)
38	Total...	$	(112,085)	$	(112,085)
39					
40	**Allocation of Revenue Requirement**		**2024**		**2025**
41	Priority Firm - 7(b) Loads..	$	5,628,303	$	5,827,280
42	Industrial Firm - 7(c) Loads...	$	7,567	$	7,657
43	New Resources - 7(f) Loads..	$	0.7719	$	0.7806
44	Surplus Firm - SP Loads..	$	247,927	$	178,491
45	Total...	$	5,883,799	$	6,013,428
46					

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2023 - September 2025 ($ 000)

	B	C		D	
40	**Allocation of Revenue Requirement**		**2024**		**2025**
41	Priority Firm - 7(b) Loads..	$	5,628,303	$	5,827,280
42	Industrial Firm - 7(c) Loads..	$	7,567	$	7,657
43	New Resources - 7(f) Loads...	$	0.7719	$	0.7806
44	Surplus Firm - SP Loads...	$	247,927	$	178,491
45	Total...	$	5,883,799	$	6,013,428
47					
48	**Other Revenue Credits**		**2024**		**2025**
49	Composite Non-Federal RSS Revenue Debit/(Credit)....................	$	(964)	$	(944)
50	Non-Slice Non-Federal RSC Revenue Debit/(Credit)....................	$	(92)	$	(92)
51					
52					
53	**Conservation & General Cost Allocators**		**2024**		**2025**
54	Priority Firm - 7(b) Loads..		0.9705		0.9790
55	Industrial Firm - 7(c) Loads..		0.0009		0.0009
56	New Resources - 7(f) Loads...		0.0000001		0.0000001
57	Surplus Firm - SP Loads...		0.0286		0.0202
58	Total...		1.0000		1.0000
59					
60	**Non-Federal RSS Revenues**		**2024**		**2025**
61	Priority Firm - 7(b) Loads..	$	(1,025)	$	(1,014)
62	Industrial Firm - 7(c) Loads..	$	(1)	$	(1)
63	New Resources - 7(f) Loads...	$	(0.0001)	$	(0.0001)
64	Surplus Firm - SP Loads...	$	(30)	$	(21)
65	Total...	$	(1,056)	$	(1,036)
66					
67	**Allocation of Revenue Requirement**		**2024**		**2025**
68	Priority Firm - 7(b) Loads..	$	5,627,278	$	5,826,266
69	Industrial Firm - 7(c) Loads..	$	7,566	$	7,656
70	New Resources - 7(f) Loads...	$	0.7718	$	0.7806
71	Surplus Firm - SP Loads...	$	247,897	$	178,470
72	Total...	$	5,882,743	$	6,012,392

Table 2.3.8

Cost of Service Analysis
Calculation and Allocation of Secondary
Revenue Credit Test Period October 2019 -
September 2021
(aMW, $ 000)

	C		D		E
4	**General Revenue Credits ($000))**		**2024**		**2025**
9					
10	BPA Secondary Sales Post-Slice (aMW)		1619		1585
11					
12	Slice Percentage		19.7407%		19.7407%
13					
14	Secondary Sales Pre-Slice, aMW		2017		1975
15					
16	aMW to GWh Multiplier		8.784		8.760
17					
18	Secondary Sales Price (Weighted Average, $/MWh)	$	25.03	$	25.57
19					
20	BPA Secondary Sales Post-Slice	$	355,927	$	354,973
21	Adjustments to Secondary Sales	$	80,550	$	84,169
22	EIM Benefits Pre-Slice	$	19,400	$	18,800
23	Post-Slice EIM Benefits	$	15,570	$	15,089
24	Firm Surplus Serving Tier 2	$	108,302	$	120,921
25	Firm Surplus Sold at Firm Surplus Price	$	77,665	$	-
26	Total Firm Surplus Secondary Sales	$	185,966	$	120,921
27					
28	Slice Secondary Sales including EIM Benefits ($000)	$	111,114	$	111,511
29					
30	BPA Secondary Sales Pre-Slice $000 (incl. CAISO Adjust, EIM Benefits excl. Firm Surplus)	$	563,160	$	565,741
31					
36					
37	**Federal Base System + NR Cost Allocators**		**2024**		**2025**
38	Priority Firm - 7(b) Loads..		0.9921		0.9917
39	Industrial Firm - 7(c) Loads..		0.0002		0.0003
40	New Resources - 7(f) Loads..		0.0000		0.0000
41	Surplus Firm - SP Loads...		0.0077		0.0080
42	Total...		1.0000		1.0000
43					
44					
45	**Allocation of Secondary Revenues Credit**		**2024**		**2025**
46	Priority Firm - 7(b) Loads..	$	(558,689)	$	(561,051)
47	Industrial Firm - 7(c) Loads..	$	(132)	$	(193)
48	New Resources - 7(f) Loads..	$	(0.0135)	$	(0.0197)
49	Surplus Firm - SP Loads...	$	(4,339)	$	(4,498)
50	Total...	$	(563,160)	$	(565,741)
51					
52	**Allocation of Revenue Requirement**		**2024**		**2025**
53	Priority Firm - 7(b) Loads..	$	5,068,589	$	5,265,215
54	Industrial Firm - 7(c) Loads..	$	7,434	$	7,463
55	New Resources - 7(f) Loads..	$	0.7583	$	0.7609
56	Surplus Firm - SP Loads...	$	243,558	$	173,972
57	Total...	$	5,319,582	$	5,446,651

Cost of Servise Analysis
Calculation and Allocation of FPS Revenue Deficiency Delta
Test Period October 2023 - September 2025
($ 000)

	B		C		D
5	**Allocation of Revenue Requirement**		2024		2025
6	Priority Firm - 7(b) Loads..	$	5,068,589	$	5,265,215
7	Industrial Firm - 7(c) Loads..	$	7,434	$	7,463
8	New Resources - 7(f) Loads...	$	0.7583	$	0.7609
9	Surplus Firm - SP Loads...	$	243,558	$	173,972
10	Total..	$	5,319,582	$	5,446,651
11					
12	**Firm Surplus and from Other Long-term Sales.............**	**$**	**(185,966)**	**$**	**(120,921)**
13	Other Surplus Sales (Non-Slice).............................	$	-	$	-
14	Firm Surplus Secondary Sales................................	$	(185,966)	$	(120,921)
15					
16	**Calculation of FPS Revenue Deficiency**		2024		2025
17	Surplus Firm - SP Loads...	$	243,558	$	173,972
18					
19	**Deficiency...**	**$**	**57,592**	**$**	**53,051**
20					
21					
22					
23	**Surplus Deficit Cost Allocators**		2024		2025
24	Priority Firm - 7(b) Loads..		0.9991		0.9991
25	Industrial Firm - 7(c) Loads..		0.0009		0.0009
26	New Resources - 7(f) Loads...		0.0000001		0.0000001
27	Surplus Firm - SP Loads...		-1.0000		-1.0000
28	Total..		0.0000		0.0000
29					
30	**Surplus Deficit Cost Allocation**		2024		2025
31	Priority Firm - 7(b) Loads..	$	57,541	$	53,004
32	Industrial Firm - 7(c) Loads..	$	52	$	47
33	New Resources - 7(f) Loads...	$	0.0053	$	0.0048
34	Surplus Firm - SP Loads...	$	(57,592)	$	(53,051)
35	Total..	$	-	$	-
36					
37					
38	**Initial Allocation of Net Revenue Requirement**		2024		2025
39	Priority Firm - 7(b) Loads..	$	5,126,130	$	5,318,219
40	Industrial Firm - 7(c) Loads..	$	7,486	$	7,510
41	New Resources - 7(f) Loads...	$	0.7636	$	0.7657
42	Surplus Firm - SP Loads...	$	185,966	$	120,921
43	Total..	$	5,319,582	$	5,446,651

Table 2.3.10

Cost of Service Analysis
Calculation of Initial Allocation Power
Rates Test Period October 2023 -
September 2025 ($ 000, aMW, $/MWh)

	B	C		D	
5	**Initial Allocation of Net Revenue Requirement ($000)**		**2024**		**2025**
6	Unbifurcated Priority Firm - 7(b) Loads.......................................	$	5,126,130	$	5,318,219
7	Industrial Firm - 7(c) Loads..	$	7,486	$	7,510
8	New Resources - 7(f) Loads...	$	0.7636	$	0.7657
9	Surplus Firm - SP Loads...	$	185,966	$	120,921
10	Total..	$	5,319,582	$	5,446,651
11					
12					
13	**Energy Billing Determinants (aMW)**		**2024**		**2025**
14					
15	Unbifurcated Priority Firm - 7(b) Loads.......................................		12,228		12,454
16	Industrial Firm - 7(c) Loads..		11		11
17	New Resources - 7(f) Loads...		0.001		0.001
18					
19					
20	**Average Power Rates ($/MWh)**		**2024**		**2025**
21					
22	Unbifurcated Priority Firm - 7(b) Loads.......................................		47.72		48.75
23	Industrial Firm - 7(c) Loads..		77.47		77.94
24	New Resources - 7(f) Loads...		77.47		77.94

Table 2.4.1

Rate Directive Step
Calculation of DSI VOR and Net Industrial
Margin Test Period October 2019 - September
2021

	B	C	D	E	F	G		H	I
5									
6	Operating Reserves - Supplemental								
8			Embedded Cost $/kW/Mo			$	5.92		
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					$	78,144	per year	
17	Value converted to $/MWh on total load					$	0.809	$/MWh	
18									
19					industrial margin		0.910		
20									
21					**net industrial margin**	**$**	**0.101**		

Rate Directive Step
Calculation of Annual Energy Rate Scalars for First IP-PF Link
Calculation Test Period October 2023 - September 2025

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P Q	R	S	T
6	**Load Shaping Rate**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
7	HLH (mills/kWh)		47.71	40.30	61.63	49.88	50.32	35.07	20.42	18.21	17.87	55.60	71.52	58.70				
8	LLH (mills/kWh)		32.91	31.39	52.69	36.73	42.01	35.84	21.67	16.34	10.33	36.92	48.93	44.18				
9	Demand Rate ($/kW/mo)		10.37	8.75	13.39	10.84	10.93	7.62	4.43	3.95	3.88	12.08	15.54	12.75				
10																		
11																		
12	**Unbifurcated PF+NR Load**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			**2024**	
13	**2024**	HLH	4756	5504	6337	6608	5743	5713	4777	4879	4807	5127	5294	4592			Energy (GWH)	107413
14		LLH	3184	3839	4614	4550	3751	3882	3161	3302	3087	3448	3178	3281			Allocated Cost	$ 5,129,217
15		Demand	481	596	1073	1037	702	937	1052	758	1007	1186	1292	728			Rate Scalar	**6.01**
16	Revenue at marginal Rates		$ 336,678	$ 347,549	$ 648,003	$ 508,005	$ 454,275	$ 346,636	$ 170,730	$ 145,786	$ 121,696	$ 426,669	$ 554,206	$ 423,786		$ 4,484,019		
17			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			**2025**	
18	**2025**	HLH	4949	5584	6406	6687	5700	5810	4908	4767	4963	5267	5300	4770			Energy (GWH)	109094
19		LLH	3165	3913	4691	4628	3765	3952	3246	3275	3164	3557	3342	3284			Allocated Cost	$ 5,321,248
20		Demand	662	609	1071	1045	662	937	1111	789	1007	1303	1165	841			Rate Scalar	**7.01**
21	Revenue at marginal Rates		$ 347,143	$ 353,219	$ 656,331	$ 514,870	$ 452,245	$ 352,561	$ 175,499	$ 143,443	$ 125,284	$ 439,890	$ 560,680	$ 435,765		$ 4,556,931		
43																		
50																		
51		**IP Load**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			**2024**	
52	**2024**	HLH	5	4	4	4	4	5	4	4	5	4	5	4			Energy (GWH)	97
53		LLH	4	4	4	4	3	4	3	4	3	4	3	4			Allocated Cost	$ 4,399
54		Demand	0	0	0	0	0	0	0	0	0	0	0	0			Rate Scalar	**5.91**
55	Revenue at marginal Rates		$ 338	$ 288	$ 471	$ 359	$ 357	$ 289	$ 166	$ 142	$ 116	$ 385	$ 507	$ 411		$ 3,828		
56			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			**2025**	
57	**2025**	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	$ 4,481
59		Demand	0	0	0	0	0	0	0	0	0	0	0	0			Rate Scalar	**6.90**
60	Revenue at marginal Rates		$ 338	$ 288	$ 471	$ 359	$ 345	$ 289	$ 166	$ 142	$ 116	$ 385	$ 507	$ 411		$ 3,816		

Table 2.4.3

Rate Directive Step
Calculation of Monthly Energy Rate Scalars for First IP-PF Link Calculation
Test Period October 2023 - September 2025
($/MWh)

	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)		47.71	40.30	61.63	49.88	50.32	35.07	20.42	18.21	17.87	55.60	71.52	58.70				
7	LLH (mills/kWh)		32.91	31.39	52.69	36.73	42.01	35.84	21.67	16.34	10.33	36.92	48.93	44.18				
8	Demand Rate ($/kW/mo)		10.37	8.75	13.39	10.84	10.93	7.62	4.43	3.95	3.88	12.08	15.54	12.75				
9																		
10																		
11	**Unbifurcated PF/NR**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
12	**2024**	HLH	53.72	46.31	67.64	55.89	56.33	41.08	26.43	24.22	23.88	61.60	77.53	64.70				**2024**
13		LLH	38.92	37.40	58.70	42.74	48.02	41.85	27.68	22.35	16.34	42.93	54.94	50.19				**6.01**
14		Demand	10.37	8.75	13.39	10.84	10.93	7.62	4.43	3.95	3.88	12.08	15.54	12.75				**Scalar**
15			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
16	**2025**	HLH	54.72	47.31	68.63	56.89	57.33	42.08	27.43	25.22	24.88	62.60	78.53	65.70				**2025**
17		LLH	39.92	38.40	59.70	43.74	49.02	42.85	28.68	23.35	17.34	43.93	55.94	51.19				**7.01**
18		Demand	10.37	8.75	13.39	10.84	10.93	7.62	4.43	3.95	3.88	12.08	15.54	12.75				**Scalar**
36																		
42																		
43		**IP**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
44	**2024**	HLH	53.62	46.21	67.53	55.79	56.23	40.98	26.33	24.11	23.78	61.50	77.43	64.60				**2024**
45		LLH	38.82	37.30	58.60	42.64	47.92	41.75	27.58	22.25	16.24	42.83	54.84	50.09				**5.91**
46		Demand	10.37	8.75	13.39	10.84	10.93	7.62	4.43	3.95	3.88	12.08	15.54	12.75				**Scalar**
47			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
48	**2025**	HLH	54.61	47.21	68.53	56.79	57.23	41.98	27.33	25.11	24.78	62.50	78.43	65.60				**2025**
49		LLH	39.81	38.29	59.59	43.63	48.91	42.74	28.57	23.24	17.23	43.82	55.83	51.08				**6.90**
50		Demand	10.37	8.75	13.39	10.84	10.93	7.62	4.43	3.95	3.88	12.08	15.54	12.75				**Scalar**

Table 2.4.4

Rate Directive Step
Calculation of First IP-PF Link Delta Test
Period October 2023 - September 2025 ($ 000)

	B	C		D		E		F		G		H
89			**FY 2024**		**FY 2025**		**FY 2026**		**FY 2027**		**FY 2028**	**FY 2029**
90	Average PF Rate	$	47.72	$	48.75	$	46.48	$	46.60	$	48.08	$ 47.92
91	Net Industrial Margin		0.101		0.101		0.101		0.101		0.101	0.101
92	Flat DSI Load (GWh)		97		96		96		96		96	96
93	Revenue 1		4,621		4,707		4,489		4,500		4,643	4,627
94												
95	IP Rate	$	77.47	$	77.94	$	77.58	$	77.59	$	73.70	$ 71.28
96	Flat DSI Load (GWh)		97		96		96		96		96	96
97	Revenue 2		7,485		7,510		7,476		7,477		7,102	6,869
98												
99	Starting Difference		2,865		2,803		2,987		2,976		2,459	2,241
100												
101	Adjustment (calculated using Goal Seek)		221.88		225.61		215.24		220.86		216	221.68
102												
103	Delta		3,087		3,029		3,202		3,197		2,675	2,463

Rate Directive Step
Reallocation of First IP-PF Link Delta and Recalculation of Rates
Test Period October 2023 - September 2025
($ 000, aMW, $/MWh)

	B		C		D
5	**Initial Allocation of Net Revenue Requirement)**		**2024**		**2025**
6	Unbifurcated Priority Firm - 7(b) Loads..............................	$	5,126,130	$	5,318,219
7	Industrial Firm - 7(c) Loads..	$	7,486	$	7,510
8	New Resources - 7(f) Loads..	$	0.7636	$	0.7657
9	Surplus Firm - SP Loads..	$	185,966	$	120,921
10	Total..	$	5,319,582	$	5,446,651
11					
12					
13	**First IP-PF Link Delta**	**$**	**3,087**	**$**	**3,029**
14					
15					
16	**7(c)(2) Delta Cost Allocators**		**2024**		**2025**
17	Unbifurcated Priority Firm - 7(b) Loads..............................		0.999999908		0.999999910
18	Industrial Firm - 7(c) Loads..		-1.000000000		-1.000000000
19	New Resources - 7(f) Loads..		0.000000092		0.000000090
20					
21	**7(c)(2) Delta Cost Allocation**		**2024**		**2025**
22	Unbifurcated Priority Firm - 7(b) Loads..............................	$	3,087	$	3,029
23	Industrial Firm - 7(c) Loads..	$	(3,087)	$	(3,029)
24	New Resources - 7(f) Loads..	$	0.000	$	0.000
25	Total..	$	0	$	0
26					
27	**Cost Allocation After 7c2 Delta ($ 000)**		**2024**		**2025**
28	Unbifurcated Priority Firm - 7(b) Loads..............................	$	5,129,216	$	5,321,247
29	Industrial Firm - 7(c) Loads..	$	4,399	$	4,481
30	New Resources - 7(f) Loads..	$	0.764	$	0.766
31	Surplus Firm - SP Loads..	$	185,966	$	120,921
32	Total..	$	5,319,582	$	5,446,651
33					
34	**Energy Billing Determinants (aMW)**		**2024**		**2025**
35	Unbifurcated Priority Firm - 7(b) Loads..............................		12,228		12,454
36	Industrial Firm - 7(c) Loads..		11		11
37	New Resources - 7(f) Loads..		0.00112204		0.001121461
38					
39					
40	**Average Power Rates ($/MWh)**		**2024**		**2025**
41					
42	Unbifurcated Priority Firm - 7(b) Loads..............................		47.75		48.78
43	Industrial Firm - 7(c) Loads..		45.53		46.51
44	New Resources - 7(f) Loads..		77.50		77.97
45					
46					
47	Base PF Exchange Rate w/o Transmission Adder...............		**48.27**		

Rate Directive Step
Calculation of IP Floor Calculation
Test Period October 2023 - September 2025

	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**	
14				**Winter**	**Summer**	**Winter**	**Summer**	**Charge**	**Average**
15				(Dec-Apr)	(May-Nov)	(Sep-Mar)	(Apr-Aug)		
16									
17	1	IP Billing Determinants[1]		109	153	112	81	262	193
18	2	IP-83 Rates		4.62	2.21	14.70	12.20	7.34	
19	3	Revenue		503	338	1,649	986	1,920	5,395
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]		27.95					
36	20	Floor Rate (mills/kWh)[8]		20.83					
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
Test Period October 2023 - September 2025

	B	C	D	E	F	G	H	I
8								
9								
10								
11		Industrial Firm Power Floor Rate Test						
12						**A**	**B**	
13								
14								
15						**Total**		**Average**
16						**Energy**	**TOTALS**	**Rate**
17								
18								
19	1	IP Billing Determinants				193		
20	2	Floor Rate (mills/kWh)				20.83		
21	3	Value of Reserves Credit (mills/kWh)						
22	4	Revenue at Floor Rate Less VOR Credit				4,019	4,019	20.83
23	5	IP Revenue Under Proposed Rates					8,880	46.02
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								

Rate Directive Step
Calculation of IOU and COU Base PF Exchange Rates
Test Period October 2023 - September 2025

	B	C	D	E	F
9		**Cost Allocation After 7c2 Delta**	**2024**	**2025**	Total
10		Unbifurcated Priority Firm - 7(b) Loads.............................	$ 5,129,216	$ 5,321,247	$ 10,450,464
11					
12		Exchange Unbifurcated Costs to 7(b) Loads......................	$ 2,210,246	$ 2,256,241	$ 4,466,486
13					
14					
15					
16					
17		**Energy Billing Determinants (aMW)**	**2024**	**2025**	
18		Unbifurcated Priority Firm - 7(b) Loads.............................	5,269	5,280	
19					
20					
21		**Average Power Rates**	**2024**	**2025**	
22					
23		Unbifurcated Priority Firm - 7(b) Loads.............................	47.75	48.78	
24					
25					
26			(GWh)		
27		Two Year PF Public Load T1	118756		
28		Two Year PF Public Load T2	5209		
29		Two Year IOU PF Exchange Load	85245		
30		Two Year COU PF Exchange Load	7297		
31		Total Two-Year Unbifurcated PF Load	216507		
32					
33					
34		T 2 Costs	$ 320,579		
35		T 1 Costs	$ 10,129,885		
36		Total	$ 10,450,464		
37					
45		Total PF Costs Minus PF T2 Costs	$ 10,129,885		
46		Total PF Load Minus PF T2 Load	211,298		
47		COU Base PF w/o Transmission	47.94		
48		Exchange Transmission Adder	5.54		
49		**COU Base PFx**	**53.48**		
50					
51					
52		Two Year COU PF Exchange Load	7297		
53		Two Year Base PF Public Exchange T2 Revenue	$ 349,844		
54					
55		Total Exchange Costs minus COU Exchange Costs	$ 4,116,642		
56		Total IOU Exchange Loads	85,245		
57		IOU Base PF w/o Transmission	48.29		
58		Exchange Transmission Adder	5.54		
59		**IOU Base PFx**	**53.83**		
60					

Table 2.4.9

Rate Directive Step
Calculation of IOU REP Benefits in Rates
Test Period October 2019 - September 2021

	B	C		D	
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		$273,600		
19	Refund Amount*		$0		
20	REP Recovery Amount		$273,600		
21					
26					
27					
28		**2024**		**2025**	
29		($000)		($000)	
30	IOU Unconstrained Benefits	$	1,044,022	$	1,044,022
31	REP Recovery Amount	**$**	**273,600**	**$**	**273,600**
32	Rate Protection Delta	$	770,422	$	770,422
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
Test Period October 2023 - September 2025

	B	C	D	E	F	G	H	I	J	K	L
5	**IOU Base PFx**	**53.83**									
6	**COU Base PFx**	**53.48**		**ASCs**			**Exchange Loads**			**Unconstrained Benefits**	
7										(load * (ASC - Base PFx)	
8				**2024**	**2025**		**2024**	**2025**		**2024**	**2025**
9											
10											
11	Avista Corporation	1		70.61	70.61		4,129	4,129		$ 69,275	$ 69,275
12	Idaho Power Company	1		66.03	66.03		7,165	7,165		$ 87,394	$ 87,394
13	NorthWestern Energy,	1		83.73	83.73		746	746		$ 22,314	$ 22,314
14	PacifiCorp	1		84.08	84.08		9,419	9,419		$ 284,912	$ 284,912
15	Portland General Electr	1		80.83	80.83		8,661	8,661		$ 233,831	$ 233,831
16	Puget Sound Energy, In	1		81.53	81.53		12,503	12,503		$ 346,297	$ 346,297
17	Clark Public Utilities	0		48.51	48.51		0	0		$ -	$ -
18	Franklin	0		0.00	0.00		0	0		$ -	$ -
19	Snohomish PUD	1		54.13	54.13		3,663	3,634		$ 2,377	$ 2,358
31	Total									**$ 1,046,399**	**$ 1,046,380**
32											
33									IOU	**$ 1,044,022**	**$ 1,044,022**

Rate Directive Step
Calculation of Utility Specific PF Exchange Rates and
REP Benefits Test Period October 2023 - September 2025

	B	D	E	F	G	H	I	J	K	L	M	N	O	P
4	**Initial Allocations**			**FY 2024**	**FY 2025**	**Average**				**Interim**	**Refund**	**Interim**	**Interim**	**Interim**
5			**Base**	**Exchange**	**Exchange**	**Exchange**	**Unconstrained**		**Refund**	**Protection**	**Cost**	**7(b)(3)**	**Utility**	**REP**
6		**ASC**	**PFx**	**Load**	**Load**	**Load**	**Benefits**	**Amount**	**Amount**	**Allocation**	**Allocation**	**Surcharge**	**PFx**	**Benefits**
7		a	b	c	d	e=avg(c,d)	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	70.61	53.83	4,129	4,129	4,129	$ 69,275			$ 51,120	$ -	12.38	66.21	$ 18,154
9	Idaho Power Company	66.03	53.83	7,165	7,165	7,165	$ 87,394			$ 64,491	$ -	9.00	62.83	$ 22,903
10	NorthWestern Energy, LLC	83.73	53.83	746	746	746	$ 22,314			$ 16,466	$ -	22.06	75.89	$ 5,848
11	PacifiCorp	84.08	53.83	9,419	9,419	9,419	$ 284,912			$ 210,247	$ -	22.32	76.15	$ 74,665
12	Portland General Electric Company	80.83	53.83	8,661	8,661	8,661	$ 233,831			$ 172,552	$ -	19.92	73.75	$ 61,278
13	Puget Sound Energy, Inc.	81.53	53.83	12,503	12,503	12,503	$ 346,297			$ 255,545	$ -	20.44	74.27	$ 90,752
14	Clark Public Utilities	0	0.00	0	0	0	$ -			$ -		0.00	0.00	$ -
15	Franklin	0	0.00	0	0	0	$ -			$ -		0.00	0.00	$ -
16	Snohomish PUD	54.13	53.48	3,663	3,634	3,649	$ 2,367			$ 1,747		0.48	53.96	$ 620
17	Total			46,286	46,257	46,271	$ 1,046,390	$273,600	$0	$ 772,169	$0			$ 274,220
18														
19	rounding to places =	$60				IOU Σ(g)	$ 1,044,022	$273,600	$273,600	$ 770,422	IOU Σ(j)		IOU REP	$ 273,600
20						COU Σ(g)	$ 2,367		$620	$ 1,747	COU Σ(j)		COU REP	$ 620
21														
22	**IOU Reallocations**													
23		**Interim**				**Final**	**Final**	**Final**		**Final**			**FY 2024**	**FY 2025**
24		**REP**	**Annual**	**Reallocation**	**Reallocated**	**Protection**	**7(b)(3)**	**Utility**		**REP**			**REP**	**REP**
25		**Benefits**	**Adjustment**	**Adjustment**	**Benefits**	**Allocation**	**Surcharge**	**PFx**		**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
27	Avista Corporation	$ 18,154	$ 2,005	$ -	$ 16,150	$ 53,125	12.87	66.69860		$ 16,150		Avista	$ 16,150	$ 16,150
28	Idaho Power Company	$ 22,903	$ -	$ -	$ 22,903	$ 64,491	9.00	62.83330		$ 22,903		Idaho Power	$ 22,903	$ 22,903
29	NorthWestern Energy, LLC	$ 5,848	$ -	$ 74	$ 5,922	$ 16,392	21.96	75.79530		$ 5,922		NorthWestern	$ 5,922	$ 5,922
30	PacifiCorp	$ 74,665	$ -	$ -	$ 74,665	$ 210,247	22.32	76.15310		$ 74,665		PacifiCorp	$ 74,665	$ 74,665
31	Portland General Electric Company	$ 61,278	$ -	$ 778	$ 62,057	$ 171,774	19.83	73.66490		$ 62,057		Portland	$ 62,057	$ 62,057
32	Puget Sound Energy, Inc.	$ 90,752	$ -	$ 1,152	$ 91,904	$ 254,393	20.35	74.17920		$ 91,904		Puget Sound	$ 91,904	$ 91,904
33	Total	$ 273,600	$ 2,005	$ 2,005	$ 273,600	$ 770,422				$ 273,600		IOU REP	$ 273,600	$ 273,600
34														
35												Clark	$ -	$ -
36												Franklin	$ -	$ -
37	**IOU Reallocation Adjustments**											Snohomish	$ 623	$ 618
38		Avista	Idaho	NorthWestern	PacifiCorp	Portland	Puget Sound	Total				COU REP	$ 623	$ 618
39		$ 2,005	$ -	$ -	$ -	$ -	$ -					Total REP	$ 274,223	$ 274,218
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	$ 274,223	$ 274,218
43	NorthWestern Energy, LLC	$ 74	$ -		$ -	$ -	$ -	$ 74						
44	PacifiCorp		$ -	$ -				$ -						
45	Portland General Electric Company	$ 778	$ -	$ -	$ -			$ 778						
46	Puget Sound Energy, Inc.	$ 1,152	$ -	$ -	$ -	$ -		$ 1,152						
47		$ 2,005	$ -	$ -	$ -	$ -	$ -	$ 2,005						

Table 2.4.12

Rate Directive Step
IOU Reallocation Balances
Test Period October 2023 - September 2025

	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	$ -	$ -	$ -	$ -	$ -

Rate Directive Step
Calculation and Allocation of the Increase in PF Exchange Revenue Requirement Due to REP Settlement
Test Period October 2023 - September 2025

	B		C		D
4	**Cost Allocation After 7c2 Delta**		**2024**		**2025**
5	Priority Firm Public - 7(b) Loads...	$	2,918,971	$	3,065,007
6	Priority Firm Exchange - 7(b) Loads....................................	$	2,210,246	$	2,256,241
7	Industrial Firm - 7(c) Loads...	$	4,399	$	4,481
8	New Resources - 7(f) Loads...	$	0.764	$	0.766
9	Surplus Firm - SP Loads..	$	185,966	$	120,921
10	Total...	$	5,319,582	$	5,446,651
11					
12					
13	**Calc Rate Protection to PFx Rate**		**2024**		**2025**
14	Unconstrained Benefits	$	1,046,399	$	1,046,380
15	REP Recovery Amount plus COU Benefits	$	(274,223)	$	(274,218)
16	delta	$	772,176	$	772,162
17					
18					
19	**Allocation Factors**		**2024**		**2025**
20	Priority Firm Public - 7(b) Loads...		-1.0000000		-1.0000000
21	Priority Firm Exchange - 7(b) Loads....................................		1.0000000		1.0000000
22	Industrial Firm - 7(c) Loads...		0.0000000		0.0000000
23	New Resources - 7(f) Loads...		0.0000000		0.0000000
24					
25					
26	**Allocation of Rate Protection Cost**		**2024**		**2025**
27	Priority Firm Public - 7(b) Loads...	$	(772,176)	$	(772,162)
28	Priority Firm Exchange - 7(b) Loads....................................	$	772,176	$	772,162
29	Industrial Firm - 7(c) Loads...	$	-	$	-
30	New Resources - 7(f) Loads...	$	-	$	-
31	Total...	$	-	$	-
32					
33					
34	**Cost Allocation After Rate Protection to PFx**		**2024**		**2025**
35	Priority Firm Public - 7(b) Loads...	$	2,146,794	$	2,292,844
36	Priority Firm Exchange - 7(b) Loads....................................	$	2,982,422	$	3,028,403
37	Industrial Firm - 7(c) Loads...	$	4,399	$	4,481
38	New Resources - 7(f) Loads...	$	0.764	$	0.766
39	Surplus Firm - SP Loads..	$	185,966	$	120,921
40	Total...	$	5,319,582	$	5,446,651
41					
42					
43	**Energy Billing Determinants (aMW)**		**2024**		**2025**
44	Priority Firm Public - 7(b) Loads...		6,959		7,173
45	Priority Firm Exchange - 7(b) Loads....................................		5,269		5,280
46	Industrial Firm - 7(c) Loads...		11		11
47	New Resources - 7(f) Loads...		0.00112204		0.001121461
48					
50					
51	**Average Power Rates**		**2024**		**2025**
52	Priority Firm Public - 7(b) Loads...		35.12		36.49
53	Priority Firm Exchange - 7(b) Loads....................................		69.98		71.01
54	Industrial Firm - 7(c) Loads...		45.53		46.51
55	New Resources - 7(f) Loads...		77.50		77.97

Rate Directive Step
Calculation of PF, IP and NR Rate Contribution to Net REP Benefit Costs
Test Period October 2023 - September 2025

	B	C		D	
25		**2024**		**2025**	
26	WP-10 Average IOU REP Benefits (before Lookback recovery)	$	265,847	$	265,847
27					
28	WP-10 7b3 Supplemental Rate Charge	$	7.38	$	7.38
29	IP/NR REP Surcharge	$	7.61	$	7.61
30	IP Load		97		96
31	NR Load		0		0
32	REP Surcharge Revenue from IP Rate	$	736	$	734
33	REP Surcharge Revenue from NR Rate	$	0	$	0
34					
35	Amount of REP Recovery remaining after IP/NR REP Surcharge	$	273,487	$	273,484
36	Remaining REP Recovery in PF, IP and NR Rates ($/MWh)	$	4.47	$	4.35
37					
38	Before Reallocation				
39	IP REP Recovery Amount in Rates	$	1,167	$	1,152
40	NR REP Recovery Amount in Rates	$	0	$	0
41					
42	After Reallocation				
43	IP REP Recovery Amount in Rates	$	734	$	732
44	NR REP Recovery Amount in Rates	$	0	$	0
45					
46					
47	Reallocation that Should be in Rates	**2024**		**2025**	
48	Priority Firm Public - 7(b) Loads..	$	273,056	$	273,066
49	Industrial Firm - 7(c) Loads...	$	1,167	$	1,152
50	New Resources - 7(f) Loads...	$	0.119	$	0.117
51		$	274,223	$	274,218
52					
53	Adjustment Necessary to Achieve Reallocation	**2024**		**2025**	
54	Priority Firm Public - 7(b) Loads..	$	(734)	$	(732)
55	Industrial Firm - 7(c) Loads...	$	734	$	732
56	New Resources - 7(f) Loads...	$	0.075	$	0.075
57		$	(0)	$	(0)
58					
59		**2024**		**2025**	
60	PF Contribution to Net REP Benefits $/MWh.............................		4.47		4.35
61	IP Contribution to Net REP Benefits $/MWh..............................		12.08		11.96
62	NR Contribution to Net REP Benefits $/MWh............................		12.08		11.96

Rate Directive Step
Reallocation of Rate Protection Provided by the IP and NR Rates
Test Period October 2023 - September 2025

	B	C		D	
4	**Cost Allocation After Rate Protection Provided by PFx**		**2024**		**2025**
5	Priority Firm Public - 7(b) Loads..	$	2,146,794	$	2,292,844
6	Priority Firm Exchange - 7(b) Loads..	$	2,982,422	$	3,028,403
7	Industrial Firm - 7(c) Loads..	$	4,399	$	4,481
8	New Resources - 7(f) Loads...	$	0.764	$	0.766
9	Surplus Firm - SP Loads..	$	185,966	$	120,921
10	Total..	$	5,319,582	$	5,446,651
11					
12					
13					
14	**Allocation of Rate Protection Provided by IP and NR**		**2024**		**2025**
15	Priority Firm Public - 7(b) Loads..	$	(734)	$	(732)
16					
17	Industrial Firm - 7(c) Loads..	$	734	$	732
18	New Resources - 7(f) Loads...	$	0.075	$	0.075
19	Total..	$	(0)	$	(0)
20					
21					
22	**Cost Allocation After Rate Protection Provided by IP and NR**		**2024**		**2025**
23	Priority Firm Public - 7(b) Loads..	$	2,146,060	$	2,292,112
24	Priority Firm Exchange - 7(b) Loads..	$	2,982,422	$	3,028,403
25	Industrial Firm - 7(c) Loads..	$	5,133	$	5,214
26	New Resources - 7(f) Loads...	$	0.839	$	0.841
27	Surplus Firm - SP Loads..	$	185,966	$	120,921
28	Total..	$	5,319,582	$	5,446,651
29					
30					
31	**Energy Billing Determinants (aMW)**		**2024**		**2025**
32	Priority Firm Public - 7(b) Loads..		6,959		7,173
33	Priority Firm Exchange - 7(b) Loads..		5,269		5,280
34	Industrial Firm - 7(c) Loads..		11		11
35	New Resources - 7(f) Loads...		0.00112204		0.001121461
36					
38					
39	**Average Power Rates After Rate Protection Reallocations**		**2024**		**2025**
40	Priority Firm Public - 7(b) Loads..		35.11		36.48
41	Priority Firm Exchange - 7(b) Loads..		69.98		71.01
42	Industrial Firm - 7(c) Loads..		53.13		54.11
43	New Resources - 7(f) Loads...		85.10		85.57

Rate Directive Step
Calculation of Annual Energy Rate Scalars for Second IP-PF Link
Calculation Test Period October 2023 - September 2025

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	R	S	T
5																	
6	**Load Shaping Rate**		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep			
7	HLH (mills/kWh)		47.71	40.30	61.63	49.88	50.32	35.07	20.42	18.21	17.87	55.60	71.52	58.70			
8	LLH (mills/kWh)		32.91	31.39	52.69	36.73	42.01	35.84	21.67	16.34	10.33	36.92	48.93	44.18			
9	Demand Rate ($/kW/mo)		10.37	8.75	13.39	10.84	10.93	7.62	4.43	3.95	3.88	12.08	15.54	12.75			
10																	
11		**PF+NR Load**	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep		**2024**	
12	**2024**	HLH	2707	3132	3606	3761	3269	3251	2719	2777	2736	2918	3013	2614		Energy (GWH)	61128
13		LLH	1812	2185	2626	2590	2135	2209	1799	1879	1757	1962	1808	1867		Allocated Cost	$ 2,147,260
14		Demand	273	339	610	590	399	533	599	432	573	675	735	415		Rate Scalar	-6.62
15		Revenue at marginal Rates	$ 191,599	$ 197,785	$ 368,770	$ 289,099	$ 258,522	$ 197,266	$ 97,160	$ 82,965	$ 69,256	$ 242,812	$ 315,392	$ 241,171	$ 2,551,798		
16			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep		**2025**	
17	**2025**	HLH	2851	3216	3690	3851	3283	3347	2827	2746	2859	3034	3053	2747		Energy (GWH)	62838
18		LLH	1823	2254	2702	2666	2169	2276	1869	1887	1823	2049	1925	1892		Allocated Cost	$ 2,293,275
19		Demand	381	351	617	602	381	540	640	454	580	750	671	484		Rate Scalar	-5.28
20		Revenue at marginal Rates	$ 199,952	$ 203,452	$ 378,043	$ 296,562	$ 260,491	$ 203,073	$ 101,086	$ 82,622	$ 72,163	$ 253,374	$ 322,948	$ 250,998	$ 2,624,765		
21			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep			
22																	
23																	
24																	
25		**IP Load**	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep		**2024**	
26	**2024**	HLH	**5**	4												Energy (GWH)	97
27		LLH	**4**	4												Allocated Cost	$ 3,934
28		Demand	**0**	0												Rate Scalar	1.10
29		Revenue at marginal Rates	$ 338	$ 288	$ 471	$ 359	$ 357	$ 289	$ 166	$ 142	$ 116	$ 385	$ 507	$ 411	$ 3,828		
30			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep		**2025**	
31	**2025**	HLH	**5**	4												Energy (GWH)	96
32		LLH	**4**	4												Allocated Cost	$ 4,051
33		Demand	**0**	0												Rate Scalar	2.44
34		Revenue at marginal Rates	$ 338	$ 288	$ 471	$ 359	$ 345	$ 289	$ 166	$ 142	$ 116	$ 385	$ 507	$ 411	$ 3,816		
35																	

Table 2.4.17

Rate Directive Step
Calculation of Monthly Energy Rate Scalars for Second IP-PF Link Rate
Calculation Test Period October 2021 - Septmentber 2023

	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)		47.71	40.30	61.63	49.88	50.32	35.07	20.42	18.21	17.87	55.60	71.52	58.70				
7	LLH (mills/kWh)		32.91	31.39	52.69	36.73	42.01	35.84	21.67	16.34	10.33	36.92	48.93	44.18				
8	Demand Rate ($/kW/mo)		10.37	8.75	13.39	10.84	10.93	7.62	4.43	3.95	3.88	12.08	15.54	12.75				
9																		
10																		
11		**PFp /NR**	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
12	**2024**	HLH	41.09	33.69	55.01	43.26	43.71	28.46	13.80	11.59	11.25	48.98	64.91	52.08				**2024**
13		LLH	26.29	24.77	46.07	30.11	35.39	29.22	15.05	9.72	3.71	30.30	42.31	37.56				**-6.62**
14		Demand	10.37	8.75	13.39	10.84	10.93	7.62	4.43	3.95	3.88	12.08	15.54	12.75				**Scalar**
15			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
16	**2025**	HLH	42.43	35.03	56.35	44.61	45.05	29.80	15.15	12.93	12.60	50.32	66.25	53.42				**2025**
17		LLH	27.63	26.11	47.41	31.45	36.73	30.56	16.39	11.06	5.05	31.64	43.65	38.90				**-5.28**
18		Demand	10.37	8.75	13.39	10.84	10.93	7.62	4.43	3.95	3.88	12.08	15.54	12.75				**Scalar**
19																		
20																		
21		**IP**	O	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
22	**2024**	HLH	48.81	41.40	62.72	50.98	51.42	36.17	21.52	19.30	18.97	56.69	72.62	59.79				**2010**
23		LLH	34.01	32.49	53.79	37.83	43.11	36.94	22.77	17.44	11.43	38.02	50.03	45.28				**1.10**
24		Demand	10.37	8.75	13.39	10.84	10.93	7.62	4.43	3.95	3.88	12.08	15.54	12.75				**Scalar**
25			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
26	**2025**	HLH	50.15	42.74	64.07	52.32	52.76	37.51	22.86	20.65	20.31	58.04	73.96	61.13				**2011**
27		LLH	35.35	33.83	55.13	39.17	44.45	38.28	24.11	18.78	12.77	39.36	51.37	46.62				**2.44**
28		Demand	10.37	8.75	13.39	10.84	10.93	7.62	4.43	3.95	3.88	12.08	15.54	12.75				**Scalar**

Rate Directive Step
Calculation of Second IP-PF Link Delta
Test Period October 2019 - September 2021

	B	C		D	
45			**FY 2024**		**FY 2025**
46	Average PF Rate	$	35.11	$	36.48
47	Net Industrial Margin		0.101		0.101
48	Flat DSI Load (GWh)		97		96
49	Revenue 1		3,402		3,525
50					
51	IP Rate	$	53.13	$	54.11
52	Flat DSI Load (GWh)		97		96
53	Revenue 2		5,133		5,214
54					
55	Difference		1,731		1,689
56					
57	Adjustment (calculated using Goal Seek)		(532.28)		(526.38)
58					
59	Delta		1,199		1,163

Rate Directive Step
Reallocation of IP-PF Link Delta and Recalculation of Rates
Test Period October 2023 - September 2025

	B	C		D		E
4	**Cost Allocation After Rate Protection Provided by IP and NR**		**2024**		**2025**	
5	Priority Firm Public - 7(b) Loads	$	2,146,060	$	2,292,112	
6	Priority Firm Exchange - 7(b) Loads	$	2,982,422	$	3,028,403	
7	Industrial Firm - 7(c) Loads	$	5,133	$	5,214	
8	New Resources - 7(f) Loads	$	0.839	$	0.841	
9	Surplus Firm - SP Loads	$	185,966	$	120,921	
10	Total	$	5,319,582	$	5,446,651	
11						
12						
13	IP-PF Link Delta	$	1,199	$	1,163	
14						
15			**2024**		**2025**	
16	Priority Firm Public - 7(b) Loads		0.99999984		0.99999984	
17	Industrial Firm - 7(c) Loads		(1.00000000)		(1.00000000)	
18	New Resources - 7(f) Loads		0.00000016		0.00000016	
19						
20						
21	**Allocation of Second IP-PF Link Delta**		**2024**		**2025**	
22	Priority Firm Public - 7(b) Loads	$	1,199	$	1,163	
23	Priority Firm Exchange - 7(b) Loads	$	-	$	-	
24	Industrial Firm - 7(c) Loads	$	(1,199)	$	(1,163)	
25	New Resources - 7(f) Loads	$	0.000	$	0.000	
26	Total	$	(0)	$	0	
27						
28						
29	**Cost Allocation After Second IP-PF Link**		**2024**		**2025**	
30	Priority Firm Public - 7(b) Loads	$	2,147,259	$	2,293,275	
31	Priority Firm Exchange - 7(b) Loads	$	2,982,422	$	3,028,403	
32	Industrial Firm - 7(c) Loads	$	3,934	$	4,051	
33	New Resources - 7(f) Loads	$	0.839	$	0.841	
34	Surplus Firm - SP Loads	$	185,966	$	120,921	
35	Total	$	5,319,582	$	5,446,651	
36						
37						
38	**Energy Billing Determinants (aMW)**		**2024**		**2025**	
39	Priority Firm Public - 7(b) Loads		6,959		7,173	
40	Priority Firm Exchange - 7(b) Loads		5,269		5,280	
41	Industrial Firm - 7(c) Loads		11		11	
42	New Resources - 7(f) Loads		0.00112204		0.001121461	
43						
45						
46	**Average Power Rates After Second IP-PF Link**		**2024**		**2025**	Average
47	Priority Firm Public - 7(b) Loads		35.13		36.50	**35.81**
48	Priority Firm Exchange - 7(b) Loads		69.97		71.01	**70.49**
49	Industrial Firm - 7(c) Loads		40.72		42.04	**41.38**
50	New Resources - 7(f) Loads		85.12		85.58	**85.35**

Table 2.4.20

Rate Design Step
REP Benefit Reconciliation
Test Period October 2019 to
September 2021

	B	D	E	F	GH	I	J	K	L
4		**2024**	**2025**	**Avg**			**2024**	**2025**	**Avg**
5	Resource Costs	3,536,766	3,535,185	3,535,975		PFx Alloc Cost	(2,982,422)	(3,028,403)	
6	PFx Revenues	(3,238,845)	(3,284,665)	(3,261,755)		Exch Tmn Cost	(256,423)	(256,261)	
7	REP Benefits	297,921	250,520	274,220			(3,238,845)	(3,284,665)	(3,261,755)
8									
9	**REP Benefits**					**PFx Revenues**			
10	Avista Corporation	16,150	16,150			Avista Corporation	288,918	293,190	
11	Idaho Power Company	22,903	22,903			Idaho Power Company	501,341	508,754	
12	NorthWestern Energy, LLC	5,922	5,922			NorthWestern Energy, LLC	52,225	52,997	
13	PacifiCorp	74,665	74,665			PacifiCorp	659,105	668,851	
14	Portland General Electric Company	62,057	62,057			Portland General Electric Compar	606,053	615,015	
15	Puget Sound Energy, Inc.	91,904	91,904			Puget Sound Energy, Inc.	874,865	887,802	
16	IOU REP	273,600	273,600	273,600		IOU REP	2,982,507	3,026,610	3,004,559
17									
18	Clark Public Utilities	-	-			Clark Public Utilities	-	-	
19	Franklin	-	-			Franklin	-	-	
20	Snohomish PUD	623	618			Snohomish PUD	256,338	258,055	
21	COU REP	623	618	620		COU REP	256,338	258,055	257,196
22									
23	Refund Amounts	-	-			Refund Amounts	-	-	
24	Total REP	274,223	274,218	274,220		Total REP	3,238,845	3,284,665	3,261,755
25				0			0	(0)	(0)
26									
27	**For Slice True-Up**								100.00%
28	IOU REP	273,600	273,600						
29	COU REP	623	618						
30	Refund Amounts	-	-						
31	Total REP	274,223	274,218						

Table 2.5.1

Rate Design Study
Allocated Cost and Unit Cost Priority Firm
Rates Test Period October 2023 - September
2025

	B	C	D	E	F	G	H	I	J	K	L
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	1,803,976	8.332	17.26%		1,032,898	8.332	771,078	8.332	
19		Fish & Wildlife	755,537	3.490	7.23%		432,596	3.490	322,941	3.490	
20		Trojan	2,400	0.011	0.02%		1,374	0.011	1,026	0.011	
21		WNP #1	147,031	0.679	1.41%		84,185	0.679	62,846	0.679	
22		WNP #2	1,225,726	5.661	11.73%		701,811	5.661	523,915	5.661	
23		WNP #3	164,602	0.760	1.58%		94,246	0.760	70,356	0.760	
24		System Augmentation	0	0.000	0.00%		0	0.000	0	0.000	
25		Balancing Power Purchases	151,403	0.699	1.45%		86,688	0.699	64,714	0.699	
26		Tier 2 Costs	320,579	1.481	3.07%		183,553	1.481	137,026	1.481	
27		Total Federal Base System	4,571,254	21.114	43.74%		2,617,351	21.114	1,953,903	21.114	
28		New Resources	0	0.000	0.00%		0	0.000	0	0.000	
29		Gross Residential Exchange	6,237,642	28.810	59.69%		3,571,470	28.810	2,666,172	28.810	
30		Conservation	320,778	1.482	3.07%		183,667	1.482	137,111	1.482	
31		BPA Programs	321,969	1.487	3.08%		184,349	1.487	137,620	1.487	
32		Power Transmission	408,957	1.889	3.91%		234,156	1.889	174,802	1.889	
33		TOTAL COSA ALLOCATIONS	11,860,601	54.781	113.49%		6,790,993	54.781	5,069,608	54.781	
34				0.000							
35				0.000							
36		Nonfirm Excess Revenue Credit	(1,119,740)	-5.172	-10.71%		(641,126)	-5.172	(478,613)	-5.172	
37		Low Density Discount Expense	119,773	0.553	1.15%		68,578	0.553	51,195	0.553	
38		Other Revenue Credits	(526,830)	-2.433	-5.04%		(301,645)	-2.433	(225,184)	-2.433	
39		Irrigation Rate Mitigation Expense		0.000	0.00%		0	0.000	0	0.000	
40		SP Revenue Surplus/Dfct Adj.	110,544	0.511	1.06%		63,294	0.511	47,250	0.511	
41		7(c)(2) Delta Adjustment	6,115	0.028	0.06%		3,501	0.028	2,614	0.028	
42		7(c)(2) Floor Rate Adjustment		0.000	0.00%		0	0.000	0	0.000	
43		TOTAL RATE DESIGN ADJUSTMENTS	(1,410,137)	-6.513	-13.49%		(807,398)	-6.513	(602,739)	-6.513	
44				0.000	0.00%						
45		Total Generation	10,450,464	**48.2684**	100.00%		5,983,594	**48.27**	4,466,869	**48.27**	
46				0.000							
47			0	0.000							
48		REP Settlement Rate Protection Adjustment		0.000			(1,545,806)	-12.470	1,544,339	1,544,339	
49		7(b)(2) - 7(c)(2) Industrial Adjustment	0	0.000			2,362	0.019	0	0.000	
50		Total Generation		0.000			**4,440,151**	**35.82**	6,011,208	**64.96**	
51											
52		Total Transmission							512,685	5.540	
53									6,523,893	**70.50**	
54											

Table 2.5.2

Rate Design Study
Allocated Cost and Unit Costs for Industrial Firm Power Rate
Test Period October 2023 - September 2025

	C	D	E	F
13		**ALLOCATED**		**PERCENT**
14		**COSTS**	**COSTS**	**CONTRIBUTION**
15	GENERATION ENERGY	($ Thousands)	(Mills/kWh)	(Percent)
16				
17	Federal Base System		0.000	
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		
26	Total Federal Base System	0	0.000	0.00%
27	New Resources	3,471	17.987	43.47%
28	Gross Residential Exchange	11,032	57.163	138.14%
29	Conservation	286	1.482	3.58%
30	BPA Programs	287	1.487	3.59%
31	Power Transmission	365	1.889	4.56%
32	TOTAL COSA ALLOCATIONS	15,440	80.008	193.35%
33			0.000	0.00%
34	Nonfirm Excess Revenue Credit	(325)	-1.686	-4.07%
35		0.00000	0.000	0.00%
36	Other Revenue Credits	(218)	-1.129	-2.73%
37			0.000	0.00%
38	SP Revenue Surplus/Dfct Adj.	99	0.511	1.23%
39	7(c)(2) Delta Adjustment	(6,115)	-31.688	-76.58%
40	7(c)(2) Floor Rate Adjustment	0	0.000	0.00%
41	TOTAL RATE DESIGN ADJSTMTS	(6,560)	-33.992	-82.15%
42	Total Generation	8,880	46.017	111.21%
43			0.000	0.00%
55	Total Allocated & Adjusted Costs	8,880	46.017	111.21%
56			0.000	0.00%
57	Settlement Adjustments		0.000	0.00%
58	REP Settlement Rate Protection Adjustment	1,467	7.601	18.37%
59	7(b)(2) - 7(c)(2) Industrial Adjustment	(2,362)	-12.239	-29.58%
60		7,985	**41.38**	100.00%
61				
62	Billing Determinants:			
63	Energy (GwH)	193		

Table 2.5.3

Rate Design Study
Allocated Costs and Unit Costs for New Resources Firm Power Rate
Test Period October 2023 - September 2025

	C	D	E	F
12		**ALLOCATED**		**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		
24	Balancing Power Purchases	0	0.000	0.00%
25	Total Federal Base System	0.000	0.000	0.00%
26	New Resources	0.3540	17.987	21.07%
27	Gross Residential Exchange	1.1250	57.164	66.97%
28	Conservation	0.0292	1.482	1.74%
29	BPA Programs	0.0664	3.376	3.96%
30	TOTAL COSA ALLOCATIONS	1.5746	80.008	93.74%
31			0.000	0.00%
32	Nonfirm Excess Revenue Credit	(0.0332)	-1.686	-1.98%
33		0.0000	0.000	0.00%
34	Other Revenue Credits	(0.0222)	-1.129	-1.32%
35			0.000	0.00%
36	SP Revenue Surplus/Dfct Adj.	0.0101	0.511	0.60%
37	7(c)(2) Delta Adjustment	0.0006	0.028	0.03%
38	7(c)(2) Floor Rate Adjustment	0.0000	0.000	0.00%
39	TOTAL RATE DESIGN ADJSTMTS	(0.0448)	-2.275	-2.67%
40	Total Generation Energy	1.5298	77.733	91.07%
41			0.000	0.00%
50			0.000	0.00%
51	Total Allocated & Adjusted Costs	1.5298	77.733	91.07%
52	Settlement Adjustments		0.000	0.00%
53	REP Settlement Rate Protection Adjustment	0.1496	7.601	8.90%
54	7(b)(2) - 7(c)(2) Industrial Adjustment	0.0004	0.019	0.02%
55			0.000	0.00%
56	Total With 7(b)(2) Adjustments	1.6797	**85.35**	100.00%
57				
58	Billing Determinant / Energy (GWh)	0.01968		

Table 2.5.4

Rate Design Study
Resource Cost Percent Contribution to Load Pools
Test Period October 2023 - September 2025

	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	2,617,351	3,571,470	0	6,188,821		42.29%	57.71%	0.00%	100.00%
18	Priority Firm - Exchange	1,953,903	2,666,172	0	4,620,075		42.29%	57.71%	0.00%	100.00%
19	Priority Firm Power - Total	4,571,254	6,237,642	0	10,808,896		42.29%	57.71%	0.00%	100.00%
20	Industrial Firm Power	0	11,032	3,471	14,503		0.00%	76.06%	23.94%	100.00%
21	New Resources Firm	0	1.125	0	1		0.00%	76.07%	23.93%	100.00%
22	Firm Power Products and Services	0	311,748	94,400	406,148		0.00%	76.76%	23.24%	100.00%
23		0			0					
24										
25	**TOTALS**	**4,571,254**	**6,560,422**	**97,872**	**11,229,548**		**40.71%**	**58.42%**	**0.87%**	**100.00%**
26										
27					216,700					
28										
29			Average Cost of Resources		51.82					
30										
31			Average Cost to Serve Load Growth		61.50					

SECTION 3: RATE DESIGN

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Table Descriptions

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 RAM2024 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 TI SFCO 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
Table lists Ice Settlement prices used to calculate the Remarketing Value.

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 the PF Load Forecast Deviation Liquidated Damages Revenue Credit
Table summarizes the total revenue credits associated with the PF Load Forecast Deviation Liquidated Damages.

Rate Design Step
Cost Aggregation under Tiered Rate Methodology
Test Period October 2021 to September 2023

	A	B	C	D	E	G	H
4						**2024**	**2025**
5		**Composite**					
6			Federal Base System				
7				Hydro			
8					Operating Expense	649,494	662,564
9					Interest	18,918	1,767
10					MRNR	124,636	132,736
11				Fish & Wildlife			
12					Operating Expense	334,065	334,997
13					Interest	3,843	262
14					MRNR	25,319	19,667
15				Trojan		1,200	1,200
16				WNP #1		73,470	73,561
17				Columbia Generating Station		582,998	642,729
18				WNP #3		83,064	81,539
19				Augmentation		-	-
20			Residentail Exchange Program				
21				REP Net Cost		274,223	274,218
22				Program Support		554	602
23				Settlement Interest Accrual		-	-
24			NewResources				
25				Cowlitz		14,414	15,322
26				Idaho		-	-
27				Tier 1 Aug (Klondike III)		10,948	12,125
28				Other		25,589	25,055
29			Conservation				
30				Operating Expense		163,917	158,788
31				Interest		389	10
32				MRNR		2,560	728
33			BPAPrograms				
34				Operating Expense		158,668	162,341
35				Interest		401	29
36				MRNR		2,643	2,195
37			Transmission				
38				Transmission and Ancillary Services		52,897	53,194
39				General Transfer Agreements		91,278	92,598
40			Nonslice Interest and MRNR Allocated to Cost Pools				
41				Interest on BPA fund Credit to Nonslice		1,165	2,665
42				Accrual Revenue (MRNR Adjustment)		-	-
43			**Total**			**2,696,652**	**2,750,891**

Rate Design Step
Cost Aggregation under Tiered Rate Methodology
Test Period October 2021 to September 2023

	A	B	C	D	E	G	H
4						**2024**	**2025**
44		**Non-Slice**					
45			FBS				
46				Balancing Purchases from Risk Mod		55,078	45,875
47				Balancing in Revenue Requirement		25,523	24,927
48				PNRR			
49					Hydro	103,623	110,238
50					Fish & Wildlife	21,051	16,333
51			Conservation				
52				PNRR		2,128	605
53			BPAPrograms				
54				Hedging Mitigation		-	-
55				RCD Expense Offset Non-Slice		-	-
56				PNRR		2,197	1,823
57			Transmission				
58				Transmission and Ancillary Services		65,246	64,334
59				Third-party T&A		-	-
60			Nonslice Interest and MRNR				
61				BPA Fund		(1,165)	(2,665)
62				Non-Slice MRNR Adjustment		-	-
63			**Total**			**273,682**	**261,471**
64		**Slice**					
65			BPAPrograms				
66				Other Slice Costs		-	-
67			**Total**			-	-
68		**Tier 2**					
69			FBS				
70				Tier 2 Purchase Costs		111,871	200,414
71				Tier 2 Rate Design Adjustments		2,916	5,378
72				Tier 2 Other Costs		-	-
73			**Total**			**114,787**	**205,792**

Rate Design Step
Cost Aggregation under Tiered Rate Methodology
Test Period October 2021 to September 2023

	A	B	C	D	E	G	H
4						**2024**	**2025**
74	**Rate Direct/Design Adjustments**						
75		Credits Allocated Against Cost Pools					
76				FBS (excluding T2 Adjustment)		(136,495)	(136,663)
77				Contract Obligations		(523)	(510)
78				New Resources		-	-
79				Conservation		-	-
80				BPAPrograms		-	-
81				Transmission		(12,104)	(12,306)
82							
83		Secondary Energy Credit (includes pre-sale and Slice)				(563,160)	(565,741)
84		Firm Surplus Secondary Sales				(185,966)	(120,921)
85		Generation Inputs Credit				(112,085)	(112,085)
86		Capacity for Delayed 168-hr Loss Returns				-	-
87		FPS Real Power Losses				-	-
88		PRSC Net Credit (Composite)				-	-
89		PRSC Net Credit (Non-Slice)				-	-
90		NR Revenues from ESS services				-	-
91		Composite FPS Revenues (excl. secondary)				-	-
92		Non-Slice FPS Revenues (excl. secondary)				-	-
93							
94		Low Density Discount				37,701	38,532
95		Irrigation Rate Mitigation Costs				21,770	21,770
96							
97		Composite Augmentation RSS Revenue Debit/(Credit)				(1,947)	(1,947)
98		Composite Tier 2 RSS Revenue Debit/(Credit)				(203)	(380)
99		Composite Tier 2 Rate Design Adjustment Debit/(Credit)				(2,713)	(4,998)
100		Composite Non-Federal RSS Revenue Debit/(Credit)				(964)	(944)
101		Non-Slice Augmentation RSC Revenue Debit/(Credit)				(842)	(842)
102		Non-Slice Tier 2 RSC Revenue Debit/(Credit)				-	-
103		Non-Slice Tier 2 Rate Design Debit/(Credit)				-	-
104		Non-Slice Non-Federal RSC Revenue Debit/(Credit)				(92)	(92)
105							
106		Firm Surplus and Secondary Credit (from unused RHWM)				(98,789)	(86,644)
107		Demand Revenue				60,247	62,636
108		Load Shaping Revenue				57,931	63,975
109							

Table 3.1.2

Rate Design Step
Unused RHWM (net) Credit Computation
Test Period October 2019 to September 2021

	B	C	D
4		**2024**	**2025**
5	Secondary (aMW)	2,017	1,975
6	T1SFCO (aMW)	6,993	6,993
7	RHWM Augmentation (aMW)	71	71
8	RP Augmentation (aMW)	-	-
9	System Augmentation (aMW)	-	-
10	Firm Surplus (aMW)	351	243
11	IP and NR Loads contributing to avoided cost	11	11
12			
13	Value of Secondary	$ 25.03	$ 25.57
14	Value of T1SFCO ($/MWh)	$ 39.89	$ 39.89
15	Value of Augmentation	$ 50.39	$ 51.14
16	Value of Firm Surplus	$ 60.31	$ 56.87
17			
18	Secondary (MWh)	17,717,163	17,299,650
19	T1SFCO (MWh)	61,423,148	61,255,325
20	RHWM Augmentation (MWh)	621,450	619,752
21	IP and NR Loads (MWh)	99,749	99,476
22	Change in T1SFCO (MWh)	(183,393)	(49,062)
23			
24	Unused RHWM (MWh)	2,866,659	2,617,904
25			
26	Unused Secondary	818,590	731,940
27	Unused T1SFCO	2,837,946	2,591,682
28	Unused Augmentation	28,713	26,221
29			
30	Value of Unused	$ 135,130,563	$ 123,425,215
31	Value of System Augmentation not Purchased	$ 36,341,218	$ 36,781,348
32			
33	Net Credit/(Cost)	$ 98,789,345	$ 86,643,867
34			
35	$/MWh value of Unused RHWM	**$ 47.14**	

Table 3.1.3

Rate Design Step
Slice Return of Network Losses Adjustment
Test Period October 2019 - September 2021

	B	C	D
4		**2024**	**2025**
5	Non Slice Loads (MWh)	47,024,117	47,269,142
6	Loss Percent Assumption	2.05%	2.05%
7	Implied Non Slice Losses	964,661	969,703
8	Average Slice&Non-Slice Tier 1 Rate	34.69	34.69
9	Implied Cost/Credit ($1000)	33,464	33,639

Table 3.1.4

Rate Design Step
Balancing Augmentation Adjustment for Change to the Equivalent Tier 1 System
Firm Critical Output Test Period October 2023 - September 2025

	A	B	C	E	F	G
4				**2024**	**2025**	
5		**Table 3.1**				
6			Regulated	6,320	6,359	
7			Independent	339	345	
8		**Table 3.2**				
9			Ashland Solar Project	-	-	
10			Columbia Generating Station	1,116	994	
11			Condon Wind Project	-	-	
12			Dworshak/Clearwater Small Hydropower	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	21	
22		**Table 3.3**				
23			Canadian Entitlement	134	134	
24			Libby Coordination	-	-	
25			BC Hydro Power Purchase	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	188	188	
37			Canadian Entitlement	454	454	
38			Non-Treaty Storage	15	16	
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	
51			Dittmer Station Service	9	9	
52						
53			Federal Power Deliveries			
54			Preference	6,959	7,173	
55			Tier 2	204	390	
56			Net Preference	6,755	6,784	
57			Industrial	11	11	
58			New Resource	0	0	
59			Intraregional Transfer	11	11	
60			FBS Obligation	659	659	
61			Seasonal or Capacity Exchange	-	-	
62			Conservation Augmentation	-	-	
63			Transmission Losses Before Slice Return	246	253	
64			Slice Return of Losses	28	29	
65			Transmission Losses After Slice Return	218	224	
66						
67		**Annual T1SFCO**		7,048	6,964	
68		**RHWM Process T1SFCO (annual)**		7,027	6,958	
69		**Difference**		21	6	
70		**Augmentation Price (zero if no incremental Augmentation)**		$ -	$ -	
71		**Hours**		8,784	8,760	
72		**Credit/Cost to Balancing Augmentation**		$ -	$ -	

Table 3.1.5

Rate Design Step
Calculation of Load Shaping and Demand Revenues
Test Period October 2023 - September 2025

	B	E	F	G	H	I	J	K	L
5	**2024**	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-23	273,473	$ 10.37	$ 2,835,915	195,370	146,772	$ 47.71	$ 32.91	$ 14,151,363
7	Nov-23	339,133	$ 8.75	$ 2,967,418	(64,109)	102,091	$ 40.30	$ 31.39	$ 621,043
8	Dec-23	610,435	$ 13.39	$ 8,173,724	165,560	376,171	$ 61.63	$ 52.69	$ 30,023,915
9	Jan-24	590,110	$ 10.84	$ 6,396,793	111,160	332,598	$ 49.88	$ 36.73	$ 17,760,962
10	Feb-24	399,434	$ 10.93	$ 4,365,811	36,540	271,724	$ 50.32	$ 42.01	$ 13,253,820
11	Mar-24	533,490	$ 7.62	$ 4,065,194	(122,839)	26,449	$ 35.07	$ 35.84	$ (3,360,036)
12	Apr-24	598,649	$ 4.43	$ 2,652,014	44,514	69,048	$ 20.42	$ 21.67	$ 2,405,245
13	May-24	431,526	$ 3.95	$ 1,704,529	(586,407)	(295,897)	$ 18.21	$ 16.34	$ (15,513,432)
14	Jun-24	573,243	$ 3.88	$ 2,224,183	(726,747)	(321,859)	$ 17.87	$ 10.33	$ (16,311,785)
15	Jul-24	674,854	$ 12.08	$ 8,152,238	(82,674)	132,444	$ 55.60	$ 36.92	$ 293,183
16	Aug-24	735,139	$ 15.54	$ 11,424,063	31,699	94,970	$ 71.52	$ 48.93	$ 6,914,017
17	Sep-24	414,504	$ 12.75	$ 5,284,922	50,116	107,529	$ 58.70	$ 44.18	$ 7,692,439
18	**Total**			**$ 60,246,804**		$ 94,222			**$ 57,930,734**
19									
20	**2025**	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-24	381,479	$ 10.37	$ 3,955,939	229,530	114,326	$ 47.71	$ 32.91	$ 14,713,348
22	Nov-24	350,685	$ 8.75	$ 3,068,497	(64,990)	101,587	$ 40.30	$ 31.39	$ 569,723
23	Dec-24	617,150	$ 13.39	$ 8,263,635	163,530	377,609	$ 61.63	$ 52.69	$ 29,974,532
24	Jan-25	601,845	$ 10.84	$ 6,524,001	112,974	334,981	$ 49.88	$ 36.73	$ 17,939,004
25	Feb-25	381,423	$ 10.93	$ 4,168,948	83,555	300,297	$ 50.32	$ 42.01	$ 16,819,953
26	Mar-25	539,556	$ 7.62	$ 4,111,414	(120,688)	28,043	$ 35.07	$ 35.84	$ (3,227,458)
27	Apr-25	639,951	$ 4.43	$ 2,834,983	50,664	73,608	$ 20.42	$ 21.67	$ 2,629,649
28	May-25	454,232	$ 3.95	$ 1,794,217	(583,431)	(294,847)	$ 18.21	$ 16.34	$ (15,442,087)
29	Jun-25	579,887	$ 3.88	$ 2,249,961	(721,568)	(320,695)	$ 17.87	$ 10.33	$ (16,207,194)
30	Jul-25	750,447	$ 12.08	$ 9,065,399	(75,784)	138,259	$ 55.60	$ 36.92	$ 890,974
31	Aug-25	670,800	$ 15.54	$ 10,424,231	13,747	121,447	$ 71.52	$ 48.93	$ 6,925,641
32	Sep-25	484,316	$ 12.75	$ 6,175,032	77,552	86,840	$ 58.70	$ 44.18	$ 8,388,910
33	**Total**			**$ 62,636,256**		$ 226,548			**$ 63,974,995**

Rate Design Step
Calculation of PF Preference Rates under Tiered Rate
Methodology Test Period October 2023 - September 2025

	B		C		D		E
5	**Costs ($000)**		**2024**		**2025**		**Rate Period**
6	**Composite**	$	2,696,652	$	2,750,891	$	5,447,543
7	**Non-Slice**	$	273,682	$	261,471	$	535,153
8	**Slice**	$	-	$	-	$	-
9	**Tier 2**	$	114,787	$	205,792	$	320,579
13							
14	**Revenues from Rate Pools to Composite Cost Pool**		**2024**		**2025**		**Rate Period**
15	DSI Revenue Credit	**$**	**(3,998)**	**$**	**(3,987)**	**$**	**(7,986)**
16	Exchange Revenues	**$**	**-**	**$**	**-**	**$**	**-**
17	New Resource Revenues	**$**	**(0.84)**	**$**	**(0.84)**	**$**	**(2)**
18	FPS Revenues	$	-	$	-	$	-
19	Non-Federal RSS Revenues	$	(964)	$	(944)	$	(1,908)
20	Other Credits	$	(261,207)	$	(261,565)	$	(522,772)
21	Tiered Rate Elements					$	-
22	Unused RHWM Credit Reallocation	$	(98,789)	$	(86,644)	$	(185,433)
23	Balancing Augmentation Adjustment Reallocation	$	(2,358)	$	(5,792)	$	(8,150)
24	Composite Augmentation RSS Revenue Debit/(Credit)	$	(1,947)	$	(1,947)	$	(3,894)
25	Composite Tier 2 RSS Revenue Debit/(Credit)	$	(203)	$	(380)	$	(583)
26	Composite Tier 2 Rate Design Adjustment Debit/(Credit)	$	(2,713)	$	(4,998)	$	(7,711)
27	Transmission Losses Adjustment Reallocation	$	(33,464)	$	(33,639)	$	(67,103)
28	Total	$	(405,645)	$	(399,897)	$	(805,542)
29							
30	**Rate Discount Costs Applied to Composite Pool**		**2024**		**2025**		**Rate Period**
31	Irigation Rate Discout Costs	$	21,770	$	21,770	$	43,540
32	Low Density Discount Costs	$	37,701	$	38,532	$	76,232
33	Total	$	59,471	$	60,302	$	119,773
34							
35			**2024**		**2025**		**Rate Period**
36	**Composite**	$	2,350,478	$	2,411,296	$	4,761,774

Rate Design Step
Calculation of PF Preference Rates under Tiered Rate
Methodology Test Period October 2023 - September 2025

	B	C		D		E	
5	**Costs ($000)**		**2024**		**2025**	**Rate Period**	
6	**Composite...**	$	2,696,652	$	2,750,891	$	5,447,543
7	**Non-Slice...**	$	273,682	$	261,471	$	535,153
8	**Slice...**	$	-	$	-	$	-
9	**Tier 2...**	$	114,787	$	205,792	$	320,579
37							
38	**Non-Slice Revenues, Credits, and Costs**		**2024**		**2025**	**Rate Period**	
39	Secondary Revenue...	$	(638,013)	$	(575,152)	$	(1,213,165)
40	Unused RHWM Credit Reallocation...	$	98,789	$	86,644	$	185,433
41	Other Long Term Contract Revenues...	$	-	$	-	$	-
42	Non-federal RSC Revenues...	$	(92)	$	(92)	$	(184)
43	NR Revenues from ESS services...	$	-	$	-	$	-
44	Load Shaping Revenue...	$	(57,931)	$	(63,975)	$	(121,906)
45	Balancing Augmentation Adjustment Reallocation...	$	2,358	$	5,792	$	8,150
46	Demand Revenue...	$	(60,247)	$	(62,636)	$	(122,883)
47	Non-Slice Augmentation RSC Revenue Debit/(Credit)...	$	(842)	$	(842)	$	(1,684)
48	Non-Slice Tier 2 RSC Revenue Debit/(Credit)...	$	-	$	-	$	-
49	Non-Slice Tier 2 Rate Design Debit/(Credit)...	$	-	$	-	$	-
50	Real Power Losses (Non-Slice)...	$	-	$	-	$	-
51	PRSC Net Credit (Non-Slice)...	$	-	$	-	$	-
52	Transmission Losses Adjustment Reallocation...	$	33,464	$	33,639	$	67,103
53	Total...	$	(622,512)	$	(576,622)	$	(1,199,135)
54							
55			**2024**		**2025**	**Rate Period**	
56	**Non-Slice...**	$	(348,830)	$	(315,151)	$	(663,982)

Table 3.1.6.3

Rate Design Step
Calculation of PF Preference Rates under Tiered Rate
Methodology Test Period October 2023 - September 2025

	B	C	D	E
5	**Costs ($000)**	**2024**	**2025**	**Rate Period**
6	**Composite**..	$ 2,696,652	$ 2,750,891	$ 5,447,543
7	**Non-Slice**..	$ 273,682	$ 261,471	$ 535,153
8	**Slice**..	$ -	$ -	$ -
9	**Tier 2**..	$ 114,787	$ 205,792	$ 320,579
57				
58	**TRM Costs after Adjustments**	**2024**	**2025**	**Rate Period**
59	**Composite**..	$ 2,350,478	$ 2,411,296	$ 4,761,774
60	**Non-Slice**..	$ (348,830)	$ (315,151)	$ (663,982)
61	**Slice**..	$ -	$ -	$ -
62	**Tier 2**..	$ 114,787	$ 205,792	$ 320,579
63	**Total Costs**	$ 2,116,435	$ 2,301,937	$ 4,418,371
64				
65	**Billing Determinants**	**2024**	**2025**	**Rate Period**
66	**TOCA**..	95.3797	95.7691	95.5744
67	**Non-slice TOCA**..	75.6390	76.0283	75.8337
68	**Slice Percentage**..	19.7407	19.7407	19.7407
69				
70	**Annual TRM Rates ($000/percent)**	**2024**	**2025**	**Rate Period**
71	**Composite**..	$ 24,643	$ 25,178	$ 24,911
72	**Non-Slice**..	$ (4,612)	$ (4,145)	$ (4,378)
73	**Slice**..	$ -	$ -	$ -
74				
75	**Monthly TRM Rates ($/percent)**	**2024**	**2025**	**Rate Period**
76	**Composite**..	2,053,615	2,098,186	2,075,946
77	**Non-Slice**..	(384,315)	(345,432)	(364,823)
78	**Slice**..	-	-	-
79				
80	**Tier 2 Rates ($/MWh)**	**2024**	**2025**	**Rate Period**
81	**Tier 2 Short Term**..	$ 63.83	$ 60.25	$ 61.50
82	**Tier 2 Load Growth**..	$ 63.83	$ 60.25	$ 62.04

Table 3.1.7.1

Rate Design Step
Calculation of Net REP Ratemaking and
Recovery Demonstration Test period October
2023 - September 2025
($ 000, $/MWh)

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
11			2024	2025		PF p	IP	NR	FPS				PF p	IP	NR
12	GENERATION ENERGY														
13													123,965	193	0.01968
14	Federal Base System														
15	Hydro		896,671	907,305		1,803,976	0.0	0.0	0				14.55	0.00	0.00
16	Fish & Wildlife		384,278	371,260		755,537	0.0	0.0	0				6.10	0.00	0.00
17	Trojan		1,200	1,200		2,400	0.0	0.0	0				0.02	0.00	0.00
18	WNP #1		73,470	73,561		147,031	0.0	0.0	0				1.19	0.00	0.00
19	WNP #2		582,998	642,729		1,225,726	0.0	0.0	0				9.89	0.00	0.00
20	WNP #3		83,064	81,539		164,602	0.0	0.0	0				1.33	0.00	0.00
21	System Augmentation		0	0		0	0.0	0.0	0				0.00	0.00	0.00
22	Balancing Power Purchases		80,601	70,802		151,403	0.0	0.0	0				1.22	0.00	0.00
23	Tier 2 Costs		114,787	205,792		320,579	0.0	0.0	0				2.59	0.00	0.00
24	Total Federal Base System		2,217,068	2,354,186		4,571,254	0.0	0.0	0.0				36.88	0.00	0.00
25															
26	New Resources		48,161	49,711		97,872	0.0	0.0	0		PFx Revenue		0.79	0.00	0.00
27	Residential Exchange		3,280,897	3,279,525		549,597	0.0	0.0	0		6,010,825		4.43	0.00	0.00
28	Conservation		168,995	160,131		329,126	0.0	0.0	0				2.66	0.00	0.00
29	BPA Programs & Transmission		373,331	376,515		749,846	0.0	0.0	0		NR Revenue		6.05	0.00	0.00
30	TOTAL COSA ALLOCATIONS		6,088,451	6,220,069		6,297,695	0	0	0		1.7		50.80	0.00	0.00
31															
32															
33	Nonfirm Excess Revenue Credit		(563,160)	(565,741)		(1,128,902)	0.0	0.0	0.0				-9.11	0.00	0.00
34	LDD/IRD Expense		59,471	60,302		119,773	0.0						0.97	0.00	0.00
35	Other Revenue Credits		(265,179)	(267,979)		(533,158)	0.0	0.0	0.0				-4.30	0.00	0.00
36						0	0.0						0.00	0.00	0.00
37	SP Revenue Surplus/Dfct Adj.		0	0		(306,888)	0	0.0	306,888				-2.48	0.00	0.00
38	NR Rate Revenue					(1.7)		1.7					0.00	0.00	85.35
39	IP Rate Revenue		0	0		(7,986)	7,986						-0.06	41.38	0.00
40															
41	TOTAL RATE DESIGN ADJUSTMENTS		(768,869)	(773,418)		(1,857,162)	7,986	1.7	306,888				-14.98	41.38	85.35
42															
43	Total Generation		5,319,582	5,446,651									**35.82**	**41.38**	**85.35**
44			**PFp Revenue Recovery**			**4,440,533**	7,986	1.7	306,888						

Rate Design Step
Demonstration that TRM PFp Rates Collect the Same Revenue Requirement as the Non-TRM PFp Rate
Test Period October 1, 2019 to September 30, 2021

	B	C	D		E		F	G
4								
5								
6		**Proof: TRM PF Revenues = Non-TRM PF Revenues**						
7								
8				2024		2025		
9		Composite Revenue..............................	$	2,376,037	$	2,385,737		
10		Non-Slice Revenue...............................	$	(331,138)	$	(332,843)		
11		Slice Revenue...	$	-	$	-		
12		Tier 2...	$	114,787	$	205,792		
13		Load Shaping Revenue..........................	$	57,931	$	63,975		
14		Demand Revenue..................................	$	60,247	$	62,636		
15		Total TRM PF Revenue	$	2,277,863	$	2,385,297		
16								
17		Slice Portion of Secondary Revenue......	$	(111,114)	$	(111,511)		
18		Total Net TRM PF Revenue	$	2,166,749	$	2,273,786		
19								
20							PF Rate	
21		Total TRM PF Revenue Analogous to w/ Slice PF			$	4,440,535	35.82	
22								
23		w/ Slice PF Public Rate Revenue from "Net REP" Table			**$**	**4,440,533**	35.82	
24				delta	$	(2)		
25								
26								

Table 3.1.8.1

Rate Design Step
Calculation of Priority Firm Tier 1
Equivalent Rate Components Test Period
October 2023 - September 2025

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24		
15	HLH (mills/kWh)	47.71	40.30	61.63	49.88	50.32	35.07	20.42	18.21	17.87	55.60	71.52	58.70		
16	LLH (mills/kWh)	32.91	31.39	52.69	36.73	42.01	35.84	21.67	16.34	10.33	36.92	48.93	44.18		
17	Demand Rate ($/kW/mo)	10.37	8.75	13.39	10.84	10.93	7.62	4.43	3.95	3.88	12.08	15.54	12.75		
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)	5,304	6,111	7,058	7,365	6,320	6,351	5,299	5,275	5,357	5,704	5,815	5,126		118,756
22	LLH (GWh)	3,446	4,248	5,123	5,060	4,130	4,291	3,488	3,571	3,389	3,816	3,542	3,565		Tier 1 Demand (MW/mo)
23	Demand (MW)	655	690	1,228	1,192	781	1,073	1,239	886	1,153	1,425	1,406	899		12,626
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)	$ 253,047	$ 246,298	$ 435,002	$ 367,379	$ 318,037	$ 222,750	$ 108,219	$ 96,059	$ 95,726	$ 317,133	$ 415,899	$ 300,880		$ 4,846,975
29	LLH ($000)	$ 113,418	$ 133,350	$ 269,953	$ 185,870	$ 173,519	$ 153,795	$ 75,589	$ 58,345	$ 35,011	$ 140,886	$ 173,305	$ 157,503		Demand Revenue ($000)
30	Demand ($000)	$ 6,792	$ 6,036	$ 16,437	$ 12,921	$ 8,535	$ 8,177	$ 5,487	$ 3,499	$ 4,474	$ 17,218	$ 21,848	$ 11,460		$ 122,883
31															$ 4,969,858
32															Tier 1 Revenue Requirement (RR) ($000)
33															**$ 4,119,955**
34															Tier 1 RR less Demand Revenue ($000)
35															$ 3,997,072
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)	40.55	33.14	54.47	42.72	43.16	27.91	13.26	11.05	10.71	48.44	64.36	51.54		7.16
38	LLH (mills/kWh)	25.75	24.23	45.53	29.57	34.85	28.68	14.51	9.18	3.17	29.76	41.77	37.02		
39	Demand ($/kW/mo)	10.37	8.75	13.39	10.84	10.93	7.62	4.43	3.95	3.88	12.08	15.54	12.75		
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)	$ 215,072	$ 202,516	$ 384,474	$ 314,627	$ 272,761	$ 177,255	$ 70,265	$ 58,293	$ 57,369	$ 276,308	$ 374,245	$ 264,199		$ 3,996,604
45	LLH ($000)	$ 88,743	$ 102,933	$ 233,270	$ 149,637	$ 143,945	$ 123,070	$ 50,613	$ 32,779	$ 10,744	$ 113,564	$ 147,945	$ 131,977		Allocated Cost Demand ($000)
46	Demand ($000)	$ 6,792	$ 6,036	$ 16,437	$ 12,921	$ 8,535	$ 8,177	$ 5,487	$ 3,499	$ 4,474	$ 17,218	$ 21,848	$ 11,460		$ 122,883
47															$ 4,119,487
48	Average Slice&Non-Slice Tier 1 Rate														
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 3,996,604	33.65												
51	Allocated Cost Demand	$ 122,883	1.03												
52	Total Allocated Costs	$ 4,119,487	34.69												
53															
54		Tier 1 Energy (GWh)	118,756												
55		Market Energy Delta (mills/kWh)	7.16												

Table 3.1.8.2

Rate Design Step
Calculation of Priority Firm Public Melded
Rate Equivalent Components
Test Period October 2023 - September 2025

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24		
15	HLH (mills/kWh)	47.71	40.30	61.63	49.88	50.32	35.07	20.42	18.21	17.87	55.60	71.52	58.70		
16	LLH (mills/kWh)	32.91	31.39	52.69	36.73	42.01	35.84	21.67	16.34	10.33	36.92	48.93	44.18		
17	Demand Rate ($/kW/mo)	10.37	8.75	13.39	10.84	10.93	7.62	4.43	3.95	3.88	12.08	15.54	12.75		
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)	5,557	6,348	7,296	7,612	6,551	6,598	5,546	5,523	5,594	5,951	6,065	5,361		123,965
22	LLH (GWh)	3,635	4,439	5,328	5,255	4,303	4,485	3,669	3,766	3,579	4,011	3,734	3,759		Tier 1 Demand (MW/mo)
23	Demand (MW)	655	690	1,228	1,192	781	1,073	1,239	886	1,153	1,425	1,406	899		12,626
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)	$ 265,135	$ 255,870	$ 449,653	$ 379,711	$ 329,694	$ 231,412	$ 113,261	$ 100,559	$ 99,971	$ 330,884	$ 433,811	$ 314,654		$ 5,053,679
29	LLH ($000)	$ 119,625	$ 139,332	$ 280,723	$ 193,029	$ 180,783	$ 160,751	$ 79,498	$ 61,529	$ 36,973	$ 148,084	$ 182,681	$ 166,056		Demand Revenue ($000)
30	Demand ($000)	$ 6,792	$ 6,036	$ 16,437	$ 12,921	$ 8,535	$ 8,177	$ 5,487	$ 3,499	$ 4,474	$ 17,218	$ 21,848	$ 11,460		$ 122,883
31															$ 5,176,562
32															Tier 1&2 Revenue Requirement (RR) ($000)
33															$ 4,440,534
34															T1&2RR less Demand Revenue ($000)
35															$ 4,317,651
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)	41.77	34.36	55.69	43.94	44.38	29.13	14.48	12.27	11.93	49.66	65.58	52.76		5.94
38	LLH (mills/kWh)	26.97	25.45	46.75	30.79	36.07	29.90	15.73	10.40	4.39	30.98	42.99	38.24		
39	Demand ($/kW/mo)	10.37	8.75	13.39	10.84	10.93	7.62	4.43	3.95	3.88	12.08	15.54	12.75		
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)	$ 232,125	$ 218,131	$ 406,325	$ 334,474	$ 290,751	$ 192,197	$ 80,305	$ 67,761	$ 66,738	$ 295,550	$ 397,763	$ 282,833		$ 4,317,245
45	LLH ($000)	$ 98,033	$ 112,966	$ 249,076	$ 161,813	$ 155,221	$ 134,109	$ 57,707	$ 39,162	$ 15,713	$ 124,259	$ 160,504	$ 143,730		Allocated Cost Demand ($000)
46	Demand ($000)	$ 6,792	$ 6,036	$ 16,437	$ 12,921	$ 8,535	$ 8,177	$ 5,487	$ 3,499	$ 4,474	$ 17,218	$ 21,848	$ 11,460		$ 122,883
47															$ 4,440,128
48	Average Slice&Non-Slice Tier 1&2 Rate														
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 4,317,245	34.83												
51	Allocated Cost Demand	$ 122,883	0.99												
52	Total Allocated Costs	$ 4,440,128	35.82												
53															
54	Tier 1&2 Energy (GWh)		123,965												
55	PF Melded Equivalent Energy Scalar (mills/kWh)		5.94												

Table 3.1.8.3

Rate Design Step
Calculation of Industrial Firm Power Rate
Components Test Period October 2023 -
September 2025

	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-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24		
15		HLH (mills/kWh)	41.77	34.36	55.69	43.94	44.38	29.13	14.48	12.27	11.93	49.66	65.58	52.76		
16		LLH (mills/kWh)	26.97	25.45	46.75	30.79	36.07	29.90	15.73	10.40	4.39	30.98	42.99	38.24		
17		Demand Rate ($/kW/mo)	10.37	8.75	13.39	10.84	10.93	7.62	4.43	3.95	3.88	12.08	15.54	12.75		
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)	9	9	9	9	8	9	9	9	9	9	9	8		193
22		LLH (GWh)	7	7	8	8	7	7	7	7	7	8	7	7		
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)	$ 389	$ 299	$ 491	$ 389	$ 375	$ 271	$ 130	$ 110	$ 108	$ 439	$ 617	$ 442		$ 6,498
29		LLH ($000)	$ 190	$ 182	$ 353	$ 232	$ 238	$ 210	$ 108	$ 77	$ 30	$ 233	$ 299	$ 285		Demand Rev ($000)
30		Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
31																$ 6,498
32																
33																VOR
34																(0.81)
35																Industrial Margin (mills/kWh)
36		IP Rate	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		0.910
37		HLH (mills/kWh)	49.48	42.07	63.40	51.65	52.09	36.84	22.19	19.98	19.64	57.37	73.29	60.47		Net industrial Margin
38		LLH (mills/kWh)	34.68	33.16	54.46	38.50	43.78	37.61	23.44	18.11	12.10	38.69	50.70	45.95		0.101
39		Demand ($/kW/mo)	10.37	8.75	13.39	10.84	10.93	7.62	4.43	3.95	3.88	12.08	15.54	12.75		Settlement Charge
40																**7.612**
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)	$ 461	$ 366	$ 559	$ 457	$ 441	$ 343	$ 199	$ 179	$ 178	$ 507	$ 689	$ 507		$ 7,986
45		LLH ($000)	$ 244	$ 237	$ 411	$ 290	$ 288	$ 264	$ 161	$ 134	$ 82	$ 291	$ 353	$ 343		Allocated Cost Demand ($000)
46		Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
47																$ 7,986
48			Average IP Rate													
49			($000)	(mills/kWh)												
50		Allocated Cost Energy	$ 7,986	41.38												
51		Allocated Cost Demand	$ -	-												
52		Total Allocated Costs	$ 7,986	41.38												
53																
54			IP Energy (GWh)	193												
55			Industrial Margin (mills/kWh)	0.91												
56			VOR	(0.81)												
57			Settlement Charge	7.61												

Table 3.1.8.4

Rate Design Step
Calculation of New Resource Rate
Components Test Period October
2023 - September 2025

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24		
15	HLH (mills/kWh)	47.71	40.30	61.63	49.88	50.32	35.07	20.42	18.21	17.87	55.60	71.52	58.70		
16	LLH (mills/kWh)	32.91	31.39	52.69	36.73	42.01	35.84	21.67	16.34	10.33	36.92	48.93	44.18		
17	Demand Rate ($/kW/mo)	10.37	8.75	13.39	10.84	10.93	7.62	4.43	3.95	3.88	12.08	15.54	12.75		
18															
19															**Totals**
20	NR Determinants	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		NR Energy (GWh)
21	HLH (GWh)	0.0009	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008		0.0197
22	LLH (GWh)	0.0009	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008		Demand (MW/mo)
23	Demand (MW)														-
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)	$ 0.0412	$ 0.0316	$ 0.0503	$ 0.0407	$ 0.0395	$ 0.0297	$ 0.0170	$ 0.0146	$ 0.0149	$ 0.0463	$ 0.0595	$ 0.0470		$ 0.7680
29	LLH ($000)	$ 0.0284	$ 0.0246	$ 0.0430	$ 0.0300	$ 0.0329	$ 0.0304	$ 0.0180	$ 0.0131	$ 0.0086	$ 0.0307	$ 0.0407	$ 0.0353		Demand Revenue ($000)
30	Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
31															$ 0.7680
32															NR Revenue Requirement (RR) ($000)
33															$ 1.6797
34															NR RR less Demand Revenue ($000)
35															$ 1.6797
36	NR Rates	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Market Energy Delta (mills/kWh)
37	HLH (mills/kWh)	94.04	86.63	107.96	96.21	96.65	81.40	66.75	64.54	64.20	101.93	117.85	105.03		(46.33)
38	LLH (mills/kWh)	79.24	77.72	99.02	83.06	88.34	82.17	68.00	62.67	56.66	83.25	95.26	90.51		
39	Demand ($/kW/mo)	10.37	8.75	13.39	10.84	10.93	7.62	4.43	3.95	3.88	12.08	15.54	12.75		
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)	$ 0.0813	$ 0.0679	$ 0.0881	$ 0.0785	$ 0.0758	$ 0.0690	$ 0.0555	$ 0.0516	$ 0.0534	$ 0.0848	$ 0.0981	$ 0.0840		$ 1.6797
45	LLH ($000)	$ 0.0685	$ 0.0609	$ 0.0808	$ 0.0678	$ 0.0693	$ 0.0697	$ 0.0566	$ 0.0501	$ 0.0471	$ 0.0693	$ 0.0793	$ 0.0724		Allocated Cost Demand ($000)
46	Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
47															$ 1.6797
48		Average NR Rate													
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 1.6797	85.35												
51	Allocated Cost Demand	$ -	-												
52	Total Allocated Costs	$ 1.6797	85.35												
53															
54		NR Energy (GWh)	0.0197												
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 Test Period October 2023 - September 2025

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24		
15	HLH (mills/kWh)	47.71	40.30	61.63	49.88	50.32	35.07	20.42	18.21	17.87	55.60	71.52	58.70		
16	LLH (mills/kWh)	32.91	31.39	52.69	36.73	42.01	35.84	21.67	16.34	10.33	36.92	48.93	44.18		
17	Demand Rate ($/kW/mo)	10.37	8.75	13.39	10.84	10.93	7.62	4.43	3.95	3.88	12.08	15.54	12.75		
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]	4,296	4,822	5,669	5,890	5,039	4,989	4,224	3,944	3,951	4,493	4,623	4,094		94,293
22	LLH (GWh) [FMDT1L]	2,788	3,413	4,221	4,153	3,395	3,416	2,797	2,711	2,557	3,084	2,855	2,869		Tier 1 Demand (MW/mo)
23	Demand (MW)	655	690	1,228	1,192	781	1,073	1,239	886	1,153	1,425	1,406	899		12,626
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)	$ 204,968	$ 194,351	$ 349,342	$ 293,807	$ 253,593	$ 174,977	$ 86,268	$ 71,818	$ 70,608	$ 249,810	$ 330,667	$ 240,281		$ 3,871,017
29	LLH ($000)	$ 91,767	$ 107,127	$ 222,398	$ 152,543	$ 142,642	$ 122,432	$ 60,614	$ 44,300	$ 26,409	$ 113,851	$ 139,697	$ 126,745		Demand Revenue ($000)
30	Demand ($000)	$ 6,792	$ 6,036	$ 16,437	$ 12,921	$ 8,535	$ 8,177	$ 5,487	$ 3,499	$ 4,474	$ 17,218	$ 21,848	$ 11,460		$ 122,883
31															$ 3,993,900
32															Tier 1 Non-Slice PF Public RR minus Tier 2 Costs
33															$ 3,359,045
34															Tier 1 RR less Demand Revenue ($000) [BLFRnD]
35															$ 3,236,162
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)	40.98	33.57	54.90	43.15	43.59	28.34	13.69	11.48	11.14	48.87	64.79	51.97		6.73
38	LLH (mills/kWh)	26.18	24.66	45.96	30.00	35.28	29.11	14.94	9.61	3.60	30.19	42.20	37.45		
39	Demand ($/kW/mo)	10.37	8.75	13.39	10.84	10.93	7.62	4.43	3.95	3.88	12.08	15.54	12.75		
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)	$ 176,055	$ 161,877	$ 311,201	$ 254,152	$ 219,658	$ 141,385	$ 57,829	$ 45,278	$ 44,015	$ 219,584	$ 299,538	$ 212,748		$ 3,236,361
45	LLH ($000)	$ 73,001	$ 84,159	$ 193,992	$ 124,593	$ 119,791	$ 99,442	$ 41,790	$ 26,054	$ 9,203	$ 93,097	$ 120,482	$ 107,437		Allocated Cost Demand ($000)
46	Demand ($000)	$ 6,792	$ 6,036	$ 16,437	$ 12,921	$ 8,535	$ 8,177	$ 5,487	$ 3,499	$ 4,474	$ 17,218	$ 21,848	$ 11,460		$ 122,883
47															$ 3,359,244
48	Average Non-Slice Tier 1 Rate														
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 3,236,361	34.32												
51	Allocated Cost Demand	$ 122,883	1.30												
52	Total Allocated Costs	$ 3,359,244	35.63												
53															
54	Tier 1 Energy (GWh) [FAT1L]		94,293												
55	Load Shaping True-up Rate (mills/kWh) [LSTUR]		6.73												

Table 3.2
Summary RSS Revenue Credits for Tier 1 Cost Pools

	A	B	C	D	E	F	G	H	I	J
1	TRM	COSA	AggregationKey	Category	FY2024	FY2025	FY2026	FY2027	FY2028	FY2029
2	C	RDS	CNTA	Augmentation RSS & RSC Adder	$ 2,790	$ 2,790	$ 2,790	$ 2,790	$ 2,790	$ 2,790
3	C	RDS	CD2RCF	Composite Augmentation RSS Revenue Debit/(Credit)	$ (1,947)	$ (1,947)	$ (1,947)	$ (1,947)	$ (1,947)	$ (1,947)
4	2.0	RDS	2D2RCF	Composite Tier 2 RSS Revenue Debit/(Credit)	$ -	$ -	$ -	$ -	$ -	$ -
5	C	RDS	CD2RCN	Composite Non-Federal RSS Revenue Debit/(Credit)	$ (964)	$ (944)	$ (944)	$ (944)	$ (944)	$ (944)
6	N	RDS	ND2RNF	Non-Slice Augmentation RSC Revenue Debit/(Credit)	$ (842)	$ (842)	$ (842)	$ (842)	$ (842)	$ (842)
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)	$ (92)	$ (92)	$ (92)	$ (92)	$ (92)	$ (92)

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 2024 and FY 2025 Tier 2 purchases as of November 1, 2022.															

Table 3.4
Inputs to TSS Monthly Rate and Charge

	A	B	C	D	E	F
1	FY2024 PTK + PTFR Scheduling Costs	FY2025 PTK + PTFR Scheduling Costs	FY2020 Scheduled MWh	FY2021 Scheduled MWh	FY2020 Number of Transactions	FY2021 Number of Transactions
2	$3,870,305	$4,064,813	37,726,366	35,789,630	124,124	112,833

Table 3.5.1
Tier 2 Short-Term Rate Costing Table

	A	B	C
1		ST.3.2020_2024	ST.4.2025_2028
2	Hours	8784	8760
3	Fiscal Year	FY2024	FY2025
4	Rate Period	BP-24	
5	Total Forecast Expected Cost	$ 109,825,237	$ 199,293,057
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	$ 2,721,136	$ 5,149,545
16	Resource Support Services	$ 189,273	$ 363,873
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	$ 189,273	$ 363,873
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	$ 189,273	$ 363,873
28	Resource Shaping Charge	$ -	$ -
29	Tier 2 Overhead	$ 2,531,863	$ 4,785,673
30	Risk Adder	$ -	$ -
31	Carbon Costs Pass Through	$ -	$ -
32	Renewable Energy Credits (MWh)	0	0
33	Quantity Purchased (MWh)	0	0
34	Tier 2 Obligation w/o losses (Billing Determinant)	1,720,663	3,307,934
35	Tier 2 Obligation w losses	1,775,893	3,414,113
36	Energy (Short)/Long (MWh)	-1,775,893	-3,414,113
37	Composite Cost Pool Augmentation (MWh) - BP12 Only		
38	Energy Short (MWh)	-1,775,893	-3,414,113
39	Energy to be Remarketed (MWh)	0	0
40	Remarketing Available (MWh)	48,101	41,373
41	Total Tier 2 Pool Shortfall (MWh)	-1,903,034	-3,565,751
42	Augmentation Price ($/MWh)	50.39	51.14
43	Flat Block RSC ($/MWh)	39.46	39.89
44	Remarketing Value ($/MWh)	60.31	56.87
45	Remarketed Purchase (MWh)	44,888	39,614
46	Remarketed Purchase Cost	2,707,169	2,252,651
47	Remaining Shortfall (MWh)	-1,731,005	-3,374,499
48	Remaining Shortfall Cost	104,396,931	191,890,861
49	Tier 2 Balancing Adjustment Debit/(Credit) - BP12 Only		
50	Remarketing Treatment (Remove From Rate) (Yes or No)	No	No
51	Additional Remarketing (MWh)		
52	Total Fixed Costs	$ 109,825,237	$ 199,293,057
53	Billing Components		
54	ShortTerm ($/MWh)	$ 63.83	$ 60.25
55	Remarketing Credit	$ -	$ -
56	Remarketing Charge	$ -	$ -
57	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (2,531,863)	$ (4,785,673)
58	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
59	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (189,273)	$ (363,873)

Table 3.5.2

Tier 2 Load Growth Rate Costing Table

	A	B	C
1		LG.1.2012_2028	LG.1.2012_2028
2	Hours	8,784	8,760
3	Fiscal Year	FY2024	FY2025
4	Rate Period	BP-24	
5	Total Forecast Expected Cost	$ 7,862,681	$ 8,851,652
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	$ 194,813	$ 228,718
16	Resource Support Services	$ 13,551	$ 16,161
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	$ 13,551	$ 16,161
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	$ 13,551	$ 16,161
28	Resource Shaping Charge	$ -	$ -
29	Tier 2 Overhead	$ 181,263	$ 212,557
30	Risk Adder	$ -	$ -
31	Carbon Costs Pass Through	$ -	$ -
32	Renewable Energy Credits (MWh)	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)	-127,141	-151,639
39	Energy to be Remarketed (MWh)	0	0
40	Remarketing Available (MWh)	48,101	41,373
41	Total Tier 2 Pool Shortfall (MWh)	-1,903,034	-3,565,751
42	Augmentation Price ($/MWh)	$ 50.39	$ 51.14
43	Flat Block RSC ($/MWh)	$ 39.46	$ 39.89
44	Remarketing value ($/MWh)	$ 60.31	$ 56.87
45	Remarketed Purchase (MWh)	3,214	1,759
46	Remarketed Purchase Cost	193,813	100,052
47	Remaining Shortfall (MWh)	-123,927	-149,879
48	Remaining Shortfall Cost	$ 7,474,054	$ 8,522,882
49	Tier 2 Balancing Adjustment Debit/(Credit) - BP12 Only	$ -	$ -
50	Remarketing Treatment (Remove From Rate) (Yes or No)	No	No
51	Additional Remarketing - Vintage Only (MWh)	0	0
52	Total Fixed Costs	$ 7,862,681	$ 8,851,652
53	Billing Components		
54	LoadGrowth ($/MWh)	$ 63.83	$ 60.25
55	Remarketing Credit	$ -	$ -
56	Remarketing Charge	$ -	$ -
57	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (181,263)	$ (212,557)
58	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
59	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (13,551)	$ (16,161)

Table 3.6
Tier 2 Overhead Adder Inputs

	A	B	C	D	E
1		**BP-24**			
2		**FY2024**		**FY2025**	
3	**Line Item**	**FY2024**	**Total Forecast Sales (MWh)**	**FY2025**	**Total Forecast Sales (MWh)**
4	Generation Project Coordination	$ 4,443,390	76,582,670	$ 4,443,390	79,329,036
5	Sales & Support	$ 17,870,548		$ 17,870,548	
6	Power Internal Support	$ 27,855,879		$ 27,855,879	
7	Agency Services G&A	$ 62,517,503		$ 64,556,782	
8	Total Costs	$ 112,687,321		$ 114,726,601	
9	**Total Costs Divided by Total Sales**		$ 1.47		$ 1.45

Table 3.7
Tier 2 Rate Revenues

	A	B	C
1	Hours	8,784	8,760
2	Fiscal Year	FY2024	FY2025
3	Rate Period	BP-24	
4	ShortTerm Rate $/MWh	$ 63.83	$ 60.25
5	LoadGrowth Rate $/MWh	$ 63.83	$ 60.25
6	Vintage Rate $/MWh	$ -	$ -
7			
8	**ShortTerm**		
9	Portfolio Purchased aMW	0.000	0.000
10	Portfolio Purchased MWh	0	0
11	Portfolio Obligation w/ Losses aMW	202	390
12	Portfolio Obligation w/ Losses MWh	1,775,893	3,414,113
13	Portfolio Billing Determinant aMW	196	378
14	Portfolio Billing Determinant MWh	1,720,663	3,307,934
15	RECs MWh	0	0
16	Base Power Purchase Cost	$ -	$ -
17	Rate Design Components	$ 2,721,136	$ 5,149,545
18	Other Costs	$ -	$ -
19	Rate $/MWh	$ 63.83	$ 60.25
20	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (2,531,863)	$ (4,785,673)
21	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
22	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (189,273)	$ (363,873)
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	$ 109,829,895	$ 199,303,004
26	Remarketing Credit	$ -	$ -
27	Remarketing Charge	$ -	$ -
28	Forecast Power Purchase Costs	$ 104,396,931	$ 191,890,861
29			
30	**LoadGrowth**		
31	Portfolio Purchased aMW	0.000	0.000
32	Portfolio Purchased MWh	0	0
33	Portfolio Obligation /w Losses aMW	14.474	17.310
34	Portfolio Obligation /w Losses MWh	127,141	151,639
35	Portfolio Billing Determinant aMW	14.024	16.772
36	Portfolio Billing Determinant MWh	123,187	146,923
37	RECs MWh	0	0
38	Base Power Purchase Cost	$ -	$ -
39	Rate Design Components	$ 194,813	$ 228,718
40	Other Costs	$ -	$ -
41	Rate $/MWh	$ 63.83	$ 60.25
42	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (181,263)	$ (212,557)
43	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
44	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (13,551)	$ (16,161)
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	$ 7,863,014	$ 8,852,094
48	Remarketing Credit	$ -	$ -
49	Remarketing Charge	$ -	$ -
50	Forecast Power Purchase Costs	$ 7,474,054	$ 8,522,882
51			
52	**Total Costs**		
53	Total Base Power Purchase Cost	$ -	$ -
54	Total Rate Design Components	$ 2,915,950	$ 5,378,264

Table 3.7 Continued
Tier 2 Rate Revenues

55	Total Other Costs	$ -	$ -
56	Forecast Power Purchase Costs	$ 111,870,986	$ 200,413,743
57	Total Cost	$ 114,786,935	$ 205,792,006
58			
59	**Total Revenue**		
60	Total Tier 2 Rate Revenue Collection	$ 117,692,910	$ 208,155,098
61	Total Tier 2 Remarketing Charge	$ -	$ -
62	Total Tier 2 Remarketing Credit	$ -	$ -
63	Non-Federal Remarketing Credit	$ (2,900,982)	$ (2,352,703)
64	Total Revenue	$ 114,791,927	$ 205,802,395
65	Value of BPA Purchased Remarketing	$ -	$ -
66	Total Tier 2 Revenue and Value of BPA Purchased Remarketing	$ 114,791,927	$ 205,802,395
67			
68	Total Tier 2 Adjustments and Credits*		
69	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (2,713,126)	$ (4,998,229)
70	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
71	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (202,823)	$ (380,034)
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
1	Rate Period	BP-24	
2	Fiscal Year	FY2024	FY2025
3	ShortTerm Remarket (MWh)	0	0
4	LoadGrowth Remarket (MWh)	0	0
5	Vintage Remarket (MWh)	0	0
6	Non-Federal Remarket (MWh)	48,101	41,373
7	Total	48,101	41,373
8			
9	ShortTerm Purchase of Remarket (MWh)	44,888	39,614
10	LoadGrowth Purchase of Remarket (MWh)	3,214	1,759
11	Vintage Purchase of Remarket (MWh)	0	0
12	BPA Purchase of Remarket (MWh)	0	0
13	Total	48,101	41,373
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	$ 2,900,982	$ 2,352,703
22			
23	ShortTerm Open Position (MWh)	1,731,005	3,374,499
24	LoadGrowth Open Position (MWh)	123,927	149,879
25	Vintage Opern Position (MWh)		
26	BPA Purchase of Remarket (MWh)	0	0
27	Total Open Position (MWh)	1,854,933	3,524,378

Table 3.9
Tier 2 Rate Inputs

	A	B	C	D	E	F
1	**Fiscal Year**	**TSS Rate ($/MWh)**	**Augmentation Price ($/MWh)**	**ICE Settlement Prices ($/MWh)**	**Remarketing Value ($/MWh)**	**Available Non-Federal Resource Remarketing (MWh)**
2	FY2024	$ 0.11	$ 50.39	$ 70.23	$ 60.31	48,101
3	FY2025	$ 0.11	$ 51.14	$ 62.59	$ 56.87	41,373

Table 3.10
Remarketing Value Inputs

	A	B	C
1	**Pricing Date**	**ICE Settlement[1/] FY 2024 $/MWh**	**ICE Settlement[1/] FY 2025 $/MWh**
2	8/15/2022	69.66	62.42
3	8/16/2022	70.33	62.62
4	8/17/2022	70.50	62.80
5	8/18/2022	70.36	62.59
6	8/19/2022	70.31	62.52
7	**Average**	**70.23**	**62.59**
8			
9	1/ All ICE Settlements in this table are calculated flat annual average prices based on ICE Settlements for monthly Mid-C electricity peak and off-peak fixed price futures.		

Table 3.11
RSS and Related Charges

	A	B	C	D	E	F	G	H	I	J
	Purchaser	Resource Name	Services & RSC	Applicable Year(s)	"Resource Input" Tab Adj. for Schedule Annual aMW	Exh. A FY2024 Annual aMW	Exh. A FY2025 Annual aMW	DFS Energy Rate $/MWh	DFS Capacity Charge $/mo	DFS Capacity $/MWh Equiv.
1	Tier 1	Klondike 3 (07PB-11860)	DFS TSS TCMS RSC	FY2024&FY2025	17.36	17.10	17.10	3.98	161,240.00	12.72
2	City of Bonners Ferry	Moyie	GMS	FY2024&FY2025	N/A	1.88	1.88	-	-	-
3	City of Centralia	Yelm Hydro	GMS	FY2024&FY2025	N/A	7.11	7.11	-	-	-
4	City of Forest Grove	Priest Rapids	SCS	FY2024&FY2025	N/A	1.58	1.58	-	-	-
5	City of Forest Grove	Wanapum	SCS	FY2024&FY2025	N/A	1.60	1.60	-	-	-
6	The City of McMinnville, a municipal corporation of	Priest Rapids	SCS	FY2024&FY2025	N/A	1.58	1.58	-	-	-
7	The City of McMinnville, a municipal corporation of	Wanapum	SCS	FY2024&FY2025	N/A	1.60	1.60	-	-	-
8	The City of McMinnville, a municipal corporation of	Riverbend Biogas	DFS FOR RSC	FY2024&FY2025	3.14	3.77	3.51	0.25	10,505.00	4.58
9	City of Milton-Freewater	Priest Rapids	SCS	FY2024&FY2025	N/A	1.58	1.58	-	-	-
10	City of Milton-Freewater	Wanapum	SCS	FY2024&FY2025	N/A	1.60	1.60	-	-	-
11	Public Utility District No. 1 of Clallam County	Packwood	DFS FOR TSS TCMS RSC	FY2024&FY2025	1.17	0.46	0.46	1.32	4,895.00	5.72
12	Columbia REA	Walla Walla Hydro	DFS FOR RSC	FY2024&FY2025	1.08	1.23	1.23	0.74	3,014.00	3.82
13	PNGC	Flathead LFGTE	DFS FOR RSC	FY2024&FY2025	1.23	1.08	1.08	0.25	6,372.00	7.08
14	PNGC	Stoltze Lumber	DFS FOR RSC	FY2024&FY2025	2.22	2.50	2.50	0.43	7,519.00	4.64
15	Northern Wasco County People's Utility District	NLSL Unspecified Resource Amount	TSS TCMS	FY2024&FY2025	N/A	77.84	102.81	-	-	-
16	Public Utility District No. 1 of Kittitas County	Priest Rapids	SCS	FY2024&FY2025	N/A	0.53	0.53	-	-	-
17	Public Utility District No. 1 of Kittitas County	Wanapum	SCS	FY2024&FY2025	N/A	0.53	0.53	-	-	-
18	Richland	Horn Rapids Solar	DFS TSS TCMS RSC	FY2024&FY2025	0.67	0.58	0.58	4.97	6,396.00	13.07
19	Public Utility District No. 3 of Mason County	Packwood	SCS TSS TCMS	FY2024&FY2025	N/A	0.66	0.66	-	-	-
20	Public Utility District No. 3 of Mason County	Nine Canyon Wind	DFS TSS TCMS RSC	FY2024&FY2025	0.82	0.81	0.81	4.55	7,234.00	12.12
21	Public Utility District No. 3 of Mason County	White Creek Wind	DFS TSS TCMS RSC	FY2024&FY2025	0.98	0.92	0.92	4.43	8,998.00	12.55
22	PNGC	Lake Creek	SCS	FY2024&FY2025	N/A	1.53	1.53	-	-	-
23	PNGC	Chester Hydro	DFS FOR RSC	FY2024&FY2025	0.73	0.97	0.97	0.36	1,558.00	2.90
24	PNGC	Island Park	SCS	FY2024&FY2025	N/A	0.99	0.99	-	-	-
25	Northern Wasco County People's Utility District	Unspecified Resource Amounts	TSS TCMS	FY2024&FY2025	N/A	12.00	12.00	-	-	-
26	Northern Wasco County People's Utility District	McNary Fishway	GMS TSS	FY2024&FY2025	N/A	4.41	4.40	-	-	-
27	Klickitat	McNary Fishway	SCS TSS TCMS	FY2024&FY2025	N/A	4.22	4.22	-	-	-
28	Klickitat	Packwood	SCS TSS TCMS	FY2024&FY2025	N/A	0.20	0.20	-	-	-
29	Klickitat	Unspecified Resource Amounts	TSS TCMS	FY2024	N/A	10.00	-	-	-	-
30	Cheney	Unspecified Resource Amounts	TSS TCMS	FY2024	N/A	1.00	-	-	-	-
31	Kootenai	Unspecified Resource Amounts	TSS TCMS	FY2024	N/A	4.00	-	-	-	-
32	Lower Valley	Unspecified Resource Amounts	TSS TCMS	FY2024&FY2025	N/A	11.00	12.00	-	-	-
33	United	Unspecified Resource Amounts	TSS TCMS	FY2024	N/A	3.00	-	-	-	-
34	Wells	Unspecified Resource Amounts	TSS TCMS	FY2024	N/A	1.00	-	-	-	-

Table 3.11 Continued
RSS and Related Charges

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
	RSC $/mo	RSC $/MWh Equiv.	FOR Capacity $/mo	FOR Capacity $/MWh Equiv.	TSS $/mo	TSS $/MWh Equiv.	TCMS $/mo	TCMS $/MWh Equiv.	SCS $/mo	SCS $/MWh Equiv.	GMS $/mo	GMS $/MWh Equiv.	Revenue Credit to Composite Cost Pool FY2024	Revenue Credit to Non-Slice Cost Pool FY2024	Revenue Credit to Composite Cost Pool FY2025	Revenue Credit to Non-Slice Cost Pool FY2025	Forecast Total $/MWh Equivalent Rate
1	$ 19,715	$ 1.56	$ -	$ -	$ 1,021	$ 0.08	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,947,136	$ 842,468	$ 1,947,136	$ 842,468	$ 18.34
2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 695	$ 0.51	$ 8,336	$ -	$ 8,336	$ -	$ 0.51
3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,387	$ 0.65	$ 40,641	$ -	$ 40,641	$ -	$ 0.65
4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 757	$ 0.66	$ -	$ -	$ 9,085	$ -	$ 9,085	$ -	$ 0.66
5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 770	$ 0.66	$ -	$ -	$ 9,236	$ -	$ 9,236	$ -	$ 0.66
6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 757	$ 0.66	$ -	$ -	$ 9,085	$ -	$ 9,085	$ -	$ 0.66
7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 770	$ 0.66	$ -	$ -	$ 9,236	$ -	$ 9,236	$ -	$ 0.66
8	$ 12,855	$ 5.60	$ 1,342	$ 0.59	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 142,169	$ 161,076	$ 142,169	$ 161,076	$ 11.02
9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 757	$ 0.66	$ -	$ -	$ 9,085	$ -	$ 9,085	$ -	$ 0.66
10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 770	$ 0.66	$ -	$ -	$ 9,236	$ -	$ 9,236	$ -	$ 0.66
11	$ (18,957)	$ (22.14)	$ 248	$ 0.29	$ 54	$ 0.06	$ -	$ -	$ -	$ -	$ -	$ -	$ 62,354	$ (213,897)	$ 62,354	$ (213,897)	$ (14.75)
12	$ 3,586	$ 4.54	$ 380	$ 0.48	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 40,723	$ 50,048	$ 40,723	$ 50,048	$ 9.58
13	$ (7,712)	$ (8.57)	$ 371	$ 0.41	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 80,912	$ (89,835)	$ 80,912	$ (89,835)	$ (0.83)
14	$ 3,068	$ 1.89	$ 1,127	$ 0.70	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 103,752	$ 45,255	$ 103,752	$ 45,255	$ 7.66
15	$ -	$ -	$ -	$ -	$ 1,010	$ 0.02	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,122	$ -	$ 12,122	$ -	$ 0.02
16	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 252	$ 0.66	$ -	$ -	$ 3,027	$ -	$ 3,027	$ -	$ 0.66
17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 257	$ 0.66	$ -	$ -	$ 3,079	$ -	$ 3,079	$ -	$ 0.66
18	$ (3,082)	$ (6.30)	$ -	$ -	$ 63	$ 0.13	$ -	$ -	$ -	$ -	$ -	$ -	$ 77,514	$ (7,805)	$ 77,514	$ (7,805)	$ 11.87
19	$ -	$ -	$ -	$ -	$ 58	$ 0.12	$ -	$ -	$ 282	$ 0.59	$ -	$ -	$ 4,084	$ -	$ 4,084	$ -	$ 0.71
20	$ 515	$ 0.86	$ -	$ -	$ 71	$ 0.12	$ -	$ -	$ -	$ -	$ -	$ -	$ 87,655	$ 38,807	$ 87,655	$ 38,807	$ 17.65
21	$ (725)	$ (1.01)	$ -	$ -	$ 79	$ 0.11	$ -	$ -	$ -	$ -	$ -	$ -	$ 108,930	$ 29,445	$ 108,930	$ 29,445	$ 16.08
22	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 540	$ 0.48	$ -	$ -	$ 6,478	$ -	$ 6,478	$ -	$ 0.48
23	$ 6,399	$ 11.93	$ 248	$ 0.46	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 21,676	$ 79,137	$ 21,676	$ 79,137	$ 15.65
24	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 429	$ 0.59	$ -	$ -	$ 5,145	$ -	$ 5,145	$ -	$ 0.59
25	$ -	$ -	$ -	$ -	$ 970	$ 0.11	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,646	$ -	$ 11,646	$ -	$ 0.11
26	$ -	$ -	$ -	$ -	$ 360	$ 0.11	$ -	$ -	$ -	$ -	$ 2,050	$ 0.64	$ 28,920	$ -	$ 28,920	$ -	$ 0.75
27	$ -	$ -	$ -	$ -	$ 345	$ 0.11	$ -	$ -	$ 1,966	$ 0.64	$ -	$ -	$ 27,727	$ -	$ 27,727	$ -	$ 0.75
28	$ -	$ -	$ -	$ -	$ 21	$ 0.15	$ -	$ -	$ 84	$ 0.59	$ -	$ -	$ 1,270	$ -	$ 1,270	$ -	$ 0.74
29	$ -	$ -	$ -	$ -	$ 811	$ 0.11	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,729	$ -	$ -	$ -	$ 0.11
30	$ -	$ -	$ -	$ -	$ 97	$ 0.13	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,166	$ -	$ -	$ -	$ 0.13
31	$ -	$ -	$ -	$ -	$ 339	$ 0.12	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,065	$ -	$ -	$ -	$ 0.12
32	$ -	$ -	$ -	$ -	$ 941	$ 0.11	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,296	$ -	$ 11,296	$ -	$ 0.11
33	$ -	$ -	$ -	$ -	$ 258	$ 0.12	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,099	$ -	$ -	$ -	$ 0.12
34	$ -	$ -	$ -	$ -	$ 97	$ 0.13	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,166	$ -	$ -	$ -	$ 0.13

Table 3.12
PF Load Forecast Deviation Liquidated Damages

	A	B	C
1		FY 2024	FY 2025
2	Forecast of Annual Consumer Load MWh	0	0
3	Actual Annual Consumer Load MWh	0	0
4	Actual Annual Consumer Load Above Forecast Amount MWh	0	0
5	Absolute Value of Load Shaping True-Up Rate	$ (6.73)	$ (6.73)
6	Annual Liquidated Damages Charge	$ -	$ -

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 PF Load Shaping rates, NR Load Shaping Rates, and the flat annual block AURORA market price forecast.

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

	A	B	C	D	E	F	G	H	I	J
1				**Calendar Year**	**Chained GDP IPD**		**Month**	**BP-24 Load Shaping Rate HLH $/MWh**	**Demand Shaping Factor**	**Monthly Demand Rate $/kW/mo**
2	Start Year of Operation (FY)	2024		2016	105.740		Oct	47.71	9.05%	$ 10.37
3	Cost of Debt	3.06%	/1	2017	107.747		Nov	40.30	7.64%	$ 8.75
4				2018	110.321		Dec	61.63	11.69%	$ 13.39
5	Inflation Rate	2.28%		2019	112.294		Jan	49.88	9.46%	$ 10.84
6	Insurance Rate	0.25%	/2	2020	113.648		Feb	50.32	9.54%	$ 10.93
7				2021	118.370		Mar	35.07	6.65%	$ 7.62
8	Debt Finance Period (years)	30	/2				Apr	20.42	3.87%	$ 4.43
9	Plant Lifecycle (years)	30	/2		102.28%	5-year Avg.	May	18.21	3.45%	$ 3.95
10							Jun	17.87	3.39%	$ 3.88
11	Lifetime Average Heat Rate Btu/kWh	8,797	/2	Chained GDP IPD from BEA -- Table 1.1.9. Implicit Price Deflators for Gross Domestic Product (2012 Base year) - Last Revised April 28, 2022			Jul	55.60	10.55%	$ 12.08
12							Aug	71.52	13.57%	$ 15.54
13	Eastside Fixed Fuel $/kW/yr with 8797 Heat Rate 2016$	$ 16.57	/2				Sep	58.70	11.13%	$ 12.75
14	Westside Fixed Fuel $/kW/yr with 8797 Heat Rate 2016$	$ 22.54	/2						**Average $/kW/mo**	**$ 9.54**
15	Average Eastside and Westside 2016$	$ 19.56								
16										
17	All-in Capital Cost Wärtsilä 18V50SG Recip $/kW 2024$	$ 1,575.18	/3	**End of Fiscal Year**	**Midyear Assessed Value**	**Debt Payment**	**Fixed O&M**	**Insurance**	**Fixed Fuel**	**Cash Expense Each Year**
18	Fixed O&M $/kW/yr 2024$	5.99	/4	2024	$ 1,548.93	$80.99	$ 5.99	$ 3.87	$ 23.42	$ 114.27
19	Fixed Fuel $/kW/yr 2024$	23.42		2025	$ 1,496.42	$80.99	$ 6.13	$ 3.74	$ 23.95	$ 114.81
20							**Rate Period Average Expense $/kW/year**			**$ 114.54**
21										
22	/1 Source BPA FY 2022 Third-Party Tax-Exempt Borrowing Rate Forecast 30-year									
23	/2 Source NWPCC 2021 Power Plan Microfin Model and Fixed Fuel Workbook									
24	/3 Source NWPCC Microfin Model assumption of $1315/kW in 2016$.									
25	/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
1		**Aurora Market Prices**				**Load Shaping Rates**	
2		HLH - $/MWh	LLH - $/MWh			HLH - $/MWh	LLH - $/MWh
3	Oct-23	48.49	33.65		October	47.71	32.91
4	Nov-23	41.22	30.89		November	40.30	31.39
5	Dec-23	64.11	52.59		December	61.63	52.69
6	Jan-24	50.35	37.23		January	49.88	36.73
7	Feb-24	50.39	41.96		February	50.32	42.01
8	Mar-24	35.01	35.81		March	35.07	35.84
9	Apr-24	20.84	21.98		April	20.42	21.67
10	May-24	16.96	14.34		May	18.21	16.34
11	Jun-24	17.60	10.25		June	17.87	10.33
12	Jul-24	55.67	36.50		July	55.60	36.92
13	Aug-24	69.21	48.23		August	71.52	48.93
14	Sep-24	55.86	42.45		September	58.70	44.18
15	Oct-24	46.94	32.17				
16	Nov-24	39.39	31.89				$/MWh
17	Dec-24	59.15	52.79	**FY2024 Aurora Flat Annual Block**			39.46
18	Jan-25	49.42	36.24	**FY2025 Aurora Flat Annual Block**			39.89
19	Feb-25	50.26	42.07				
20	Mar-25	35.14	35.87				
21	Apr-25	20.00	21.36				
22	May-25	19.46	18.33				
23	Jun-25	18.15	10.40				
24	Jul-25	55.53	37.33				
25	Aug-25	73.83	49.62				
26	Sep-25	61.53	45.91				

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)**
2	LG.1.2012_2028_FY2024	LG.1.2012_2028	FY2024	14.024	14.474
3	LG.1.2012_2028_FY2025	LG.1.2012_2028	FY2025	16.772	17.310
4	ST.3.2020_2024_FY2024	ST.3.2020_2024	FY2024	195.886	202.174
5	ST.4.2025_2028_FY2025	ST.4.2025_2028	FY2025	377.618	389.739
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		\$2,081,414	
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			\$19,450,694
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			\$6.38
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				\$17,369,280					

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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	Franklin PUD	13,084.284	22,897.496	23,715.264	22,079.728	12,630.475	94,407.247	0.00%	0.000
5	10231	Klickitat	3,082.499	4,137.060	5,575.639	4,578.816	4,258.715	21,632.729	7.00%	1,514.291
6	10286	Okanogan PUD	7,203.742	10,441.534	14,718.217	12,876.538	10,168.120	55,408.151	0.00%	0.000
7	10025	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
8	10027	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
9	10391	United	5,273.820	10,806.706	12,770.236	9,182.704	6,236.687	44,270.153	3.00%	1,328.105
10	10046	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
11	10109	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
12	10111	Columbia Power	706.641	866.742	1,530.227	1,432.169	691.870	5,227.649	7.00%	365.935
13	10113	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
14	10173	Fall River	721.884	12,605.402	20,135.316	9,028.407	1,818.987	44,309.996	7.00%	3,101.700
15	10197	Harney	19,540.495	20,142.982	26,028.119	22,023.182	12,164.427	99,899.205	7.00%	6,992.944
16	10209	Inland	10,963.601	14,641.767	12,471.610	11,584.325	10,451.398	60,112.701	7.00%	4,207.889
17	10242	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
18	10256	Midstate	7,679.733	8,829.777	11,222.582	9,712.913	4,044.309	41,489.314	6.50%	2,696.805
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	OTEC	4,715.415	7,780.401	10,076.149	7,938.224	5,750.412	36,260.601	5.00%	1,813.030
21	10331	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
22	10142	East End	1,061.340	1,353.162	1,240.237	1,171.183	943.562	5,769.484	2.50%	144.237
23	10338	Riverside	528.123	986.578	1,167.444	906.478	566.587	4,155.210	3.00%	124.656
24	10360	Southside	2,180.245	5,429.243	5,273.390	4,387.577	2,738.885	20,009.340	4.50%	900.420
25	10343	Salmon River	1,257.157	2,671.504	2,659.622	2,533.409	1,383.969	10,505.661	7.00%	735.396
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	4.00%	9,150.897
28	10442	Wasco	1,883.529	2,101.872	2,215.155	1,766.387	1,766.387	9,733.330	7.00%	681.333
29	10446	Wells	846.538	1,717.671	1,928.492	1,812.765	865.874	7,171.340	6.50%	466.137
30	10502	Yakama Power	1,463.062	1,175.985	1,228.497	1,619.426	1,702.727	7,189.697	7.00%	503.279
31	10436	Vigilante	5,362.005	10,090.787	11,936.481	8,014.268	3,459.717	38,863.258	7.00%	2,720.428
32	10258	Mission Valley	1,857.275	3,714.550	6,500.462	5,571.825	742.910	18,387.022	5.00%	919.351
33								**Wt. LDD**	**4.6%**	

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

	A	B	C	D	E	F
1	**FY 2024**					
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	McMinnville, City of	3.773	33,142	60.31	$1,998,796	$166,566
4	Mason County PUD #3	1.702	14,950	60.31	$901,657	$75,138
5	Total	5.475	48,092		$2,900,453	$241,704
6	**FY 2025**					
7	**Customers receiving remarketing credits for non-Federal resource(s) with DFS**	**Remarketing Amount (aMW)**	**Remarketing Amount (MWh)**	**Remarketing Value ($/MWh)**	**Annual Remarketing Credit**	**Monthly Remarketing Credit**
8	McMinnville, City of	3.505	30,704	56.87	$1,745,972	$145,498
9	Mason County PUD #3	1.219	10,678	56.87	$607,229	$50,602
10	Total	4.724	41,382		$1,745,972	$145,498

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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, WECC fees, and transfer service delivery.

Table 6.1

Transfer Service Costs and Rates

Rate Inputs

BPAT Loss Factor	2.04%	
Schedule 5 & 6	0.015	
BPAT Spin Reserve Rate	0.01105	kWh
BPAT Supp Reserve Rate	0.00722	kWh
BPAT Reg & Freq Rate	0.00046	kWh

Regulation and Operating Reserves Charges

Transfer Loads Forecast (MWh)	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
FY 2021	903,709	1,001,392	1,223,754	1,224,744	1,082,598	1,020,597	927,537	939,086	983,393	1,090,025	1,056,609	917,222
FY 2022	928,857	1,018,272	1,258,115	1,261,415	1,089,167	1,042,885	959,653	959,697	1,009,471	1,115,805	1,078,314	922,627
Total	1,832,566	2,019,664	2,481,870	2,486,159	2,171,765	2,063,483	1,887,189	1,898,783	1,992,864	2,205,830	2,134,923	1,839,849

2024 Rate recovery ($1000s)	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
Spin	153	169	207	207	183	173	157	159	166	184	179	155	2,092
Supp	100	111	135	135	120	113	103	104	109	120	117	101	1,367
Reg & Freq	416	461	563	563	498	469	427	432	452	501	486	422	5,691
WECC Fee	26	26	26	26	26	26	26	26	26	26	26	26	312
Total	694	767	931	932	827	781	712	721	753	832	808	704	9,462

2025 Rate recovery ($1000s)	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
Spin	157	172	213	213	184	176	162	162	171	189	182	156	2,139
Supp	103	113	139	139	120	115	106	106	112	123	119	102	1,397
Reg & Freq	427	468	579	580	501	480	441	441	464	513	496	424	5,816
WECC Fee	26	26	26	26	26	26	26	26	26	26	26	26	312
Total	713	779	957	959	832	797	736	736	773	851	824	708	9,665

Delivery Charge

Distribution and Low Voltage Costs	2,634,316	$
BPA Customer System Peak	2,358,445	Peak kW
Proposed Rate	$ 1.12	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)

	FY 2024	**FY 2025**
Avista	$70.61	$70.61
Idaho Power	$66.03	$66.03
NorthWestern	$83.73	$83.73
PacifiCorp	$84.08	$84.08
PGE	$80.83	$80.83
Puget Sound Energy	$81.53	$81.53
Clark	$48.45	$48.45
Snohomish	$54.02	$54.02

Note: Rate Period ASCs are determined through the ASC review process

Table 8.2

IOU Residential Loads and
COU Forecast Exchange Loads (MWh)

	Oct-23***	Nov-23***	Dec-23***	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24***	Sep-24***	FY 2024
Avista	254,896	306,989	410,968	459,294	418,801	430,264	317,826	273,567	268,443	335,109	369,714	283,006	**4,128,877**
Idaho Power Company	464,615	436,478	545,727	676,925	640,200	577,788	484,723	515,838	563,855	796,249	824,028	638,154	**7,164,579**
Northwestern Energy	49,059	52,412	68,041	80,255	73,180	71,477	63,503	54,614	52,447	60,599	66,274	54,477	**746,336**
PacifiCorp	600,843	698,195	924,210	1,043,903	924,506	830,986	699,203	643,951	675,340	826,475	857,512	694,034	**9,419,158**
Portland General Electric	575,519	625,581	839,112	967,677	849,427	770,350	674,466	607,179	607,492	704,237	797,305	642,654	**8,660,999**
Puget	831,587	1,025,014	1,273,760	1,421,122	1,297,790	1,277,714	1,098,609	922,767	832,917	849,676	852,098	819,498	**12,502,551**

	Oct-24***	Nov-24***	Dec-24***	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25***	Sep-25***	FY 2025
Avista	254,896	306,989	410,968	459,294	418,801	430,264	317,826	273,567	268,443	335,109	369,714	283,006	**4,128,877**
Idaho Power Company	464,615	436,478	545,727	676,925	640,200	577,788	484,723	515,838	563,855	796,249	824,028	638,154	**7,164,579**
Northwestern Energy	49,059	52,412	68,041	80,255	73,180	71,477	63,503	54,614	52,447	60,599	66,274	54,477	**746,336**
PacifiCorp	600,843	698,195	924,210	1,043,903	924,506	830,986	699,203	643,951	675,340	826,475	857,512	694,034	**9,419,158**
Portland General Electric	575,519	625,581	839,112	967,677	849,427	770,350	674,466	607,179	607,492	704,237	797,305	642,654	**8,660,999**
Puget	831,587	1,025,014	1,273,760	1,421,122	1,297,790	1,277,714	1,098,609	922,767	832,917	849,676	852,098	819,498	**12,502,551**

*** indicates forecast is based on one month due to data availability

COUs FY 2024-2025 Forecast Exchange Loads
(MWh)

	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	FY 2024
Clark	194,253	258,150	339,361	319,786	256,301	256,398	198,813	182,354	167,936	196,464	191,033	156,615	**2,717,464**
Snohomish	248,721	296,368	392,265	480,787	367,187	421,584	283,647	264,972	234,896	219,413	231,387	222,053	**3,663,281**

	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	FY 2025
Clark	197,662	262,595	344,813	324,850	260,515	260,613	201,917	185,617	171,143	200,404	194,882	159,492	**2,764,505**
Snohomish	245,032	291,973	386,448	478,089	365,126	419,218	282,055	263,485	233,577	218,181	230,088	220,807	**3,634,079**

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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
VER Facilities in FY 2024-2025
Table provides a list of Variable Energy Resources (VERs) within the BPA BA that require balancing service.

Table 9.3.1.3
Balancing Reserve Capacity Quantity Forecast for FY 2024-2025
The forecast quantities of balancing reserves needed on a monthly basis to support the 99.7 percent planning standard.

Table 9.3.1.4
Balancing Area Net Load and Generation for FY 2020-2025
Historic, FY 2020-2023, and forecasted, FY 2024-2025 monthly net loads and generation within the BPA BA.

Table 9.3.1.5
Forecast Operating Reserve Obligations for FY 2024-2025
The forecasted monthly operating reserve obligation. Includes self- and third party supply, BPA obligation and total BA obligation.

Table 9.3.1.6
FCRPS 1-Hour Peaking Capacity for FY 2024-2025
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 9.3.1.7
Capacity Costs
Forecasted BPA Power costs allocated to capacity for FY 2024-2025. Includes capital related costs, fish and wildlife costs, power purchase costs and two cost adjustments.

Table 9.3.1.8
Embedded Cost Calculation
Table provides inputs and assumptions to calculate the unit embedded cost of system capacity.

Table 9.3.1.9
Heavy Load Hour Market Prices for FY 2024
Table provides forecast HLH market prices by month of the most recent 30 water years.

Table 9.3.1.10
Heavy Load Hour Market Prices for FY 2025
Table provides forecast HLH market prices by month of the most recent 30 water years.

Table 9.3.1.11
Light Load Hour Market Prices for FY 2024
Table provides forecast LLH market prices by month of the most recent 30 water years.

Table 9.3.1.12
Light Load Hour Market Prices for FY 2025
Table provides forecast LLH market prices by month of the most recent 30 water years.

Table 9.3.1.13
Variable Costs Sub-Categories of Stand Ready Costs from the GARD Model
Table provides a rate period annual average forecast of energy shift, efficiency loss and spill costs associated with holding spinning and non-spinning incremental capacity as well as decremental capacity.

Table 9.3.1.14
Variable Cost Components for Reserves
Table provides a rate period annual average forecast reserve requirement (MWs) and associated variable costs for components of balancing and operating reserves under the 99.7 percent level of service standard.

Table 9.3.1.15
GARD Stand-ready Costs and EIM Cost Reduction
Table provides a rate period annual average forecast of GARD costs by reserve components and sub-categories as well as EIM cost reduction assuming 95% variable cost reduction for non-regulation reserves.

Table 9.3.1.16
7HA.02 SCCT Frame Annual Costs
Table provides forecast of annual costs for the General Electric 7HA.02 combustion turbine.

Table 9.3.1.17
Cost of Capacity Calculation
Table provides inputs and assumptions for calculating annual average of FY 2024-2025 capacity costs by reserve type. Both embedded and variable costs are included.

Table 9.3.1.18
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 for FY 2018 through 2020 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 FY 2024 and 2025. 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 FY 20219 to August 2022
Historical, FY 2019 to August 2022, and forecasted, FY 2024-2025 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 9.1 Revenue at Current Rates

	A B C D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	**Table 9.1 -Revenue at Current Rates**													**2023**	
2	**Category**	**202210**	**202211**	**202212**	**202301**	**202302**	**202303**	**202304**	**202305**	**202306**	**202307**	**202308**	**202309**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 193,968	$ 193,968	$ 193,968	$ 193,968	$ 193,968	$ 193,968	$ 193,968	$ 193,968	$ 193,968	$ 193,968	$ 193,968	$ 193,968	$ 2,327,617	5,032
4	Non-Slice Revenue	$ (24,646)	$ (24,646)	$ (24,646)	$ (24,646)	$ (24,646)	$ (24,646)	$ (24,646)	$ (24,646)	$ (24,646)	$ (24,646)	$ (24,646)	$ (24,646)	$ (295,754)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	2,684
6	Load Shaping Revenue	$ (2,616)	$ (13,222)	$ 16,735	$ 38,251	$ 29,914	$ 9,320	$ 11,814	$ (12,699)	$ (18,675)	$ (16,248)	$ (11,145)	$ (7,269)	$ 24,160	21
7	Demand Revenue	$ 2,582	$ 3,376	$ 8,619	$ 5,925	$ 4,101	$ 5,074	$ 3,109	$ 2,141	$ 3,010	$ 6,048	$ 7,619	$ 4,341	$ 55,946	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,161)	$ (4,725)	$ (5,441)	$ (4,465)	$ (2,717)	$ (20,509)	-
9	Low Density Discount	$ (2,881)	$ (2,482)	$ (3,437)	$ (3,751)	$ (3,519)	$ (3,048)	$ (3,284)	$ (2,903)	$ (2,929)	$ (3,388)	$ (3,479)	$ (3,010)	$ (38,109)	-
10	Tier 2	$ 4,158	$ 4,030	$ 4,158	$ 4,160	$ 3,757	$ 4,154	$ 4,026	$ 4,160	$ 4,026	$ 4,160	$ 4,160	$ 4,026	$ 48,973	173
11	RSS (Non-Federal) and Other	$ 88	$ 88	$ 88	$ 88	$ 88	$ 88	$ 88	$ 88	$ 88	$ 88	$ 88	$88	$ 1,052	-
12	**PF customers (TRM) sub-total**	**$ 170,653**	**$ 161,112**	**$ 195,485**	**$ 213,995**	**$ 203,663**	**$ 184,910**	**$ 185,075**	**$ 156,946**	**$ 150,116**	**$ 154,540**	**$ 162,099**	**$ 164,782**	**$ 2,103,374**	**7,910**
13	**NR sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
14	**DSIs sub-total**	**$ 379**	**$ 379**	**$ 438**	**$ 389**	**$ 365**	**$ 367**	**$ 312**	**$ 264**	**$ 239**	**$ 383**	**$ 405**	**$ 361**	**$ 4,279**	**12**
15	**FPS sub-total**	**$ 623**	**$ 728**	**$ 852**	**$ 841**	**$ 735**	**$ 703**	**$ 643**	**$ 653**	**$ 693**	**$ 753**	**$ 724**	**$ 629**	**$ 8,577**	**-**
16	**Short-term market sales sub-total**	**$ 48,342**	**$ 79,444**	**$ 76,010**	**$ 75,426**	**$ 116,137**	**$ 73,925**	**$ 38,009**	**$ 48,138**	**$ 41,993**	**$ 75,925**	**$ 58,623**	**$ 29,045**	**$ 761,014**	**1,644**
17	**Long Term Contractual Obligations sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**462**
19	**Other Sales sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 8,337**	**$ 8,337**	**-**
20	**Gross Sales**	**$219,997**	**$241,662**	**$272,785**	**$290,650**	**$320,900**	**$259,904**	**$224,039**	**$206,000**	**$193,040**	**$231,601**	**$221,851**	**$203,152**	**$2,885,582**	**10,028**
21	Transfer Service Delivery charge	$ 217	$ 222	$ 315	$ 346	$ 300	$ 248	$ 222	$ 233	$ 243	$ 264	$ 258	$ 233	$ 3,100	-
22	Energy Efficiency Revenues	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 300	-
23	Irrigation Pumping Power	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102	$ 1,221	15
24	Reserve Energy	$ 861	$ 861	$ 861	$ 861	$ 861	$ 861	$ 861	$ 861	$ 861	$ 861	$ 861	$ 861	$ 10,327	160
25	USBR Owyhee Wheeling Project	$ 139	$ 139	$ 139	$ 139	$ 139	$ 139	$ 139	$ 139	$ 139	$ 139	$ 139	$ 139	$ 1,670	-
26	Downstream Benefits	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 7,443	-
27	Upper Baker Revenues	$ -	$ 91	$ 112	$ 100	$ 98	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 402	-
28	**Miscellaneous Revenue**	**$1,964**	**$2,060**	**$2,174**	**$2,193**	**$2,145**	**$1,995**	**$1,969**	**$1,979**	**$1,990**	**$2,010**	**$2,005**	**$1,979**	**$24,463**	**175**
29	Balancing Reserve Capacity	$ 4,153	$ 4,153	$ 4,153	$ 4,153	$ 4,153	$ 4,153	$ 4,153	$ 4,153	$ 4,153	$ 4,153	$ 4,153	$ 4,153	$ 49,831	-
30	ACS Risk Share	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
31	Risk Mitigation Tool	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
32	Imbalance Adjustment for Third-Party Deployed Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
33	Operating Reserve - Spinning	$ 1,280	$ 1,541	$ 1,791	$ 2,042	$ 1,888	$ 1,937	$ 1,908	$ 1,944	$ 2,018	$ 2,006	$ 1,845	$ 1,673	$ 21,873	-
34	Operating Reserve - Supplemental	$ 836	$ 1,007	$ 1,170	$ 1,333	$ 1,233	$ 1,265	$ 1,246	$ 1,270	$ 1,318	$ 1,310	$ 1,205	$ 1,093	$ 14,284	-
35	Operating Reserve - Spinning Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
36	Operating Reserve - Supplemental Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
37	Operating Reserve - Energy	$ 43	$ 39	$ 70	$ 51	$ 51	$ 20	$ 75	$ 67	$ 100	$ 86	$ 67	$ 57	$ 728	-
38	Synchronous Condensing	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 923	-
39	Generation Dropping	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 365	-
40	Redispatch	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 370	-
41	Segmentation of COE/Reclamation Network and Delivery Facilities	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 9,502	-
42	Station Service	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 2,295	9
43	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
44	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
45	Energy Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	Generation Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	**Generation Inputs / Inter-business line**	**$ 7,432**	**$ 7,861**	**$ 8,305**	**$ 8,700**	**$ 8,446**	**$ 8,495**	**$ 8,503**	**$ 8,555**	**$ 8,709**	**$ 8,676**	**$ 8,391**	**$ 8,097**	**$ 100,170**	**9**
48	4(h)(10)(c)	$ 13,325	$ 6,788	$ 7,233	$ 10,254	$ 5,350	$ 8,819	$ 7,466	$ 8,095	$ 7,564	$ 7,929	$ 6,479	$ 8,692	$ 97,995	-
49	Colville Settlement	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
50	**Treasury Credits**	**$ 13,709**	**$ 7,171**	**$ 7,616**	**$ 10,637**	**$ 5,734**	**$ 9,203**	**$ 7,849**	**$ 8,478**	**$ 7,948**	**$ 8,312**	**$ 6,863**	**$ 9,075**	**$ 102,595**	**-**
51	Augmentation Power Purchase sub-total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
52	Balancing Power Purchase sub-total	$ 3,959	$ 5,282	$ 10,326	$ 10,823	$ 5,554	$ 5,773	$ 3,865	$ 660	$ 3,520	$ 3,398	$ 4,484	$ 2,412	$ 60,055	100
53	Other Power Purchase sub-total	$ 3,995	$ 3,882	$ 3,995	$ 3,995	$ 3,609	$ 3,990	$ 3,866	$ 3,995	$ 3,866	$ 3,995	$ 3,995	$ 3,856	$ 47,041	175
54	**Power Purchases**	**$ 7,954**	**$ 9,164**	**$ 14,321**	**$ 14,818**	**$ 9,162**	**$ 9,763**	**$ 7,732**	**$ 4,655**	**$ 7,387**	**$ 7,394**	**$ 8,479**	**$ 6,268**	**$ 107,096**	**275**

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**													**2024**	
2	**Category**	**202310**	**202311**	**202312**	**202401**	**202402**	**202403**	**202404**	**202405**	**202406**	**202407**	**202408**	**202409**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 188,550	$ 188,550	$ 188,550	$ 188,550	$ 188,550	$ 188,550	$ 188,550	$ 188,550	$ 188,550	$ 188,550	$ 188,550	$ 188,550	$ 2,262,599	5,353
4	Non-Slice Revenue	$ (23,753)	$ (23,753)	$ (23,753)	$ (23,753)	$ (23,753)	$ (23,753)	$ (23,753)	$ (23,753)	$ (23,753)	$ (23,753)	$ (23,753)	$ (23,753)	$ (285,038)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	1,405
6	Load Shaping Revenue	$ 9,795	$ 1,395	$ 17,456	$ 11,689	$ 8,485	$ (2,782)	$ 2,175	$ (14,125)	$ (15,324)	$ (223)	$ 3,264	$ 3,607	$ 25,411	11
7	Demand Revenue	$ 2,307	$ 3,209	$ 6,926	$ 6,437	$ 4,422	$ 4,458	$ 3,581	$ 2,062	$ 2,734	$ 7,148	$ 7,804	$ 3,590	$ 54,677	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,222)	$ (4,816)	$ (5,546)	$ (4,551)	$ (2,769)	$ (20,905)	-
9	Low Density Discount	$ (3,312)	$ (3,312)	$ (3,312)	$ (3,312)	$ (3,312)	$ (3,312)	$ (3,312)	$ (3,312)	$ (3,312)	$ (3,312)	$ (3,312)	$ (3,312)	$ (39,746)	-
10	Tier 2	$ 4,655	$ 4,512	$ 4,655	$ 4,655	$ 4,355	$ 4,649	$ 4,505	$ 4,655	$ 4,505	$ 4,655	$ 4,655	$ 4,505	$ 54,964	211
11	RSS (Non-Federal) and Other	$ 93	$ 93	$ 93	$ 93	$ 93	$ 93	$ 93	$ 93	$ 93	$ 93	$ 93	$ 93	$ 1,115	-
12	**PF customers (TRM) sub-total**	**$ 178,335**	**$ 170,693**	**$ 190,615**	**$ 184,359**	**$ 178,839**	**$ 167,902**	**$ 171,838**	**$ 150,947**	**$ 148,677**	**$ 167,612**	**$ 172,750**	**$ 170,511**	**$ 2,053,077**	**6,980**
13	**NR sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
14	**DSIs sub-total**	**$ 347**	**$ 347**	**$ 400**	**$ 357**	**$ 346**	**$ 337**	**$ 286**	**$ 242**	**$ 218**	**$ 351**	**$ 370**	**$ 331**	**$ 3,933**	**11**
15	**FPS sub-total**	**$ 715**	**$ 742**	**$ 804**	**$ 805**	**$ 765**	**$ 747**	**$ 721**	**$ 725**	**$ 737**	**$ 767**	**$ 757**	**$ 719**	**$ 9,004**	**-**
16	**Short-term market sales sub-total**	**$ 21,998**	**$ 41,595**	**$ 47,031**	**$ 68,253**	**$ 72,787**	**$ 61,312**	**$ 41,724**	**$ 55,556**	**$ 58,959**	**$ 86,499**	**$ 59,492**	**$ 22,807**	**$ 638,012**	**1,619**
17	**Long Term Contractual Obligations sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**462**
19	**Other Sales sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
20	**Gross Sales**	**$201,395**	**$213,377**	**$238,851**	**$253,774**	**$252,736**	**$230,298**	**$214,569**	**$207,468**	**$208,591**	**$255,229**	**$233,370**	**$194,367**	**$2,704,026**	**9,072**
21	Transfer Service Delivery charge	$ 217	$ 222	$ 315	$ 346	$ 300	$ 248	$ 222	$ 233	$ 243	$ 264	$ 258	$ 233	$ 3,100	-
22	Energy Efficiency Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
23	Irrigation Pumping Power	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 1,203	15
24	Reserve Energy	$ 863	$ 863	$ 863	$ 863	$ 863	$ 863	$ 863	$ 863	$ 863	$ 863	$ 863	$ 863	$ 10,358	160
25	USBR Owyhee Wheeling Project	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 1,608	-
26	Downstream Benefits	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 7,438	-
27	Upper Baker Revenues	$ -	$ 108	$ 158	$ 130	$ 127	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 523	-
28	**Miscellaneous Revenue**	**$1,934**	**$2,048**	**$2,191**	**$2,194**	**$2,144**	**$1,965**	**$1,939**	**$1,950**	**$1,960**	**$1,981**	**$1,976**	**$1,950**	**$24,230**	**175**
29	Balancing Reserve Capacity	$ 5,068	$ 5,083	$ 5,083	$ 5,083	$ 5,083	$ 5,083	$ 5,083	$ 5,083	$ 5,083	$ 5,083	$ 5,083	$ 5,083	$ 60,979	-
30	ACS Risk Share	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
31	Risk Mitigation Tool	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
32	Imbalance Adjustment for Third-Party Deployed Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
33	Operating Reserve - Spinning	$ 1,609	$ 2,175	$ 1,991	$ 2,300	$ 2,695	$ 2,396	$ 2,341	$ 2,691	$ 2,281	$ 2,326	$ 2,223	$ 2,072	$ 27,100	-
34	Operating Reserve - Supplemental	$ 988	$ 1,335	$ 1,223	$ 1,413	$ 1,655	$ 1,471	$ 1,438	$ 1,653	$ 1,401	$ 1,428	$ 1,365	$ 1,273	$ 16,643	-
35	Operating Reserve - Spinning Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
36	Operating Reserve - Supplemental Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
37	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
38	Synchronous Condensing	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 1,292	-
39	Generation Dropping	$ 46	$ 46	$ 46	$ 46	$ 46	$ 46	$ 46	$ 46	$ 46	$ 46	$ 46	$ 46	$ 553	-
40	Redispatch	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 332	-
41	Segmentation of COE/Reclamation Network and Delivery Facilities	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 706	-
42	Station Service	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 3,307	9
43	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
44	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
45	Energy Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	Generation Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	**Generation Inputs / Inter-business line**	**$ 8,181**	**$ 9,108**	**$ 8,812**	**$ 9,311**	**$ 9,949**	**$ 9,466**	**$ 9,378**	**$ 9,943**	**$ 9,280**	**$ 9,353**	**$ 9,187**	**$ 8,944**	**$ 110,911**	**9**
48	4(h)(10)(c)	$ 13,978	$ 7,921	$ 13,533	$ 12,117	$ 9,760	$ 8,618	$ 8,566	$ 7,335	$ 6,525	$ 7,233	$ 5,974	$ 9,726	$ 111,288	-
49	Colville Settlement	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
50	**Treasury Credits**	**$ 14,361**	**$ 8,305**	**$ 13,917**	**$ 12,500**	**$ 10,143**	**$ 9,002**	**$ 8,949**	**$ 7,719**	**$ 6,908**	**$ 7,617**	**$ 6,358**	**$ 10,110**	**$ 115,888**	**-**
51	Augmentation Power Purchase sub-total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
52	Balancing Power Purchase sub-total	$ 12,177	$ 4,031	$ 18,164	$ 13,209	$ 11,592	$ 4,991	$ 3,820	$ 28	$ 28	$ 1,203	$ 4,550	$ 6,808	$ 80,601	173
53	Other Power Purchase sub-total	$ 9,323	$ 9,323	$ 9,323	$ 9,323	$ 9,323	$ 9,323	$ 9,323	$ 9,323	$ 9,323	$ 9,323	$ 9,323	$ 9,323	$ 111,871	217
54	**Power Purchases**	**$ 21,499**	**$ 13,354**	**$ 27,487**	**$ 22,531**	**$ 20,915**	**$ 14,313**	**$ 13,142**	**$ 9,351**	**$ 9,351**	**$ 10,526**	**$ 13,872**	**$ 16,131**	**$ 192,472**	**389**

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**													**2025**	
2	**Category**	**202410**	**202411**	**202412**	**202501**	**202502**	**202503**	**202504**	**202505**	**202506**	**202507**	**202508**	**202509**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 188,550	$ 188,550	$ 188,550	$ 188,550	$ 188,550	$ 188,550	$ 188,550	$ 188,550	$ 188,550	$ 188,550	$ 188,550	$ 188,550	$ 2,262,599	6,755
4	Non-Slice Revenue	$ (23,753)	$ (23,753)	$ (23,753)	$ (23,753)	$ (23,753)	$ (23,753)	$ (23,753)	$ (23,753)	$ (23,753)	$ (23,753)	$ (23,753)	$ (23,753)	$ (285,038)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	1,388
6	Load Shaping Revenue	$ 9,945	$ 1,445	$ 17,563	$ 11,920	$ 11,142	$ (2,644)	$ 2,364	$ (14,028)	$ (15,236)	$ 76	$ 3,159	$ 3,695	$ 29,399	26
7	Demand Revenue	$ 2,891	$ 3,269	$ 7,012	$ 6,542	$ 4,053	$ 4,513	$ 3,620	$ 2,093	$ 2,754	$ 7,134	$ 7,044	$ 4,239	$ 55,163	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,222)	$ (4,816)	$ (5,546)	$ (4,551)	$ (2,769)	$ (20,905)	-
9	Low Density Discount	$ (3,312)	$ (3,312)	$ (3,312)	$ (3,312)	$ (3,312)	$ (3,312)	$ (3,312)	$ (3,312)	$ (3,312)	$ (3,312)	$ (3,312)	$ (3,312)	$ (39,746)	-
10	Tier 2	$ 4,466	$ 4,328	$ 4,466	$ 4,466	$ 4,034	$ 4,460	$ 4,322	$ 4,466	$ 4,322	$ 4,466	$ 4,466	$ 4,322	$ 52,582	394
11	RSS (Non-Federal) and Other	$ 93	$ 93	$ 93	$ 93	$ 93	$ 93	$ 93	$ 93	$ 93	$ 93	$ 93	$ 93	$ 1,115	-
12	**PF customers (TRM) sub-total**	**$ 178,879**	**$ 170,619**	**$ 190,619**	**$ 184,505**	**$ 180,806**	**$ 167,906**	**$ 171,884**	**$ 150,887**	**$ 148,601**	**$ 167,707**	**$ 171,695**	**$ 171,064**	**$ 2,055,171**	**8,563**
13	**NR sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
14	**DSIs sub-total**	**$ 347**	**$ 347**	**$ 400**	**$ 357**	**$ 334**	**$ 337**	**$ 286**	**$ 242**	**$ 218**	**$ 351**	**$ 370**	**$ 331**	**$ 3,921**	**11**
15	**FPS sub-total**	**$ 732**	**$ 757**	**$ 824**	**$ 825**	**$ 777**	**$ 764**	**$ 741**	**$ 741**	**$ 755**	**$ 785**	**$ 774**	**$ 731**	**$ 9,206**	**-**
16	**Short-term market sales sub-total**	**$ 16,967**	**$ 36,645**	**$ 42,484**	**$ 62,894**	**$ 64,468**	**$ 57,196**	**$ 36,580**	**$ 44,208**	**$ 54,434**	**$ 80,988**	**$ 58,102**	**$ 20,185**	**$ 575,152**	**1,585**
17	**Long Term Contractual Obligations sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**462**
19	**Other Sales sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
20	**Gross Sales**	**$196,926**	**$208,369**	**$234,327**	**$248,581**	**$246,385**	**$226,203**	**$209,490**	**$196,077**	**$204,009**	**$249,831**	**$230,941**	**$192,310**	**$2,643,449**	**10,622**
21	Transfer Service Delivery charge	$ 217	$ 222	$ 315	$ 346	$ 300	$ 248	$ 222	$ 233	$ 243	$ 264	$ 258	$ 233	$ 3,100	-
22	Energy Efficiency Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
23	Irrigation Pumping Power	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 1,203	15
24	Reserve Energy	$ 863	$ 863	$ 863	$ 863	$ 863	$ 863	$ 863	$ 863	$ 863	$ 863	$ 863	$ 863	$ 10,358	160
25	USBR Owyhee Wheeling Project	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 1,608	-
26	Downstream Benefits	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 7,438	-
27	Upper Baker Revenues	$ -	$ 105	$ 150	$ 129	$ 127	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 510	-
28	**Miscellaneous Revenue**	**$1,934**	**$2,044**	**$2,182**	**$2,192**	**$2,143**	**$1,965**	**$1,939**	**$1,950**	**$1,960**	**$1,981**	**$1,976**	**$1,950**	**$24,217**	**175**
29	Balancing Reserve Capacity	$ 5,110	$ 5,110	$ 5,173	$ 5,173	$ 5,173	$ 5,173	$ 5,173	$ 5,173	$ 5,173	$ 5,173	$ 5,173	$ 5,579	$ 62,355	-
30	ACS Risk Share	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
31	Risk Mitigation Tool	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
32	Imbalance Adjustment for Third-Party Deployed Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
33	Operating Reserve - Spinning	$ 1,610	$ 2,220	$ 2,110	$ 2,386	$ 2,754	$ 2,427	$ 2,430	$ 2,738	$ 2,473	$ 2,308	$ 2,174	$ 2,070	$ 27,702	-
34	Operating Reserve - Supplemental	$ 989	$ 1,364	$ 1,296	$ 1,465	$ 1,692	$ 1,491	$ 1,492	$ 1,682	$ 1,519	$ 1,418	$ 1,335	$ 1,271	$ 17,012	-
35	Operating Reserve - Spinning Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
36	Operating Reserve - Supplemental Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
37	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
38	Synchronous Condensing	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 1,292	-
39	Generation Dropping	$ 46	$ 46	$ 46	$ 46	$ 46	$ 46	$ 46	$ 46	$ 46	$ 46	$ 46	$ 46	$ 553	-
40	Redispatch	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 332	-
41	Segmentation of COE/Reclamation Network and Delivery Facilities	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 706	-
42	Station Service	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 3,307	9
43	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
44	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
45	Energy Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	Generation Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	**Generation Inputs / Inter-business line**	**$ 8,225**	**$ 9,210**	**$ 9,094**	**$ 9,540**	**$ 10,135**	**$ 9,607**	**$ 9,610**	**$ 10,109**	**$ 9,681**	**$ 9,415**	**$ 9,198**	**$ 9,437**	**$ 113,260**	**9**
48	4(h)(10)(c)	$ 13,800	$ 8,089	$ 12,853	$ 11,966	$ 9,623	$ 8,608	$ 8,499	$ 8,304	$ 5,912	$ 7,513	$ 6,297	$ 9,994	$ 111,456	-
49	Colville Settlement	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
50	**Treasury Credits**	**$ 14,183**	**$ 8,472**	**$ 13,236**	**$ 12,349**	**$ 10,006**	**$ 8,991**	**$ 8,882**	**$ 8,687**	**$ 6,295**	**$ 7,896**	**$ 6,680**	**$ 10,377**	**$ 116,056**	**-**
51	Augmentation Power Purchase sub-total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
52	Balancing Power Purchase sub-total	$ 9,446	$ 3,461	$ 16,012	$ 12,187	$ 11,414	$ 4,480	$ 3,062	$ 172	$ 28	$ 1,404	$ 3,661	$ 5,474	$ 70,802	153
53	Other Power Purchase sub-total	$ 16,701	$ 16,701	$ 16,701	$ 16,701	$ 16,701	$ 16,701	$ 16,701	$ 16,701	$ 16,701	$ 16,701	$ 16,701	$ 16,701	$ 200,414	407
54	**Power Purchases**	**$ 26,147**	**$ 20,162**	**$ 32,714**	**$ 28,888**	**$ 28,115**	**$ 21,181**	**$ 19,763**	**$ 16,873**	**$ 16,730**	**$ 18,105**	**$ 20,362**	**$ 22,175**	**$ 271,215**	**560**

Table 9.2 Revenue at Proposed Rates

	A B C D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	**Table 9.2 -Revenue at Proposed Rates**													**2023**	
2	**Category**	**202210**	**202211**	**202212**	**202301**	**202302**	**202303**	**202304**	**202305**	**202306**	**202307**	**202308**	**202309**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 193,9	$ 193,9	$ 193,9	$ 193,9	$ 193,9	$ 193,9	$ 193,9	$ 193,9	$ 193,9	$ 193,9	$ 193,9	$ 193,9	$ 2,327,617	
4	Non-Slice Revenue	$ 68 (24,64	$ 68 (24,64	$ 68 (24,64	$ 68 (24,64	$ 68 (24,64	$ 68 (24,64	$ 68 (24,64	$ 68 (24,64	$ 68 (24,64	$ 68 (24,64	$ 68 (24,64	$ 68 (24,64	$ (295,754) 5,032	
5	Slice	$ 6)	$ 6)	$ 6)	$ 6)	$ 6)	$ 6)	$ 6)	$ 6)	$ 6)	$ 6)	$ 6)	$ 6)	$	-
6	Load Shaping Revenue	$ (2,61 -	$ (13,22 -	$ 16,7 -	$ 38,2 -	$ 29,9 -	$ 9,3 -	$ 11,8 -	$ (12,69 -	$ (18,67 -	$ (16,24 -	$ (11,14 -	$ (7,26 -	$ 24,16 2,684	
7	Demand Revenue	$ 6) 2,5	$ 2) 3,3	$ 35 8,6	$ 51 5,9	$ 14 4,1	$ 20 5,0	$ 14 3,1	$ 9) 2,1	$ 5) 3,0	$ 8) 6,0	$ 5) 7,6	$ 9) 4,3	$ 0,21 55,94	
8	Irrigation Rate Discount	$ 82	$ 76	$ 19	$ 25	$ 01	$ 74	$ 09	$ 41 (3,16	$ 10 (4,72	$ 48 (5,44	$ 19 (4,46	$ 41 (2,71	$ 6 (20,509)	-
9	Low Density Discount	$ (2,88 -	$ (2,48 -	$ (3,43 -	$ (3,75 -	$ (3,51 -	$ (3,04 -	$ (3,28 -	$ 1) (2,90	$ 5) (2,92	$ 1) (3,38	$ 5) (3,47	$ 7) (3,01	$ (38,109)	-
10	Tier 2	$ 1) 4,1	$ 2) 4,0	$ 7) 4,1	$ 1) 4,1	$ 9) 3,7	$ 8) 4,1	$ 4) 4,0	$ 3) 4,1	$ 9) 4,0	$ 8) 4,1	$ 9) 4,1	$ 0) 4,0	$ 48,97	-
11	RSS (Non-Federal) and Other	$ 58	$ 30	$ 58	$ 60	$ 57	$ 54	$ 26	$ 60	$ 26	$ 60	$ 60	26 $88	$ 3 1,05 173	
12	**PF customers (TRM) sub-total**	**$ 170,6 88**	**$ 161,1 88**	**$ 195,4 88**	**$ 213,9 88**	**$ 203,6 88**	**$ 184,9 88**	**$ 185,0 88**	**$ 156,9 88**	**$ 150,1 88**	**$ 154,5 88**	**$ 162,0 88**	**$ 164,7**	**$ 2,103,374**	-
13	**NR sub-total**	**$ 53**	**$ 12**	**$ 85**	**$ 95**	**$ 63**	**$ 10**	**$ 75**	**$ 46**	**$ 16**	**$ 40**	**$ 99**	**$ 82**	**$ 7,910**	-
14	**DSIs sub-total**	**$ 3 -**	**$ 3 -**	**$ 4 -**	**$ 3 -**	**$ 3 -**	**$ 3 -**	**$ 3 -**	**$ 2 -**	**$ 2 -**	**$ 3 -**	**$ 4 -**	**$ 3 -**	**$ 4,27 -**	
15	**FPS sub-total**	**$ 79 6**	**$ 79 7**	**$ 38 8**	**$ 89 8**	**$ 65 7**	**$ 67 7**	**$ 12 6**	**$ 64 6**	**$ 39 6**	**$ 83 7**	**$ 05 7**	**$ 61 6**	**$ 912 8,57**	
16	**Short-term market sales sub-total**	**$ 23 48,3**	**$ 28 79,4**	**$ 52 76,0**	**$ 41 75,4**	**$ 35 116,1**	**$ 03 73,9**	**$ 43 38,0**	**$ 53 48,1**	**$ 93 41,9**	**$ 53 75,9**	**$ 24 58,6**	**$ 29 29,0**	**$ 7 761,01**	-
17	**Long Term Contractual Obligations sub-total**	**$ 42**	**$ 44**	**$ 10**	**$ 26**	**$ 37**	**$ 25**	**$ 09**	**$ 38**	**$ 93**	**$ 25**	**$ 23**	**$ 45**	**$ 4 1,644**	-
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
19	**Other Sales sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 8,3 -**	**$ 8,33 462**	
20	**Gross Sales**	**$219,997**	**$241,662**	**$272,785**	**$290,650**	**$320,900**	**$259,904**	**$224,039**	**$206,000**	**$193,040**	**$231,601**	**$221,851**	**$203,152 37**	**$2,885,582 7**	-
21	Transfer Service Delivery charge	$ 217	$ 222	$ 315	$ 346	$ 300	$ 248	$ 222	$ 233	$ 243	$ 264	$ 258	$ 233	$ 3,10	**10,028**
22	Energy Efficiency Revenues	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 0 30	-
23	Irrigation Pumping Power	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102	$ 102	$ 0 1,22	-
24	Reserve Energy	$ 861	$ 861	$ 861	$ 861	$ 861	$ 861	$ 861	$ 861	$ 861	$ 861	$ 861	$ 861	$ 115 10,32	
25	USBR Owyhee Wheeling Project	$ 139	$ 139	$ 139	$ 139	$ 139	$ 139	$ 139	$ 139	$ 139	$ 139	$ 139	$ 139	$ 7 1,67 160	
26	Downstream Benefits	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 0 7,44	-
27	Upper Baker Revenues	$ -	$ 91	$ 112	$ 100	$ 98	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3 40	-
28	**Miscellaneous Revenue**	**$1,964**	**$2,060**	**$2,174**	**$2,193**	**$2,145**	**$1,995**	**$1,969**	**$1,979**	**$1,990**	**$2,010**	**$2,005**	**$1,979**	**$24,463 2**	-
29	Balancing Reserve Capacity	$ 4,153	$ 4,153	$ 4,153	$ 4,153	$ 4,153	$ 4,153	$ 4,153	$ 4,153	$ 4,153	$ 4,153	$ 4,153	$ 4,153	$ 49,83 **175**	
30	ACS Risk Share	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1	- -
31	Risk Mitigation Tool	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
32	Imbalance Adjustment for Third-Party Deployed Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
33	Operating Reserve - Spinning	$ 1,280	$ 1,541	$ 1,791	$ 2,042	$ 1,888	$ 1,937	$ 1,908	$ 1,944	$ 2,018	$ 2,006	$ 1,845	$ 1,673	$ 21,87 -	
34	Operating Reserve - Supplemental	$ 836	$ 1,007	$ 1,170	$ 1,333	$ 1,233	$ 1,265	$ 1,246	$ 1,270	$ 1,318	$ 1,310	$ 1,205	$ 1,093	$ 3 14,28	-
35	Operating Reserve - Spinning Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4	- -
36	Operating Reserve - Supplemental Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
37	Operating Reserve - Energy	$ 43	$ 39	$ 70	$ 51	$ 51	$ 20	$ 75	$ 67	$ 100	$ 86	$ 67	$ 57	$ 72 -	
38	Synchronous Condensing	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 8 92	-
39	Generation Dropping	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 3 36	-
40	Redispatch	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 5 37	-
41	Segmentation of COE/Reclamation Network and Delivery Facilities	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 0 9,50	-
42	Station Service	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 2 2,29	9
43	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5	-
44	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
45	Energy Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	Generation Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	**Generation Inputs / Inter-business line**	**$ 7,432**	**$ 7,861**	**$ 8,305**	**$ 8,700**	**$ 8,446**	**$ 8,495**	**$ 8,503**	**$ 8,555**	**$ 8,709**	**$ 8,676**	**$ 8,391**	**$ 8,097**	**$ 100,17 -**	
48	4(h)(10)(c)	$ 13,325	$ 6,788	$ 7,233	$ 10,254	$ 5,350	$ 8,819	$ 7,466	$ 8,095	$ 7,564	$ 7,929	$ 6,479	$ 8,692	$ **0 9** 97,99	
49	Colville Settlement	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 5 4,60	-
50	**Treasury Credits**	**$ 13,709**	**$ 7,171**	**$ 7,616**	**$ 10,637**	**$ 5,734**	**$ 9,203**	**$ 7,849**	**$ 8,478**	**$ 7,948**	**$ 8,312**	**$ 6,863**	**$ 9,075**	**$ 0 102,59**	-
51	Augmentation Power Purchase sub-total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ **5**	- -
52	Balancing Power Purchase sub-total	$ 3,959	$ 5,282	$ 10,326	$ 10,823	$ 5,554	$ 5,773	$ 3,865	$ 660	$ 3,520	$ 3,398	$ 4,484	$ 2,412	$ 60,05 -	
53	Other Power Purchase sub-total	$ 3,995	$ 3,882	$ 3,995	$ 3,995	$ 3,609	$ 3,990	$ 3,866	$ 3,995	$ 3,866	$ 3,995	$ 3,995	$ 3,856	$ 5 47,04 100	
54	**Power Purchases**	**$ 7,954**	**$ 9,164**	**$ 14,321**	**$ 14,818**	**$ 9,162**	**$ 9,763**	**$ 7,732**	**$ 4,655**	**$ 7,387**	**$ 7,394**	**$ 8,479**	**$ 6,268**	**$ 107,09 175**	

6 275

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**													**2024**	
2	**Category**	**202310**	**202311**	**202312**	**202301**	**202302**	**202303**	**202304**	**202405**	**202406**	**202407**	**202408**	**202409**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 198,003	$ 198,003	$ 198,003	$ 198,003	$ 198,003	$ 198,003	$ 198,003	$ 198,003	$ 198,003	$ 198,003	$ 198,003	$ 198,003	$ 2,376,037	5,353
4	Non-Slice Revenue	$ (27,595)	$ (27,595)	$ (27,595)	$ (27,595)	$ (27,595)	$ (27,595)	$ (27,595)	$ (27,595)	$ (27,595)	$ (27,595)	$ (27,595)	$ (27,595)	$ (331,138)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	1,405
6	Load Shaping Revenue	$ 14,151	$ 621	$ 30,024	$ 17,761	$ 13,254	$ (3,360)	$ 2,405	$ (15,513)	$ (16,312)	$ 293	$ 6,914	$ 7,692	$ 57,931	11
7	Demand Revenue	$ 2,836	$ 2,967	$ 8,174	$ 6,397	$ 4,366	$ 4,065	$ 2,652	$ 1,705	$ 2,224	$ 8,152	$ 11,424	$ 5,285	$ 60,247	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,356)	$ (5,015)	$ (5,776)	$ (4,740)	$ (2,883)	$ (21,770)	-
9	Low Density Discount	$ (3,101)	$ (2,608)	$ (3,474)	$ (3,122)	$ (2,980)	$ (2,594)	$ (2,975)	$ (2,717)	$ (2,802)	$ (3,822)	$ (4,185)	$ (3,322)	$ (37,701)	-
10	Tier 2	$ 9,566	$ 9,566	$ 9,566	$ 9,566	$ 9,566	$ 9,566	$ 9,566	$ 9,566	$ 9,566	$ 9,566	$ 9,566	$ 9,566	$ 114,787	211
11	RSS (Non-Federal) and Other	$ 80	$ 80	$ 80	$ 80	$ 80	$ 80	$ 80	$ 80	$ 80	$ 80	$ 80	$ 80	$ 964	-
12	**PF customers (TRM) sub-total**	**$ 193,941**	**$ 181,034**	**$ 214,778**	**$ 201,090**	**$ 194,694**	**$ 178,166**	**$ 182,136**	**$ 160,173**	**$ 158,149**	**$ 178,902**	**$ 189,468**	**$ 186,826**	**$ 2,219,356**	**6,980**
13	**NR sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
14	**DSIs sub-total**	**$ 353**	**$ 302**	**$ 485**	**$ 373**	**$ 371**	**$ 304**	**$ 180**	**$ 157**	**$ 130**	**$ 399**	**$ 521**	**$ 425**	**$ 4,001**	**11**
15	**FPS sub-total**	**$ 715**	**$ 742**	**$ 804**	**$ 805**	**$ 765**	**$ 747**	**$ 721**	**$ 725**	**$ 737**	**$ 767**	**$ 757**	**$ 719**	**$ 9,004**	**-**
16	**Short-term market sales sub-total**	**$ 21,998**	**$ 41,595**	**$ 47,031**	**$ 68,253**	**$ 72,787**	**$ 61,312**	**$ 41,724**	**$ 55,556**	**$ 58,959**	**$ 86,499**	**$ 59,492**	**$ 22,807**	**$ 638,012**	**1,619**
17	**Long Term Contractual Obligations sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**462**
19	**Other Sales sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
20	**Gross Sales**	**$217,007**	**$223,673**	**$263,099**	**$270,521**	**$268,616**	**$240,529**	**$224,761**	**$216,610**	**$217,975**	**$266,567**	**$250,239**	**$210,777**	**$2,870,373**	**9,072**
21	Transfer Service Delivery charge	$ 217	$ 222	$ 315	$ 346	$ 300	$ 248	$ 222	$ 233	$ 243	$ 264	$ 258	$ 233	$ 3,100	-
22	Energy Efficiency Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
23	Irrigation Pumping Power	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 1,203	15
24	Reserve Energy	$ 863	$ 863	$ 863	$ 863	$ 863	$ 863	$ 863	$ 863	$ 863	$ 863	$ 863	$ 863	$ 10,358	160
25	USBR Owyhee Wheeling Project	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 1,608	-
26	Downstream Benefits	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 7,438	-
27	Upper Baker Revenues	$ -	$ 108	$ 158	$ 130	$ 127	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 523	-
28	**Miscellaneous Revenue**	**$1,934**	**$2,048**	**$2,191**	**$2,194**	**$2,144**	**$1,965**	**$1,939**	**$1,950**	**$1,960**	**$1,981**	**$1,976**	**$1,950**	**$24,230**	**175**
29	Balancing Reserve Capacity	$ 5,068	$ 5,083	$ 5,083	$ 5,083	$ 5,083	$ 5,083	$ 5,083	$ 5,083	$ 5,083	$ 5,083	$ 5,083	$ 5,083	$ 60,979	-
30	ACS Risk Share	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
31	Risk Mitigation Tool	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
32	Imbalance Adjustment for Third-Party Deployed Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
33	Operating Reserve - Spinning	$ 1,609	$ 2,175	$ 1,991	$ 2,300	$ 2,695	$ 2,396	$ 2,341	$ 2,691	$ 2,281	$ 2,326	$ 2,223	$ 2,072	$ 27,100	-
34	Operating Reserve - Supplemental	$ 988	$ 1,335	$ 1,223	$ 1,413	$ 1,655	$ 1,471	$ 1,438	$ 1,653	$ 1,401	$ 1,428	$ 1,365	$ 1,273	$ 16,643	-
35	Operating Reserve - Spinning Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
36	Operating Reserve - Supplemental Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
37	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
38	Synchronous Condensing	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 1,292	-
39	Generation Dropping	$ 46	$ 46	$ 46	$ 46	$ 46	$ 46	$ 46	$ 46	$ 46	$ 46	$ 46	$ 46	$ 553	-
40	Redispatch	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 332	-
41	Segmentation of COE/Reclamation Network and Delivery Facilities	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 706	-
42	Station Service	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 3,307	9
43	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
44	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
45	Energy Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	Generation Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	**Generation Inputs / Inter-business line**	**$ 8,181**	**$ 9,108**	**$ 8,812**	**$ 9,311**	**$ 9,949**	**$ 9,466**	**$ 9,378**	**$ 9,943**	**$ 9,280**	**$ 9,353**	**$ 9,187**	**$ 8,944**	**$ 110,911**	**9**
48	4(h)(10)(c)	$ 13,978	$ 7,921	$ 13,533	$ 12,117	$ 9,760	$ 8,618	$ 8,566	$ 7,335	$ 6,525	$ 7,233	$ 5,974	$ 9,726	$ 111,288	-
49	Colville Settlement	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
50	**Treasury Credits**	**$ 14,361**	**$ 8,305**	**$ 13,917**	**$ 12,500**	**$ 10,143**	**$ 9,002**	**$ 8,949**	**$ 7,719**	**$ 6,908**	**$ 7,617**	**$ 6,358**	**$ 10,110**	**$ 115,888**	**-**
51	Augmentation Power Purchase sub-total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
52	Balancing Power Purchase sub-total	$ 12,177	$ 4,031	$ 18,164	$ 13,209	$ 11,592	$ 4,991	$ 3,820	$ 28	$ 28	$ 1,203	$ 4,550	$ 6,808	$ 80,601	173
53	Other Power Purchase sub-total	$ 9,323	$ 9,323	$ 9,323	$ 9,323	$ 9,323	$ 9,323	$ 9,323	$ 9,323	$ 9,323	$ 9,323	$ 9,323	$ 9,323	$ 111,871	217
54	**Power Purchases**	**$ 21,499**	**$ 13,354**	**$ 27,487**	**$ 22,531**	**$ 20,915**	**$ 14,313**	**$ 13,142**	**$ 9,351**	**$ 9,351**	**$ 10,526**	**$ 13,872**	**$ 16,131**	**$ 192,472**	**389**

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**													**2025**	
2	**Category**	**202410**	**202411**	**202412**	**202501**	**202502**	**202503**	**202504**	**202505**	**202506**	**202507**	**202508**	**202509**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 198,811	$ 198,811	$ 198,811	$ 198,811	$ 198,811	$ 198,811	$ 198,811	$ 198,811	$ 198,811	$ 198,811	$ 198,811	$ 198,811	$ 2,385,737	6,755
4	Non-Slice Revenue	$ (27,737)	$ (27,737)	$ (27,737)	$ (27,737)	$ (27,737)	$ (27,737)	$ (27,737)	$ (27,737)	$ (27,737)	$ (27,737)	$ (27,737)	$ (27,737)	$ (332,843)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	1,388
6	Load Shaping Revenue	$ 14,713	$ 570	$ 29,975	$ 17,939	$ 16,820	$ (3,227)	$ 2,630	$ (15,442)	$ (16,207)	$ 891	$ 6,926	$ 8,389	$ 63,975	26
7	Demand Revenue	$ 3,956	$ 3,068	$ 8,264	$ 6,524	$ 4,169	$ 4,111	$ 2,835	$ 1,794	$ 2,250	$ 9,065	$ 10,424	$ 6,175	$ 62,636	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,356)	$ (5,015)	$ (5,776)	$ (4,740)	$ (2,883)	$ (21,770)	-
9	Low Density Discount	$ (3,196)	$ (2,647)	$ (3,512)	$ (3,183)	$ (3,106)	$ (2,641)	$ (3,038)	$ (2,765)	$ (2,851)	$ (3,953)	$ (4,238)	$ (3,404)	$ (38,532)	-
10	Tier 2	$ 17,149	$ 17,149	$ 17,149	$ 17,149	$ 17,149	$ 17,149	$ 17,149	$ 17,149	$ 17,149	$ 17,149	$ 17,149	$ 17,149	$ 205,792	394
11	RSS (Non-Federal) and Other	$ 79	$ 79	$ 79	$ 79	$ 79	$ 79	$ 79	$ 79	$ 79	$ 79	$ 79	$ 79	$ 944	-
12	**PF customers (TRM) sub-total**	**$ 203,776**	**$ 189,294**	**$ 223,029**	**$ 209,583**	**$ 206,186**	**$ 186,546**	**$ 190,729**	**$ 168,534**	**$ 166,479**	**$ 188,530**	**$ 196,674**	**$ 196,579**	**$ 2,325,939**	**8,563**
13	**NR sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
14	**DSIs sub-total**	**$ 353**	**$ 302**	**$ 485**	**$ 373**	**$ 358**	**$ 304**	**$ 180**	**$ 157**	**$ 130**	**$ 399**	**$ 521**	**$ 425**	**$ 3,988**	**11**
15	**FPS sub-total**	**$ 732**	**$ 757**	**$ 824**	**$ 825**	**$ 777**	**$ 764**	**$ 741**	**$ 741**	**$ 755**	**$ 785**	**$ 774**	**$ 731**	**$ 9,206**	**-**
16	**Short-term market sales sub-total**	**$ 16,967**	**$ 36,645**	**$ 42,484**	**$ 62,894**	**$ 64,468**	**$ 57,196**	**$ 36,580**	**$ 44,208**	**$ 54,434**	**$ 80,988**	**$ 58,102**	**$ 20,185**	**$ 575,152**	**1,585**
17	**Long Term Contractual Obligations sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**462**
19	**Other Sales sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
20	**Gross Sales**	**$221,829**	**$226,998**	**$266,823**	**$273,676**	**$271,790**	**$244,810**	**$228,230**	**$213,640**	**$221,798**	**$270,702**	**$256,072**	**$217,919**	**$2,914,285**	**10,622**
21	Transfer Service Delivery charge	$ 217	$ 222	$ 315	$ 346	$ 300	$ 248	$ 222	$ 233	$ 243	$ 264	$ 258	$ 233	$ 3,100	-
22	Energy Efficiency Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
23	Irrigation Pumping Power	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 100	$ 1,203	15
24	Reserve Energy	$ 863	$ 863	$ 863	$ 863	$ 863	$ 863	$ 863	$ 863	$ 863	$ 863	$ 863	$ 863	$ 10,358	160
25	USBR Owyhee Wheeling Project	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 1,608	-
26	Downstream Benefits	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 620	$ 7,438	-
27	Upper Baker Revenues	$ -	$ 105	$ 150	$ 129	$ 127	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 510	-
28	**Miscellaneous Revenue**	**$1,934**	**$2,044**	**$2,182**	**$2,192**	**$2,143**	**$1,965**	**$1,939**	**$1,950**	**$1,960**	**$1,981**	**$1,976**	**$1,950**	**$24,217**	**175**
29	Balancing Reserve Capacity	$ 5,110	$ 5,110	$ 5,173	$ 5,173	$ 5,173	$ 5,173	$ 5,173	$ 5,173	$ 5,173	$ 5,173	$ 5,173	$ 5,579	$ 62,355	-
30	ACS Risk Share	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
31	Risk Mitigation Tool	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
32	Imbalance Adjustment for Third-Party Deployed Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
33	Operating Reserve - Spinning	$ 1,610	$ 2,220	$ 2,110	$ 2,386	$ 2,754	$ 2,427	$ 2,430	$ 2,738	$ 2,473	$ 2,308	$ 2,174	$ 2,070	$ 27,702	-
34	Operating Reserve - Supplemental	$ 989	$ 1,364	$ 1,296	$ 1,465	$ 1,692	$ 1,491	$ 1,492	$ 1,682	$ 1,519	$ 1,418	$ 1,335	$ 1,271	$ 17,012	-
35	Operating Reserve - Spinning Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
36	Operating Reserve - Supplemental Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
37	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
38	Synchronous Condensing	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 108	$ 1,292	-
39	Generation Dropping	$ 46	$ 46	$ 46	$ 46	$ 46	$ 46	$ 46	$ 46	$ 46	$ 46	$ 46	$ 46	$ 553	-
40	Redispatch	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 332	-
41	Segmentation of COE/Reclamation Network and Delivery Facilities	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 59	$ 706	-
42	Station Service	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 276	$ 3,307	9
43	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
44	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
45	Energy Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	Generation Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	**Generation Inputs / Inter-business line**	**$ 8,225**	**$ 9,210**	**$ 9,094**	**$ 9,540**	**$ 10,135**	**$ 9,607**	**$ 9,610**	**$ 10,109**	**$ 9,681**	**$ 9,415**	**$ 9,198**	**$ 9,437**	**$ 113,260**	**9**
48	4(h)(10)(c)	$ 13,800	$ 8,089	$ 12,853	$ 11,966	$ 9,623	$ 8,608	$ 8,499	$ 8,304	$ 5,912	$ 7,513	$ 6,297	$ 9,994	$ 111,456	-
49	Colville Settlement	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
50	**Treasury Credits**	**$ 14,183**	**$ 8,472**	**$ 13,236**	**$ 12,349**	**$ 10,006**	**$ 8,991**	**$ 8,882**	**$ 8,687**	**$ 6,295**	**$ 7,896**	**$ 6,680**	**$ 10,377**	**$ 116,056**	**-**
51	Augmentation Power Purchase sub-total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
52	Balancing Power Purchase sub-total	$ 9,446	$ 3,461	$ 16,012	$ 12,187	$ 11,414	$ 4,480	$ 3,062	$ 172	$ 28	$ 1,404	$ 3,661	$ 5,474	$ 70,802	153
53	Other Power Purchase sub-total	$ 16,701	$ 16,701	$ 16,701	$ 16,701	$ 16,701	$ 16,701	$ 16,701	$ 16,701	$ 16,701	$ 16,701	$ 16,701	$ 16,701	$ 200,414	407
54	**Power Purchases**	**$ 26,147**	**$ 20,162**	**$ 32,714**	**$ 28,888**	**$ 28,115**	**$ 21,181**	**$ 19,763**	**$ 16,873**	**$ 16,730**	**$ 18,105**	**$ 20,362**	**$ 22,175**	**$ 271,215**	**560**

Table 9.3.1.1
Inter-Business Line Allocations
Annual Average for FY 2024-2025

	A	B	C	
	Generation Inputs	Reserve Quantity Forecast (MW)	Revenue Forecast ($)	
1	Reserve Forecast			
2	Balancing Reserves	740	$	61,667,056
3	Operating Reserves		$	44,228,769
4	Operating Reserves - Spinning	237	$	27,401,371
5	Operating Reserves - Supplemental	237	$	16,827,398
6	Reserves Total (lines 2+3)		$	105,895,824
7				
8	Other Forecasts			
9	Synchronous Condensing		$	1,291,757
10	Generation Dropping		$	552,686
11	Redispatch		$	332,147
12	Segmentation of COE/BOR		$	706,000
13	Station Service		$	3,306,944
14	Other Total (lines 9-13)		$	6,189,534
15				
16	Total Generation Inputs Credit Forecast (lines 6+14)		$	112,085,359

Table 9.3.1.2
VER Facilities in FY 2024-2025
Balancing Reserve Capacity Quantity Forecast

	A	B	C	D	E
	Project Name	**Nameplate Capacity (MW)**	**VER Type**	**County, State**	**Start Month and Year**
1	Vansycle	25	WIND	Umatilla, OR	Oct-98
2	Stateline	90	WIND	Walla Walla, WA	Dec-01
3	Condon	50	WIND	Gilliam, OR	Jun-02
4	Blue Sky/Hopkins Ridge	157	WIND	Columbia, WA	Nov-05
5	White Creek	204	WIND	Klickitat, WA	Oct-07
6	Nine Canyon 1-3	50	WIND	Benton, WA	May-08
7	Arlington Wind	103	WIND	Gilliam, OR	Dec-08
8	Willow Creek	72	WIND	Morrow, OR	Jan-09
9	Wheatfield Wind	97	WIND	Gilliam, OR	Mar-09
10	Windy Flats Dooley	262	WIND	Klickitat, WA	Nov-09
11	Harvest-White Creek III	100	WIND	Klickitat, WA	Dec-09
12	Combine Hills	63	WIND	Umatilla, OR	Jan-10
13	Linden Ranch	50	WIND	Klickitat, WA	Jun-10
14	Coastal Energy Wind	6	WIND	Grays Harbor, WA	Jun-10
15	Kittitas Valley	101	WIND	Kittitas, WA	Nov-10
16	Patu (Oregon Trail Wind)	10	WIND	Sherman, OR	Nov-10
17	North Hurlburt	266	WIND	Gilliam, OR	Aug-11
18	Lower Snake Wind 1	343	WIND	Garfield, WA	Jan-12
19	South Hurlburt	290	WIND	Gilliam, OR	Jun-12
20	HorseShoe Bend	291	WIND	Morrow, OR	Aug-12
21	Outback Solar	5	SOLAR	Lake, OR	Sep-12
22	Starvation Solar	10	SOLAR	Harney, OR	Jan-20
23	West Hines Solar	10	SOLAR	Harney, OR	Jul-20
24	Alkali Solar	10	SOLAR	Lake, OR	Jul-20
25	Fort Rock II Solar	10	SOLAR	Lake, OR	Aug-20
26	Fort Rock Solar	10	SOLAR	Lake, OR	Aug-20
27	Riley Solar	10	SOLAR	Harney, OR	Aug-20
28	Suntex Solar	10	SOLAR	Harney, OR	Aug-20
29	Rock Garden Solar	10	SOLAR	Lake, OR	Aug-20
30	Wheatridge Wind 2	200	WIND	Morrow, OR	Oct-20
31	Horn Rapids Solar	4.2	SOLAR	Benton, WA	Feb-21
32	Wheatridge Solar	50	SOLAR	Morrow, OR	Feb-22
33	Four Mile	250	WIND	Benton, WA	Oct-23
34	Goose Praire Solar	80	SOLAR	Yakima, WA	Oct-23
35	Tygh Valley Solar	20	SOLAR	Wasco, OR	Nov-23
36	Ponderosa Solar 1	200	SOLAR	Deschutes, OR	Dec-24
37	Lower Snake Wind 3	142	WIND	Garfield, WA	Sep-25
38	Lower Snake Wind 4	250	WIND	Columbia, OR	Sep-25

Table 9.3.1.3
Total Balancing Reserve Capacity Requirment (Values in MW)
for FY2024-2025 Balancing Reserve Capacity Quantity Forecast

	A	B	C	D	E	F	G	H	I	J	K	L	M
		Intalled Capacity				**Balancing Reserve by Type**				**Balancing Reserve Total (Federal vs. Non-Federal)**			
						Regulation		**Non-regulation**		**Total Federal**		**Total Non-Federal**	
	Date	**Wind**	**Solar**	**Non-federal Thermal**	**FCRPS**	**INC**	**DEC**	**INC**	**DEC**	**INC**	**DEC**	**INC**	**DEC**
1	Oct '23	3080	139	1537	3739	318	-339	414	-538	22	-23	711	-854
2	Nov '23	3080	239	1537	3739	319	-340	416	-538	22	-23	713	-855
3	Dec '23	3080	239	1537	3739	319	-340	416	-538	22	-23	713	-855
4	Jan '24	3080	239	1537	3739	319	-340	416	-538	22	-23	713	-855
5	Feb '24	3080	239	1537	3739	319	-340	416	-538	22	-23	713	-855
6	Mar '24	3080	239	1537	3739	319	-340	416	-538	22	-23	713	-855
7	Apr '24	3080	239	1537	3739	319	-340	416	-538	22	-23	713	-855
8	May '24	3080	239	1537	3739	319	-340	416	-538	22	-23	713	-855
9	Jun '24	3080	239	1537	3739	319	-340	416	-538	22	-23	713	-855
10	Jul '24	3080	239	1537	3739	319	-340	416	-538	22	-23	713	-855
11	Aug '24	3080	239	1537	3739	319	-340	416	-538	22	-23	713	-855
12	Sep '24	3080	239	1537	3739	319	-340	416	-538	22	-23	713	-855
13	Oct '24	3080	239	1537	3739	322	-342	414	-539	22	-23	715	-857
14	Nov '24	3080	239	1537	3739	322	-342	414	-539	22	-23	715	-857
15	Dec '24	3080	439	1537	3739	326	-345	417	-541	22	-23	721	-863
16	Jan '25	3080	439	1537	3739	326	-345	417	-541	22	-23	721	-863
17	Feb '25	3080	439	1537	3739	326	-345	417	-541	22	-23	721	-863
18	Mar '25	3080	439	1537	3739	326	-345	417	-541	22	-23	721	-863
19	Apr '25	3080	439	1537	3739	326	-345	417	-541	22	-23	721	-863
20	May '25	3080	439	1537	3739	326	-345	417	-541	22	-23	721	-863
21	Jun '25	3080	439	1537	3739	326	-345	417	-541	22	-23	721	-863
22	Jul '25	3080	439	1537	3739	326	-345	417	-541	22	-23	721	-863
23	Aug '25	3080	439	1537	3739	326	-345	417	-541	22	-23	721	-863
24	Sep '25	3472	439	1537	3739	342	-384	457	-573	22	-23	778	-934
25	**BP-24 AVG**	**3096**	**318**	**1537**	**3739**	**323**	**-344**	**418**	**-541**	**22**	**-23**	**719**	**-861**

Table 9.3.1.4
Balancing Area Net Load and Generation (MWs)

	A	B	C	D	E	F	G
	BPA Balancing Area Net Load						
	Month	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
1	OCT	6,062	5,589	5,749	5,649	5,773	5,895
2	NOV	6,635	6,336	6,307	6,333	6,504	6,614
3	DEC	7,028	6,881	7,543	7,743	7,118	7,656
4	JAN	7,061	6,771	7,145	6,945	6,997	7,250
5	FEB	6,964	7,203	6,627	6,640	7,434	7,355
6	MAR	6,644	6,992	6,479	6,179	7,233	7,177
7	APR	6,048	5,987	5,970	6,355	6,405	6,637
8	MAY	5,852	5,949	5,815	6,315	6,159	6,587
9	JUN	5,972	6,714	6,141	6,041	6,945	6,306
10	JUL	6,276	6,479	6,243	6,366	6,748	6,632
11	AUG	6,087	6,122	6,043	5,943	6,213	6,516
12	SEP	5,381	5,639	5,560	5,360	5,833	5,807
13	**AVG**	**6,334**	**6,388**	**6,330**	**6,322**	**6,614**	**6,703**
14	**BPA Balancing Area Net Generation**						
15	**Month**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
16	OCT	7,803	8,718	7,848	8,048	8,651	9,129
17	NOV	9,590	10,476	10,014	10,032	10,395	10,910
18	DEC	9,652	10,936	12,288	12,456	12,836	13,128
19	JAN	11,313	12,432	13,444	13,144	13,724	13,915
20	FEB	12,980	12,333	12,684	13,004	13,229	14,000
21	MAR	10,076	10,221	13,279	13,329	13,714	13,900
22	APR	9,042	8,966	13,035	13,015	13,064	13,886
23	MAY	12,824	9,986	12,867	13,067	12,885	13,938
24	JUN	13,550	10,503	13,547	13,947	13,398	14,047
25	JUL	12,595	10,475	12,882	13,882	13,370	13,662
26	AUG	10,935	10,015	11,886	11,486	10,929	11,897
27	SEP	8,991	8,126	11,050	10,450	10,742	10,831
28	**AVG**	**10,779**	**10,265**	**12,069**	**12,155**	**12,245**	**12,770**

Table 9.3.1.5
Forecast Operating Reserve Obligation (MW)

	A	B	C	D
	Total Balancing Area Obligation			
		2024	**2025**	**AVG**
1	OCT	422.5	422.7	422.6
2	NOV	563.7	573.2	568.5
3	DEC	532.4	557.0	544.7
4	JAN	602.2	620.1	611.2
5	FEB	683.8	696.2	690.0
6	MAR	607.9	614.4	611.1
7	APR	572.4	590.7	581.6
8	MAY	643.8	653.5	648.7
9	JUN	557.0	596.9	576.9
10	JUL	571.4	567.8	569.6
11	AUG	548.8	538.6	543.7
12	SEP	516.6	516.1	516.4
13	**AVG**	**568.5**	**578.9**	**573.7**
14	**Self- and Third Party Supply**			
15		**2024**	**2025**	**AVG**
16	OCT	88.6	88.6	88.6
17	NOV	112.6	112.6	112.6
18	DEC	119.4	119.4	119.4
19	JAN	125.0	125.0	125.0
20	FEB	124.7	124.7	124.7
21	MAR	110.8	110.8	110.8
22	APR	86.7	86.7	86.7
23	MAY	85.4	85.4	85.4
24	JUN	83.8	83.8	83.8
25	JUL	88.9	88.9	88.9
26	AUG	87.6	87.6	87.6
27	SEP	86.6	86.6	86.6
28	**AVG**	**100.0**	**100.0**	**100.0**
29	**BPA Obligation**			
30		**2024**	**2025**	**AVG**
31	OCT	333.9	334.1	334.0
32	NOV	451.1	460.7	455.9
33	DEC	413.0	437.7	425.4
34	JAN	477.2	495.1	486.2
35	FEB	559.1	571.5	565.3
36	MAR	497.1	503.6	500.4
37	APR	485.7	504.1	494.9
38	MAY	558.4	568.1	563.3
39	JUN	473.2	513.1	493.2
40	JUL	482.5	478.9	480.7
41	AUG	461.2	451.0	456.1
42	SEP	430.0	429.5	429.7
43	**AVG**	**468.5**	**478.9**	**473.7**

Table 9.3.1.6
FCRPS 1-Hour Peaking Capacity for FY 2024 and FY 2025 Adjusted for Transmission Losses
Monthly P10 Water Conditions

	A	B	C	D	E	F	G	H	I	J	K	L	M	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 2024 Federal Resources**															
2	Regulated Hydro	**11,778**	9,599	11,612	12,823	12,053	12,241	12,704	11,279	10,647	12,530	12,307	13,093	10,428	10,552	10,901
3	Independent Hydro	**481**	472	531	498	450	309	338	381	627	535	540	615	455	601	441
4	Small Hydro	**4**	4	4	5	5	5	5	5	5	5	4	3	3	3	3
5	Large Thermal (Columbia Generation Station)	**1,171**	1,181	1,179	1,180	1,178	1,175	1,177	1,166	1,166	1,151	1,154	1,168	1,163	1,163	1,179
6	Renewable Resources	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Augmentation Purchases	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Augmentation Purchases (to serve Tier 2 Load)	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	**FY 2025 Federal Resources**	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Regulated Hydro	**11,591**	9,157	11,370	12,863	12,175	12,297	12,684	11,487	10,775	11,171	14,023	10,893	10,658	10,434	10,885
11	Independent Hydro	**502**	472	586	498	450	309	338	373	627	769	562	551	455	601	441
12	Small Hydro	**4**	4	4	5	5	5	5	5	5	5	4	3	3	3	3
13	Large Thermal (Columbia Generation Station)	**1,171**	1,181	1,179	1,180	1,178	1,175	1,177	1,166	1,166	1,151	1,154	1,168	1,163	1,163	1,179
14	Renewable Resources	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Augmentation Purchases	**147**	147	147	147	147	147	147	147	147	147	147	147	147	147	147
16	Augmentation Purchases (to serve Tier 2 Load)	**-**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	**Rate Period Average After Losses**	**-**														
18	Regulated Hydro	**11,314**														
19	Independent Hydro	**476**														
20	Small Hydro	**4**														
21	Large Thermal (Columbia Generation Station)	**1,134**														
22	Renewable Resources	**-**														
23	Augmentation Purchases	**71**														
24	Augmentation Purchases (to serve Tier 2 Load)	**-**														
25	1-Hour Capacity Adjusted for Transmission Losses	**12,998**														

	Oct	Nov	Dec	Jan	Feb	Mar	1-Apr	16-Apr	May	Jun	Jul	1-Aug	16-Aug	Sep
2024	31	30	31	31	29	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
2025	31	30	31	31	28	31	15	15	31	30	31	15	16	30

Table 9.3.1.7
Capacity Costs ($ in thousands)

	A	B FY 2024	C FY 2025	Capacity Classification (%)	D Annual Average for FY 2024-FY 2025 Classified to Capacity
1	**Capital Related Costs**				
2	Depreciation	$ 139,703	$ 143,600	100%	$ 141,652
3	Amortization	$ 290,232	$ 299,644	100%	$ 294,938
4	Interest Expense	$ 218,133	$ 190,558	100%	$ 204,346
5	Minimum Required Net Revenues	$ 155,158	$ 155,327	100%	$ 155,242
6	Decomissioning Costs	$ 26,580	$ 27,374	100%	$ 26,977.03
7	**Subtotal**	**$ 829,806**	**$ 816,504**		**$ 823,155**
8					
9	**Fish & Wildlife Costs**				
10	Fish & Wildlife (Other than Planning Council)	$ 302,000	$ 301,630	100%	$ 301,815
11	Fish & Wildlife - Planning Council	$ 11,942	$ 11,942	50%	$ 5,971
12	**Subtotal**	**$ 302,000**	**$ 301,630**		**$ 307,786**
13					
14	**Power Purchase Costs**				
15	Clearwater Hatchery Generation	$ 1,368	$ 1,410	60%	$ 840
16	Non-Tier 2 Augmentation Power Purchases	$ -	$ -	50%	$ -
17	Tier 2 Augmentation Power Purchases	$ -	$ 8,360	50%	$ 2,090
18	**Subtotal**	**$ 1,368**	**$ 9,770**		**$ 2,930**
19					
20	**Cost Adjustments**				
21	4h10C	$ (113,184)	$ (111,627)	62%	$ (69,854.24)
22	Synchronous Condensing	$ (1,292)	$ (1,292)	17%	$ (217)
23	**Subtotal**	**$ (114,475)**	**$(112,919)**		**$ (70,071)**
24	**Total Allocated Costs**				**$ 1,063,800**

Table 9.3.1.8
Embedded Cost Calculation
($ in Thousands)

	A	B
		Annual Average FY 2024 - FY 2025
1	**Assumptions for Calculation:**	
2	1Hr Capacity adjusted for Transmission Losses (MW)	12,998
3	Regulation Reserve (MW)	323
4	Non-regulation Reserve (MW)	418
5	Operating Reserve (MW)	474
6		
7	**Forecast of Total Capacity of Federal System Resources:**	
8	1Hr Capacity adjusted for Transmission Losses (Line 2)	12,998
9	Total PS Reserve Obligation (Line 3+4+5)	1,214
10	Total Capacity of Federal System Resources (Line 9+10)	14,212
11		
12	**Revenue Requirement:**	
13	Capacity Costs	$ 1,063,800
14	Hydro Projects Capacity System Uses (Line 10)	14,212
15	Total kW/month/year Hydro Project Capacity System Uses (Line 14 * 12 months * 1000 kW/MW)	170,546,624.59
16	**Unit Cost Allocation of Capacity System Uses $/kW/month (Line 13 / Line 15)**	$ 6.24

Table 9.3.1.9
Heavy Load Hour (HLH) Market Prices for FY 2024 by Month and Water Year
($/MWh)

	A	B	C	D	E	F	G	H	I	J	K	L	M
	Water Year	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24
1	1989	51.90	41.59	65.10	56.96	69.63	41.57	17.41	18.14	27.94	71.97	76.69	57.96
2	1990	48.31	38.52	58.45	44.70	42.74	39.75	18.71	20.10	12.39	50.60	62.37	58.47
3	1991	53.45	28.99	57.22	43.96	41.20	35.10	20.92	19.00	15.75	42.86	59.01	57.77
4	1992	52.20	46.54	82.39	61.09	55.48	49.84	34.65	25.42	39.99	85.30	77.22	61.29
5	1993	58.68	46.50	76.93	66.87	74.39	44.96	32.32	15.75	24.66	59.93	66.97	51.88
6	1994	47.48	44.49	72.49	64.98	63.12	46.89	28.19	23.22	35.85	76.54	82.11	56.98
7	1995	57.38	48.60	73.95	59.42	51.03	33.10	35.46	22.46	13.31	53.51	68.59	56.01
8	1996	35.38	25.12	34.37	30.67	24.80	11.65	11.10	11.50	9.80	39.17	60.69	56.25
9	1997	41.98	38.94	52.67	25.20	25.45	15.86	7.08	-1.71	-2.57	30.74	50.89	43.43
10	1998	21.53	34.34	63.24	50.99	44.62	37.25	25.81	6.57	9.75	49.98	66.88	54.34
11	1999	49.59	47.15	58.15	35.42	41.97	15.41	14.50	14.09	6.68	30.19	48.93	55.34
12	2000	44.87	30.06	50.95	45.71	46.58	33.01	12.88	14.41	23.61	58.43	70.75	59.04
13	2001	46.55	47.22	82.13	65.29	59.94	49.61	37.59	33.88	38.16	76.85	77.97	59.41
14	2002	58.55	53.26	68.12	59.15	58.70	43.57	19.04	18.55	10.38	44.77	71.65	55.77
15	2003	51.44	46.06	74.01	60.66	56.89	36.90	24.70	22.41	16.49	72.69	84.30	59.39
16	2004	51.28	42.83	67.74	62.95	64.24	44.77	26.50	23.02	23.18	66.20	75.84	53.41
17	2005	40.43	41.67	61.54	50.32	46.37	44.14	36.81	27.54	28.20	62.47	79.83	57.92
18	2006	55.09	39.66	63.29	39.97	36.97	36.74	14.71	7.27	11.53	55.34	72.29	53.71
19	2007	57.30	40.91	61.82	44.64	50.97	26.04	18.89	19.79	24.33	62.30	79.14	56.31
20	2008	51.40	43.60	69.77	55.02	56.39	43.67	34.72	14.18	4.81	45.04	65.69	56.02
21	2009	55.22	43.62	75.77	51.79	56.01	48.91	18.66	18.58	20.10	69.41	80.06	54.49
22	2010	51.42	46.81	67.95	62.68	63.97	51.60	33.84	33.17	10.23	54.15	73.12	55.70
23	2011	50.61	46.18	59.68	39.72	36.83	28.96	11.78	8.33	-1.94	16.31	51.44	51.77
24	2012	41.55	42.77	67.71	52.04	46.83	30.38	6.89	9.31	5.59	34.17	60.31	60.49
25	2013	43.06	30.28	48.43	49.60	49.19	42.24	14.54	13.69	14.93	47.89	67.31	50.17
26	2014	43.41	44.06	76.20	53.51	72.50	28.86	14.40	12.89	15.53	51.15	67.07	56.45
27	2015	44.60	31.96	50.46	40.71	36.11	23.89	22.44	30.37	34.95	82.58	77.62	56.01
28	2016	57.80	48.41	61.57	53.08	59.44	29.22	12.24	16.88	28.24	69.28	73.74	55.32
29	2017	45.21	29.31	62.40	44.07	41.94	5.88	3.52	1.43	4.69	51.51	56.94	55.44
30	2018	47.14	47.12	58.81	39.33	37.48	29.89	14.44	4.71	14.27	58.65	71.02	59.17

HLH is the period of clock hours 8:00-23:00 each day.

Table 9.3.1.10
Heavy Load Hour (HLH) Market Prices for FY 2025 by Month and Water Year
($/MWh)

	A	B	C	D	E	F	G	H	I	J	K	L	M
	Water Year	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25
1	1989	34.99	31.86	55.79	48.86	59.25	46.67	17.91	14.90	19.99	49.43	54.25	43.57
2	1990	33.27	28.23	46.08	30.51	30.49	43.38	20.12	17.75	3.67	36.74	46.08	44.16
3	1991	36.51	15.96	43.33	25.83	24.81	36.98	22.90	15.33	6.37	20.01	42.37	42.54
4	1992	36.85	35.22	71.50	52.10	53.53	52.96	39.08	23.77	30.51	57.14	54.71	48.17
5	1993	37.82	36.16	65.02	57.81	61.29	49.02	35.65	10.77	15.36	42.75	47.31	39.29
6	1994	32.69	34.70	62.35	55.98	58.09	50.39	32.07	22.31	27.28	51.42	53.37	43.01
7	1995	40.53	37.63	63.35	50.53	49.00	35.22	33.51	19.98	3.74	39.51	50.89	43.37
8	1996	27.43	10.94	13.70	10.56	7.51	5.93	9.87	6.78	1.69	14.34	42.79	41.98
9	1997	30.45	29.77	40.41	7.97	9.22	9.81	5.83	-3.23	-8.18	10.26	34.64	33.31
10	1998	15.46	23.43	51.28	36.56	36.33	41.37	29.70	2.57	1.96	35.69	48.57	42.01
11	1999	34.09	36.76	46.99	15.72	26.23	9.07	14.57	9.52	0.05	9.49	31.65	39.98
12	2000	31.49	18.89	36.21	28.13	38.97	36.38	12.18	10.87	15.84	42.46	50.88	44.91
13	2001	32.50	36.76	68.00	56.35	56.11	51.19	39.82	33.59	31.13	50.71	52.82	44.29
14	2002	39.44	40.81	58.20	49.85	55.53	47.49	20.82	16.47	2.44	26.68	50.47	43.49
15	2003	34.87	35.70	63.82	52.57	54.48	42.07	27.51	21.84	8.05	51.24	56.28	45.50
16	2004	36.41	32.84	57.28	52.74	59.37	48.63	30.03	22.21	15.14	47.01	51.80	41.38
17	2005	29.74	32.48	47.59	38.71	42.07	47.99	38.35	27.41	20.97	45.36	54.35	45.48
18	2006	36.57	30.23	53.90	22.44	21.62	39.44	14.11	3.67	3.38	39.46	50.74	41.47
19	2007	38.18	31.44	51.83	30.15	48.64	22.08	21.65	16.53	15.74	45.69	53.69	43.56
20	2008	34.66	33.49	59.70	45.26	53.82	48.51	37.46	10.95	-1.66	28.76	46.97	42.99
21	2009	39.33	33.91	64.85	39.99	53.14	51.10	19.75	15.01	11.26	48.54	52.96	41.50
22	2010	35.43	36.60	59.15	53.48	59.53	53.57	38.78	32.73	2.71	39.74	52.81	43.12
23	2011	34.36	35.78	47.68	21.17	19.91	27.20	9.93	4.76	-7.28	1.54	33.67	38.25
24	2012	29.13	33.22	57.20	38.24	41.72	30.34	4.91	5.42	-0.39	10.27	42.19	45.44
25	2013	30.68	22.42	34.30	37.69	46.63	45.30	14.72	10.20	6.38	33.98	46.74	38.60
26	2014	31.13	34.63	65.95	39.03	60.00	26.73	13.96	8.83	6.40	33.32	49.26	43.98
27	2015	30.79	23.61	36.56	24.77	20.90	18.51	25.91	30.03	28.35	53.53	51.88	42.52
28	2016	38.84	37.28	53.29	41.88	55.70	25.88	11.30	12.99	20.44	47.91	50.41	42.03
29	2017	32.57	19.25	51.95	29.59	33.39	1.98	2.44	-0.90	-1.42	37.54	41.63	39.75
30	2018	33.20	36.65	50.39	22.47	21.32	28.34	14.43	1.59	5.05	43.82	50.90	43.97

HLH is the period of clock hours 8:00-23:00 each day.

Table 9.3.1.11
Light Load Hour (LLH) Market Prices for FY 2024 by Month and Water Year
($/MWh)

	A	B	C	D	E	F	G	H	I	J	K	L	M
	Water Year	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24
1	1989	52.12	44.21	63.33	58.39	69.61	41.71	15.66	19.72	27.14	68.34	78.35	61.84
2	1990	47.74	34.40	53.06	44.37	44.28	40.87	16.54	23.64	15.80	51.49	60.76	64.17
3	1991	47.94	27.12	54.10	42.17	39.54	34.64	19.68	20.60	17.24	43.41	63.32	64.01
4	1992	49.08	44.06	71.83	58.19	55.69	48.71	33.00	31.26	31.14	80.98	84.32	65.09
5	1993	59.43	47.64	73.74	72.00	76.07	48.80	35.77	20.21	30.04	59.23	79.82	62.82
6	1994	45.67	42.67	64.14	60.82	60.52	47.33	28.22	29.47	30.07	72.83	86.21	62.68
7	1995	50.78	44.62	63.08	55.62	52.52	33.19	36.53	20.44	13.86	56.27	75.62	59.72
8	1996	34.33	22.85	31.83	25.42	24.15	8.83	9.13	12.65	10.26	33.94	58.43	57.94
9	1997	43.37	38.21	50.61	24.33	22.55	16.77	4.59	-2.84	-2.78	30.68	54.32	47.95
10	1998	19.06	29.24	56.90	48.21	46.00	37.25	25.69	7.45	15.45	51.83	64.00	58.17
11	1999	46.86	45.35	54.83	34.36	38.98	13.86	11.58	17.83	6.92	30.99	52.21	61.10
12	2000	42.50	27.51	47.31	41.10	45.36	33.97	13.72	19.95	25.73	60.54	73.28	65.28
13	2001	48.64	49.48	73.63	67.36	59.10	50.27	40.17	37.46	38.24	77.32	83.24	64.23
14	2002	53.41	51.75	65.64	61.29	60.18	43.68	17.39	20.92	11.87	44.08	71.06	60.88
15	2003	51.27	42.36	68.92	60.45	57.48	38.92	26.20	26.69	18.61	74.80	92.27	68.06
16	2004	48.25	38.84	61.32	58.71	63.30	47.51	27.68	27.02	24.31	73.22	89.38	63.98
17	2005	37.93	37.84	54.85	49.62	47.23	43.80	34.56	29.21	28.90	61.79	80.50	62.61
18	2006	56.37	40.76	60.09	42.62	41.14	38.23	13.88	9.04	13.77	56.56	81.45	59.65
19	2007	50.32	37.51	55.49	43.99	49.38	23.92	15.50	20.83	23.92	61.42	82.52	62.70
20	2008	52.98	42.35	64.88	55.06	54.95	44.03	33.15	17.12	6.70	48.75	70.42	63.05
21	2009	49.90	39.43	66.52	49.56	55.18	47.94	16.70	17.78	20.74	65.30	86.11	60.99
22	2010	50.61	45.03	65.07	62.46	63.01	50.38	31.97	33.71	11.63	53.12	80.10	60.89
23	2011	51.05	45.52	55.81	40.14	39.72	32.07	11.74	11.37	-2.24	13.38	51.98	58.52
24	2012	41.22	39.51	61.39	48.32	47.75	28.29	2.72	12.09	5.11	25.48	57.30	60.18
25	2013	48.93	33.92	49.86	51.69	53.85	45.71	15.27	17.91	16.16	56.66	82.54	63.79
26	2014	41.41	41.55	65.86	47.86	63.59	26.16	14.31	14.98	17.05	45.11	62.83	57.71
27	2015	49.50	34.38	51.48	41.05	40.60	26.28	25.80	37.64	36.00	88.16	94.15	64.71
28	2016	50.21	44.20	58.83	53.69	59.30	26.78	7.64	18.86	27.05	71.22	80.10	59.01
29	2017	42.70	27.82	56.07	45.38	42.46	4.82	0.96	3.87	4.63	52.47	65.61	62.55
30	2018	44.54	41.59	53.91	38.27	34.20	28.46	12.71	1.99	13.84	56.43	72.75	61.79

LLH is the period of clock hours 23:00-08:00 each day.

Table 9.3.1.12
Light Load Hour (LLH) Market Prices for FY 2025 by Month and Water Year
($/MWh)

	A	B	C	D	E	F	G	H	I	J	K	L	M
	Water Year	Oct-24	Nov-24	Dec-24	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25
1	1989	35.24	37.26	57.22	48.94	62.92	47.01	16.76	17.58	18.67	49.02	53.28	46.20
2	1990	32.39	27.90	45.35	30.26	32.45	44.26	17.08	23.12	5.69	37.04	42.30	46.61
3	1991	32.52	17.65	43.35	24.29	22.30	35.81	21.11	20.12	7.26	22.69	43.84	47.67
4	1992	33.29	36.72	69.10	49.81	52.77	50.25	36.80	33.03	23.86	54.34	56.18	48.17
5	1993	39.80	38.97	69.75	61.50	66.61	52.99	40.32	17.07	19.46	44.67	56.22	48.33
6	1994	30.81	34.66	58.64	51.83	56.43	50.75	31.99	31.15	22.11	51.48	54.86	46.63
7	1995	34.17	37.22	59.93	45.77	48.90	35.27	35.11	19.18	4.27	41.11	52.40	45.30
8	1996	25.68	12.02	16.84	8.03	7.63	4.15	7.93	8.82	2.20	12.41	40.02	44.03
9	1997	31.32	30.61	41.30	7.27	6.44	9.98	3.74	-4.97	-8.43	9.94	36.02	36.89
10	1998	12.50	21.66	49.21	34.16	38.47	41.34	29.20	3.06	5.24	36.05	45.30	44.18
11	1999	32.63	38.02	47.71	16.03	23.49	8.41	11.58	15.30	0.66	10.27	32.42	43.64
12	2000	29.48	19.12	35.43	25.50	37.96	37.19	12.93	16.81	15.55	45.07	50.99	47.59
13	2001	33.47	41.08	69.84	57.83	55.85	52.21	43.00	39.34	30.68	53.11	54.52	47.36
14	2002	35.19	42.38	62.58	51.90	56.53	47.33	18.86	20.19	3.48	25.45	49.16	45.18
15	2003	34.80	34.80	63.36	51.22	54.31	43.96	29.44	28.09	9.22	54.85	59.74	51.11
16	2004	33.33	32.47	57.76	49.34	58.41	52.32	31.48	28.52	15.82	53.56	59.72	48.75
17	2005	27.83	31.98	47.51	37.21	43.77	46.93	38.36	32.02	22.41	46.62	54.48	46.17
18	2006	37.97	34.36	54.02	23.68	24.83	41.11	13.40	5.47	4.64	40.73	55.35	45.56
19	2007	34.14	31.54	49.03	29.19	45.64	19.84	15.94	19.67	15.21	44.97	53.74	45.64
20	2008	35.72	35.35	61.33	45.64	52.34	48.27	37.65	15.03	-0.70	31.14	50.30	48.04
21	2009	33.87	33.39	61.44	36.32	51.66	49.48	18.34	16.34	11.55	47.33	55.98	46.75
22	2010	35.18	37.42	61.49	52.90	58.02	51.93	36.44	35.68	3.77	38.01	53.64	45.15
23	2011	34.98	38.09	49.56	20.53	22.64	29.85	11.06	7.66	-7.16	-0.43	31.96	44.43
24	2012	28.96	32.54	57.66	34.35	42.35	27.24	1.99	9.23	-0.82	7.46	38.71	45.42
25	2013	33.01	27.06	39.37	40.30	50.03	48.43	15.71	15.34	6.28	41.59	56.25	48.27
26	2014	28.77	33.66	62.58	35.26	57.67	23.57	14.18	12.04	7.57	29.82	42.58	41.99
27	2015	34.51	27.71	42.28	23.37	22.83	20.27	28.86	39.67	29.55	58.73	61.15	49.79
28	2016	33.52	37.07	53.53	42.75	55.10	23.94	6.58	17.07	19.16	49.12	52.22	43.40
29	2017	29.56	20.20	48.19	30.58	34.65	2.35	0.97	1.40	-1.59	39.57	45.62	44.57
30	2018	30.36	33.67	48.42	21.38	18.82	28.44	12.92	-0.13	5.08	42.34	49.69	44.52

LLH is the period of clock hours 23:00-08:00 each day.

Table 9.3.1.13
Variable Costs Sub-Categories of
Stand Ready Costs from the GARD Model

	A	B	C
		Annual Average (MWh)	**Annual Average ($)**
1	Energy Shift dec	134,901	14,395,972
2	Energy Shift Non-Spinning inc	78,675	8,395,824
3	Energy Shift Spinning inc	80,866	8,629,614
4	*Energy Shift Subtotal:*	*294,441*	*31,421,409*
5	Efficiency Loss dec	9,697	(3,897,468)
6	Efficiency Loss Non-Spinning	6,419	(2,579,873)
7	Efficiency Loss Spinning	3,077	(1,236,636)
8	*Efficiency Loss Subtotal:*	*19,192*	*(7,713,977)*
9	Spill Losses Non-Spinning	165,094	5,406,587
10	Spill Losses Spinning	55,128	1,805,376
11	*Spill Losses Subtotal:*	*220,222*	*7,211,963*
12	**Total**	**533,856**	**30,919,396**

Table 9.3.1.14
Variable Cost Components for Reserves Under 99.7% Level of Service with Self Supply of Generation Imbalance

	A	B	C
	Component	MW	$
1	Regulation Reserve *inc*	323	3,875,886
2	Regulation Reserve *dec*	344	4,080,778
3	Non-Regulation Reserve *inc*	418	7,797,289
4	Non-Regulation Reserve *dec*	541	6,417,726
5	Operating Reserves - Spinning	237	8,747,717
6	Total Variable Cost	977	30,919,396

Table 9.3.1.15
GARD Stand-ready Costs and EIM Cost Reduction

	A	B	C	D	E	F	G
		Regulation *inc* ($)	Regulation *dec* ($)	Non-regulation *inc* ($)	Non-regulation *dec* ($)	Operating Reserves Spinning ($)	All Reserves ($)
1	Energy shift	3,636,238	5,595,727	6,310,029	8,800,245	7,079,171	31,421,409
2	Efficiency	(521,078)	(1,514,949)	(1,553,062)	(2,382,519)	(1,742,368)	(7,713,977)
3	Spill	760,727	-	3,040,323	-	3,410,914	7,211,963
4	Total	3,875,886	4,080,778	7,797,289	6,417,726	8,747,717	30,919,396
5	95% Variable Cost Reduction	-	-	7,407,424	6,096,840	-	13,504,265
6	Total After EIM Cost Reduction	3,875,886	4,080,778	389,864	320,886	8,747,717	17,415,131

Table 9.3.1.16
7HA.02 SCCT Frame Annual Costs

	A	B	C	D	E	F	G	H	I	J
1				**Calendar Year**	**Chained GDP IPD**		**Month**	**BP-22 Load Shaping Rate HLH $/MWh**	**Demand Shaping Factor**	**Monthly Demand Rate $/kW/mo**
2	Start Year of Operation (FY)	2024		2016	105.740		Oct	29.92	8.50%	$ 5.94
3	Cost of Debt	3.06%	/1	2017	107.747		Nov	31.71	9.01%	$ 6.29
4				2018	110.321		Dec	38.76	11.01%	$ 7.69
5	Inflation Rate	2.28%		2019	112.294		Jan	34.29	9.74%	$ 6.80
6	Insurance Rate	0.25%	/2	2020	113.648		Feb	34.79	9.88%	$ 6.90
7				2021	118.370		Mar	27.57	7.83%	$ 5.47
8	Debt Finance Period (years)	30	/2				Apr	20.71	5.88%	$ 4.11
9	Plant Lifecycle (years)	30	/2		102.28%	5-year Avg.	May	16.28	4.62%	$ 3.23
10							Jun	17.15	4.87%	$ 3.40
11	Lifetime Average Heat Rate Btu/kWh	9,566	/2				Jul	36.83	10.46%	$ 7.30
12				Chained GDP IPD from BEA -- Table 1.1.9. Implicit Price Deflators for Gross Domestic Product (2012 Base year) - Last Revised August 25, 2022			Aug	35.87	10.19%	$ 7.12
13	Eastside Fixed Fuel $/kW/yr with 9566 Heat Rate 2016$	$ 18.02	/2				Sep	28.15	8.00%	$ 5.59
14	Westside Fixed Fuel $/kW/yr with 9566 Heat Rate 2016$	$ 24.51	/2						**Average $/kW/mo**	**$ 5.82**
15	Average Eastside and Westside 2016$	$ 21.27								
16										
17	All-in Capital Cost Frame $/kW 2024$	$ 694.76	/3	**End of Fiscal Year**	**Midyear Assessed Value**	**Debt Payment**	**Fixed O&M**	**Insurance**	**Fixed Fuel**	**Cash Expense Each Year**
18	Fixed O&M $/kW/yr 2024$	6.59	/4	2024	$ 683.18	$35.72	$ 6.59	$ 1.71	$ 25.47	$ 69.49
19	Fixed Fuel $/kW/yr 2024$	25.47		2025	$ 660.02	$35.72	$ 6.74	$ 1.65	$ 26.05	$ 70.16
20						**Rate Period Average Expense $/kW/year**				**$ 69.83**
21										
22	/1 Source BPA FY 2022 Third-Party Tax-Exempt Borrowing Rate Forecast 30-year									
23	/2 Source NWPCC 2021 Power Plan Microfin Model and Fixed Fuel Workbook					Wärtsilä 18V50SG Average Expense $/kW/mo /5				$9.54
24	/3 Source NWPCC Microfin Model assumption of $1315/kW in 2016$.					7HA.02 SCCT Frame Average Expense $/kW/mo				$5.82
25	/4 Source NWPCC Microfin Model assumption of $5/kW/yr in 2016$.					Expense Delta				$3.72
26	/5 Source Power Rates Study Documentation BP-24-E-BPA-01A Table 4.1.									
27										

Table 9.3.1.17
Cost of Capacity Calculation

	A	B
		Annual Average FY2024-FY2025 ($/kW/mo)
1	**Assumptions for Calculation:**	
2	Embedded Unit Cost of Capacity	6.24
3		
4	**Variable Costs:**	
5	Regulation inc	0.48
6	Regulation dec	0.99
7	Non-regulation inc	0.48
8	Non-regulation dec	0.05
9	Operating Reserves	1.54
10		
11	**Base Cost of Capacity by Reserve Type**	
12	Regulation inc (Line 2 + 5)	6.72
13	Regulation dec (Line 6)	0.99
14	Non-regulation inc (Line 2 + 7)	6.72
15	Non-regulation dec (Line 8)	0.05
16	Operating Reserves - Spinning and Supplemental (Line 2 + 9)	7.78
18		
19	**Rate Design Delta:**	
20	Inc value delta	3.72
21	Regulation inc weighted value delta	2.10
22	Non-regulation inc weighted value delta	-1.62
23	Operating Reserves - Spinning value delta	1.86
24	Operating Reserves - Supplemental value delta	-1.86
25		
26	**Total Cost of Capacity by Reserve Type:**	
27	Regulation inc (Line 12 + 21)	8.82
28	Regulation dec (Line 13)	0.99
29	Non-regulation inc (Line 14 + 22)	5.10
30	Non-regulation dec (Line 15)	0.05
31	Operating Reserves - Spining (Line 16 + 23)	9.64
32	Operating Reserves - Supplemental (Line 16 + 24)	5.92

Table 9.3.1.18
Revenue Forecast

	A	B
1	**Cost of Capacity by Reserve Type (See Table 4.4)**	**$ / kW/mo**
2	Regulation inc	$8.82
3	Regulation dec	$0.99
4	Non-regulation inc	$5.10
5	Non-regulation dec	$0.05
6	Operating Reserves - Spinning	$9.64
7	Operating Reserves - Supplemental	$5.92
8		
9	**Operating Reserve Quantity**	**MW**
10	Operating Reserves Spinning	237
11	Operating Reserves Supplemental	237
12		
13	**Balancing Reserve Quantity** (excludes Federal Generation Balancing Reserves)	**MW**
14	Regulation Reserves inc	302
15	Regulation Reserves dec	322
16	Non-regulation Reserves inc	418
17	Non-regulation Reserves dec	541
18		
19	**Revenue Forecast**	**$ in Thousands**
20	(Cost from A1 * Quantity from A9 or A13 * 12)	
21	Balancing Reserves - Regulation inc	$31,962
22	Balancing Reserves - Regulation dec	$3,822
23	Balancing Reserves - Non-regulation inc	$25,559
24	Balancing Reserves - Non-regulation dec	$324
25	**Balancing Reserves - Total**	$61,667
26		
27	Operating Reserves Spinning	$27,401
28	Operating Reserves Supplemental	$16,827
29	**Operating Reserves - Total**	$44,229
30		
31	**Total Revenue Forecast (B25 + B29)**	$105,896
32		
33		**$/kW/mo**
34	**Average Cost of Balancing Reserves (B25/((B14+B16)*12)**	$7.14
35	**Average Cost of Operating Reserves (B29/((B10+B11)*12)**	$7.78

*Federal Generation Balancing Costs are not included in the Total Revenue Forecast because 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 2018**	**Condensing Hours FY 2019**	**Condensing Hours FY 2020**	**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	1,582	4,472	4,735	3,596	10,789	$ 427,460
2	**The Dalles, units 15-20**	99	1.5	units 15-20	870	430	1,177	826	1,239	$ 49,069
3								**SUBTOTAL - SOUTHERN INTERTIE***	**12,028**	**$ 476,530**
4	**Grand Coulee, units 19-24**	690 (units 19-21) 805 (units 22-24)	11.0	units 19-21	1,160	1,224	1,168	1,184	13,024	$ 516,011
5	**Dworshak (small units)**	103	4.0	units 1-2	1	55	0	19	75	$ 2,958
6	**Dworshak (big unit)**	259	8.0	unit 3	0	10	45	18	147	$ 5,811
7	**Palisades, units 1-4**	44	0.6	units 1-4	9	4,264	4,996	3,090	1,854	$ 73,448
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***	**15,099**	**$ 598,228**
13								**TOTAL ENERGY COST**	**27,127**	**$ 1,074,757**
14	**Market Price Forecast of energy ($/MWh)**	**$ 39.62**								

***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
		FY 2024	**FY 2025**	**Annual Average of FY 2024 - FY2025**
1	**Synchronous Condensers Net Plant**	$ 5,186	$ 5,083	$ 5,134
2	Total Corps/Reclamation Average Net Plant	$ 6,128,241	$ 6,352,023	$ 6,240,132
3	**percent**	0.08%	0.08%	0.08%
4	Corps/Reclamation Net Interest	$ 18,918	$ 1,767	$ 10,342
5	**Sync Cond Net Interest**	$ 16	$ 1	$ 9
6	Corps/Reclamation MRNR	$ 124,636	$ 132,736	$ 128,686
7	**Sync Cond MRNR**	$ 105	$ 106	$ 106
8	**Sync Cond Depreciation**	$ 103	$ 103	$ 103
9	**Total Sync Cond Plant Modification Costs**	$ 224	$ 210	$ 217

* 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
		FY 2024	**FY 2025**	**Annual Average of FY2024 - FY2025**
1	Modifications at John Day and The Dalles*	$ 224,000	$ 210,000	$ 217,000
2	**Energy Consumption - John Day and The Dalles**	$ 476,530	$ 476,530	$ 476,530
3	**Subtotal - Southern Intertie**	**$ 700,530**	**$ 686,530**	**$ 693,530**
4	**Energy Consumption - Network**	$ 598,228	$ 598,228	$ 598,228
5	**Total Synchronous Condenser Costs**	**$ 1,298,757**	**$ 1,284,757**	**$ 1,291,757.21**

* 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%	$ 1,105,000	$ 442	0.04%	$ 5,506	$ 2	0.04%	1	$ 2,088,712	$ 835	**$ 1,280**
2	Main Power Transformer (equal to replacement)	0.015%	$ 12,612,249	$ 1,892	0.015%	$ 63,602	$ 10	0.018%	1	$ 2,088,712	$ 376	**$ 2,277**
3	Generator (rewinding)	0.71%	$ 28,067,000	$ 199,276	0.71%	$ 501,426	$ 3,560	0.71%	18	$ 37,596,813	$ 266,937	**$ 469,773**
4	Turbine (refurbished)	0.24%	$ 2,210,000	$ 5,304	0.24%	$ 501,426	$ 1,203	0.05%	16	$ 33,419,389	$ 16,710	**$ 23,217**
5	500 kV Cable (replacement)	0.055%	$ 8,314,020	$ 4,573	0.055%	$ 313,981	$ 173	0.055%	1	$ 2,088,712	$ 1,149	**$ 5,894**
6	**Total Cost Per Drop**			**$ 211,486**			**$ 4,948**				**$ 286,007**	**$ 502,442**
7	**Total Generation Dropping Cost per year** (3)			**$ 552,686**								

(1) Updated to FY 2024-FY 2025 from original Harza Engineering Company study using the Handy-Whitman Index to calculate cost multiplier

2.21

(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 ($39.62) during the FY 2024-2025 rate period.

(3) Drops per year 1.2

Table 9.3.4.1
Redispatch Costs FY 2019 to August 2022

	A	B	C	D	E	F	G
1	**Fiscal Year**	**Discretionary**	**Transmission Purchases: Redispatch**	**NT Redispatch: FCRPS Redispatch (INC/DEC)**	**Emergency**	**Transmission Purchases: Stranded Load**	**Total Redispatch (sum of B to F)**
2	**2019**	$ 16,033.33	$ 34,977.05	$ -	$ -	$ 251,557.40	$ 302,567.78
3	**2020**	$ -	$ 253,226.20	$ 9,100.00	$ -	$ 71,778.73	$ 334,104.93
4	**2021**	$ -	$ 87,437.49	$ -	$ -	$ 208,360.96	$ 295,798.45
5	**2022**	$ -	$ 165,928.62	$ -	$ -	$ 203,617.52	$ 369,546.14
6	**Total FY2019-2022:**	$ 16,033.33	$ 541,569.35	$ 9,100.00	$ -	$ 735,314.61	$ 1,302,017.29
7	**FY Average (FY24-25 Forecast):**	$ 4,090.14	$ 138,155.45	$ 2,321.43	$ -	$ 187,580.26	$ 332,147.27

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	39,353	2,715,341					
2	Medium	5,943	410,065					
3	Small	1,448	99,911					
4	Big Eddy/Celilo Complex		1,822,937					
5	Ross Complex		1,749,300					
6	**Total**	**46,744**	**6,797,554**	**81,571**	**1,664**	**$39.62**	**$5.52**	**$ 3,306,944**

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 2.04% (D * 0.0204)

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).

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