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-22 Rate Proceeding

Final Proposal

Power Rates Study Documentation

BP-22-FS-BPA-01A

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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
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
COE	U.S. Army Corps of Engineers
COI	California-Oregon Intertie
Commission	Federal Energy Regulatory Commission
Corps	U.S. Army Corps of Engineers
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council	Northwest Power and Conservation Council (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
GMS	Grandfathered Generation Management Service
GSP	Generation System Peak
GSR	Generation Supplied Reactive
GRSPs	General Rate Schedule Provisions
GTA	General Transfer Agreement
GWh	gigawatthour
HLH	Heavy Load Hour(s)
HOSS	Hourly Operating and Scheduling Simulator (computer model)
HYDSIM	Hydrosystem Simulator (computer model)
Hz	Hertz
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
KSI	key strategic initiative
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
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)
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
NWPA	Northwest Power Act/Pacific Northwest Electric Power Planning and Conservation Act
NWPP	Northwest Power Pool

O&M	operations and maintenance
OATI	Open Access Technology International, Inc.
OATT	Open Access Transmission Tariff
OCBR	Operational Controls for Balancing Reserves
OS	Oversupply
OY	operating year (August through July)
PDCI	Pacific DC Intertie
PF	Priority Firm Power
PFp	Priority Firm Public
PFx	Priority Firm Exchange
PMA	Power Marketing Administration
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)
RBC	Reliability-based control
RCD	Regional Cooperation Debt
RD	Regional Dialogue
RDC	Reserves Distribution Clause
REC	Renewable Energy Certificate
Reclamation	U.S. Bureau of Reclamation
REP	Residential Exchange Program
REPSIA	REP Settlement Implementation Agreement
RevSim	Revenue Simulation Model
RFA	Revenue Forecast Application (database)
RHWM	Rate Period High Water Mark
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RR	Resource Replacement
RRS	Resource Remarketing Service
RSC	Resource Shaping Charge
RSS	Resource Support Services
RT1SC	RHWM Tier 1 System Capability
RTD-IIE	Real-Time Dispatch – Instructed Imbalance Energy
RTIEO	Real-Time Imbalance Energy Offset
SCD	Scheduling, System Control, and Dispatch Service

SCS	Secondary Crediting Service
SDD	Short Distance Discount
SILS	Southeast Idaho Load Service
Slice	Slice of the System (product)
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
UFE	unaccounted for energy
UFT	Use of Facilities Transmission
UIC	Unauthorized Increase Charge
UIE	Uninstructed Imbalance Energy
ULS	Unanticipated Load Service
USACE	U.S. Army Corps of Engineers
USFWS	U.S. Fish & Wildlife Service
VER	Variable Energy Resource
VERBS	Variable Energy Resource Balancing Service
VOR	Value of Reserves
VR1-2014	First Vintage Rate of the BP-14 rate period (PF Tier 2 rate)
VR1-2016	First Vintage Rate of the BP-16 rate period (PF Tier 2 rate)
WECC	Western Electricity Coordinating Council
WSPP	Western Systems Power Pool

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BP-22 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 (RAM2022). RAM2022 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 RAM2022 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 2022–2023, and at current rates for the fiscal year immediately preceding the two-year rate period, FY 2021.

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-22-FS-BPA-03):

Federal System Load Obligation Forecasts

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

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

Hydro Regulation Study (HYDSIM)

The Federal system regulated hydro resource estimates are derived by BPA's hydro regulation model (HYDSIM), which estimates project generation for 80 water years (October 1928 through September 2008). 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 80 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 2022-2023.

The HYDSIM studies encompass the power and non-power operating requirements expected to be in effect during the rate period, including those described in applicable biological opinions issued by the National Oceanic and Atmospheric Administration (NOAA) Fisheries and the U.S. Fish and Wildlife Service (USFWS); relevant operations described in the Northwest Power and Conservation Council's (NPCC) Fish and Wildlife Program published October 2014 and amended in 2020; and other mitigation measures such as those described in the *2018 Biological Assessment of Effects of the Operations and Maintenance of the Federal Columbia River System on ESA-Listed Species* (2018 BA). The HYDSIM studies incorporate spring spill up to applicable water quality standards for Total Dissolved Gas (TDG) and summer spill informed by the results of biological performance standard testing conducted over the last decade to measure dam passage survival for out-migrating juvenile fish ("performances standard spill"). In addition, the HYDSIM studies include the operational Measures contained in the CRSO FEIS Preferred Alternative study that would be implemented in the rate period, which are also in the biological opinions. Each hydro regulation study specifies particular hydroelectric project operations for fish, such as seasonal flow objectives, minimum flow levels for fish, spill for juvenile fish passage, reservoir target elevations and drawdown limitations, and turbine operation requirements. 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 1937 water conditions, 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-22-FS-BPA-02):

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

POWER MARKET PRICE STUDY (BP-22-FS-BPA-04):

The Power Market Price Study is composed of two different electricity market price runs. These runs are the "market price" run, which is based on hydro generation for 80 water years, and the "critical water price" run, which is based on hydro generation under 1937 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-22-FS-BPA-05.

The tool used to calculate electric energy prices is a model of the Western Electricity Coordinating Council (WECC) power system called AURORA©. AURORA© uses a linear program to minimize the cost of meeting load, subject to a number of operating constraints.

Given the solution (an output level for all generating resources and a flow level for all interties), the price at any hub is the cost, including wheeling and losses, of delivering a unit of power from the least-cost available resource. This cost approximates the price of electricity by assuming that all resources are centrally dispatched (the equivalent of cost-minimization in production theory) and that the marginal cost of producing electricity approximates the price.

AURORA© produces a single electricity price forecast as a function of its inputs. Thus, to produce a given number of price forecasts requires that AURORA© be run that same number of times using different inputs. Risk models provide inputs to AURORA© and the resulting distribution of electricity price forecasts represents a quantitative measure of electricity price risk. As described in the Power and Transmission Risk Study, BP-22-E-BPA-05, 3,200 independent games from the joint distribution of the risk models serve as the basis for the 3,200 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-22-FS-BPA-05)

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

In addition to the Power operating net revenues used in the calculation of TPP, results from the modeling of various Power operating risks that are components of net revenues are provided for input into the Rate Analysis Model for the BP-22 rate case (RAM2022).

Results Provided for Input into RAM2022 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 80 years of historical streamflow conditions (1929-2008). Inputs used to calculate load and resource balance are forecast loads, non-hydro resources, and hydro generation.

RevSim uses the 80 water year results from the Loads and Resources Study to compute the available HLH and LLH surplus energy and deficits in the Federal hydro system under varying streamflow conditions. RevSim applies HLH and LLH monthly spot market prices supplied by the AURORA© model (see the Power Market Price Study subsection above for a description of the AURORA© model) to the sales and purchase amounts to calculate revenues from surplus energy sales and expenses from balancing power purchases. It also computes augmentation costs based on hydro generation data and AURORA© prices under 1937 hydro conditions. As described in the Power Rates Study below, RAM2022 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-22-FS-BPA-01)

Rate Analysis Model (RAM2022)

RAM2022 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 RAM2022 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 RAM2022 using unique database keys.

RAM2022 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. RAM2022 designs rates for each rate pool.

Resource Support Services Module of RAM2022

The Resource Support Services (RSS) module of RAM2022, 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 RAM2022); 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 RAM2022

The Tier 2 module of RAM2022, 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 RAM2022. 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.

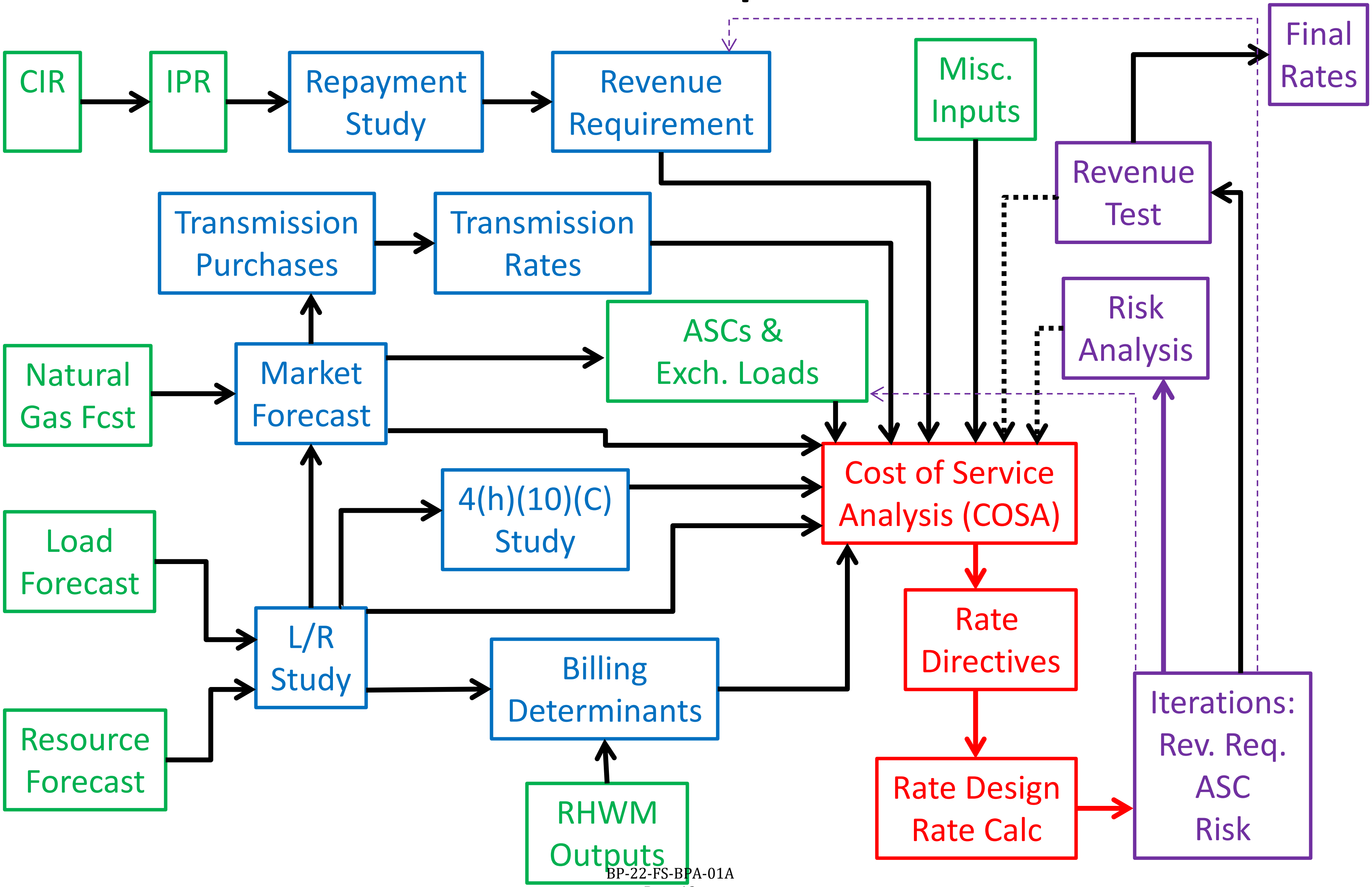
FY 2022-2023 Average System Cost (ASC) Forecasts

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-22 rates, BPA is using the ASC Reports published by BPA on July 28, 2021.

Revenue and Power Purchase Expense Forecast

The Revenue Forecast presents BPA's expected level of revenue and power purchase expense for FY 2021-2023, FY 2021 revenues are forecast to estimate the level of reserves at the beginning of the rate period. Selected power purchase expenses that affect the sales of surplus energy are also included. The revenue forecast documents the revenues at both current and proposed rates by applying rates (PF, IP, and NR, if applicable) to projected billing determinants. These two revenue forecasts, one with current rates and the other with proposed rates, are used to demonstrate whether current rates will recover BPA's revenue requirement and, if not, whether proposed rates will recover the revenue requirement. The revenue test is described in the Power Revenue Requirement Study. The Revenue Forecast uses outputs from a number of sources to determine total revenues expected, and to obtain short-term marketing revenues, firm surplus energy revenues, balancing power purchase expenses, augmentation power purchase expenses, 4(h)(10)(C) credits, and Power Services' transmission and ancillary service expenses.

Power Rate Development Process



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SECTION 2: RATEMAKING METHODOLOGY AND PROCESS

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Description of Ratemaking Tables

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

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

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

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

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

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

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

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

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

Table 2.3.4.1
Allocation of Costs: FBS and LDD/IRD (COSA 04-1)
Worksheet allocates FBS costs as directed by section 7(b) of the Northwest Power Act. Worksheet allocates LDD/IRD costs due to the forgone revenue associated with the LDD and IRD rate discounts, which are allocated to PF load.

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

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

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

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

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

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

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

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

Table 2.3.7.5
Allocation of Revenue Credits: Generals (COSA 07-5)
Worksheet allocates revenue credits associated with providing generation inputs as directed by section 7(g) of the Northwest Power Act, and other revenues that are allocated pro rata to all loads.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Table 2.4.18
IP-PF Link (RDS 18)
Worksheet uses shaped energy rates from previous worksheet to calculate the IP-PF link delta. The IP-PF Link 7(c)(2) adjustment is necessary to account for the difference between the revenues expected to be recovered from the DSIs at the IP rate and the costs allocated to the DSIs at this point in the ratemaking. This difference, known as the 7(c)(2) Delta, is allocated to non-DSI rates, primarily the PF rate. The IP rate is a formula rate based on the "applicable wholesale rate"—the load-weighted PF and NR rates. The interaction between the applicable

wholesale rate and the IP rate has been reduced to an algebraic formula to approximate a solution, and then the RAM uses an intrinsic Excel function, “Goal Seek,” to converge to a solution for each year of the rate test period.

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

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

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

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

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

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

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Rate Data Input
Disaggregated Loads
Test Period October 2021 - September 2023
(MWh)

	A	B	C	E	F
4				2022	2023
5	Preference			57,217,147	57,654,212
6		Block		4,155,928	4,144,330
7		Slice Block		11,330,798	11,775,170
8		Slice		13,322,796	13,064,358
9		Load Following		27,035,896	27,153,105
10		Tier 2		1,371,728	1,517,250
11	Industrial			105,120	105,120
12		Smelter		0	0
13		Other Industrial		105,120	105,120
14	New Resource			10	10
15	Firm Power and Services			5,839,869	5,826,617
16		Intraregional Transfer		98,426	98,426
17			WNP#3 Settlement	0	0
18			Dittmer Station Service	82,668	82,668
19			Transfer Gen Losses	15,758	15,758
27		FBS Obligation		5,728,190	5,728,191
28			Canadian Entitlement	3,979,668	3,979,668
29			USBR Pump Load	1,648,376	1,648,376
30			Hungry Horse	0	0
31			Upper Baker	11,228	11,228
32			Non-Treaty Storage	88,918	88,919
33			Libby Coordination	0	0
38		Seasonal or Capacity Exchange		13,253	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	13,253	0
45			PacifiCorp	0	0
49	Firm Surplus Sale			441,775	0
50	Presale of Secondary			0	0
51	Conservation			0	0
52					
53					
54	Loss Percentage			3.21%	3.21%

Table 2.1.2

Rate Data Input
Disaggregated Resources
Test Period October 2021 - September 2023
(MWh)

	A	B	C	E	F
5				2022	2023
6	Hydro			56,214,256	56,207,367
7		Regulated		51,986,038	51,979,253
8		Independent		3,052,662	3,052,662
9			Cowlitz Falls	232,343	232,343
10			Idaho Falls	0	0
11			PreAct	2,820,320	2,820,320
19		Hydro Other		1,175,556	1,175,452
20			Canadian Entitlement	1,175,556	1,175,452
21			Libby Coordination	0	0
22			Other	0	0
30	Non Hydro			10,112,888	8,913,502
31		Water		23,039	23,039
32			Dworshak/Clearwater Small Hydropower	23,039	23,039
33			Elwha Hydro	0	0
34			Glines Canyon Hydro	0	0
42		Thermal		9,776,160	8,704,656
43			Columbia Generating Station	9,776,160	8,704,656
53		Wind		313,689	185,808
54			Foote Creek 1	0	0
55			Foote Creek 2	0	0
56			Foote Creek 4	0	0
57			Stateline Wind Project	185,808	185,808
58			Condon Wind Project	102,710	0
59			Klondike I	25,172	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			557,743	552,828
76		Imports		557,743	552,828
77			Riverside Exchange Energy	0	0
78			Pasadena Exchange Energy	0	0
79			BC Hydro Power Purchase	8,760	8,760
80			Slice Return of Losses	253,383	248,468
81			Southeast Idaho Load Service	295,600	295,600
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			105,505	105,505
110		Tier 1 Resources		105,505	105,505
111			Klondike III	103,302	103,302
112			Rocky Brook	2,203	2,203
113					
114	Transmission Losses			(2,105,102)	(2,066,600)

Table 2.1.3

Rate Data Input
Exchange ASCs, Loads, and Gross Costs
Test Period October 2021 - September 2023

	B	D	E
7	**Exchange ASCs ($/MWh)**	**2022**	**2023**
8			
9	Avista Corporation	$ 62.93	$ 62.93
10	Idaho Power Company	$ 58.17	$ 58.17
11	NorthWestern Energy, LLC	$ 68.34	$ 68.34
12	PacifiCorp	$ 77.61	$ 77.61
13	Portland General Electric Company	$ 70.09	$ 70.09
14	Puget Sound Energy, Inc.	$ 67.28	$ 67.28
15	Clark Public Utilities	$ -	$ -
17	Snohomish PUD	$ 55.83	$ 55.83
18			
19	**Exchange Loads (GWh)**	**2022**	**2023**
20			
21	Avista Corporation	3,971	3,971
22	Idaho Power Company	6,857	6,857
23	NorthWestern Energy, LLC	714	714
24	PacifiCorp	9,147	9,147
25	Portland General Electric Company	12,392	12,392
26	Puget Sound Energy, Inc.	11,952	11,952
27	Clark Public Utilities	0	0
29	Snohomish PUD	3,715	3,731
30		48,749	48,765
31			
32	**Exchange Resource Cost ($000)**	**2022**	**2023**
33			
34	Avista Corporation	$ 249,924	$ 249,924
35	Idaho Power Company	$ 398,876	$ 398,876
36	NorthWestern Energy, LLC	$ 48,803	$ 48,803
37	PacifiCorp	$ 709,911	$ 709,911
38	Portland General Electric Company	$ 868,539	$ 868,539
39	Puget Sound Energy, Inc.	$ 804,160	$ 804,160
40	Clark Public Utilities	$ -	$ -
42	Snohomish PUD	$ 207,384	$ 208,278
43		$ 3,287,597	$ 3,288,491

Energy Allocation Factor
Power Sales and Resources
Test Period October 2021 - September 2023
(aMW)

	B	C	E	F
4			**2022**	**2023**
5	**Sales**			
6	Public			
7		Load Following	3,086	3,100
8		Tier 2 (block net of remarketing)	152	169
9		Slice (output energy)	1,521	1,491
10		Block	1,768	1,817
12	Exports			
13		BC Hydro (Cdn Entitlement)	454	454
14		Non-Treaty Storage	10	10
15		Libby Coordination	0	0
16		Pasadena Capacity	0	0
17		Pasadena Seasonal	0	0
18		Riverside Capacity	0	0
19		Riverside Seasonal	0	0
20		PacifiCorp	0	0
21		PG&E	0	0
22		Federal Generation Transmission Losses	1.80	1.80
23		Intertie Losses	1.51	0.00
24	Intra-regional Transfers			
25		Firm Surplus Sale	50	0
26		Dittmer/Substation Sale	9	9
27	Other Loads			
28		USBR Pump Load	188	188
29		Hungry Horse	0	0
30		Upper Baker	1	1
31		Direct Service Industries	12	12
32		New Resource	0	0
33	Total Firm Obligations		**7,257**	**7,255**
34				
35	**Resources**			
36	Hydro			
37		Regulated	5,934	5,934
38		Independent		
39		Cowlitz Falls	27	27
40		Idaho Falls	0	0
41		PreAct	322	322
42		Non-Fed CER (Canada)	134	134
43		Libby Coordination	0	0
44	Other Hydro Resources			
45				

Table 2.2.1.2

Energy Allocation Factor
Power Sales and Resources
Test Period October 2021 - September 2023
(aMW)

	B	C	E	F
4			**2022**	**2023**
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	12	0
53		Klondike I	3	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	29	28
69	Regional Transfers (In)			
70		Southeast Idaho Load Purchase	34	34
71		PacifiCorp	0	0
72	Large Thermal		1,116	994
73	Non-Utility Generation			
74		Dworshak/Clearwater Small Hydropower	2.63	2.63
75		Elwha Hydro	0	0
76		Glines Canyon Hydro	0	0
77		Rocky Brook	0	0
78	Tier 2 Purchases		152	169
79	Federal Trans. Losses		(239)	(234)
80	Total Net Resources		**7,561**	**7,444**
81				
82	Firm System Surplus/(Deficit)		**305**	**189**

Table 2.2.2.1

Energy Allocation Factor
Aggregated Loads and Resources
Test Period October 2021 - September 2023
(aMW)

	B	C	E	F
4			**2022**	**2023**
7	**Loads**			
8	Priority Firm - 7(b) Loads			
9		Block	1,824	1,875
10		Load Following	3,185	3,199
11		Slice (output energy)	1,570	1,539
12		Tier 2	157	175
13		Undistributed Conservation	0	0
14		5(c) Exchange	5,743	5,745
15	Industrial Firm - 7(c) Loads			
16		Direct Service Industries	12.39	12.39
17	New Resources - 7(f) Loads			
18		NR	0.001	0.001
19	Surplus Firm - SP Loads			
20		Firm Surplus Sale	52	0
21		Dittmer/Substation Sale	10	10
22	Total Loads		**12,554**	**12,556**
23				
24	**Resources**			
25	Federal Base System			
26		Hydro	6,391	6,390
27		Other Resources		
28		Small Thermal & Misc.		
29		Combustion Turbines		
30		Renewables	0	0
31		Cogeneration		
32		Imports	1	1
33		Regional Transfers (In)	34	34
34		Large Thermal	1,116	994
35		Non-Utility Generation	0	0
36		Slice Loss Return	29	28
37		Augmentation Purchases	0	0
38		Tier 2 Purchases	157	175

Energy Allocation Factor
Aggregated Loads and Resources
Test Period October 2021 - September 2023
(aMW)

	B	C	E	F
4			**2022**	**2023**
39	less: FBS Obligations			
40		BC Hydro (Cdn Entitlement)	(469)	(469)
41		Non-Treaty Storage	(11)	(11)
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	(2)	0
53	Exchange Resources			
54		5(c) Exchange	5,743	5,745
55	New Resources			
56		Cowlitz Falls	27	27
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	12	0
63		Klondike I	3	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 Hydropowe	3	3
70		Elwha Hydro	0	0
71		Glines Canyon Hydro	0	0
72		Rocky Brook	0	0
73	Total Resources		**12,870**	**12,752**

Energy Allocation Factor
Calculation of Energy Allocation Factors
Test Period October 2021 - September 2023

	B	C	D
4		**2022**	**2023**
5			
6	**Loads (after adjustments)**		
7	Public	6,737	6,788
8	Exchange	5,743	5,745
9	DSI	12	12
10	NR	0.001	0.001
11	FPS	377	206
12			
13	Load Pools -- Program Case		
14	Priority Firm - 7(b) Loads	12,480	12,534
15	Industrial Firm - 7(c) Loads	12	12
16	New Resources - 7(f) Loads	0.001	0.001
17	Surplus Firm - SP Loads	377	206
18	Total Firm Loads	12,870	12,752
19	Secondary	2,342	2,338
20	Surplus Firm - SP Loads (for rate protection)	377	206
21			
22	**Resources (after adjustments)**		
23	Federal Base System	7,049	6,944
24	Exchange Resources	5,743	5,745
25	New Resources	77	62
26	Total Firm Resources	12,870	12,752
27			
28	Allocators -- Program Case		
29	Federal Base System		
30	Priority Firm - 7(b) Loads	7,049	6,944
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	5,431	5,590
36	Industrial Firm - 7(c) Loads	10	9
37	New Resources - 7(f) Loads	0.0009	0.0008
38	Surplus Firm - SP Loads	302	147
39	New Resources		
40	Priority Firm - 7(b) Loads	0	0
41	Industrial Firm - 7(c) Loads	2	4
42	New Resources - 7(f) Loads	0	0
43	Surplus Firm - SP Loads	75	59

Energy Allocation Factor
Calculation of Energy Allocation Factors
Test Period October 2021 - September 2023

	B	C	D
4		**2022**	**2023**
44			
45	**Allocation Factors -- Program Case with Exchange**		
46	Federal Base System + NR		
47	Priority Firm - 7(b) Loads	0.9892	0.9911
48	Industrial Firm - 7(c) Loads	0.0003	0.0005
49	New Resources - 7(f) Loads	0.0000	0.0000
50	Surplus Firm - SP Loads	0.0105	0.0084
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	0.9456	0.9729
58	Industrial Firm - 7(c) Loads	0.0017	0.0015
59	New Resources - 7(f) Loads	0.0000	0.0000
60	Surplus Firm - SP Loads	0.0526	0.0256
61	New Resources		
62	Priority Firm - 7(b) Loads	0.0000	0.0000
63	Industrial Firm - 7(c) Loads	0.0318	0.0567
64	New Resources - 7(f) Loads	0.0000	0.0000
65	Surplus Firm - SP Loads	0.9682	0.9433
66	Conservation & General		
67	Priority Firm - 7(b) Loads	0.9697	0.9829
68	Industrial Firm - 7(c) Loads	0.0010	0.0010
69	New Resources - 7(f) Loads	0.0000	0.0000
70	Surplus Firm - SP Loads	0.0293	0.0161
81	Surplus Deficit		
82	Priority Firm - 7(b) Loads	0.9990	0.9990
83	Industrial Firm - 7(c) Loads	0.0010	0.0010
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	0.6777	0.6920
91	Industrial Firm - 7(c) Loads	0.0015	0.0015
92	New Resources - 7(f) Loads	0.0000	0.0000
93	Secondary Sales	0.3208	0.3065

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2021 - September 2023
($ 000)

	B	D	E
4		**2022**	**2023**
5	**Power System Generation Resources**		
6	**Operating Generation**		
7	Columbia Generating Station (WNP-2)	278,643	304,748
8	Bureau of Reclamation	152,269	152,963
9	Corps of Engineers	252,557	252,557
10	CRFM Studies	7,266	3,619
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	33,783	28,925
27	PNCA Headwater Benefits	3,100	3,100
28	Tier 1 Augmentation Resources (Klondike III)	8,163	9,335
29	Hedging/Mitigation	9,114	8,793
30	Other Committed Purchase (excl. Hedging)	370	370
31	Bookout Adj to Contracted Power Purchases	-	-
32			
33	**Exchanges and Settlements**		
34	Residential Exchange (IOU)	259,001	259,001
35	Residential Exchange (COU)	6,308	6,335
36	Residential Exchange (Refund)	-	-
37	Residential Exchange Program Support	464	426
38	Residential Exchange Interest Accrual	-	-
39			
40	**Renewable and Conservation Generation**		
41	Renewables R&D	-	-
42	Renewable Generation	26,255	20,132
43	Conservation Infrastructure	27,300	27,300
44	Generation Conservation R&D	1,570	1,570
45	DR & Smart Grid	215	215
46	Conservation Acquisition	67,357	67,357
47	Low Income Energy Efficiency	6,005	6,005
48	Reimbursable Energy Efficiency Development	8,000	8,000
49	Legacy Conservation	590	590
50	Market Transformation	11,800	11,800
51			

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2021 - September 2023
($ 000)

	B	D	E
4		**2022**	**2023**
52	**Transmission Acquisition and Ancillary Services**		
53	Trans & Ancillary Svcs (non-slice)	79,432	76,103
54	Trans & Ancillary Svcs (sys oblig)	31,919	31,933
55	Third Party GTA Wheeling	81,854	83,243
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	14,723	14,809
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	3,804	3,780
66	Generation Project Coordination	3,947	4,035
67	Slice costs Charged to Slice Customers	-	-
68	Slice Implementation	971	1,003
69			
70	**PS Scheduling**		
71	Operations Scheduling	9,600	9,910
72	Operations Planning	8,708	9,006
73			
74	**PS Marketing and Business Support**		
75	Sales and Support	15,172	15,563
76	Strategy, Finance & Risk Mgmt	3,566	3,679
77	Executive and Administrative Svcs	6,672	6,886
78	Conservation Support	7,876	8,131
79	Power R&D	957	957
80	Grid Mod	2,223	2,285
81	Power Internal Support	13,976	14,825
82	KSI Commercial Operations Expense	-	-
83	EIM Support Costs	-	-
84			
85	**Fish and Wildlife/USF&W/Planning Council/Env Req.**		
86	Fish and Wildlife	247,508	247,196
87	USF&W Lower Snake Hatcheries	33,000	29,000
88	Planning Council	11,942	12,431
89			
90	**BPA Internal Support**		
91	Additional Post-Retirement Contribution	18,666	19,354
92	Agency Svs for Power for Rev Req schedule	44,522	44,909
93	F&W Corporate Support - G&A	11,720	11,783
94	Agency Svs for Energy Efficiency for Rev Req schedule	10,563	10,469
95			
96	**Bad Debt Expense/Other**		
97	Bad Debt Expense (composite)	-	-
101	Other Income & Expense (non-slice) - RCD Offset	-	-
102	Other Income & Expense (composite) - Expense Offset (EE)	-	-
103			

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2021 - September 2023
($ 000)

	B	D	E
4		**2022**	**2023**
104	**Depreciation and Amortization**		
105	**Depreciation**		
106	Depreciation - BPA	4,685	4,222
107	Depreciation - Corps	106,932	109,967
108	Depreciation - Bureau	29,332	29,966
109			
110	**Amortization**		
111	Amortization - Legacy Conservation	-	-
112	Amortization - Conservation Acquisitions	42,078	32,975
113	Amortization - CRFM	18,387	18,387
114	Amortization - Fish & Widlife	35,275	35,911
115	Amortization -- CGS	149,004	153,890
116	Accretion -- CGS Decomm Trust liability	36,754	38,363
117	Amortization -- WNP1	32,755	32,755
118	Amortization -- WNP3	37,637	37,637
119	Amortization -- Cowlitz Falls	4,108	4,108
120	Amortization -- N. Wasco	1,656	1,656
121			
122	**Interest Expense**		
123	**Net Interest**		
124	Interest On Appropriated Funds	38,411	38,609
125	Capitalization Adjustment	(45,937)	(45,937)
126	Interest On Treasury Bonds	43,986	39,113
127	Non Federal Interest (Prepay)	7,854	6,799
128	Non Federal Interest (CGS)	140,096	133,098
129	Non Federal Interest (WNP 1)	38,892	39,175
130	Non Federal Interest (WNP 3)	46,118	46,192
131	Non Federal Interest (N Wasco)	279	195
132	Non Federal Interest (Lewis County)	3,079	2,868
133	Premiums/Discounts	767	1,768
134	Amortization of Refinancing Premiums/Discounts	(7,562)	(7,491)
135	Amortization of Cost of Issuance	169	169
136	Gains/losses on Extinguishment	-	-
137	AFUDC	(11,005)	(11,469)
138	Interest Income on Decommissioning Trust	(9,857)	(10,198)
139	Other Expense and (Income) (Gains/Losses on Decomm Trust)	(3,399)	(3,516)
140	Interest Earned on BPA Fund for Power (composite)	(1,384)	(1,235)
141	Interest Earned on BPA Fund for Power (non-slice)	(86)	(189)
142			
143	**Net Interest into Cost Pools**		
144	Power Net Interest - Hydro Allocation	26,160	22,708
145	Power Net Interest - Fish & Wildlife Allocation	3,323	2,780
146	Power Net Interest - Conservation Allocation	2,631	1,606
147	Power Net Interest - BPA Programs Allocation	493	365
148			

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2021 - September 2023
($ 000)

	B	D	E
4		**2022**	**2023**
149	**Net Interest into Cost Pools 7b2**		
150	Power Net Interest Hydro 7b2 Allocation	26,160	22,708
151	Power Net Interest Fish & Wildlife 7b2 Allocation	3,323	2,780
152	Power Net Interest BPA Programs 7b2 Allocation	3,124	1,971
153			
154	**Net Revenue**		
155	**Minimum Required Net Revenue**		
156	Repayment of Treasury Borrowings	495,001	525,000
157	Payment of Irrigation Assistance	16,060	12,762
158	Depreciation (MRNR - Reverse sign)	(140,949)	(144,155)
159	Amortization (MRNR - Reverse sign)	(357,654)	(355,682)
160	Non Federal Interest (Prepay) (MRNR - Reverse Sign)	(7,854)	(6,799)
161	Capitalization Adjustment (MRNR - Reverse Sign)	45,937	45,937
162	Amortization of Refinancing Premiums/Discounts (MRNR - Reverse Sig	7,562	7,491
163	Amortization of Cost of Issuance (MRNR-reverse sign)	(169)	(169)
164	Gains/Losses on Extinguishment	-	-
165	Repayment of Federal Appropriations	-	-
166	Accrual Revenues (MRNR Adjustment - Reverse Sign)	-	-
167	Prepay Revenue Credits (MRNR - Reverse Sign)	30,600	30,600
168	Non-Cash Expenses	(77,926)	(73,155)
169	Repayment of NF Obligations (LOC)	-	-
170	Repayment of NF Obligations (CGS)	9,818	14,925
171	Repayment of NF Obligations (WNP 1)	296	-
172	Repayment of NF Obligations (WNP 3)	-	-
173	Repayment of NF Obligations (N Wasco)	1,671	1,751
174	Repayment of NF Obligations (Cowlitz Falls)	4,220	4,435
175	Cash freed up by DSR refinancing	(16,510)	(16,865)
176	Cash Contribution to CGS Decomm Trust	4,472	4,651
177	Interest Income on Decommissioning Trust (MRNR - Reverse Sign)	9,857	10,198
178	Other Expense and (Income) (Gains/Losses on Decomm Trust) (MRNR	3,399	3,516
179	Revenue Financing Requirement	40,000	40,000
180	Depreciation Exceeds Cash Expense	(67,831)	(104,443)
181			
182	**Minimum Net Revenue into Cost Pools**		
183	Power MNetRev - Hydro Allocation	54,420	86,373
184	Power MNetRev - Fish & Wildlife Allocation	6,913	10,574
185	Power MNetRev - Conservation Allocation	5,472	6,107
186	Power MNetRev - BPA Programs Allocation	1,025	1,389
187			
188	**Minimum Net Revenue into Cost Pools 7b2**		
189	Power MNetRev - Hydro 7b2 Allocation	54,420	86,373
190	Power MNetRev - Fish & Wildlife 7b2 Allocation	6,913	10,574
191	Power MNetRev - PBA Programs 7b2 Allocation	6,498	7,496
192			
193	**Planned Net Revenues for Risk into Cost Pools**		
194	Power PNetRev - Hydro Allocation	24,871	25,637
195	Power PNetRev - Fish & Wildlife Allocation	3,159	3,139
196	Power PNetRev - Conservation Allocation	2,501	1,812
197	Power PNetRev - BPA Programs Allocation	469	412
198			
199	**Planned Net Revenues for Risk into Cost Pools 7b2**		
200	Power PNetRev - Hydro 7b2 Allocation	24,871	25,637
201	Power PNetRev - Fish & Wildlife 7b2 Allocation	3,159	3,139
202	Power PNetRev - BPA Programs 7b2 Allocation	2,970	2,225
203			

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2021 - September 2023
($ 000)

	B	D	E
4		**2022**	**2023**
204	**Internally Computed Line Items**		
205	Augmentation Power Purchases	-	-
206	Balancing Purchases	42,896	37,718
207	Secondary Energy Credit	(503,856)	(447,898)
208	Low Density Discount Costs	39,482	40,009
209	Irrigation Rate Mitigation Costs	20,509	20,509
210	**Charges/Credits to Tiered Rate Pools**		
211	Firm Surplus and Secondary Credit (from unused RHWM)	(86,168)	(79,301)
212	Balancing Augmentation	4,070	(4,019)
213	Transmission Loss Adjustment	(30,187)	(30,577)
214	Demand Revenue	54,969	55,946
215	Load Shaping Revenue	12,713	23,082
216	**Tier 2 and RSS Charges/Credits to Tiered Rate Pools**		
217	Augmentation RSS & RSC Adder	2,086	2,086
218	Tier 2 Purchase Costs	44,321	47,041
219	Tier 2 Rate Design Adjustments (Cost)	1,688	1,934
220	Tier 2 Other Costs	-	-
221			
222	**Revenue Credits / Rate Design Adjustments**		
223	Downstream Benefits and Pumping Power	(20,661)	(20,661)
224	Generation Inputs Revenue	(104,245)	(104,245)
225	Capacity for Delayed 168-hr Loss Returns	-	-
226	FPS Real Power Losses	-	-
227	4(h)(10)(C)	(94,171)	(94,216)
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	(8,000)	(8,000)
234	Miscellaneous Credits (incl. GTA)	(11,621)	(11,696)
235	Pre-sub/Hungry Horse	-	-
236	Other Locational/Seasonal Exchange	-	-
237	Upper Baker	(411)	(402)
238	Other Surplus Sales (Non-Slice)	-	-
239	PF Load Forecast Deviation Liquidated Damages	(1,070)	(1,070)
240	NR Revenues from ESS energy and capacity charges	-	-
241	**Tier 2**		
242	Composite Augmentation RSS Revenue Debit/(Credit)	(2,010)	(2,010)
243	Composite Tier 2 RSS Revenue Debit/(Credit)	(151)	(167)
244	Composite Tier 2 Rate Design Adjustment Debit/(Credit)	(1,537)	(1,767)
245	Composite Non-Federal RSS Revenue Debit/(Credit)	(879)	(879)
246	Non-Slice Augmentation RSC Revenue Debit/(Credit)	(76)	(76)
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)	(236)	(236)

Cost of Service Analysis
Cost Pool Aggregation
Test Period October 2021 - September 2023
($ 000)

	B		D	E
3			2022	2023
4				
5	**Federal Base System**		**1,886,750**	**1,939,849**
6	Hydro		736,042	761,776
7		Operating Expense	630,591	627,058
8		Net Interest	26,160	22,708
9		PNRR	24,871	25,637
10		MRNR	54,420	86,373
11	BPA Fish and Wildlife Program		319,841	323,814
12		Operating Expense	306,445	307,321
13		Net Interest	3,323	2,780
14		PNRR	3,159	3,139
15		MRNR	6,913	10,574
16	Trojan		1,200	1,200
17	WNP #1		72,788	73,105
18	WNP #2		583,848	609,062
19	WNP #3		83,756	83,830
20	System Augmentation		-	-
21	Balancing		43,266	38,088
22	Tier 2 Costs		46,009	48,975
23				
24	**New Resources**		**54,276**	**50,117**
25	Idaho Falls		-	-
26	Tier 1 Aug (Klondike III)		8,163	9,335
27	Cowlitz Falls		12,987	13,903
28	Other NR		33,126	26,879
29				
30	**Residential Exchange**		**3,288,062**	**3,288,917**
31				
32	**Conservation**		**199,259**	**189,237**
33		Operating Expense	188,654	179,711
34		Net Interest	2,631	1,606
35		PNRR	2,501	1,812
36		MRNR	5,472	6,107
37				
38	**BPA Programs**		**139,456**	**142,580**
39		Operating Expense	137,469	140,414
40		Net Interest	493	365
41		PNRR	469	412
42		MRNR	1,025	1,389
43				
44				
45	**Transmission**		**211,227**	**209,388**
46	TBL Transmission/Ancillary Services		129,374	126,145
47	3Rd Party Trans/Ancillary Services		-	-
48	General Transfer Agreements		81,854	83,243
49				
50	**Total PBL Revenue Requirement**		**5,779,030**	**5,820,087**
51				

Cost of Service Analysis
Computation of Low Density and Irrigation Rate Discount Costs
Test Period October 2021 - September 2023
($ 000)

	B	D	E	F	G	H
18	**Program Totals**	**2022**	**2023**			
19	**Low Density Discount Expenses........................**	**$ 39,482**	**$ 40,009**			
20	**Irrigation Rate Discount...................................**	**$ 20,509**	**$ 20,509**			
21						
22						
23	**TRM Costs after Adjustments**	**2022**	**2023**			
24	**Composite..**	$ 2,271,748	$ 2,279,201			
25	**Non-Slice..**	$ (286,530)	$ (287,761)			
26	**Slice...**	$ -	$ -			
27	**Tier 2...**	$ 46,009	$ 48,975			
28	**Total Costs**	$ 2,031,228	$ 2,040,415			
29						
30	**Low Density Discount**					
31	**Customer Charge LDD**	**2022**	**2023**			
32	**TOCA LDD Offest %.......................................**	1.84%	1.86%			
33	**LDD Customer Charge ($000).........................**	$ 36,561	$ 36,966			
34						
35	**Irrigation Rate Discount**					
36	**IRD Percentage..**	37.06%				
37	**Total Irrigation Load (MWh)..........................**	1,881,605				
38	**RT1SC...**	6,736				
39	**Irrigation Load Weighted LDD.......................**	4.8%				
40						
41		**2022**	**2023**			
42	**Hours..**	8760	8760			
43	**IRD TOCA..**	3.18859%	3.18859%			
44	**Composite Revenue...**	$ 76,465,602	$ 76,465,602			
45	**Non-Slice Revenue..**	$ (12,624,654)	$ (12,624,654)			
46	**Load Shaping Revenue......................................**	$ (5,713,712)	$ (5,713,712)			
47	**Total after LDD...**	$ 55,337,129	$ 55,337,129			
48						
49	**Irrigation Rate Discount...................................**	**10.90**				
50						
51						

Table 2.3.3.2

Cost of Service Analysis
Computation of Low Density and Irrigation Rate Discount Costs
Test Period October 2021 - September 2023
($ 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-21	11,685	(6,150)	$ 9.87	$ 29.92	$ (68,648)
54	Oct-21	-	345	$ 9.87	$ 28.27	$ 9,742
55	Nov-21	14,794	(14,738)	$ 10.46	$ 31.71	$ (312,594)
56	Nov-21	-	(5,649)	$ 10.46	$ 29.14	$ (164,591)
57	Dec-21	29,862	3,468	$ 12.78	$ 38.76	$ 516,037
58	Dec-21	-	1,222	$ 12.78	$ 32.05	$ 39,170
59	Jan-22	22,235	13,440	$ 11.31	$ 34.29	$ 712,413
60	Jan-22	-	7,482	$ 11.31	$ 25.85	$ 193,427
61	Feb-22	16,303	10,395	$ 11.47	$ 34.79	$ 548,622
62	Feb-22	-	4,586	$ 11.47	$ 28.29	$ 129,752
63	Mar-22	24,336	(3,031)	$ 9.09	$ 27.57	$ 137,660
64	Mar-22	-	(98)	$ 9.09	$ 28.44	$ (2,783)
65	Apr-22	22,760	5,215	$ 6.83	$ 20.71	$ 263,445
66	Apr-22	-	5,385	$ 6.83	$ 25.66	$ 138,182
67	May-22	12,806	(13,831)	$ 5.36	$ 16.28	$ (156,493)
68	May-22	-	3,830	$ 5.36	$ 16.30	$ 62,411
69	Jun-22	20,166	(14,608)	$ 5.65	$ 17.15	$ (136,610)
70	Jun-22	-	6,969	$ 5.65	$ 10.62	$ 74,001
71	Jul-22	20,552	(2,492)	$ 12.14	$ 36.83	$ 157,727
72	Jul-22	-	11,524	$ 12.14	$ 21.36	$ 246,188
73	Aug-22	26,683	(46)	$ 11.83	$ 35.87	$ 313,993
74	Aug-22	-	7,569	$ 11.83	$ 26.85	$ 203,271
75	Sep-22	17,625	(7,347)	$ 9.29	$ 28.15	$ (43,090)
76	Sep-22	-	2,062	$ 9.29	$ 28.95	$ 59,695
77	**Total**					**$ 2,920,926**

Cost of Service Analysis
Computation of Low Density and Irrigation Rate Discount Costs
Test Period October 2021 - September 2023
($ 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-22	12,333	(5,970)	$ 9.87	$ 29.92	$ (56,873)
80	Oct-22	-	206	$ 9.87	$ 28.27	$ 5,813
81	Nov-22	15,527	(14,885)	$ 10.46	$ 31.71	$ (309,593)
82	Nov-22	-	(5,555)	$ 10.46	$ 29.14	$ (161,841)
83	Dec-22	30,812	3,369	$ 12.78	$ 38.76	$ 524,369
84	Dec-22	-	1,448	$ 12.78	$ 32.05	$ 46,407
85	Jan-23	22,857	13,756	$ 11.31	$ 34.29	$ 730,269
86	Jan-23	-	7,420	$ 11.31	$ 25.85	$ 191,830
87	Feb-23	16,838	10,647	$ 11.47	$ 34.79	$ 563,515
88	Feb-23	-	4,618	$ 11.47	$ 28.29	$ 130,676
89	Mar-23	24,998	(3,072)	$ 9.09	$ 27.57	$ 142,528
90	Mar-23	-	27	$ 9.09	$ 28.44	$ 779
91	Apr-23	20,512	5,256	$ 6.83	$ 20.71	$ 248,933
92	Apr-23	-	5,553	$ 6.83	$ 25.66	$ 142,501
93	May-23	15,847	(13,804)	$ 5.36	$ 16.28	$ (139,755)
94	May-23	-	3,736	$ 5.36	$ 16.30	$ 60,875
95	Jun-23	20,759	(14,468)	$ 5.65	$ 17.15	$ (130,857)
96	Jun-23	-	6,880	$ 5.65	$ 10.62	$ 73,061
97	Jul-23	21,249	(2,300)	$ 12.14	$ 36.83	$ 173,265
98	Jul-23	-	11,465	$ 12.14	$ 21.36	$ 244,927
99	Aug-23	27,349	120	$ 11.83	$ 35.87	$ 327,857
100	Aug-23	-	7,686	$ 11.83	$ 26.85	$ 206,391
101	Sep-23	18,083	(7,235)	$ 9.29	$ 28.15	$ (35,656)
102	Sep-23	-	2,203	$ 9.29	$ 28.95	$ 63,772
103	**Total**					**$ 3,043,191**

Cost of Service Analysis
Allocation of Costs
Test Period October 2021 - September 2023
($ 000)

	B	C		D	
4	**Costs ($000)**		**2022**		**2023**
5	**FBS...**	$	1,886,750	$	1,939,849
6	**New Resources.....................................**	$	54,276	$	50,117
7	**Residential Exchange...........................**	$	3,288,062	$	3,288,917
8	**Conservation..**	$	199,259	$	189,237
9	**BPAPrograms......................................**	$	139,456	$	142,580
10	**Transmission..**	$	211,227	$	209,388
11	**Irrigation/Low Density Discounts.......**	$	59,992	$	60,519
12	Total..	$	5,839,021	$	5,880,606
13					
14	**Cost Allocation**				
15					
16	**FBS...**	$	1,886,750	$	1,939,849
17					
18	**Federal Base System Allocators...........**		**2022**		**2023**
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............................**		**2022**		**2023**
26	Priority Firm - 7(b) Loads.....................	$	1,886,750	$	1,939,849
27	Industrial Firm - 7(c) Loads..................	$	-	$	-
28	New Resources - 7(f) Loads..................	$	-	$	-
29	Surplus Firm - SP Loads.......................	$	-	$	-
30	Total..	$	1,886,750	$	1,939,849
31					
32					
33	**Irrigation/Low Density Discounts.......**	$	59,992	$	60,519
34					
35	**Irrigation/LDD Allocators..................**		**2022**		**2023**
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...........**		**2022**		**2023**
43	Priority Firm - 7(b) Loads.....................	$	59,992	$	60,519
44	Industrial Firm - 7(c) Loads..................	$	-	$	-
45	New Resources - 7(f) Loads..................	$	-	$	-
46	Surplus Firm - SP Loads.......................	$	-	$	-
47	Total..	$	59,992	$	60,519

Cost of Service Analysis
Allocation of Costs
Test Period October 2021 - September 2023
($ 000)

	B		C		D
4	**Costs ($000)**		**2022**		**2023**
5	**FBS..**	$	1,886,750	$	1,939,849
6	**New Resources......................................**	$	54,276	$	50,117
7	**Residential Exchange............................**	$	3,288,062	$	3,288,917
8	**Conservation...**	$	199,259	$	189,237
9	**BPAPrograms.......................................**	$	139,456	$	142,580
10	**Transmission...**	$	211,227	$	209,388
11	**Irrigation/Low Density Discounts.........**	$	59,992	$	60,519
12	Total...	$	5,839,021	$	5,880,606
13					
14	**Cost Allocation (continued)**				
15					
16	**New Resources......................................**	$	54,276	$	50,117
17					
18	**New Resources Allocators**		**2022**		**2023**
19	Priority Firm - 7(b) Loads......................		0.0000		0.0000
20	Industrial Firm - 7(c) Loads....................		0.0318		0.0567
21	New Resources - 7(f) Loads...................		0.00000298		0.00000530
22	Surplus Firm - SP Loads.........................		0.9682		0.9433
23	Total...		1.0000		1.0000
24					
25	**New Resources Cost Allocation...........**		**2022**		**2023**
26	Priority Firm - 7(b) Loads......................	$	-	$	-
27	Industrial Firm - 7(c) Loads....................	$	1,727	$	2,843
28	New Resources - 7(f) Loads...................	$	0.1619	$	0.2657
29	Surplus Firm - SP Loads.........................	$	52,549	$	47,273
30	Total...	$	54,276	$	50,117
31					
32					
33	**Residential Exchange............................**	$	3,288,062	$	3,288,917
34	Costs Functionalized to Transmission.....	$	(270,555)	$	(270,643)
35	Costs Functionalized to Generation.........	$	3,017,507	$	3,018,273
36					
37	**Residential Exchange Allocators**		**2022**		**2023**
38	Priority Firm - 7(b) Loads......................		0.9456		0.9729
39	Industrial Firm - 7(c) Loads....................		0.0017		0.0015
40	New Resources - 7(f) Loads...................		0.00000016		0.00000014
41	Surplus Firm - SP Loads.........................		0.0526		0.0256
42	Total...		1.0000		1.0000
43					
44	**Residential Exchange Cost Allocation**		**2022**		**2023**
45	Priority Firm - 7(b) Loads......................	$	2,853,422	$	2,936,380
46	Industrial Firm - 7(c) Loads....................	$	5,220	$	4,646
47	New Resources - 7(f) Loads...................	$	0.489	$	0.434
48	Surplus Firm - SP Loads.........................	$	158,864	$	77,247
49	Total...	$	3,017,507	$	3,018,273

Cost of Service Analysis
Allocation of Costs
Test Period October 2021 - September 2023
($ 000)

	B	C		D	
4	**Costs ($000)**		**2022**		**2023**
5	**FBS..**	$	1,886,750	$	1,939,849
6	**New Resources................................**	$	54,276	$	50,117
7	**Residential Exchange.......................**	$	3,288,062	$	3,288,917
8	**Conservation....................................**	$	199,259	$	189,237
9	**BPAPrograms..................................**	$	139,456	$	142,580
10	**Transmission...................................**	$	211,227	$	209,388
11	**Irrigation/Low Density Discounts...**	$	59,992	$	60,519
12	Total..	$	5,839,021	$	5,880,606
13					
14	**Cost Allocation (continued)**				
15					
16	**Conservation....................................**	$	199,259	$	189,237
17					
18	**BPAPrograms..................................**	$	139,456	$	142,580
19					
20	**Transmission...................................**	$	211,227	$	209,388
21					
22					
23	**Conservation & General Allocators**		**2022**		**2023**
24	Priority Firm - 7(b) Loads.................		0.9697		0.9829
25	Industrial Firm - 7(c) Loads..............		0.0010		0.0010
26	New Resources - 7(f) Loads..............		0.0000		0.0000
27	Surplus Firm - SP Loads...................		0.0293		0.0161
28	Total..		1.0000		1.0000
29					
30	**Conservation Cost Allocation..........**		**2022**		**2023**
31	Priority Firm - 7(b) Loads.................	$	193,231	$	185,997
32	Industrial Firm - 7(c) Loads..............	$	192	$	184
33	New Resources - 7(f) Loads..............	$	0	$	0
34	Surplus Firm - SP Loads...................	$	5,836	$	3,056
35	Total..	$	199,259	$	189,237
36					
37	**BPA Programs Cost Allocation.......**		**2022**		**2023**
38	Priority Firm - 7(b) Loads.................	$	135,237	$	140,139
39	Industrial Firm - 7(c) Loads..............	$	134	$	138
40	New Resources - 7(f) Loads..............	$	0	$	0
41	Surplus Firm - SP Loads...................	$	4,085	$	2,302
42	Total..	$	139,456	$	142,580
43					
44	**Transmission Cost Allocation..........**		**2022**		**2023**
45	Priority Firm - 7(b) Loads.................	$	204,837	$	205,804
46	Industrial Firm - 7(c) Loads..............	$	203	$	203
47	New Resources - 7(f) Loads..............	$	0	$	0
48	Surplus Firm - SP Loads...................	$	6,187	$	3,381
49	Total..	$	211,227	$	209,388

Cost of Service Analysis
Allocation of Costs Summary
Test Period October 2021 - September 2023
($ 000)

	B		C		D
4	**Costs ($000)**		**2022**		**2023**
5	**FBS...**	$	1,886,750	$	1,939,849
6	**New Resources..**	$	54,276	$	50,117
7	**Residential Exchange..................................**	$	3,288,062	$	3,288,917
8	**Conservation..**	$	199,259	$	189,237
9	**BPAPrograms..**	$	139,456	$	142,580
10	**Transmission...**	$	211,227	$	209,388
11	**Irrigation/Low Density Discounts.............**	$	59,992	$	60,519
12	Total...	$	5,839,021	$	5,880,606
13					
14	**Cost Allocation (continued)**				
15					
16					
17	**Initial Cost Allocation (Costs /$1000)**		**2022**		**2023**
18	Priority Firm - 7(b) Loads............................	$	5,333,469	$	5,468,688
19	Industrial Firm - 7(c) Loads.........................	$	7,476	$	8,015
20	New Resources - 7(f) Loads.........................	$	0.70	$	0.75
21	Surplus Firm - SP Loads..............................	$	227,521	$	133,259
22	Total Costs Functionalized to Power...........	$	5,568,467	$	5,609,963
23					
24					
25					
26	REP Cost Functionalized to Transmission	$	270,555	$	270,643
27					
28	Total COSA Revenue Requirement	$	5,839,021	$	5,880,606

Cost of Service Analysis
General Revenue Credits
Test Period October 2021 - September 2023
($ 000)

	B	C		D	
5	**General Revenue Credits ($000))**		**2022**		**2023**
6					
7	**FBS.....**	**$**	**(121,120)**	**$**	**(121,411)**
8	Hydro and Renewable.....	$	(25,261)	$	(25,261)
9	Downstream Benefits and Pumping Power.....	$	(20,661)	$	(20,661)
10	Colville and Spokane Settlements.....	$	(4,600)	$	(4,600)
11	Green Tags (FBS resources).....	$	-	$	-
12	Fish and Wildlife.....	$	(94,171)	$	(94,216)
13	4(h)(10)(c).....	$	(94,171)	$	(94,216)
14	Tier 2 Adjustment.....	$	(1,688)	$	(1,934)
15	**Contract Obligations.....**	**$**	**(411)**	**$**	**(402)**
16	Pre-sub/Hungry Horse.....	$	-	$	-
17	Other Locational/Seasonal Exchange.....	$	-	$	-
18	Upper Baker.....	$	(411)	$	(402)
19	**New Resources.....**	**$**	**-**	**$**	**-**
20	Green Tags (New resources).....	$	-	$	-
21	**Conservation.....**	**$**	**(8,000)**	**$**	**(8,000)**
22	Energy Efficiency Revenues.....	$	(8,000)	$	(8,000)
23	**BPAPrograms.....**	**$**	**-**	**$**	**-**
24	**Transmission.....**	**$**	**(11,621)**	**$**	**(11,696)**
25	Miscellaneous Credits (incl. GTA).....	$	(11,621)	$	(11,696)
26					
27	**Other Revenue Credits ($ 000))**		**2022**		**2023**
28	Secondary Revenue.....	**$**	**(526,230)**	**$**	**(501,343)**
29	Incl. Slice.....	$	(526,230)	$	(501,343)
30	Generation Inputs Revenue.....	**$**	**(104,245)**	**$**	**(104,245)**
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).....	**$**	**(879)**	**$**	**(879)**
35	Non-Slice Non-Federal RSC Revenue Debit/(Credit).....	**$**	**(236)**	**$**	**(236)**
36	NR Revenues from ESS energy and capacity charges.....	**$**	**-**	**$**	**-**
37	PF Load Forecast Deviation Liquidated Damages.....	$	(1,070)	$	(1,070)
38	**Firm Surplus and from Other Long-term Sales.....**	**$**	**(85,545)**	**$**	**(51,001)**
39	Other Surplus Sales (Non-Slice).....	$	-	$	-
40	Firm Surplus Secondary Sales.....	$	(85,545)	$	(51,001)
41					
42	**Total Revenue Credits**	$	(859,358)	$	(800,283)

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2021 - September 2023
($ 000)

	B		C		D
4	**Allocation of Revenue Requirement**		**2022**		**2023**
5	Priority Firm - 7(b) Loads.......................................	$	5,333,469	$	5,468,688
6	Industrial Firm - 7(c) Loads....................................	$	7,476	$	8,015
7	New Resources - 7(f) Loads....................................	$	1	$	1
8	Surplus Firm - SP Loads...	$	227,521	$	133,259
9	Total..	$	5,568,467	$	5,609,963
10					
11	**General Revenue Credits ($000))**		**2022**		**2023**
12					
13	**FBS...**	**$**	**(121,531)**	**$**	**(121,812)**
14	Hydro and Renewable.......................................	$	(25,261)	$	(25,261)
15	Downstream Benefits and Pumping Power..	$	(20,661)	$	(20,661)
16	Colville and Spokane Settlements................	$	(4,600)	$	(4,600)
17	Green Tags (FBS resources).......................	$	-	$	-
18	Fish and Wildlife...	$	(94,171)	$	(94,216)
19	4(h)(10)(c)...	$	(94,171)	$	(94,216)
20	Tier 2 Adjustment..	$	(1,688)	$	(1,934)
21	Contract Obligations...	$	(411)	$	(402)
22	Pre-sub/Hungry Horse................................	$	-	$	-
23	Other Locational/Seasonal Exchange...........	$	-	$	-
24	Upper Baker..	$	(411)	$	(402)
25					
26	**Federal Base System Allocators**		**2022**		**2023**
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**		**2022**		**2023**
34	Priority Firm - 7(b) Loads.......................................	$	(121,531)	$	(121,812)
35	Industrial Firm - 7(c) Loads....................................	$	-	$	-
36	New Resources - 7(f) Loads....................................	$	-	$	-
37	Surplus Firm - SP Loads...	$	-	$	-
38	Total..	$	(121,531)	$	(121,812)
39					
40	**Allocation of Revenue Requirement**		**2022**		**2023**
41	Priority Firm - 7(b) Loads.......................................	$	5,211,939	$	5,346,875
42	Industrial Firm - 7(c) Loads....................................	$	7,476	$	8,015
43	New Resources - 7(f) Loads....................................	$	1	$	1
44	Surplus Firm - SP Loads...	$	227,521	$	133,259
45	Total..	$	5,446,936	$	5,488,151

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2021 - September 2023
($ 000)

	B		C		D
40	**Allocation of Revenue Requirement**		**2022**		**2023**
41	Priority Firm - 7(b) Loads.......................................	$	5,211,939	$	5,346,875
42	Industrial Firm - 7(c) Loads....................................	$	7,476	$	8,015
43	New Resources - 7(f) Loads....................................	$	1	$	1
44	Surplus Firm - SP Loads...	$	227,521	$	133,259
45	Total..	$	5,446,936	$	5,488,151
46					
47					
48	**General Revenue Credits (/$1000))**		**2022**		**2023**
49					
50	**Transmission..**	**$**	**(11,621)**	**$**	**(11,696)**
51	Miscellaneous Credits (incl. GTA)...................	$	(11,621)	$	(11,696)
52					
53	**Conservation & General Cost Allocators**		**2022**		**2023**
54	Priority Firm - 7(b) Loads.......................................		0.9697		0.9829
55	Industrial Firm - 7(c) Loads....................................		0.0010		0.0010
56	New Resources - 7(f) Loads....................................		0.0000		0.0000
57	Surplus Firm - SP Loads...		0.0293		0.0161
58	Total..		1.0000		1.0000
59					
60	**Transmission Allocation**		**2022**		**2023**
61	Priority Firm - 7(b) Loads.......................................	$	(11,270)	$	(11,495)
62	Industrial Firm - 7(c) Loads....................................	$	(11)	$	(11)
63	New Resources - 7(f) Loads....................................	$	(0)	$	(0)
64	Surplus Firm - SP Loads...	$	(340)	$	(189)
65	Total..	$	(11,621)	$	(11,696)
66					
67	**Allocation of Revenue Requirement**		**2022**		**2023**
68	Priority Firm - 7(b) Loads.......................................	$	5,200,669	$	5,335,380
69	Industrial Firm - 7(c) Loads....................................	$	7,465	$	8,004
70	New Resources - 7(f) Loads....................................	$	1	$	1
71	Surplus Firm - SP Loads...	$	227,180	$	133,070
72	Total..	$	5,435,315	$	5,476,455

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2021 - September 2023
($ 000)

	B		C		D
4	**Allocation of Revenue Requirement**		**2022**		**2023**
5	Priority Firm - 7(b) Loads................................	$	5,200,669	$	5,335,380
6	Industrial Firm - 7(c) Loads.............................	$	7,465	$	8,004
7	New Resources - 7(f) Loads............................	$	1	$	1
8	Surplus Firm - SP Loads..................................	$	227,180	$	133,070
9	Total..	$	5,435,315	$	5,476,455
10					
11					
12	**General Revenue Credits ($000))**		**2022**		**2023**
13					
14	**New Resources..**	**$**	**-**	**$**	**-**
15	Green Tags (New resources)......................	$	-	$	-
16					
17					
18	**New Resources Cost Allocators**		**2022**		**2023**
19	Priority Firm - 7(b) Loads................................		0.0000		0.0000
20	Industrial Firm - 7(c) Loads.............................		0.0318		0.0567
21	New Resources - 7(f) Loads............................		0.000003		0.000005
22	Surplus Firm - SP Loads..................................		0.9682		0.9433
23	Total..		1.0000		1.0000
24					
25	**New Resources Allocation**		**2022**		**2023**
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**		**2022**		**2023**
33	Priority Firm - 7(b) Loads................................	$	5,200,669	$	5,335,380
34	Industrial Firm - 7(c) Loads.............................	$	7,465	$	8,004
35	New Resources - 7(f) Loads............................	$	0.700	$	0.748
36	Surplus Firm - SP Loads..................................	$	227,180	$	133,070
37	Total..	$	5,435,315	$	5,476,455
38					

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2021 - September 2023
($ 000)

	B	C		D	
32	**Allocation of Revenue Requirement**		**2022**		**2023**
33	Priority Firm - 7(b) Loads................................	$	5,200,669	$	5,335,380
34	Industrial Firm - 7(c) Loads.............................	$	7,465	$	8,004
35	New Resources - 7(f) Loads............................	$	0.700	$	0.748
36	Surplus Firm - SP Loads..................................	$	227,180	$	133,070
37	Total..	$	5,435,315	$	5,476,455
39					
40	**General Revenue Credits (/$1000))**		**2022**		**2023**
41					
42	**Conservation..**	**$**	**(8,000)**	**$**	**(8,000)**
43	Energy Efficiency Revenues.......................	$	(8,000)	$	(8,000)
44					
45	**Conservation & General Cost Allocators**		**2022**		**2023**
46	Priority Firm - 7(b) Loads................................		0.9697		0.9829
47	Industrial Firm - 7(c) Loads.............................		0.0010		0.0010
48	New Resources - 7(f) Loads............................		0.0000001		0.0000001
49	Surplus Firm - SP Loads..................................		0.0293		0.0161
50	Total..		1.0000		1.0000
51					
52	**Conservation Allocation**		**2022**		**2023**
53	Priority Firm - 7(b) Loads................................	$	(7,758)	$	(7,863)
54	Industrial Firm - 7(c) Loads.............................	$	(8)	$	(8)
55	New Resources - 7(f) Loads............................	$	(0.001)	$	(0.001)
56	Surplus Firm - SP Loads..................................	$	(234)	$	(129)
57	Total..	$	(8,000)	$	(8,000)
58					
59	**Allocation of Revenue Requirement**		**2022**		**2023**
60	Priority Firm - 7(b) Loads................................	$	5,192,911	$	5,327,517
61	Industrial Firm - 7(c) Loads.............................	$	7,457	$	7,996
62	New Resources - 7(f) Loads............................	$	0.699	$	0.747
63	Surplus Firm - SP Loads..................................	$	226,946	$	132,941
64	Total..	$	5,427,315	$	5,468,455

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2021 - September 2023
($ 000)

	B	C		D	
4	**Allocation of Revenue Requirement**		**2022**		**2023**
5	Priority Firm - 7(b) Loads......	$	5,192,911	$	5,327,517
6	Industrial Firm - 7(c) Loads......	$	7,457	$	7,996
7	New Resources - 7(f) Loads......	$	0.6992	$	0.7473
8	Surplus Firm - SP Loads......	$	226,946	$	132,941
9	Total......	$	5,427,315	$	5,468,455
10					
11	**General Revenue Credits (/$1000))**		**2022**		**2023**
12					
13	**Generation Inputs Revenue......**	**$**	**(104,245)**	**$**	**(104,245)**
14					
15	**Real Power Losses (Non-Slice)......**	**$**	**-**	**$**	**-**
16					
17	**PRSC Net Credit (Composite)......**	**$**	**-**	**$**	**-**
18					
19	**PRSC Net Credit (Non-Slice)......**	**$**	**-**	**$**	**-**
20					
21	**NR Revenues from ESS energy and capacity charges......**	**$**	**-**	**$**	**-**
22					
23	**PF Load Forecast Deviation Liquidated Damages......**	**$**	**(1,070)**	**$**	**(1,070)**
25					
26	**Conservation & General Cost Allocators**		**2022**		**2023**
27	Priority Firm - 7(b) Loads......		0.9697		0.9829
28	Industrial Firm - 7(c) Loads......		0.0010		0.0010
29	New Resources - 7(f) Loads......		0.0000001		0.0000001
30	Surplus Firm - SP Loads......		0.0293		0.0161
31	Total......		1.0000		1.0000
32					
33	**Gen Inputs & Wind Integration Credit Allocation**		**2022**		**2023**
34	Priority Firm - 7(b) Loads......	$	(102,130)	$	(103,513)
35	Industrial Firm - 7(c) Loads......	$	(101)	$	(102)
36	New Resources - 7(f) Loads......	$	(0)	$	(0)
37	Surplus Firm - SP Loads......	$	(3,085)	$	(1,701)
38	Total......	$	(105,316)	$	(105,316)
39					
40	**Allocation of Revenue Requirement**		**2022**		**2023**
41	Priority Firm - 7(b) Loads......	$	5,090,781	$	5,224,004
42	Industrial Firm - 7(c) Loads......	$	7,356	$	7,894
43	New Resources - 7(f) Loads......	$	0.6897	$	0.7377
44	Surplus Firm - SP Loads......	$	223,861	$	131,241
45	Total......	$	5,321,999	$	5,363,139
46					

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2021 - September 2023
($ 000)

	B		C		D
40	**Allocation of Revenue Requirement**		**2022**		**2023**
41	Priority Firm - 7(b) Loads.......	$	5,090,781	$	5,224,004
42	Industrial Firm - 7(c) Loads.......	$	7,356	$	7,894
43	New Resources - 7(f) Loads.......	$	0.6897	$	0.7377
44	Surplus Firm - SP Loads.......	$	223,861	$	131,241
45	Total.......	$	5,321,999	$	5,363,139
47					
48	**Other Revenue Credits**		**2022**		**2023**
49	Composite Non-Federal RSS Revenue Debit/(Credit).......	$	(879)	$	(879)
50	Non-Slice Non-Federal RSC Revenue Debit/(Credit).......	$	(236)	$	(236)
51					
52					
53	**Conservation & General Cost Allocators**		**2022**		**2023**
54	Priority Firm - 7(b) Loads.......		0.9697		0.9829
55	Industrial Firm - 7(c) Loads.......		0.0010		0.0010
56	New Resources - 7(f) Loads.......		0.0000001		0.0000001
57	Surplus Firm - SP Loads.......		0.0293		0.0161
58	Total.......		1.0000		1.0000
59					
60	**Non-Federal RSS Revenues**		**2022**		**2023**
61	Priority Firm - 7(b) Loads.......	$	(1,081)	$	(1,096)
62	Industrial Firm - 7(c) Loads.......	$	(1)	$	(1)
63	New Resources - 7(f) Loads.......	$	(0.0001)	$	(0.0001)
64	Surplus Firm - SP Loads.......	$	(33)	$	(18)
65	Total.......	$	(1,115)	$	(1,115)
66					
67	**Allocation of Revenue Requirement**		**2022**		**2023**
68	Priority Firm - 7(b) Loads.......	$	5,089,700	$	5,222,908
69	Industrial Firm - 7(c) Loads.......	$	7,355	$	7,893
70	New Resources - 7(f) Loads.......	$	0.6896	$	0.7376
71	Surplus Firm - SP Loads.......	$	223,829	$	131,223
72	Total.......	$	5,320,884	$	5,362,024

Cost of Service Analysis
Calculation and Allocation of Secondary Revenue Credit
Test Period October 2021 - September 2023
(aMW, $ 000)

	C	D		E	
4	**General Revenue Credits ($000))**		**2022**		**2023**
9					
10	BPA Secondary Sales Post-Slice (aMW)		1818		1815
11					
12	Slice Percentage		22.3627%		22.3627%
13					
14	Secondary Sales Pre-Slice, aMW		2342		2338
15					
16	aMW to GWh Multiplier		8.760		8.760
17					
18	Secondary Sales Price (Weighted Average, $/MWh)	$	22.32	$	21.82
19					
20	BPA Secondary Sales Post-Slice	$	355,433	$	346,946
21	Committed Sales	$	62,877	$	49,952
22					
23	Tier 1 System Firm Surplus Serving Tier 2	$	42,907	$	45,545
24	Tier 1 System Firm Surplus Sold @ Forward Market Price	$	42,638	$	5,456
25	Total Firm Surplus Secondary Sales	$	85,545	$	51,001
26					
27	Slice Secondary Sales ($000)	$	107,920	$	104,446
28					
29	BPA Secondary Sales Pre-Slice $000 (incl. CAISO Adjust, excl. Firm Surplus)	$	526,230	$	501,343
30					
35					
36	**Federal Base System + NR Cost Allocators**		**2022**		**2023**
37	Priority Firm - 7(b) Loads..........		0.9892		0.9911
38	Industrial Firm - 7(c) Loads..........		0.0003		0.0005
39	New Resources - 7(f) Loads..........		0.0000		0.0000
40	Surplus Firm - SP Loads..........		0.0105		0.0084
41	Total..........		1.0000		1.0000
42					
43					
44	**Allocation of Secondary Revenues Credit**		**2022**		**2023**
45	Priority Firm - 7(b) Loads..........	$	(520,544)	$	(496,878)
46	Industrial Firm - 7(c) Loads..........	$	(181)	$	(253)
47	New Resources - 7(f) Loads..........	$	(0.0170)	$	(0.0237)
48	Surplus Firm - SP Loads..........	$	(5,506)	$	(4,212)
49	Total..........	$	(526,230)	$	(501,343)
50					
51	**Allocation of Revenue Requirement**		**2022**		**2023**
52	Priority Firm - 7(b) Loads..........	$	4,569,156	$	4,726,031
53	Industrial Firm - 7(c) Loads..........	$	7,174	$	7,640
54	New Resources - 7(f) Loads..........	$	0.6726	$	0.7140
55	Surplus Firm - SP Loads..........	$	218,323	$	127,011
56	Total..........	$	4,794,654	$	4,860,681

Cost of Servise Analysis
Calculation and Allocation of FPS Revenue Deficiency Delta
Test Period October 2021 - September 2023
($ 000)

	B		C		D
5	**Allocation of Revenue Requirement**		2022		2023
6	Priority Firm - 7(b) Loads..	$	4,569,156	$	4,726,031
7	Industrial Firm - 7(c) Loads...	$	7,174	$	7,640
8	New Resources - 7(f) Loads..	$	0.6726	$	0.7140
9	Surplus Firm - SP Loads..	$	218,323	$	127,011
10	Total..	$	4,794,654	$	4,860,681
11					
12	**Firm Surplus and from Other Long-term Sales.............**	**$**	**(85,545)**	**$**	**(51,001)**
13	Other Surplus Sales (Non-Slice).............................	$	-	$	-
14	Firm Surplus Secondary Sales................................	$	(85,545)	$	(51,001)
15					
16	**Calculation of FPS Revenue Deficiency**		2022		2023
17	Surplus Firm - SP Loads..	$	218,323	$	127,011
18					
19	**Deficiency...**	**$**	**132,778**	**$**	**76,009**
20					
21					
22					
23	**Surplus Deficit Cost Allocators**		2022		2023
24	Priority Firm - 7(b) Loads..		0.9990		0.9990
25	Industrial Firm - 7(c) Loads...		0.0010		0.0010
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**		2022		2023
31	Priority Firm - 7(b) Loads..	$	132,646	$	75,934
32	Industrial Firm - 7(c) Loads...	$	132	$	75
33	New Resources - 7(f) Loads..	$	0.0123	$	0.0070
34	Surplus Firm - SP Loads..	$	(132,778)	$	(76,009)
35	Total..	$	-	$	-
36					
37					
38	**Initial Allocation of Net Revenue Requirement**		2022		2023
39	Priority Firm - 7(b) Loads..	$	4,701,803	$	4,801,965
40	Industrial Firm - 7(c) Loads...	$	7,305	$	7,715
41	New Resources - 7(f) Loads..	$	0.6849	$	0.7210
42	Surplus Firm - SP Loads..	$	85,545	$	51,001
43	Total..	$	4,794,654	$	4,860,681

Cost of Service Analysis
Calculation of Initial Allocation Power Rates
Test Period October 2021 - September 2023
($ 000, aMW, $/MWh)

	B	C		D	
5	**Initial Allocation of Net Revenue Requirement ($000)**		**2022**		**2023**
6	Unbifurcated Priority Firm - 7(b) Loads.......................................	$	4,701,803	$	4,801,965
7	Industrial Firm - 7(c) Loads..	$	7,305	$	7,715
8	New Resources - 7(f) Loads...	$	0.6849	$	0.7210
9	Surplus Firm - SP Loads..	$	85,545	$	51,001
10	Total...	$	4,794,654	$	4,860,681
11					
12					
13	**Energy Billing Determinants (aMW)**		**2022**		**2023**
14					
15	Unbifurcated Priority Firm - 7(b) Loads.......................................		12,097		12,148
16	Industrial Firm - 7(c) Loads..		12		12
17	New Resources - 7(f) Loads...		0.001		0.001
18					
19					
20	**Average Power Rates ($/MWh)**		**2022**		**2023**
21					
22	Unbifurcated Priority Firm - 7(b) Loads.......................................		44.37		45.12
23	Industrial Firm - 7(c) Loads..		69.49		73.39
24	New Resources - 7(f) Loads...		69.49		73.39

Rate Directive Step
Calculation of DSI VOR and Net Industrial Margin
Test Period October 2021 - September 2023

	B	C	D	E	F	G	H	I
5								
6	Operating Reserves - Supplemental							
8			Embedded Cost $/kW/Mo			$ 5.27		
9								
10	1) Assumed DSI sale					12	aMW	
11	Assumed Wheel Turning Load					0	aMW	
12	Interruptible Load					12		
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					$ 75,888	per year	
17	Value converted to $/MWh on total load					$ 0.722	$/MWh	
18								
19					industrial margin	0.808		
20								
21					**net industrial margin**	**$ 0.086**		

Table 2.4.2

Rate Directive Step
Calculation of Annual Energy Rate Scalars for First IP-PF Link Calculation
Test Period October 2021 - September 2023

	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)		29.92	31.71	38.76	34.29	34.79	27.57	20.71	16.28	17.15	36.83	35.87	28.15				
8	LLH (mills/kWh)		28.27	29.14	32.05	25.85	28.29	28.44	25.66	16.30	10.62	21.36	26.85	28.95				
9	Demand Rate ($/kW/mo)		9.87	10.46	12.78	11.31	11.47	9.09	6.83	5.36	5.65	12.14	11.83	9.29				
10																		
11																		
12	**Unbifurcated PF+NR Load**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			**2022**	
13	**2022**	HLH	4876	5594	6267	6042	5238	5536	4612	4809	5156	5275	5414	4746			Energy (GWH)	105966
14		LLH	3171	3890	4596	4485	3606	3640	3031	3195	2917	3509	3191	3170			Allocated Cost	**$ 4,704,619**
15		Demand	446	577	1227	950	644	1017	934	613	972	908	1178	883			Rate Scalar	**15.34**
16	Revenue at marginal Rates		$ 239,907	$ 296,794	$ 405,863	$ 333,895	$ 291,604	$ 265,406	$ 179,648	$ 133,638	$ 124,901	$ 280,273	$ 293,804	$ 233,567		**$ 3,079,299**		
17			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			**2023**	
18	**2023**	HLH	4910	5645	6369	6049	5282	5586	4575	4806	5074	5306	5455	4793			Energy (GWH)	106419
19		LLH	3178	3908	4572	4562	3636	3668	3142	3050	2867	3547	3223	3215			Allocated Cost	**$ 4,805,117**
20		Demand	483	596	1245	967	660	1030	840	737	983	920	1189	863			Rate Scalar	**16.03**
21	Revenue at marginal Rates		$ 241,534	$ 299,116	$ 409,292	$ 336,313	$ 294,193	$ 267,690	$ 181,085	$ 131,900	$ 123,028	$ 282,346	$ 296,272	$ 235,993		**$ 3,098,764**		
43																		
50																		
51		**IP Load**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			**2022**	
52	**2022**	HLH	5	5	5	5	5	5	5	5	5	5	5	5			Energy (GWH)	105
53		LLH	4	4	4	4	4	4	4	4	4	4	4	4			Allocated Cost	**$ 4,490**
54		Demand	0	0	0	0	0	0	0	0	0	0	0	0			Rate Scalar	**15.25**
55	Revenue at marginal Rates		$ 261	$ 264	$ 318	$ 272	$ 258	$ 249	$ 198	$ 145	$ 124	$ 265	$ 286	$ 246		**$ 2,886**		
56			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			**2023**	
57	**2023**	HLH	5	5	5	5	5	5	5	5	5	5	5	5			Energy (GWH)	105
58		LLH	4	4	4	4	4	4	4	4	4	4	4	4			Allocated Cost	**$ 4,563**
59		Demand	0	0	0	0	0	0	0	0	0	0	0	0			Rate Scalar	**15.95**
60	Revenue at marginal Rates		$ 261	$ 264	$ 318	$ 272	$ 258	$ 249	$ 198	$ 145	$ 124	$ 265	$ 286	$ 246		**$ 2,886**		

Table 2.4.3

Rate Directive Step
Calculation of Monthly Energy Rate Scalars for First IP-PF Link Calculation
Test Period October 2021 - September 2023
($/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)		29.92	31.71	38.76	34.29	34.79	27.57	20.71	16.28	17.15	36.83	35.87	28.15				
7	LLH (mills/kWh)		28.27	29.14	32.05	25.85	28.29	28.44	25.66	16.30	10.62	21.36	26.85	28.95				
8	Demand Rate ($/kW/mo)		9.87	10.46	12.78	11.31	11.47	9.09	6.83	5.36	5.65	12.14	11.83	9.29				
9																		
10																		
11	**Unbifurcated PF/NR**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
12	**2022**	HLH	45.26	47.05	54.10	49.63	50.13	42.91	36.04	31.62	32.49	52.17	51.20	43.49				**2022**
13		LLH	43.61	44.48	47.39	41.19	43.63	43.78	41.00	31.64	25.96	36.70	42.19	44.29				**15.34**
14		Demand	9.87	10.46	12.78	11.31	11.47	9.09	6.83	5.36	5.65	12.14	11.83	9.29				**Scalar**
15			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
16	**2023**	HLH	45.95	47.74	54.79	50.33	50.82	43.60	36.74	32.31	33.19	52.87	51.90	44.18				**2023**
17		LLH	44.30	45.17	48.08	41.88	44.32	44.47	41.69	32.33	26.65	37.39	42.88	44.98				**16.03**
18		Demand	9.87	10.46	12.78	11.31	11.47	9.09	6.83	5.36	5.65	12.14	11.83	9.29				**Scalar**
36																		
42																		
43		**IP**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
44	**2022**	HLH	45.17	46.96	54.01	49.55	50.04	42.82	35.96	31.53	32.40	52.08	51.12	43.40				**2022**
45		LLH	43.52	44.39	47.30	41.10	43.54	43.69	40.91	31.55	25.87	36.61	42.10	44.20				**15.25**
46		Demand	9.87	10.46	12.78	11.31	11.47	9.09	6.83	5.36	5.65	12.14	11.83	9.29				**Scalar**
47			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
48	**2023**	HLH	45.87	47.66	54.71	50.24	50.74	43.52	36.65	32.23	33.10	52.78	51.81	44.10				**2023**
49		LLH	44.22	45.09	48.00	41.80	44.24	44.39	41.61	32.25	26.57	37.31	42.80	44.90				**15.95**
50		Demand	9.87	10.46	12.78	11.31	11.47	9.09	6.83	5.36	5.65	12.14	11.83	9.29				**Scalar**

Table 2.4.4

Rate Directive Step
Calculation of First IP-PF Link Delta
Test Period October 2021 - September 2023
($ 000)

	B	C	D	E	F	G	H
89		**FY 2022**	**FY 2023**	**FY 2024**	**FY 2025**	**FY 2026**	**FY 2027**
90	Average PF Rate	$ 44.37	$ 45.12	$ 48.78	$ 47.37	$ 49.57	$ 49.11
91	Net Industrial Margin	0.086	0.086	0.086	0.086	0.086	0.086
92	Flat DSI Load (GWh)	105	105	105	105	105	105
93	Revenue 1	4,673	4,752	5,137	4,989	5,220	5,171
94							
95	IP Rate	$ 69.49	$ 73.39	$ 73.43	$ 75.48	$ 76.25	$ 77.82
96	Flat DSI Load (GWh)	105	105	105	105	105	105
97	Revenue 2	7,305	7,715	7,719	7,934	8,015	8,180
98							
99	Starting Difference	2,632	2,963	2,582	2,946	2,796	3,009
100							
101	Adjustment (calculated using Goal Seek)	183.89	188.99	455.28	474.24	485.82	502.07
102							
103	Delta	2,815	3,152	3,037	3,420	3,281	3,511

Rate Directive Step
Reallocation of First IP-PF Link Delta and Recalculation of Rates
Test Period October 2021 - September 2023
($ 000, aMW, $/MWh)

	B	C		D	
5	**Initial Allocation of Net Revenue Requirement)**		**2022**		**2023**
6	Unbifurcated Priority Firm - 7(b) Loads..............................	$	4,701,803	$	4,801,965
7	Industrial Firm - 7(c) Loads...	$	7,305	$	7,715
8	New Resources - 7(f) Loads..	$	0.6849	$	0.7210
9	Surplus Firm - SP Loads..	$	85,545	$	51,001
10	Total..	$	4,794,654	$	4,860,681
11					
12					
13	**First IP-PF Link Delta**	**$**	**2,815**	**$**	**3,152**
14					
15					
16	**7(c)(2) Delta Cost Allocators**		**2022**		**2023**
17	Unbifurcated Priority Firm - 7(b) Loads..............................		0.999999907		0.999999908
18	Industrial Firm - 7(c) Loads...		-1.000000000		-1.000000000
19	New Resources - 7(f) Loads..		0.000000093		0.000000092
20					
21	**7(c)(2) Delta Cost Allocation**		**2022**		**2023**
22	Unbifurcated Priority Firm - 7(b) Loads..............................	$	2,815	$	3,152
23	Industrial Firm - 7(c) Loads...	$	(2,815)	$	(3,152)
24	New Resources - 7(f) Loads..	$	0.000	$	0.000
25	Total..	$	0	$	(0)
26					
27	**Cost Allocation After 7c2 Delta ($ 000)**		**2022**		**2023**
28	Unbifurcated Priority Firm - 7(b) Loads..............................	$	4,704,618	$	4,805,117
29	Industrial Firm - 7(c) Loads...	$	4,490	$	4,563
30	New Resources - 7(f) Loads..	$	0.685	$	0.721
31	Surplus Firm - SP Loads..	$	85,545	$	51,001
32	Total..	$	4,794,654	$	4,860,681
33					
34	**Energy Billing Determinants (aMW)**		**2022**		**2023**
35	Unbifurcated Priority Firm - 7(b) Loads..............................		12,097		12,148
36	Industrial Firm - 7(c) Loads...		12		12
37	New Resources - 7(f) Loads..		0.001125114		0.001121461
38					
39					
40	**Average Power Rates ($/MWh)**		**2022**		**2023**
41					
42	Unbifurcated Priority Firm - 7(b) Loads..............................		44.40		45.15
43	Industrial Firm - 7(c) Loads...		42.71		43.41
44	New Resources - 7(f) Loads..		69.52		73.42
45					
46					
47	Base PF Exchange Rate w/o Transmission Adder...............		**44.78**		

Rate Directive Step
Calculation of IP Floor Calculation
Test Period October 2021 - September 2023

	B	C	D	E	F	G	H	I	J
10		Industrial Firm Power Floor Rate Calculation							
11				**A**	**B**	**C**	**D**	**E**	**F**
12									
13				**DEMAND**		**ENERGY**		**Customer**	**Total/**
14				**Winter**	**Summer**	**Winter**	**Summer**	**Charge**	**Average**
15				(Dec-Apr)	(May-Nov)	(Sep-Mar)	(Apr-Aug)		
16									
17	1	IP Billing Determinants[1]		118	167	122	88	285	210
18	2	IP-83 Rates		4.62	2.21	14.70	12.20	7.34	
19	3	Revenue		547	368	1,795	1,075	2,091	5,876
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]		20.82					
37									
38		Note 1 - Demand billing determinants are the test period DSI load expressed in noncoincidental demand MWs.							
39		Note 2 - Billing determinants as forecast in the 1983 Rate Case Final Proposal (WP-83-FS-BPA-07, p. 82).							
40		Note 3 - Transmission Costs as forecast in the 1983 Rate Case Final Proposal (WP-83-FS-BPA-07, p. 80).							
41		Note 4 - Line 15 / Line 14							
42		Note 5 - Rebate or Surcharge for IP divided by OY 1985 IP Billing Determinants							
43		Note 6 - 1985 Final Rate Proposal (WP-85-FS-BPA-08A, p. 15).							
44		Note 7 - Total Revenue Col F, divided by IP Billing Determinants, Col F							
45		Note 8 - IP-83 Avg Rate adjusted for the effects of the Exchange and Deferral, Lines 16 + 17 + 18 + 19							

Rate Directive Step
IP Floor Rate Test
Test Period October 2021 - September 2023

	B	C	D	E	F	G	H	I	J
8									
9									
10									
11		Industrial Firm Power Floor Rate Test							
12						**A**	**B**	**C**	
13									
14									
15						**Total**		**Average**	
16						**Energy**	**TOTALS**	**Rate**	
17									
18									
19	1	IP Billing Determinants				210			
20	2	Floor Rate (mills/kWh)				20.82			
21	3	Value of Reserves Credit (mills/kWh)							
22	4	Revenue at Floor Rate Less VOR Credit				4,378	4,378	20.82	
23	5	IP Revenue Under Proposed Rates					9,053	43.06	
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 2021 - September 2023

	B	C	D	E	F
9		**Cost Allocation After 7c2 Delta**	**2022**	**2023**	Total
10		Unbifurcated Priority Firm - 7(b) Loads.............................	$ 4,704,618	$ 4,805,117	$ 9,509,735
11					
12		Exchange Unbifurcated Costs to 7(b) Loads.......................	$ 2,164,318	$ 2,201,862	$ 4,366,180
13					
14					
15					
16					
17		**Energy Billing Determinants (aMW)**	**2022**	**2023**	
18		Unbifurcated Priority Firm - 7(b) Loads.............................	5,565	5,567	
19					
20					
21		**Average Power Rates**	**2022**	**2023**	
22					
23		Unbifurcated Priority Firm - 7(b) Loads.............................	44.40	45.15	
24					
25					
26			(GWh)		
27		Two Year PF Public Load T1	111982		
28		Two Year PF Public Load T2	2889		
29		Two Year IOU PF Exchange Load	90068		
30		Two Year COU PF Exchange Load	7445		
31		Total Two-Year Unbifurcated PF Load	212385		
32					
33					
34		T 2 Costs	$ 94,984		
35		T 1 Costs	$ 9,414,751		
36		Total	$ 9,509,735		
37					
45		Total PF Costs Minus PF T2 Costs	$ 9,414,751		
46		Total PF Load Minus PF T2 Load	209,496		
47		COU Base PF w/o Transmission	44.94		
48		Exchange Transmission Adder	5.55		
49		**COU Base PFx**	**50.49**		
50					
51					
52		Two Year COU PF Exchange Load	7445		
53		Two Year Base PF Public Exchange T2 Revenue	$ 334,585		
54					
55		Total Exchange Costs minus COU Exchange Costs	$ 4,031,595		
56		Total IOU Exchange Loads	90,068		
57		IOU Base PF w/o Transmission	44.76		
58		Exchange Transmission Adder	5.55		
59		**IOU Base PFx**	**50.31**		
60					

Table 2.4.9

Rate Directive Step
Calculation of IOU REP Benefits in Rates
Test Period October 2021 - September 2023

	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		$259,000		
19	Refund Amount*		$0		
20	REP Recovery Amount		$259,000		
21					
26					
27					
28			**2022**		**2023**
29			($000)		($000)
30	IOU Unconstrained Benefits	$	814,477	$	814,477
31	REP Recovery Amount	**$**	**259,000**	**$**	**259,000**
32	Rate Protection Delta	$	555,477	$	555,477
33					
34	**Refund of Initial EOFY2011 Lookback Completed by end of FY 2019*				

Rate Directive Step
Calculation of REP Base Exchange Benefits
Test Period October 2021 - September 2023

	B	C	D	E	F	G	H	I	J	K	L
5	**IOU Base PFx**	**50.31**									
6	**COU Base PFx**	**50.49**		**ASCs**			**Exchange Loads**			**Unconstrained Benefits**	
7										(load * (ASC - Base PFx)	
8				**2022**	**2023**		**2022**	**2023**		**2022**	**2023**
9											
10											
11	Avista Corporation	1		62.93	62.93		3,971	3,971		$ 50,113	$ 50,113
12	Idaho Power Company	1		58.17	58.17		6,857	6,857		$ 53,885	$ 53,885
13	NorthWestern Energy,	1		68.34	68.34		714	714		$ 12,874	$ 12,874
14	PacifiCorp	1		77.61	77.61		9,147	9,147		$ 249,702	$ 249,702
15	Portland General Elect	1		70.09	70.09		12,392	12,392		$ 245,089	$ 245,089
16	Puget Sound Energy, I	1		67.28	67.28		11,952	11,952		$ 202,813	$ 202,813
17	Clark Public Utilities	0		42.14	42.14		0	0		$ -	$ -
18	Franklin	0		0.00	0.00		0	0		$ -	$ -
19	Snohomish PUD	1		55.83	55.83		3,715	3,731		$ 19,835	$ 19,921
31	Total									**$ 834,312**	**$ 834,398**
32											
33									IOU	**$ 814,477**	**$ 814,477**

Rate Directive Step
Calculation of Utility Specific PF Exchange Rates and REP Benefits
Test Period October 2021 - September 2023

	B	D	E	F	G	H	I	J	K	L	M	N	O	P
4	**Initial Allocations**			**FY 2022**	**FY 2023**	**Average**				**Interim**	**Refund**	**Interim**	**Interim**	**Interim**
5			**Base**	**Exchange**	**Exchange**	**Exchange**	**Unconstrained**	**Scheduled**	**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	62.93	50.31	3,971	3,971	3,971	$ 50,113			$ 34,177	$ -	8.61	58.92	$ 15,936
9	Idaho Power Company	58.17	50.31	6,857	6,857	6,857	$ 53,885			$ 36,750	$ -	5.36	55.67	$ 17,135
10	NorthWestern Energy, LLC	68.34	50.31	714	714	714	$ 12,874			$ 8,780	$ -	12.30	62.61	$ 4,094
11	PacifiCorp	77.61	50.31	9,147	9,147	9,147	$ 249,702			$ 170,298	$ -	18.62	68.93	$ 79,404
12	Portland General Electric Company	70.09	50.31	12,392	12,392	12,392	$ 245,089			$ 167,152	$ -	13.49	63.80	$ 77,937
13	Puget Sound Energy, Inc.	67.28	50.31	11,952	11,952	11,952	$ 202,813			$ 138,320	$ -	11.57	61.88	$ 64,494
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	55.83	50.49	3,715	3,731	3,723	$ 19,878			$ 13,557		3.64	54.13	$ 6,321
17	Total						$ 834,355	$259,000	$0	$ 569,034	$0			$ 265,321
18														
19	rounding to places = $896					IOU Σ(g)	$ 814,477	$259,000	$259,000	$ 555,477	IOU Σ(j)		IOU REP	$ 259,000
20						COU Σ(g)	$ 19,878		$6,321	$ 13,557	COU Σ(j)		COU REP	$ 6,321
21														
22	**IOU Reallocations**													
23		**Interim**				**Final**	**Final**	**Final**		**Final**			**FY 2022**	**FY 2023**
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	$ 15,936	$ 2,005	$ -	$ 13,931	$ 36,182	9.11	59.42220		$ 13,931		Avista	$ 13,931	$ 13,931
28	Idaho Power Company	$ 17,135	$ -	$ -	$ 17,135	$ 36,750	5.36	55.67110		$ 17,135		Idaho Power	$ 17,135	$ 17,135
29	NorthWestern Energy, LLC	$ 4,094	$ -	$ 56	$ 4,150	$ 8,724	12.22	62.52860		$ 4,150		NorthWestern	$ 4,150	$ 4,150
30	PacifiCorp	$ 79,404	$ -	$ -	$ 79,404	$ 170,298	18.62	68.92920		$ 79,405		PacifiCorp	$ 79,405	$ 79,405
31	Portland General Electric Company	$ 77,937	$ -	$ 1,066	$ 79,003	$ 166,085	13.40	63.71450		$ 79,004		Portland	$ 79,004	$ 79,004
32	Puget Sound Energy, Inc.	$ 64,494	$ -	$ 882	$ 65,376	$ 137,437	11.50	61.81030		$ 65,376		Puget Sound	$ 65,376	$ 65,376
33	Total	$ 259,000	$ 2,005	$ 2,005	$ 259,000	$ 555,477				$ 259,001		IOU REP	$ 259,001	$ 259,001
34														
35												Clark	$ -	$ -
36												Franklin	$ -	$ -
37	**IOU Reallocation Adjustments**											Snohomish	$ 6,308	$ 6,335
38		Avista	Idaho	NorthWestern	PacifiCorp	Portland	Puget Sound	Total				COU REP	$ 6,308	$ 6,335
39		$ 2,005	$ -	$ -	$ -	$ -	$ -					Total REP	$ 265,308	$ 265,336
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	$ 265,308	$ 265,336
43	NorthWestern Energy, LLC	$ 56	$ -		$ -	$ -	$ -	$ 56						
44	PacifiCorp		$ -	$ -				$ -						
45	Portland General Electric Company	$ 1,066	$ -	$ -	$ -			$ 1,066						
46	Puget Sound Energy, Inc.	$ 882	$ -	$ -	$ -	$ -		$ 882						
47		$ 2,005	$ -	$ -	$ -	$ -	$ -	$ 2,005						

Table 2.4.12

Rate Directive Step
IOU Reallocation Balances
Test Period October 2021 - September 2023

	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						
21						
22		**FY2012 Realloc**	**Accrued Interest**	**FY2013 Realloc**	**Accrued Interest**	**Remain Balance**
23	Avista Corporation	$ 2,004,778	$ 659,503	$ 2,004,778	$ 619,144	$ 20,254,901
24	Idaho Power Company	$ 2,521,193	$ 1,316,387	$ 2,521,193	$ 1,280,243	$ 42,694,414
25	NorthWestern Energy, LLC	$ (766,000)	$ -	$ (766,000)	$ -	$ (2,298,000)
26	PacifiCorp	$ 8,442,636	$ 1,875,000	$ 8,442,636	$ 1,677,971	$ 53,389,014
27	Portland General Electric Company	$ 1,237,583	$ 121,513	$ 1,237,583	$ 88,031	$ 2,403,600
28						
29		**FY2014 Realloc**	**Accrued Interest**	**FY2015 Realloc**	**Accrued Interest**	**Remain Balance**
30	Avista Corporation	$ 2,004,778	$ 577,575	$ 4,287	$ 534,759	$ 17,357,680
31	Idaho Power Company	$ 3,001,474	$ 1,235,810	$ 3,001,474	$ 1,182,840	$ 39,110,117
32	NorthWestern Energy, LLC	$ (766,000)	$ -	$ (766,000)	$ -	$ (766,000)
33	PacifiCorp	$ 8,442,636	$ 1,475,031	$ 8,442,636	$ 1,266,003	$ 39,244,775
34	Portland General Electric Company	$ 1,237,583	$ 53,544	$ 1,237,583	$ 18,023	$ -
35						
36		**FY2016 Realloc**	**Accrued Interest**	**FY2017 Realloc**	**Accrued Interest**	**Remain Balance**
37	Avista Corporation	$ 2,004,778	$ 490,659	$ 2,004,778	$ 445,235	$ 14,284,017
38	Idaho Power Company	$ 10,183,223	$ 1,020,555	$ 10,183,223	$ 745,675	$ 20,509,901
39	NorthWestern Energy, LLC	$ (383,000)	$ -	$ (383,000)	$ -	$ -
40	PacifiCorp	$ 8,442,636	$ 1,050,704	$ 8,442,636	$ 828,946	$ 24,239,153
41	Portland General Electric Company	$ -	$ -	$ -	$ -	$ -
42						
43		**FY2018 Realloc**	**Accrued Interest**	**FY2019 Realloc**	**Accrued Interest**	**Remain Balance**
44	Avista Corporation	$ 2,004,778	$ 398,449	$ 2,004,778	$ 350,259	$ 11,023,169
45	Idaho Power Company	$ 10,254,951	$ 461,473	$ 10,254,951	$ 167,668	$ 629,141
46	NorthWestern Energy, LLC	$ -	$ -	$ -	$ -	$ -
47	PacifiCorp	$ 8,442,636	$ 600,535	$ 8,442,636	$ 365,272	$ 8,319,688
48	Portland General Electric Company	$ -	$ -	$ -	$ -	$ -
49						
50		**FY2020 Realloc**	**Accrued Interest**	**FY2021 Realloc**	**Accrued Interest**	**Remain Balance**
51	Avista Corporation	$ 2,004,778	$ 300,623	$ 2,004,778	$ 249,499	$ 7,563,736
52	Idaho Power Company	$ 314,571	$ 14,156	$ 314,571	$ 5,143	$ -
53	NorthWestern Energy, LLC	$ -	$ -	$ -	$ -	$ -
54	PacifiCorp	$ 4,159,844	$ 187,193	$ 4,159,844	$ 68,013	$ -
55	Portland General Electric Company	$ -	$ -	$ -	$ -	$ -
56						
57		**FY2022 Realloc**	**Accrued Interest**	**FY2023 Realloc**	**Accrued Interest**	**Remain Balance**
58	Avista Corporation	$ 2,004,778	$ 196,840	$ 2,004,778	$ 142,602	$ 3,893,622
59	Idaho Power Company	$ -	$ -	$ -	$ -	$ -
60	NorthWestern Energy, LLC	$ -	$ -	$ -	$ -	$ -
61	PacifiCorp	$ -	$ -	$ -	$ -	$ -
62	Portland General Electric Company	$ -	$ -	$ -	$ -	$ -
63						

Rate Directive Step
Calculation and Allocation of the Increase in PF Exchange Revenue Requirement Due to REP Settlement
Test Period October 2021 - September 2023

	B		C		D
4	**Cost Allocation After 7c2 Delta**		**2022**		**2023**
5	Priority Firm Public - 7(b) Loads...	$	2,540,301	$	2,603,254
6	Priority Firm Exchange - 7(b) Loads....................................	$	2,164,318	$	2,201,862
7	Industrial Firm - 7(c) Loads...	$	4,490	$	4,563
8	New Resources - 7(f) Loads...	$	0.685	$	0.721
9	Surplus Firm - SP Loads..	$	85,545	$	51,001
10	Total..	$	4,794,654	$	4,860,681
11					
12					
13	**Calc Rate Protection to PFx Rate**		**2022**		**2023**
14	Unconstrained Benefits	$	834,312	$	834,398
15	REP Recovery Amount plus COU Benefits	$	(265,308)	$	(265,336)
16	delta	$	569,004	$	569,062
17					
18					
19	**Allocation Factors**		**2022**		**2023**
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**		**2022**		**2023**
27	Priority Firm Public - 7(b) Loads...	$	(569,004)	$	(569,062)
28	Priority Firm Exchange - 7(b) Loads....................................	$	569,004	$	569,062
29	Industrial Firm - 7(c) Loads...	$	-	$	-
30	New Resources - 7(f) Loads...	$	-	$	-
31	Total..	$	-	$	-
32					
33					
34	**Cost Allocation After Rate Protection to PFx**		**2022**		**2023**
35	Priority Firm Public - 7(b) Loads...	$	1,971,297	$	2,034,192
36	Priority Firm Exchange - 7(b) Loads....................................	$	2,733,322	$	2,770,924
37	Industrial Firm - 7(c) Loads...	$	4,490	$	4,563
38	New Resources - 7(f) Loads...	$	0.685	$	0.721
39	Surplus Firm - SP Loads..	$	85,545	$	51,001
40	Total..	$	4,794,654	$	4,860,681
41					
42					
43	**Energy Billing Determinants (aMW)**		**2022**		**2023**
44	Priority Firm Public - 7(b) Loads...		6,532		6,582
45	Priority Firm Exchange - 7(b) Loads....................................		5,565		5,567
46	Industrial Firm - 7(c) Loads...		12		12
47	New Resources - 7(f) Loads...		0.001125114		0.001121461
48					
50					
51	**Average Power Rates**		**2022**		**2023**
52	Priority Firm Public - 7(b) Loads...		34.45		35.28
53	Priority Firm Exchange - 7(b) Loads....................................		61.62		62.37
54	Industrial Firm - 7(c) Loads...		42.71		43.41
55	New Resources - 7(f) Loads...		69.52		73.42

Table 2.4.14

Rate Directive Step
Calculation of PF, IP and NR Rate Contribution to Net REP Benefit Costs
Test Period October 2021 - September 2023

	B	C		D	
25			**2022**		**2023**
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	$	7.37	$	7.37
30	IP Load		105		105
31	NR Load		0		0
32	REP Surcharge Revenue from IP Rate	$	774	$	774
33	REP Surcharge Revenue from NR Rate	$	0	$	0
34					
35	Amount of REP Recovery remaining after IP/NR REP Surcharge	$	264,534	$	264,561
36	Remaining REP Recovery in PF, IP and NR Rates ($/MWh)	$	4.61	$	4.58
37					
38	Before Reallocation				
39	IP REP Recovery Amount in Rates	$	1,259	$	1,256
40	NR REP Recovery Amount in Rates	$	0	$	0
41					
42	After Reallocation				
43	IP REP Recovery Amount in Rates	$	772	$	773
44	NR REP Recovery Amount in Rates	$	0	$	0
45					
46					
47	Reallocation that Should be in Rates		**2022**		**2023**
48	Priority Firm Public - 7(b) Loads..	$	264,049	$	264,080
49	Industrial Firm - 7(c) Loads..	$	1,259	$	1,256
50	New Resources - 7(f) Loads..	$	0.118	$	0.117
51		$	265,308	$	265,336
52					
53	Adjustment Necessary to Achieve Reallocation		**2022**		**2023**
54	Priority Firm Public - 7(b) Loads..	$	(773)	$	(773)
55	Industrial Firm - 7(c) Loads..	$	772	$	773
56	New Resources - 7(f) Loads..	$	0.072	$	0.072
57		$	0	$	(0)
58					
59			**2022**		**2023**
60	PF Contribution to Net REP Benefits $/MWh.............................		4.61		4.58
61	IP Contribution to Net REP Benefits $/MWh..............................		11.98		11.95
62	NR Contribution to Net REP Benefits $/MWh............................		11.98		11.95

Rate Directive Step
Reallocation of Rate Protection Provided by the IP and NR Rates
Test Period October 2021 - September 2023

	B		C		D
4	**Cost Allocation After Rate Protection Provided by PFx**		**2022**		**2023**
5	Priority Firm Public - 7(b) Loads	$	1,971,297	$	2,034,192
6	Priority Firm Exchange - 7(b) Loads	$	2,733,322	$	2,770,924
7	Industrial Firm - 7(c) Loads	$	4,490	$	4,563
8	New Resources - 7(f) Loads	$	0.685	$	0.721
9	Surplus Firm - SP Loads	$	85,545	$	51,001
10	Total	$	4,794,654	$	4,860,681
11					
12					
13					
14	**Allocation of Rate Protection Provided by IP and NR**		**2022**		**2023**
15	Priority Firm Public - 7(b) Loads	$	(773)	$	(773)
16					
17	Industrial Firm - 7(c) Loads	$	772	$	773
18	New Resources - 7(f) Loads	$	0.072	$	0.072
19	Total	$	0	$	(0)
20					
21					
22	**Cost Allocation After Rate Protection Provided by IP and NR**		**2022**		**2023**
23	Priority Firm Public - 7(b) Loads	$	1,970,524	$	2,033,419
24	Priority Firm Exchange - 7(b) Loads	$	2,733,322	$	2,770,924
25	Industrial Firm - 7(c) Loads	$	5,262	$	5,336
26	New Resources - 7(f) Loads	$	0.758	$	0.793
27	Surplus Firm - SP Loads	$	85,545	$	51,001
28	Total	$	4,794,654	$	4,860,681
29					
30					
31	**Energy Billing Determinants (aMW)**		**2022**		**2023**
32	Priority Firm Public - 7(b) Loads		6,532		6,582
33	Priority Firm Exchange - 7(b) Loads		5,565		5,567
34	Industrial Firm - 7(c) Loads		12		12
35	New Resources - 7(f) Loads		0.001125114		0.001121461
36					
38					
39	**Average Power Rates After Rate Protection Reallocations**		**2022**		**2023**
40	Priority Firm Public - 7(b) Loads		34.44		35.27
41	Priority Firm Exchange - 7(b) Loads		61.62		62.37
42	Industrial Firm - 7(c) Loads		50.06		50.76
43	New Resources - 7(f) Loads		76.87		80.77

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

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
5																			
6		**Load Shaping Rate**	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep					
7		HLH (mills/kWh)	29.92	31.71	38.76	34.29	34.79	27.57	20.71	16.28	17.15	36.83	35.87	28.15					
8		LLH (mills/kWh)	28.27	29.14	32.05	25.85	28.29	28.44	25.66	16.30	10.62	21.36	26.85	28.95					
9		Demand Rate ($/kW/mo)	9.87	10.46	12.78	11.31	11.47	9.09	6.83	5.36	5.65	12.14	11.83	9.29					
10																			
11		**PF+NR Load**	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				**2022**	
12	**2022**	HLH	2633	3021	3384	3262	2828	2989	2490	2597	2784	2849	2923	2563				Energy (GWH)	57217
13		LLH	1712	2101	2482	2422	1947	1966	1636	1725	1575	1895	1723	1712				Allocated Cost	$ 1,971,550
14		Demand	241	311	662	513	348	549	504	331	525	490	636	477				Rate Scalar	**5.40**
15		Revenue at marginal Rates	$ 129,540	$ 160,257	$ 219,149	$ 180,290	$ 157,454	$ 143,308	$ 97,003	$ 72,159	$ 67,441	$ 151,336	$ 158,642	$ 126,117			$ 1,662,695		
16			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				**2023**	
17	**2023**	HLH	2660	3058	3451	3277	2862	3026	2479	2604	2749	2875	2956	2596				Energy (GWH)	57654
18		LLH	1722	2117	2477	2471	1970	1987	1702	1652	1553	1922	1746	1742				Allocated Cost	$ 2,034,438
19		Demand	262	323	674	524	358	558	455	399	533	498	644	467				Rate Scalar	**6.17**
20		Revenue at marginal Rates	$ 130,855	$ 162,051	$ 221,741	$ 182,203	$ 159,384	$ 145,026	$ 98,106	$ 71,459	$ 66,653	$ 152,966	$ 160,510	$ 127,853			$ 1,678,809		
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				**2022**	
26	**2022**	HLH	5	5	5	5	5	5	5	5	5	5	5	5				Energy (GWH)	105
27		LLH	4	4	4	4	4	4	4	4	4	4	4	4				Allocated Cost	$ 4,237
28		Demand	0	0	0	0	0	0	0	0	0	0	0	0				Rate Scalar	**12.85**
29		Revenue at marginal Rates	$ 261	$ 264	$ 318	$ 272	$ 258	$ 249	$ 198	$ 145	$ 124	$ 265	$ 286	$ 246			$ 2,886		
30			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				**2023**	
31	**2023**	HLH	5	5	5	5	5	5	5	5	5	5	5	5				Energy (GWH)	105
32		LLH	4	4	4	4	4	4	4	4	4	4	4	4				Allocated Cost	$ 4,318
33		Demand	0	0	0	0	0	0	0	0	0	0	0	0				Rate Scalar	**13.62**
34		Revenue at marginal Rates	$ 261	$ 264	$ 318	$ 272	$ 258	$ 249	$ 198	$ 145	$ 124	$ 265	$ 286	$ 246			$ 2,886		
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)		29.92	31.71	38.76	34.29	34.79	27.57	20.71	16.28	17.15	36.83	35.87	28.15				
7	LLH (mills/kWh)		28.27	29.14	32.05	25.85	28.29	28.44	25.66	16.30	10.62	21.36	26.85	28.95				
8	Demand Rate ($/kW/mo)		9.87	10.46	12.78	11.31	11.47	9.09	6.83	5.36	5.65	12.14	11.83	9.29				
9																		
10																		
11		**PFp /NR**	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
12	**2022**	HLH	35.32	37.11	44.16	39.69	40.19	32.97	26.10	21.68	22.55	42.23	41.26	33.55				**2022**
13		LLH	33.67	34.54	37.45	31.25	33.69	33.84	31.06	21.70	16.02	26.76	32.25	34.35				**5.40**
14		Demand	9.87	10.46	12.78	11.31	11.47	9.09	6.83	5.36	5.65	12.14	11.83	9.29				**Scalar**
15			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
16	**2023**	HLH	36.09	37.88	44.93	40.46	40.96	33.74	26.87	22.45	23.32	43.00	42.03	34.32				**2023**
17		LLH	34.44	35.31	38.22	32.02	34.46	34.61	31.83	22.47	16.79	27.53	33.02	35.12				**6.17**
18		Demand	9.87	10.46	12.78	11.31	11.47	9.09	6.83	5.36	5.65	12.14	11.83	9.29				**Scalar**
19																		
20																		
21		**IP**	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
22	**2022**	HLH	42.77	44.56	51.61	47.14	47.64	40.42	33.55	29.13	30.00	49.68	48.71	41.00				**2010**
23		LLH	41.12	41.99	44.90	38.70	41.14	41.29	38.51	29.15	23.47	34.21	39.70	41.80				**12.85**
24		Demand	9.87	10.46	12.78	11.31	11.47	9.09	6.83	5.36	5.65	12.14	11.83	9.29				**Scalar**
25			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
26	**2023**	HLH	43.54	45.33	52.38	47.92	48.41	41.19	34.33	29.90	30.77	50.45	49.49	41.77				**2011**
27		LLH	41.89	42.76	45.67	39.47	41.91	42.06	39.28	29.92	24.24	34.98	40.47	42.57				**13.62**
28		Demand	9.87	10.46	12.78	11.31	11.47	9.09	6.83	5.36	5.65	12.14	11.83	9.29				**Scalar**

Table 2.4.18

Rate Directive Step
Calculation of Second IP-PF Link Delta
Test Period October 2021 - September 2023

	B	C		D	
45			**FY 2022**		**FY 2023**
46	Average PF Rate	$	34.44	$	35.27
47	Net Industrial Margin		0.086		0.086
48	Flat DSI Load (GWh)		105		105
49	Revenue 1		3,629		3,717
50					
51	IP Rate	$	50.06	$	50.76
52	Flat DSI Load (GWh)		105		105
53	Revenue 2		5,262		5,336
54					
55	Difference		1,633		1,619
56					
57	Adjustment (calculated using Goal Seek)		(607.87)		(601.75)
58					
59	Delta		1,025		1,017

Rate Directive Step
Reallocation of IP-PF Link Delta and Recalculation of Rates
Test Period October 2021 - September 2023

	B	C		D		E
4	**Cost Allocation After Rate Protection Provided by IP and NR**		**2022**		**2023**	
5	Priority Firm Public - 7(b) Loads	$	1,970,524	$	2,033,419	
6	Priority Firm Exchange - 7(b) Loads	$	2,733,322	$	2,770,924	
7	Industrial Firm - 7(c) Loads	$	5,262	$	5,336	
8	New Resources - 7(f) Loads	$	0.758	$	0.793	
9	Surplus Firm - SP Loads	$	85,545	$	51,001	
10	Total	$	4,794,654	$	4,860,681	
11						
12						
13	IP-PF Link Delta	$	1,025	$	1,017	
14						
15			**2022**		**2023**	
16	Priority Firm Public - 7(b) Loads		0.99999983		0.99999983	
17	Industrial Firm - 7(c) Loads		(1.00000000)		(1.00000000)	
18	New Resources - 7(f) Loads		0.00000017		0.00000017	
19						
20						
21	**Allocation of Second IP-PF Link Delta**		**2022**		**2023**	
22	Priority Firm Public - 7(b) Loads	$	1,025	$	1,017	
23	Priority Firm Exchange - 7(b) Loads	$	-	$	-	
24	Industrial Firm - 7(c) Loads	$	(1,025)	$	(1,017)	
25	New Resources - 7(f) Loads	$	0.000	$	0.000	
26	Total	$	0	$	0	
27						
28						
29	**Cost Allocation After Second IP-PF Link**		**2022**		**2023**	
30	Priority Firm Public - 7(b) Loads	$	1,971,549	$	2,034,437	
31	Priority Firm Exchange - 7(b) Loads	$	2,733,322	$	2,770,924	
32	Industrial Firm - 7(c) Loads	$	4,237	$	4,318	
33	New Resources - 7(f) Loads	$	0.758	$	0.794	
34	Surplus Firm - SP Loads	$	85,545	$	51,001	
35	Total	$	4,794,654	$	4,860,681	
36						
37						
38	**Energy Billing Determinants (aMW)**		**2022**		**2023**	
39	Priority Firm Public - 7(b) Loads		6,532		6,582	
40	Priority Firm Exchange - 7(b) Loads		5,565		5,567	
41	Industrial Firm - 7(c) Loads		12		12	
42	New Resources - 7(f) Loads		0.001125114		0.001121461	
43						
45						
46	**Average Power Rates After Second IP-PF Link**		**2022**		**2023**	Average
47	Priority Firm Public - 7(b) Loads		34.46		35.29	**34.87**
48	Priority Firm Exchange - 7(b) Loads		61.62		62.37	**62.00**
49	Industrial Firm - 7(c) Loads		40.31		41.08	**40.69**
50	New Resources - 7(f) Loads		76.89		80.79	**78.84**

Rate Design Step
REP Benefit Reconciliation
Test Period October 2021 to September 2023

	B	D	E	F	GH	I	J	K	L
4		**2022**	**2023**	**Avg**			**2022**	**2023**	**Avg**
5	Resource Costs	3,287,597	3,288,491	3,288,044		PFx Alloc Cost	(2,733,322)	(2,770,924)	
6	PFx Revenues	(3,003,876)	(3,041,568)	(3,022,722)		Exch Tmn Cost	(270,555)	(270,643)	
7	REP Benefits	283,721	246,923	265,322			(3,003,876)	(3,041,568)	(3,022,722)
8									
9	**REP Benefits**					**PFx Revenues**			
10	Avista Corporation	13,931	13,931			Avista Corporation	244,720	247,710	
11	Idaho Power Company	17,135	17,135			Idaho Power Company	422,531	427,693	
12	NorthWestern Energy, LLC	4,150	4,150			NorthWestern Energy, LLC	44,004	44,542	
13	PacifiCorp	79,405	79,405			PacifiCorp	563,646	570,531	
14	Portland General Electric Company	79,004	79,004			Portland General Electric Compar	763,578	772,905	
15	Puget Sound Energy, Inc.	65,376	65,376			Puget Sound Energy, Inc.	736,507	745,503	
16	IOU REP	259,001	259,001	259,001		IOU REP	2,774,985	2,808,883	2,791,934
17									
18	Clark Public Utilities	-	-			Clark Public Utilities	-	-	
19	Franklin	-	-			Franklin	-	-	
20	Snohomish PUD	6,308	6,335			Snohomish PUD	228,891	232,685	
21	COU REP	6,308	6,335	6,321		COU REP	228,891	232,685	230,788
22									
23	Refund Amounts	-	-			Refund Amounts	-	-	
24	Total REP	265,308	265,336	265,322		Total REP	3,003,876	3,041,568	3,022,722
25				0			(0)	(0)	(0)
26									
27	**For Slice True-Up**								100.00%
28	IOU REP	259,001	259,001						
29	COU REP	6,308	6,335						
30	Refund Amounts	-	-						
31	Total REP	265,308	265,336						

Table 2.5.1

Rate Design Study
Allocated Cost and Unit Cost Priority Firm Rates
Test Period October 2021 - September 2023

	C	D	E	F	H	I	J	K
11								
12		**A**	**B**	**C**	**PF Public**		**PF Exchange**	
13		**ALLOCATED**	**UNIT**	**PERCENT**	**ALLOCATED**		**ALLOCATED**	
14		**COSTS**	**COSTS**	**CONTRIBUTION**	**COSTS**		**COSTS**	
15	GENERATION ENERGY	($ Thousands)	(Mills/kWh)	(Percent)				
16								
17	Federal Base System							
18	Hydro	1,497,818	7.052	15.75%	810,117	7.052	687,701	7.052
19	Fish & Wildlife	643,655	3.031	6.77%	348,130	3.031	295,524	3.031
20	Trojan	2,400	0.011	0.03%	1,298	0.011	1,102	0.011
21	WNP #1	145,893	0.687	1.53%	78,908	0.687	66,984	0.687
22	WNP #2	1,192,910	5.617	12.54%	645,203	5.617	547,707	5.617
23	WNP #3	167,585	0.789	1.76%	90,641	0.789	76,944	0.789
24	System Augmentation	0	0.000	0.00%	0	0.000	0	0.000
25	Balancing Power Purchases	81,354	0.383	0.86%	44,002	0.383	37,353	0.383
26	Tier 2 Costs	94,984	0.447	1.00%	51,374	0.447	43,611	0.447
27	Total Federal Base System	3,826,599	18.017	40.24%	2,069,673	18.017	1,756,925	18.017
28	New Resources	0	0.000	0.00%				
29	Gross Residential Exchange	5,789,802	27.261	60.88%	3,131,501	27.261	2,658,301	27.261
30	Conservation	379,228	1.786	3.99%	205,111	1.786	174,117	1.786
31	BPA Programs	275,377	1.297	2.90%	148,942	1.297	126,435	1.297
32	Power Transmission	410,641	1.933	4.32%	222,101	1.933	188,540	1.933
33	TOTAL COSA ALLOCATIONS	10,681,647	50.294	112.32%	5,777,329	50.294	4,904,318	50.294
34			0.000					
35			0.000					
36	Nonfirm Excess Revenue Credit	(1,017,421)	-4.790	-10.70%	(550,287)	-4.790	(467,134)	-4.790
37	Low Density Discount Expense	120,510	0.567	1.27%	65,180	0.567	55,331	0.567
38	Other Revenue Credits	(489,549)	-2.305	-5.15%	(264,780)	-2.305	(224,769)	-2.305
39	Irrigation Rate Mitigation Expense		0.000	0.00%	0	0.000	0	0.000
40	SP Revenue Surplus/Dfct Adj.	208,581	0.982	2.19%	112,814	0.982	95,767	0.982
41	7(c)(2) Delta Adjustment	5,967	0.028	0.06%	3,227	0.028	2,740	0.028
42	7(c)(2) Floor Rate Adjustment		0.000	0.00%	0	0.000	0	0.000
43	TOTAL RATE DESIGN ADJUSTMENTS	(1,171,912)	-5.518	-12.32%	(633,846)	-5.518	(538,066)	-5.518
44			0.000	0.00%				
45	Total Generation	9,509,735	**44.7760**	100.00%	5,143,483	**44.78**	4,366,252	**44.78**
46			0.000					
47		0	0.000					
48	REP Settlement Rate Protection Adjustment		0.000		(1,139,611)	-9.921	1,138,066	1,138,066
49	7(b)(2) - 7(c)(2) Industrial Adjustment	0	0.000		2,042	0.018	0	0.000
50	Total Generation		0.000		**4,005,914**	**34.87**	5,504,319	**56.45**
51								
52	Total Transmission						541,198	5.550
53							6,045,517	**62.00**
54								

Table 2.5.2

Rate Design Study
Allocated Cost and Unit Costs for Industrial Firm Power Rate
Test Period October 2021 - September 2023

	C	D	E	F
13		**ALLOCATED**	**UNIT**	**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	4,570	21.738	53.42%
28	Gross Residential Exchange	9,866	46.928	115.33%
29	Conservation	376	1.786	4.39%
30	BPA Programs	273	1.297	3.19%
31	Power Transmission	407	1.934	4.75%
32	TOTAL COSA ALLOCATIONS	15,491	73.684	181.09%
33			0.000	0.00%
34	Nonfirm Excess Revenue Credit	(434)	-2.066	-5.08%
35		0.00000	0.000	0.00%
36	Other Revenue Credits	(244)	-1.160	-2.85%
37			0.000	0.00%
38	SP Revenue Surplus/Dfct Adj.	207	0.983	2.42%
39	7(c)(2) Delta Adjustment	(5,967)	-28.382	-69.75%
40	7(c)(2) Floor Rate Adjustment	0	0.000	0.00%
41	TOTAL RATE DESIGN ADJSTMTS	(6,439)	-30.625	-75.26%
42	Total Generation	9,053	43.059	105.82%
43			0.000	0.00%
55	Total Allocated & Adjusted Costs	9,053	43.059	105.82%
56			0.000	0.00%
57	Settlement Adjustments		0.000	0.00%
58	REP Settlement Rate Protection Adjustment	1,545	7.349	18.06%
59	7(b)(2) - 7(c)(2) Industrial Adjustment	(2,042)	-9.715	-23.88%
60		8,555	**40.69**	100.00%
61				
62	Billing Determinants:			
63	Energy (GwH)	210		

Table 2.5.3

Rate Design Study
Allocated Costs and Unit Costs for New Resources Firm Power Rate
Test Period October 2021 - September 2023

	C	D	E	F
12		**ALLOCATED**	**UNIT**	**PERCENT**
13		**COSTS**	**COSTS**	**CONTRIBUTION**
14	GENERATION ENERGY	($ Thousands)	(Mills/kWh)	(Percent)
15				
16	Federal Base System			
17	Hydro	0	0.000	0.00%
18	Fish & Wildlife	0	0.000	0.00%
19	Trojan	0	0.000	0.00%
20	WNP #1	0	0.000	0.00%
21	WNP #2	0	0.000	0.00%
22	WNP #3	0	0.000	0.00%
23	System Augmentation	0		
24	Balancing Power Purchases	0	0.000	0.00%
25	Total Federal Base System	0.000	0.000	0.00%
26	New Resources	0.4276	21.730	27.56%
27	Gross Residential Exchange	0.9236	46.933	59.53%
28	Conservation	0.0352	1.786	2.27%
29	BPA Programs	0.0636	3.231	4.10%
30	TOTAL COSA ALLOCATIONS	1.4500	73.680	93.46%
31			0.000	0.00%
32	Nonfirm Excess Revenue Credit	(0.0406)	-2.065	-2.62%
33		0.0000	0.000	0.00%
34	Other Revenue Credits	(0.0228)	-1.160	-1.47%
35			0.000	0.00%
36	SP Revenue Surplus/Dfct Adj.	0.0194	0.983	1.25%
37	7(c)(2) Delta Adjustment	0.0006	0.028	0.04%
38	7(c)(2) Floor Rate Adjustment	0.0000	0.000	0.00%
39	TOTAL RATE DESIGN ADJSTMTS	(0.0436)	-2.213	-2.81%
40	Total Generation Energy	1.4065	71.467	90.66%
41			0.000	0.00%
50			0.000	0.00%
51	Total Allocated & Adjusted Costs	1.4065	71.467	90.66%
52	Settlement Adjustments		0.000	0.00%
53	REP Settlement Rate Protection Adjustment	0.1446	7.349	9.32%
54	7(b)(2) - 7(c)(2) Industrial Adjustment	0.0004	0.018	0.02%
55			0.000	0.00%
56	Total With 7(b)(2) Adjustments	1.5514	**78.83**	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 2021 - September 2023

	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	2,069,673	3,131,501	0	5,201,174		39.79%	60.21%	0.00%	100.00%
18	Priority Firm - Exchange	1,756,925	2,658,301	0	4,415,226		39.79%	60.21%	0.00%	100.00%
19	Priority Firm Power - Total	3,826,599	5,789,802	0	9,616,401		39.79%	60.21%	0.00%	100.00%
20	Industrial Firm Power	0	9,866	4,570	14,436		0.00%	68.34%	31.66%	100.00%
21	New Resources Firm	0	0.924	0	1		0.00%	68.35%	31.65%	100.00%
22	Firm Power Products and Services	0	236,111	99,822	335,933		0.00%	70.29%	29.71%	100.00%
23		0			0					
24										
25	**TOTALS**	**3,826,599**	**6,035,780**	**104,393**	**9,966,772**		**38.39%**	**60.56%**	**1.05%**	**100.00%**
26										
27					212,595					
28										
29				Average Cost of Resources	46.88					
30										
31				Average Cost to Serve Load Growth	33.65					

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 RAM2022. 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 prices used for Tier 2 surplus credit or deficit debit.

Table 3.10
Remarketing Value Inputs
Table lists prices used to calculate the Remarketing Value.

Table 3.11
Rates and Charges for RSS and Related Services in FY 2022 and FY 2023
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.

Table 3.1.1.1

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

	A	B	C	D	E	G	H
4						**2022**	**2023**
5		**Composite**					
6			Federal Base System				
7				Hydro			
8					Operating Expense	630,591	627,058
9					Interest	26,160	22,708
10					MRNR	54,420	86,373
11				Fish & Wildlife			
12					Operating Expense	306,445	307,321
13					Interest	3,323	2,780
14					MRNR	6,913	10,574
15				Trojan		1,200	1,200
16				WNP #1		72,788	73,105
17				Columbia Generating Station		583,848	609,062
18				WNP #3		83,756	83,830
19				Augmentation		-	-
20			Residentail Exchange Program				
21				REP Net Cost		265,308	265,336
22				Program Support		464	426
23				Settlement Interest Accrual		-	-
24			NewResources				
25				Cowlitz		12,987	13,903
26				Idaho		-	-
27				Tier 1 Aug (Klondike III)		10,249	11,421
28				Other		33,126	26,879
29			Conservation				
30				Operating Expense		188,654	179,711
31				Interest		2,631	1,606
32				MRNR		5,472	6,107
33			BPAPrograms				
34				Operating Expense		137,469	140,414
35				Interest		493	365
36				MRNR		1,025	1,389
37			Transmission				
38				Transmission and Ancillary Services		49,942	50,042
39				General Transfer Agreements		81,854	83,243
40			Nonslice Interest and MRNR Allocated to Cost Pools				
41				Interest on BPA fund Credit to Nonslice		86	189
42				Accrual Revenue (MRNR Adjustment)		-	-
43			**Total**			**2,559,205**	**2,605,042**

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

	A	B	C	D	E	G	H
4						**2022**	**2023**
44		**Non-Slice**					
45			FBS				
46				Balancing Purchases from Risk Mod		33,783	28,925
47				Balancing in Revenue Requirement		9,484	9,163
48				PNRR			
49					Hydro	24,871	25,637
50					Fish & Wildlife	3,159	3,139
51			Conservation				
52				PNRR		2,501	1,812
53			BPAPrograms				
54				Hedging Mitigation		-	-
55				RCD Expense Offset Non-Slice		-	-
56				PNRR		469	412
57			Transmission				
58				Transmission and Ancillary Services		79,432	76,103
59				Third-party T&A		-	-
60			Nonslice Interest and MRNR				
61				BPA Fund		(86)	(189)
62				Non-Slice MRNR Adjustment		-	-
63			**Total**			**153,613**	**145,002**
64		**Slice**					
65			BPAPrograms				
66				Other Slice Costs		-	-
67			**Total**			-	-
68		**Tier 2**					
69			FBS				
70				Tier 2 Purchase Costs		44,321	47,041
71				Tier 2 Rate Design Adjustments		1,688	1,934
72				Tier 2 Other Costs		-	-
73			**Total**			**46,009**	**48,975**

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

	A	B	C	D	E	G	H
4						2022	2023
74		Rate Direct/Design Adjustments					
75			Credits Allocated Against Cost Pools				
76				FBS (excluding T2 Adjustment)		(119,432)	(119,477)
77				Contract Obligations		(411)	(402)
78				New Resources		-	-
79				Conservation		(8,000)	(8,000)
80				BPAPrograms		-	-
81				Transmission		(11,621)	(11,696)
82							
83			Secondary Energy Credit (includes pre-sale and Slice)			(526,230)	(501,343)
84			Firm Surplus Secondary Sales			(85,545)	(51,001)
85			Generation Inputs Credit			(104,245)	(104,245)
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)			(1,070)	(1,070)
92			Non-Slice FPS Revenues (excl. secondary)			-	-
93							
94			Low Density Discount			39,482	40,009
95			Irrigation Rate Mitigation Costs			20,509	20,509
96							
97			Composite Augmentation RSS Revenue Debit/(Credit)			(2,010)	(2,010)
98			Composite Tier 2 RSS Revenue Debit/(Credit)			(151)	(167)
99			Composite Tier 2 Rate Design Adjustment Debit/(Credit)			(1,537)	(1,767)
100			Composite Non-Federal RSS Revenue Debit/(Credit)			(879)	(879)
101			Non-Slice Augmentation RSC Revenue Debit/(Credit)			(76)	(76)
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)			(236)	(236)
105							
106			Firm Surplus and Secondary Credit (from unused RHWM)			(86,168)	(79,301)
107			Demand Revenue			54,969	55,946
108			Load Shaping Revenue			12,713	23,082

Table 3.1.2

Rate Design Step
Unused RHWM (net) Credit Computation
Test Period October 2021 to September 2023

	B	C	D
4		**2022**	**2023**
5	Secondary (aMW)	2,342	2,338
6	T1SFCO (aMW)	6,667	6,667
7	RHWM Augmentation (aMW)	69	69
8	RP Augmentation (aMW)	-	-
9	System Augmentation (aMW)	-	-
10	Firm Surplus (aMW)	305	189
11	IP and NR Loads contributing to avoided cost	12	12
12			
13	Value of Secondary	$ 22.32	$ 21.82
14	Value of T1SFCO ($/MWh)	$ 27.82	$ 27.82
15	Value of Augmentation	$ 34.48	$ 34.17
16	Value of Firm Surplus	$ 32.05	$ 30.73
17			
18	Secondary (MWh)	20,514,136	20,484,284
19	T1SFCO (MWh)	58,403,796	58,403,796
20	RHWM Augmentation (MWh)	606,709	606,709
21	IP and NR Loads (MWh)	108,505	108,505
22	Change in T1SFCO (MWh)	186,021	250,904
23			
24	Unused RHWM (MWh)	3,109,175	2,925,794
25			
26	Unused Secondary	1,080,859	1,015,629
27	Unused T1SFCO	3,077,208	2,895,713
28	Unused Augmentation	31,967	30,081
29			
30	Value of Unused	$ 110,828,350	$ 103,740,256
31	Value of System Augmentation not Purchased	$ 24,660,589	$ 24,438,871
32			
33	Net Credit/(Cost)	$ 86,167,761	$ 79,301,385
34			
35	$/MWh value of Unused RHWM	**$ 35.55**	

Table 3.1.3

Rate Design Step
Slice Return of Network Losses Adjustment
Test Period October 2021 - September 2023

	B	C	D
4	**Annual Evaluation**	**2022**	**2023**
5	Non Slice Loads (MWh)	42,522,625	43,072,599
6	Loss Percent Assumption	2.03%	2.03%
7	Implied Non Slice Losses	864,452	875,643
8	Average Slice&Non-Slice Tier 1 Rate	34.92	34.92
9	Implied Cost/Credit ($1000)	30,187	30,577

Table 3.1.4

Rate Design Step
Balancing Augmentation Adjustment for Change to the Equivalent Tier 1 System Firm Critical Output
Test Period October 2021 - September 2023

	A	B	C	E	F	G
4				**2022**	**2023**	
5		**Table 3.1**				
6			Regulated	5,934	5,934	
7			Independent	348	348	
8		**Table 3.2**				
9			Ashland Solar Project	-	-	
10			Columbia Generating Station	1,116	994	
11			Condon Wind Project	12	-	
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	3	-	
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	10	10	
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	6,532	6,582	
55			Tier 2	157	173	
56			Net Preference	6,375	6,408	
57			Industrial	12	12	
58			New Resource	0	0	
59			Intraregional Transfer	11	11	
60			FBS Obligation	654	654	
61			Seasonal or Capacity Exchange	2	-	
62			Conservation Augmentation	-	-	
63			Transmission Losses Before Slice Return	226	227	
64			Slice Return of Losses	29	28	
65			Transmission Losses After Slice Return	197	199	
66						
67		**Annual T1SFCO**		6,712	6,573	
68		**RHWM Process T1SFCO (annual)**		6,733	6,601	
69		**Difference**		(21)	(29)	
70		**Augmentation Price (zero if no incremental Augmentation)**		$ -	$ -	
71		**Hours**		8,760	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 2021 - September 2023

	B	E	F	G	H	I	J	K	L
5	**2022**	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-21	240,598	$ 9.87	$ 2,374,707	(197,718)	111,103	$ 29.92	$ 28.27	$ (2,774,841)
7	Nov-21	311,366	$ 10.46	$ 3,256,888	(390,111)	(64,236)	$ 31.71	$ 29.14	$ (14,242,272)
8	Dec-21	662,407	$ 12.78	$ 8,465,556	280,709	121,448	$ 38.76	$ 32.05	$ 14,772,707
9	Jan-22	513,053	$ 11.31	$ 5,802,630	676,661	475,163	$ 34.29	$ 25.85	$ 35,485,665
10	Feb-22	347,566	$ 11.47	$ 3,986,585	544,800	297,572	$ 34.79	$ 28.29	$ 27,371,914
11	Mar-22	549,172	$ 9.09	$ 4,991,974	117,233	151,909	$ 27.57	$ 28.44	$ 7,552,414
12	Apr-22	504,335	$ 6.83	$ 3,444,611	237,065	227,947	$ 20.71	$ 25.66	$ 10,758,742
13	May-22	330,867	$ 5.36	$ 1,773,449	(809,108)	38,570	$ 16.28	$ 16.30	$ (12,543,580)
14	Jun-22	524,742	$ 5.65	$ 2,964,791	(1,059,927)	323	$ 17.15	$ 10.62	$ (18,174,316)
15	Jul-22	490,206	$ 12.14	$ 5,951,104	(537,766)	177,801	$ 36.83	$ 21.36	$ (16,008,107)
16	Aug-22	636,317	$ 11.83	$ 7,527,634	(390,178)	103,371	$ 35.87	$ 26.85	$ (11,220,178)
17	Sep-22	476,739	$ 9.29	$ 4,428,906	(343,859)	48,849	$ 28.15	$ 28.95	$ (8,265,444)
18	**Total**			**$ 54,968,836**		$ (182,378)			**$ 12,712,703**
19									
20	**2023**	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-22	261,618	$ 9.87	$ 2,582,173	(189,155)	115,775	$ 29.92	$ 28.27	$ (2,386,571)
22	Nov-22	322,761	$ 10.46	$ 3,376,085	(376,629)	(50,419)	$ 31.71	$ 29.14	$ (13,412,140)
23	Dec-22	674,425	$ 12.78	$ 8,619,151	298,723	137,987	$ 38.76	$ 32.05	$ 16,000,977
24	Jan-23	523,881	$ 11.31	$ 5,925,098	699,465	491,513	$ 34.29	$ 25.85	$ 36,690,286
25	Feb-23	357,503	$ 11.47	$ 4,100,556	565,494	311,507	$ 34.79	$ 28.29	$ 28,486,080
26	Mar-23	558,228	$ 9.09	$ 5,074,296	135,535	167,042	$ 27.57	$ 28.44	$ 8,487,375
27	Apr-23	455,217	$ 6.83	$ 3,109,131	219,417	280,945	$ 20.71	$ 25.66	$ 11,753,180
28	May-23	399,463	$ 5.36	$ 2,141,123	(758,832)	17,912	$ 16.28	$ 16.30	$ (12,061,832)
29	Jun-23	532,657	$ 5.65	$ 3,009,513	(1,045,933)	10,601	$ 17.15	$ 10.62	$ (17,825,163)
30	Jul-23	498,207	$ 12.14	$ 6,048,239	(523,002)	189,955	$ 36.83	$ 21.36	$ (15,204,747)
31	Aug-23	644,060	$ 11.83	$ 7,619,224	(374,017)	116,209	$ 35.87	$ 26.85	$ (10,295,764)
32	Sep-23	467,293	$ 9.29	$ 4,341,152	(322,877)	67,001	$ 28.15	$ 28.95	$ (7,149,329)
33	**Total**			**$ 55,945,741**		$ 184,215			**$ 23,082,352**

Rate Design Step
Calculation of PF Preference Rates under Tiered Rate Methodology
Test Period October 2021 - September 2023

	B	C	D	E
5	**Costs ($000)**	**2022**	**2023**	**Rate Period**
6	**Composite**	$ 2,559,205	$ 2,605,042	$ 5,164,246
7	**Non-Slice**	$ 153,613	$ 145,002	$ 298,615
8	**Slice**	$ -	$ -	$ -
9	**Tier 2**	$ 46,009	$ 48,975	$ 94,984
13				
14	**Revenues from Rate Pools to Composite Cost Pool**	**2022**	**2023**	**Rate Period**
15	DSI Revenue Credit	**$ (4,277)**	**$ (4,277)**	**$ (8,555)**
16	Exchange Revenues	**$ -**	**$ -**	**$ -**
17	New Resource Revenues	**$ (0.76)**	**$ (0.79)**	**$ (2)**
18	FPS Revenues	$ (1,070)	$ (1,070)	$ (2,141)
19	Non-Federal RSS Revenues	$ (879)	$ (879)	$ (1,758)
20	Other Credits	$ (243,709)	$ (243,819)	$ (487,528)
21	Tiered Rate Elements			$ -
22	Unused RHWM Credit Reallocation	$ (86,168)	$ (79,301)	$ (165,469)
23	Balancing Augmentation Adjustment Reallocation	$ 4,070	$ (4,019)	$ 51
24	Composite Augmentation RSS Revenue Debit/(Credit)	$ (2,010)	$ (2,010)	$ (4,020)
25	Composite Tier 2 RSS Revenue Debit/(Credit)	$ (151)	$ (167)	$ (318)
26	Composite Tier 2 Rate Design Adjustment Debit/(Credit)	$ (1,537)	$ (1,767)	$ (3,305)
27	Transmission Losses Adjustment Reallocation	$ (30,187)	$ (30,577)	$ (60,764)
28	Total	$ (365,919)	$ (367,888)	$ (733,807)
29				
30	**Rate Discount Costs Applied to Composite Pool**	**2022**	**2023**	**Rate Period**
31	Irigation Rate Discout Costs	$ 20,509	$ 20,509	$ 41,019
32	Low Density Discount Costs	$ 39,482	$ 40,009	$ 79,491
33	Total	$ 59,992	$ 60,519	$ 120,510
34				
35		**2022**	**2023**	**Rate Period**
36	**Composite**	$ 2,253,277	$ 2,297,672	$ 4,550,949

Rate Design Step
Calculation of PF Preference Rates under Tiered Rate Methodology
Test Period October 2021 - September 2023

	B	C	D	E
5	**Costs ($000)**	**2022**	**2023**	**Rate Period**
6	**Composite...**	$ 2,559,205	$ 2,605,042	$ 5,164,246
7	**Non-Slice...**	$ 153,613	$ 145,002	$ 298,615
8	**Slice...**	$ -	$ -	$ -
9	**Tier 2...**	$ 46,009	$ 48,975	$ 94,984
37				
38	**Non-Slice Revenues, Credits, and Costs**	**2022**	**2023**	**Rate Period**
39	Secondary Revenue...	$ (503,856)	$ (447,898)	$ (951,754)
40	Unused RHWM Credit Reallocation...	$ 86,168	$ 79,301	$ 165,469
41	Other Long Term Contract Revenues...	$ -	$ -	$ -
42	Non-federal RSC Revenues...	$ (236)	$ (236)	$ (472)
43	NR Revenues from ESS services...	$ -	$ -	$ -
44	Load Shaping Revenue...	$ (12,713)	$ (23,082)	$ (35,795)
45	Balancing Augmentation Adjustment Reallocation...	$ (4,070)	$ 4,019	$ (51)
46	Demand Revenue...	$ (54,969)	$ (55,946)	$ (110,915)
47	Non-Slice Augmentation RSC Revenue Debit/(Credit)...	$ (76)	$ (76)	$ (152)
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...	$ 30,187	$ 30,577	$ 60,764
53	Total...	$ (459,565)	$ (413,341)	$ (872,905)
54				
55		**2022**	**2023**	**Rate Period**
56	**Non-Slice...**	$ (305,952)	$ (268,339)	$ (574,291)

Rate Design Step
Calculation of PF Preference Rates under Tiered Rate Methodology
Test Period October 2021 - September 2023

	B	C	D	E
5	**Costs ($000)**	**2022**	**2023**	**Rate Period**
6	**Composite....**	$ 2,559,205	$ 2,605,042	$ 5,164,246
7	**Non-Slice....**	$ 153,613	$ 145,002	$ 298,615
8	**Slice....**	$ -	$ -	$ -
9	**Tier 2....**	$ 46,009	$ 48,975	$ 94,984
57				
58	**TRM Costs after Adjustments**	**2022**	**2023**	**Rate Period**
59	**Composite....**	$ 2,253,277	$ 2,297,672	$ 4,550,949
60	**Non-Slice....**	$ (305,952)	$ (268,339)	$ (574,291)
61	**Slice....**	$ -	$ -	$ -
62	**Tier 2....**	$ 46,009	$ 48,975	$ 94,984
63	**Total Costs**	$ 1,993,334	$ 2,078,308	$ 4,071,643
64				
65	**Billing Determinants**	**2022**	**2023**	**Rate Period**
66	**TOCA....**	94.7312	95.0419	94.8865
67	**Non-slice TOCA....**	72.3685	72.6792	72.5239
68	**Slice Percentage....**	22.3627	22.3627	22.3627
69				
70	**Annual TRM Rates ($000/percent)**	**2022**	**2023**	**Rate Period**
71	**Composite....**	$ 23,786	$ 24,175	$ 23,981
72	**Non-Slice....**	$ (4,228)	$ (3,692)	$ (3,959)
73	**Slice....**	$ -	$ -	$ -
74				
75	**Monthly TRM Rates ($/percent)**	**2022**	**2023**	**Rate Period**
76	**Composite....**	1,982,168	2,014,613	1,998,417
77	**Non-Slice....**	(352,308)	(307,675)	(329,943)
78	**Slice....**	-	-	-
79				
80	**Tier 2 Rates ($/MWh)**	**2022**	**2023**	**Rate Period**
81	**Tier 2 Short Term....**	$ 34.39	$ 32.99	$ 33.65
82	**Tier 2 Load Growth....**	$ 34.39	$ 32.99	$ 33.69

Table 3.1.7.1

Rate Design Step
Calculation of Net REP Ratemaking and Recovery Demonstration
Test period October 2021 - September 2023
($ 000, $/MWh)

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
11			2022	2023		PF p	IP	NR	FPS				PF p	IP	NR
12	GENERATION ENERGY														
13													114,871	210	0.01968
14	Federal Base System														
15	Hydro		736,042	761,776		1,497,818	0.0	0.0	0				13.04	0.00	0.00
16	Fish & Wildlife		319,841	323,814		643,655	0.0	0.0	0				5.60	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		72,788	73,105		145,893	0.0	0.0	0				1.27	0.00	0.00
19	WNP #2		583,848	609,062		1,192,910	0.0	0.0	0				10.39	0.00	0.00
20	WNP #3		83,756	83,830		167,585	0.0	0.0	0				1.46	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		43,266	38,088		81,354	0.0	0.0	0				0.71	0.00	0.00
23	Tier 2 Costs		46,009	48,975		94,984	0.0	0.0	0				0.83	0.00	0.00
24	Total Federal Base System		1,886,750	1,939,849		3,826,599	0.0	0.0	0.0				33.31	0.00	0.00
25															
26	New Resources		54,276	50,117		104,393	0.0	0.0	0		PFx Revenue		0.91	0.00	0.00
27	Residential Exchange		3,017,507	3,018,273		531,534	0.0	0.0	0		5,504,246		4.63	0.00	0.00
28	Conservation		199,259	189,237		388,496	0.0	0.0	0				3.38	0.00	0.00
29	BPA Programs & Transmission		350,684	351,968		702,652	0.0	0.0	0		NR Revenue		6.12	0.00	0.00
30	TOTAL COSA ALLOCATIONS		5,508,475	5,549,444		5,553,673	0	0	0		1.6		48.35	0.00	0.00
31															
32															
33	Nonfirm Excess Revenue Credit		(526,230)	(501,343)		(1,027,573)	0.0	0.0	0.0				-8.95	0.00	0.00
34	LDD/IRD Expense		59,992	60,519		120,510	0.0						1.05	0.00	0.00
35	Other Revenue Credits		(247,583)	(247,939)		(495,521)	0.0	0.0	0.0				-4.31	0.00	0.00
36						0	0.0						0.00	0.00	0.00
37	SP Revenue Surplus/Dfct Adj.		0	0		(136,546)	0	0.0	136,546				-1.19	0.00	0.00
38	NR Rate Revenue					(1.6)		1.6					0.00	0.00	78.83
39	IP Rate Revenue		0	0		(8,555)	8,555						-0.07	40.69	0.00
40															
41	TOTAL RATE DESIGN ADJUSTMENTS		(713,821)	(688,763)		(1,547,687)	8,555	1.6	136,546				-13.47	40.69	78.83
42															
43	Total Generation		4,794,654	4,860,681									**34.87**	**40.69**	**78.83**
44				**PFp Revenue Recovery**		**4,005,986**	8,555	1.6	136,546						

Table 3.1.7.2

Rate Design Step
Demonstration that TRM PFp Rates Collect the Same Revenue Requirement as the Non-TRM PFp Rate
Test Period October 1, 2021 to September 30, 2023

	B	C	D		E		F	G
4								
5								
6		**Proof: TRM PF Revenues = Non-TRM PF Revenues**						
7								
8				2022		2023		
9		Composite Revenue..............................	$	2,271,748	$	2,279,201		
10		Non-Slice Revenue...............................	$	(286,530)	$	(287,761)		
11		Slice Revenue...	$	-	$	-		
12		Tier 2..	$	46,009	$	48,975		
13		Load Shaping Revenue..........................	$	12,713	$	23,082		
14		Demand Revenue.................................	$	54,969	$	55,946		
15		Total TRM PF Revenue	$	2,098,909	$	2,119,443		
16								
17		Slice Portion of Secondary Revenue......	$	(107,920)	$	(104,446)		
18		Total Net TRM PF Revenue	$	1,990,990	$	2,014,997		
19								
20							PF Rate	
21		Total TRM PF Revenue Analogous to w/ Slice PF			$	4,005,987	34.87	
22								
23		w/ Slice PF Public Rate Revenue from "Net REP" Table			**$**	**4,005,986**	34.87	
24				delta	$	(1)		
25								
26								

Rate Design Step
Calculation of Priority Firm Tier 1 Equivalent Rate Components
Test Period October 2021 - September 2023

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22		
15	HLH (mills/kWh)	29.92	31.71	38.76	34.29	34.79	27.57	20.71	16.28	17.15	36.83	35.87	28.15		
16	LLH (mills/kWh)	28.27	29.14	32.05	25.85	28.29	28.44	25.66	16.30	10.62	21.36	26.85	28.95		
17	Demand Rate ($/kW/mo)	9.87	10.46	12.78	11.31	11.47	9.09	6.83	5.36	5.65	12.14	11.83	9.29		
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)	5,156	5,947	6,697	6,408	5,563	5,873	4,835	5,066	5,395	5,591	5,737	5,027		111,982
22	LLH (GWh)	3,326	4,112	4,850	4,780	3,822	3,850	3,235	3,267	3,028	3,703	3,366	3,348		Tier 1 Demand (MW/mo)
23	Demand (MW)	502	634	1,337	1,037	705	1,107	960	730	1,057	988	1,280	944		11,283
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)	$ 154,256	$ 188,577	$ 259,566	$ 219,751	$ 193,537	$ 161,925	$ 100,107	$ 82,456	$ 92,541	$ 205,928	$ 205,747	$ 141,512		$ 3,151,215
29	LLH ($000)	$ 94,019	$ 119,830	$ 155,455	$ 123,557	$ 108,122	$ 109,498	$ 83,020	$ 53,251	$ 32,161	$ 79,092	$ 90,386	$ 96,920		Demand Revenue ($000)
30	Demand ($000)	$ 4,957	$ 6,633	$ 17,085	$ 11,728	$ 8,087	$ 10,066	$ 6,554	$ 3,915	$ 5,974	$ 11,999	$ 15,147	$ 8,770		$ 110,915
31															$ 3,262,129
32															Tier 1 Revenue Requirement (RR) ($000)
33															**$ 3,911,002**
34															Tier 1 RR less Demand Revenue ($000)
35															$ 3,800,087
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)	35.71	37.50	44.55	40.08	40.58	33.36	26.50	22.07	22.94	42.62	41.66	33.94		(5.79)
38	LLH (mills/kWh)	34.06	34.93	37.84	31.64	34.08	34.23	31.45	22.09	16.41	27.15	32.64	34.74		
39	Demand ($/kW/mo)	9.87	10.46	12.78	11.31	11.47	9.09	6.83	5.36	5.65	12.14	11.83	9.29		
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)	$ 184,107	$ 223,013	$ 298,356	$ 256,821	$ 225,758	$ 195,928	$ 128,120	$ 111,799	$ 123,772	$ 238,293	$ 238,985	$ 170,622		$ 3,799,629
45	LLH ($000)	$ 113,276	$ 143,640	$ 183,539	$ 151,232	$ 130,251	$ 131,790	$ 101,753	$ 72,167	$ 49,695	$ 100,531	$ 109,877	$ 116,304		Allocated Cost Demand ($000)
46	Demand ($000)	$ 4,957	$ 6,633	$ 17,085	$ 11,728	$ 8,087	$ 10,066	$ 6,554	$ 3,915	$ 5,974	$ 11,999	$ 15,147	$ 8,770		$ 110,915
47															$ 3,910,543
48	Average Slice&Non-Slice Tier 1 Rate														
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 3,799,629	33.93												
51	Allocated Cost Demand	$ 110,915	0.99												
52	Total Allocated Costs	$ 3,910,543	34.92												
53															
54	Tier 1 Energy (GWh)		111,982												
55	Market Energy Delta (mills/kWh)		(5.79)												

Table 3.1.8.2

Rate Design Step
Calculation of Priority Firm Public Melded Rate Equivalent Components
Test Period October 2021 - September 2023

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22		
15	HLH (mills/kWh)	29.92	31.71	38.76	34.29	34.79	27.57	20.71	16.28	17.15	36.83	35.87	28.15		
16	LLH (mills/kWh)	28.27	29.14	32.05	25.85	28.29	28.44	25.66	16.30	10.62	21.36	26.85	28.95		
17	Demand Rate ($/kW/mo)	9.87	10.46	12.78	11.31	11.47	9.09	6.83	5.36	5.65	12.14	11.83	9.29		
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)	5,293	6,079	6,834	6,540	5,690	6,016	4,969	5,200	5,533	5,723	5,879	5,159		114,871
22	LLH (GWh)	3,434	4,218	4,959	4,893	3,917	3,953	3,338	3,378	3,129	3,816	3,469	3,453		Tier 1 Demand (MW/mo)
23	Demand (MW)	502	634	1,337	1,037	705	1,107	960	730	1,057	988	1,280	944		11,283
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)	$ 158,361	$ 192,760	$ 264,883	$ 224,275	$ 197,942	$ 165,853	$ 102,891	$ 84,648	$ 94,894	$ 210,787	$ 210,857	$ 145,225		$ 3,230,588
29	LLH ($000)	$ 97,077	$ 122,915	$ 158,922	$ 126,490	$ 110,809	$ 112,415	$ 85,664	$ 55,055	$ 33,225	$ 81,515	$ 93,149	$ 99,975		Demand Revenue ($000)
30	Demand ($000)	$ 4,957	$ 6,633	$ 17,085	$ 11,728	$ 8,087	$ 10,066	$ 6,554	$ 3,915	$ 5,974	$ 11,999	$ 15,147	$ 8,770		$ 110,915
31															$ 3,341,503
32															Tier 1&2 Revenue Requirement (RR) ($000)
33															$ 4,005,986
34															T1&2RR less Demand Revenue ($000)
35															$ 3,895,072
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)	35.70	37.49	44.54	40.07	40.57	33.35	26.49	22.06	22.93	42.61	41.65	33.93		(5.78)
38	LLH (mills/kWh)	34.05	34.92	37.83	31.63	34.07	34.22	31.44	22.08	16.40	27.14	32.63	34.73		
39	Demand ($/kW/mo)	9.87	10.46	12.78	11.31	11.47	9.09	6.83	5.36	5.65	12.14	11.83	9.29		
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)	$ 188,953	$ 227,899	$ 304,399	$ 262,043	$ 230,840	$ 200,621	$ 131,633	$ 114,719	$ 126,864	$ 243,858	$ 244,862	$ 175,048		$ 3,894,582
45	LLH ($000)	$ 116,926	$ 147,295	$ 187,583	$ 154,773	$ 133,449	$ 135,261	$ 104,960	$ 74,578	$ 51,309	$ 103,573	$ 113,201	$ 119,935		Allocated Cost Demand ($000)
46	Demand ($000)	$ 4,957	$ 6,633	$ 17,085	$ 11,728	$ 8,087	$ 10,066	$ 6,554	$ 3,915	$ 5,974	$ 11,999	$ 15,147	$ 8,770		$ 110,915
47															$ 4,005,496
48	Average Slice&Non-Slice Tier 1&2 Rate														
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 3,894,582	33.90												
51	Allocated Cost Demand	$ 110,915	0.97												
52	Total Allocated Costs	$ 4,005,496	34.87												
53															
54	Tier 1&2 Energy (GWh)		114,871												
55	PF Melded Equivalent Energy Scalar (mills/kWh)		(5.78)												

Rate Design Step
Calculation of Industrial Firm Power Rate Components
Test Period October 2021 - September 2023

	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-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22		
15		HLH (mills/kWh)	35.70	37.49	44.54	40.07	40.57	33.35	26.49	22.06	22.93	42.61	41.65	33.93		
16		LLH (mills/kWh)	34.05	34.92	37.83	31.63	34.07	34.22	31.44	22.08	16.40	27.14	32.63	34.73		
17		Demand Rate ($/kW/mo)	9.87	10.46	12.78	11.31	11.47	9.09	6.83	5.36	5.65	12.14	11.83	9.29		
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)	10	9	10	10	9	10	10	10	10	10	10	9		210
22		LLH (GWh)	8	8	8	8	7	8	8	8	7	8	8	8		
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)	$ 363	$ 356	$ 428	$ 387	$ 368	$ 339	$ 259	$ 216	$ 226	$ 411	$ 427	$ 310		$ 6,988
29		LLH ($000)	$ 262	$ 273	$ 312	$ 259	$ 241	$ 262	$ 236	$ 179	$ 121	$ 223	$ 248	$ 283		Demand Rev ($000)
30		Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
31																$ 6,988
32																
33																VOR
34																(0.72)
35																Industrial Margin (mills/kWh)
36		IP Rate	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		0.808
37		HLH (mills/kWh)	43.15	44.94	51.99	47.52	48.02	40.80	33.94	29.51	30.38	50.06	49.10	41.38		Net industrial Margin
38		LLH (mills/kWh)	41.50	42.37	45.28	39.08	41.52	41.67	38.89	29.53	23.85	34.59	40.08	42.18		0.086
39		Demand ($/kW/mo)	9.87	10.46	12.78	11.31	11.47	9.09	6.83	5.36	5.65	12.14	11.83	9.29		Settlement Charge
40																**7.365**
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)	$ 439	$ 427	$ 500	$ 459	$ 435	$ 415	$ 332	$ 288	$ 300	$ 483	$ 504	$ 378		$ 8,554
45		LLH ($000)	$ 319	$ 331	$ 373	$ 321	$ 293	$ 320	$ 292	$ 239	$ 177	$ 284	$ 304	$ 343		Allocated Cost Demand ($000)
46		Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
47																$ 8,554
48			Average IP Rate													
49			($000)	(mills/kWh)												
50		Allocated Cost Energy	$ 8,554	40.69												
51		Allocated Cost Demand	$ -	-												
52		Total Allocated Costs	$ 8,554	40.69												
53																
54			IP Energy (GWh)	210												
55			Industrial Margin (mills/kWh)	0.81												
56			VOR	(0.72)												
57			Settlement Charge	7.37												

Table 3.1.8.4

Rate Design Step
Calculation of New Resource Rate Components
Test Period October 2021 - September 2023

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22		
15	HLH (mills/kWh)	29.92	31.71	38.76	34.29	34.79	27.57	20.71	16.28	17.15	36.83	35.87	28.15		
16	LLH (mills/kWh)	28.27	29.14	32.05	25.85	28.29	28.44	25.66	16.30	10.62	21.36	26.85	28.95		
17	Demand Rate ($/kW/mo)	9.87	10.46	12.78	11.31	11.47	9.09	6.83	5.36	5.65	12.14	11.83	9.29		
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)	$ 0.0259	$ 0.0249	$ 0.0316	$ 0.0280	$ 0.0273	$ 0.0234	$ 0.0172	$ 0.0130	$ 0.0143	$ 0.0306	$ 0.0298	$ 0.0225		$ 0.5358
29	LLH ($000)	$ 0.0244	$ 0.0228	$ 0.0262	$ 0.0211	$ 0.0222	$ 0.0241	$ 0.0213	$ 0.0130	$ 0.0088	$ 0.0178	$ 0.0223	$ 0.0232		Demand Revenue ($000)
30	Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
31															$ 0.5358
32															NR Revenue Requirement (RR) ($000)
33															$ 1.5514
34															NR RR less Demand Revenue ($000)
35															$ 1.5514
36	NR Rates	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Market Energy Delta (mills/kWh)
37	HLH (mills/kWh)	81.53	83.32	90.37	85.90	86.40	79.18	72.32	67.89	68.76	88.44	87.48	79.76		(51.61)
38	LLH (mills/kWh)	79.88	80.75	83.66	77.46	79.90	80.05	77.27	67.91	62.23	72.97	78.46	80.56		
39	Demand ($/kW/mo)	9.87	10.46	12.78	11.31	11.47	9.09	6.83	5.36	5.65	12.14	11.83	9.29		
40															
41															
42															
43	evenues @ Posted NR Rate	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Allocated Cost Energy ($000)
44	HLH ($000)	$ 0.0704	$ 0.0653	$ 0.0737	$ 0.0701	$ 0.0677	$ 0.0671	$ 0.0602	$ 0.0543	$ 0.0572	$ 0.0736	$ 0.0728	$ 0.0638		$ 1.5515
45	LLH ($000)	$ 0.0690	$ 0.0633	$ 0.0683	$ 0.0632	$ 0.0626	$ 0.0679	$ 0.0643	$ 0.0543	$ 0.0518	$ 0.0607	$ 0.0653	$ 0.0644		Allocated Cost Demand ($000)
46	Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
47															$ 1.5515
48		Average NR Rate													
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 1.5515	78.84												
51	Allocated Cost Demand	$ -	-												
52	Total Allocated Costs	$ 1.5515	78.84												
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 2021 - September 2023

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22		
15	HLH (mills/kWh)	29.92	31.71	38.76	34.29	34.79	27.57	20.71	16.28	17.15	36.83	35.87	28.15		
16	LLH (mills/kWh)	28.27	29.14	32.05	25.85	28.29	28.44	25.66	16.30	10.62	21.36	26.85	28.95		
17	Demand Rate ($/kW/mo)	9.87	10.46	12.78	11.31	11.47	9.09	6.83	5.36	5.65	12.14	11.83	9.29		
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]	3,850	4,365	5,256	5,222	4,514	4,549	3,803	3,503	3,628	4,024	4,204	3,684		85,595
22	LLH (GWh) [FMDT1L]	2,596	3,116	3,769	3,881	3,065	3,018	2,593	2,511	2,317	2,917	2,629	2,582		Tier 1 Demand (MW/mo)
23	Demand (MW)	502	634	1,337	1,037	705	1,107	960	730	1,057	988	1,280	944		11,283
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)	$ 115,182	$ 138,411	$ 203,696	$ 179,094	$ 157,038	$ 125,413	$ 78,749	$ 57,012	$ 62,222	$ 148,196	$ 150,783	$ 103,709		$ 2,417,079
29	LLH ($000)	$ 73,380	$ 90,808	$ 120,784	$ 100,333	$ 86,707	$ 85,836	$ 66,539	$ 40,923	$ 24,611	$ 62,309	$ 70,582	$ 74,760		Demand Revenue ($000)
30	Demand ($000)	$ 4,957	$ 6,633	$ 17,085	$ 11,728	$ 8,087	$ 10,066	$ 6,554	$ 3,915	$ 5,974	$ 11,999	$ 15,147	$ 8,770		$ 110,915
31															$ 2,527,994
32															Tier 1 Non-Slice PF Public RR minus Tier 2 Costs
33															**$ 3,050,810**
34															Tier 1 RR less Demand Revenue ($000) [BLFRnD]
35															$ 2,939,895
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)	36.03	37.82	44.87	40.40	40.90	33.68	26.82	22.39	23.26	42.94	41.98	34.26		(6.11)
38	LLH (mills/kWh)	34.38	35.25	38.16	31.96	34.40	34.55	31.77	22.41	16.73	27.47	32.96	35.06		
39	Demand ($/kW/mo)	9.87	10.46	12.78	11.31	11.47	9.09	6.83	5.36	5.65	12.14	11.83	9.29		
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)	$ 138,703	$ 165,083	$ 235,818	$ 210,976	$ 184,627	$ 153,205	$ 102,002	$ 78,421	$ 84,382	$ 172,775	$ 176,487	$ 126,222		$ 2,940,092
45	LLH ($000)	$ 89,240	$ 109,848	$ 143,811	$ 124,048	$ 105,434	$ 104,277	$ 82,383	$ 56,262	$ 38,771	$ 80,133	$ 86,644	$ 90,539		Allocated Cost Demand ($000)
46	Demand ($000)	$ 4,957	$ 6,633	$ 17,085	$ 11,728	$ 8,087	$ 10,066	$ 6,554	$ 3,915	$ 5,974	$ 11,999	$ 15,147	$ 8,770		$ 110,915
47															$ 3,051,007
48	Average Non-Slice Tier 1 Rate														
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 2,940,092	34.35												
51	Allocated Cost Demand	$ 110,915	1.30												
52	Total Allocated Costs	$ 3,051,007	35.64												
53															
54	Tier 1 Energy (GWh) [FAT1L]		85,595												
55	Load Shaping True-up Rate (mills/kWh) [LSTUR]		(6.11)												

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	FY2022	FY2023	FY2024	FY2025	FY2026	FY2027
2	C	RDS	CNTA	Augmentation RSS & RSC Adder	$ 2,086	$ 2,086	$ 2,086	$ 2,086	$ 2,086	$ 2,086
3	C	RDS	CD2RCF	Composite Augmentation RSS Revenue Debit/(Credit)	$ (2,010)	$ (2,010)	$ (2,010)	$ (2,010)	$ (2,010)	$ (2,010)
4	2.0	RDS	2D2RCF	Composite Tier 2 RSS Revenue Debit/(Credit)	$ -	$ -	$ -	$ -	$ -	$ -
5	C	RDS	CD2RCN	Composite Non-Federal RSS Revenue Debit/(Credit)	$ (910)	$ (910)	$ (910)	$ (910)	$ (910)	$ (910)
6	N	RDS	ND2RNF	Non-Slice Augmentation RSC Revenue Debit/(Credit)	$ (76)	$ (76)	$ (76)	$ (76)	$ (76)	$ (76)
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)	$ (236)	$ (236)	$ (236)	$ (236)	$ (236)	$ (236)

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 2022 and FY 2023 Tier 2 purchases as of June 1, 2021.															

Table 3.4
Inputs to TSS Monthly Rate and Charge

	A	B	C	D	E	F
1	FY2022 PTK + PTFR Scheduling Costs	FY2023 PTK + PTFR Scheduling Costs	FY2019 Scheduled MWh	FY2020 Scheduled MWh	FY2019 Number of Transactions	FY2020 Number of Transactions
2	$4,045,456	$4,170,713	36,054,512	37,726,366	121,718	124,124

Table 3.5.1

Tier 2 Short-Term Rate Costing Table

	A	B	C
1		ST.3.2020_2024	ST.3.2020_2024
2	Hours	8760	8760
3	Fiscal Year	FY2022	FY2023
4	Rate Period	BP-22	
5	Total Forecast Expected Cost	$ 43,012,077	$ 46,017,247
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	$ 1,539,243	$ 1,778,059
16	Resource Support Services	$ 137,570	$ 153,432
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	$ 137,570	$ 153,432
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	$ 137,570	$ 153,432
28	Resource Shaping Charge	$ -	$ -
29	Tier 2 Overhead	$ 1,401,673	$ 1,624,627
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)	1,250,639	1,394,837
35	Tier 2 Obligation w losses	1,290,782	1,439,609
36	Energy (Short)/Long (MWh)	-1,290,782	-1,439,609
37	Composite Cost Pool Augmentation (MWh) - BP12 Only		
38	Energy Short (MWh)	-1,290,782	-1,439,609
39	Energy to be Remarketed (MWh)	0	0
40	Remarketing Available (MWh)	36,328	35,171
41	Total Tier 2 Pool Shortfall (MWh)	-1,415,758	-1,565,942
42	Augmentation Price ($/MWh)	$ 34.48	$ 34.17
43	Flat Block RSC ($/MWh)	$ 27.82	$ 27.13
44	Remarketing Value ($/MWh)	$ 32.13	$ 30.73
45	Remarketed Purchase (MWh)	33,121	32,334
46	Remarketed Purchase Cost	$ 1,064,174	$ 993,622
47	Remaining Shortfall (MWh)	-1,257,661	-1,407,275
48	Remaining Shortfall Cost	$ 40,408,660	$ 43,245,566
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	$ 43,012,077	$ 46,017,247
53	Billing Components		
54	ShortTerm ($/MWh)	$ 34.39	$ 32.99
55	Remarketing Credit	$ -	$ -
56	Remarketing Charge	$ -	$ -
57	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (1,401,673)	$ (1,624,627)
58	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
59	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (137,570)	$ (153,432)

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	8,760	8,760
3	Fiscal Year	FY2022	FY2023
4	Rate Period	BP-22	
5	Total Forecast Expected Cost	$ 4,164,519	$ 4,038,228
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	$ 149,033	$ 156,033
16	Resource Support Services	$ 13,320	$ 13,464
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	$ 13,320	$ 13,464
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	$ 13,320	$ 13,464
28	Resource Shaping Charge	$ -	$ -
29	Tier 2 Overhead	$ 135,713	$ 142,569
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)	121,089	122,403
35	Tier 2 Obligation w losses	124,976	126,332
36	Energy (Short)/Long (MWh)	-124,976	-126,332
37	Composite Cost Pool Augmentation (MWh) - BP12 Only	0	0
38	Energy Short (MWh)	-124,976	-126,332
39	Energy to be Remarketed (MWh)	0	0
40	Remarketing Available (MWh)	36,328	35,171
41	Total Tier 2 Pool Shortfall (MWh)	-1,415,758	-1,565,942
42	Augmentation Price ($/MWh)	$ 34.48	$ 34.17
43	Flat Block RSC ($/MWh)	$ 27.82	$ 27.13
44	Remarketing value ($/MWh)	$ 32.13	$ 30.73
45	Remarketed Purchase (MWh)	3,207	2,837
46	Remarketed Purchase Cost	$ 103,036	$ 87,195
47	Remaining Shortfall (MWh)	-121,769	-123,495
48	Remaining Shortfall Cost	$ 3,912,451	$ 3,795,000
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	$ 4,164,519	$ 4,038,228
53	Billing Components		
54	LoadGrowth ($/MWh)	$ 34.39	$ 32.99
55	Remarketing Credit	$ -	$ -
56	Remarketing Charge	$ -	$ -
57	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (135,713)	$ (142,569)
58	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
59	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (13,320)	$ (13,464)

Table 3.6
Tier 2 Overhead Adder Inputs

	A	B	C	D	E
1		**BP-22**			
2		**FY2022**		**FY2023**	
3	**Line Item**	**FY2022**	**Total Forecast Sales (MWh)**	**FY2023**	**Total Forecast Sales (MWh)**
4	Executive and Administrative Services	$ 6,672,235	75,206,909	$ 6,885,512	74,023,161
5	Generation Project Coordination	$ 3,946,608		$ 4,035,145	
6	Sales & Support	$ 15,172,284		$ 15,563,291	
7	Power Internal Support	$ 13,976,425		$ 14,825,090	
8	Agency Services G&A	$ 44,521,752		$ 44,908,915	
9	Total Costs	$ 84,289,303		$ 86,217,952	
10	**Total Costs Divided by Total Sales**		**$1.12**		**$1.16**

Table 3.7
Tier 2 Rate Revenues

	A	B	C
1	Hours	8,760	8,760
2	Fiscal Year	FY2022	FY2023
3	Rate Period	BP-22	
4	ShortTerm Rate $/MWh	$ 34.39	$ 32.99
5	LoadGrowth Rate $/MWh	$ 34.39	$ 32.99
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	147.350	164.339
12	Portfolio Obligation w/ Losses MWh	1,290,782	1,439,609
13	Portfolio Billing Determinant aMW	142.767	159.228
14	Portfolio Billing Determinant MWh	1,250,639	1,394,837
15	RECs MWh	0	0
16	Base Power Purchase Cost	$ -	$ -
17	Rate Design Components	$ 1,539,243	$ 1,778,059
18	Other Costs	$ -	$ -
19	Rate $/MWh	$ 34.39	$ 32.99
20	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (1,401,673)	$ (1,624,627)
21	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
22	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (137,570)	$ (153,432)
23	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -
24	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -
25	Total ShortTerm Rate Revenue	$ 43,009,472	$ 46,015,682
26	Remarketing Credit	$ -	$ -
27	Remarketing Charge	$ -	$ -
28	Forecast Power Purchase Costs	$ 40,408,660	$ 43,245,566
29			
30	**LoadGrowth**		
31	Portfolio Purchased aMW	0.000	0.000
32	Portfolio Purchased MWh	0	0
33	Portfolio Obligation /w Losses aMW	14.267	14.422
34	Portfolio Obligation /w Losses MWh	124,976	126,332
35	Portfolio Billing Determinant aMW	13.823	13.973
36	Portfolio Billing Determinant MWh	121,089	122,403
37	RECs MWh	0	0
38	Base Power Purchase Cost	$ -	$ -
39	Rate Design Components	$ 149,033	$ 156,033
40	Other Costs	$ -	$ -
41	Rate $/MWh	$ 34.39	$ 32.99
42	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (135,713)	$ (142,569)
43	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
44	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (13,320)	$ (13,464)
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	$ 4,164,267	$ 4,038,091
48	Remarketing Credit	$ -	$ -
49	Remarketing Charge	$ -	$ -
50	Forecast Power Purchase Costs	$ 3,912,451	$ 3,795,000
51			
52	**Total Costs**		
53	Total Base Power Purchase Cost	$ -	$ -
54	Total Rate Design Components	$ 1,688,276	$ 1,934,092

Table 3.7 Continued
Tier 2 Rate Revenues

55	Total Other Costs	$ -	$ -
56	Forecast Power Purchase Costs	$ 44,321,111	$ 47,040,566
57	Total Cost	$ 46,009,386	$ 48,974,658
58			
59	**Total Revenue**		
60	Total Tier 2 Rate Revenue Collection	$ 47,173,740	$ 50,053,773
61	Total Tier 2 Remarketing Charge	$ -	$ -
62	Total Tier 2 Remarketing Credit	$ -	$ -
63	Non-Federal Remarketing Credit	$ (1,167,210)	$ (1,080,817)
64	Total Revenue	$ 46,006,530	$ 48,972,956
65	Value of BPA Purchased Remarketing	$ -	$ -
66	Total Tier 2 Revenue and Value of BPA Purchased Remarketing	$ 46,006,530	$ 48,972,956
67			
68	Total Tier 2 Adjustments and Credits*		
69	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (1,537,386)	$ (1,767,195)
70	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
71	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (150,890)	$ (166,896)
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-22	
2	Fiscal Year	FY2022	FY2023
3	ShortTerm Remarket (MWh)	0	0
4	LoadGrowth Remarket (MWh)	0	0
5	Vintage Remarket (MWh)		
6	Non-Federal Remarket (MWh)	36,328	35,171
7	Total	36,328	35,171
8			
9	ShortTerm Purchase of Remarket (MWh)	33,121	32,334
10	LoadGrowth Purchase of Remarket (MWh)	3,207	2,837
11	Vintage Purchase of Remarket (MWh)		
12	BPA Purchase of Remarket (MWh)	0	0
13	Total	36,328	35,171
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	$ 1,167,210	$ 1,080,817
22			
23	ShortTerm Open Position (MWh)	1,257,661	1,407,275
24	LoadGrowth Open Position (MWh)	121,769	123,495
25	Vintage Opern Position (MWh)		
26	BPA Purchase of Remarket (MWh)	0	0
27	Total Open Position (MWh)	1,379,431	1,530,770

Table 3.9
Tier 2 Rate Inputs

	A	B	C	D	E	F	G
1	Fiscal Year	TSS Rate ($/MWh)	Aurora Flat Annual Block Market Forecast ($/MWh)	Augmentation Price ($/MWh)	Augmentation Amount (MWh)	Remarketing Value ($/MWh)	Available Non-Federal Resource Remarketing (MWh)
2	FY2022	$ 0.11	$ 27.82	$ 34.48	-	$ 32.13	36,328
3	FY2023	$ 0.11	$ 27.13	$ 34.17	-	$ 30.73	35,171

Table 3.10
Remarketing Value Inputs

	A	B	C	D	E	F	G	H
1	**Pricing Date**	**ICE Settlement[1/] FY 2022 $/MWh**	**ICE Settlement[1/] FY 2023 $/MWh**		**Comparison of Tier 2 purchases made by BPA to ICE Settlements[1/]:**			
2	9/21/2020	29.38	28.56		Tier 2 Purchase Date	11/16/2012	11/16/2012	2/20/2017
3	9/22/2020	30.00	29.11		Delivery Period	FY 2014	FY 2015	FY 2019
4	9/23/2020	29.92	29.09					
5	9/24/2020	30.18	29.40		Tier 2 Purchase Price $/MWh	33.28	37.25	23.00
6	9/25/2020	30.04	29.22		Tier 2 Purchase Date ICE Settlement $/MWh	33.10	36.58	22.22
7	3/22/2021	32.93	31.56		**Delta $/MWh**	**0.18**	**0.67**	**0.78**
8	3/23/2021	33.22	31.18					
9	3/24/2021	33.39	31.23					
10	3/25/2021	33.60	31.38					
11	3/26/2021	33.68	31.61					
12	**Average**	**31.63**	**30.23**					
13								
14	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 for FY 2022 and FY 2023

	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 FY2022 Annual aMW	Exh. A FY2023 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	FY2022&FY2023	17.315	15.140	15.140	$ 2.79	$ 166,501	$ 13.14
2	Northern Wasco County People's Utility District	Unspecified Resource Amounts	TSS TCMS	FY2022&FY2023	N/A	7.000	9.000	$ -	$ -	$ -
3	City of Bonners Ferry	Moyie	GMS	FY2022&FY2023	N/A	1.881	1.881	$ -	$ -	$ -
4	City of Centralia	Yelm Hydro	GMS	FY2022&FY2023	N/A	7.114	7.114	$ -	$ -	$ -
5	City of Forest Grove	Priest Rapids	SCS	FY2022&FY2023	N/A	1.577	1.577	$ -	$ -	$ -
6	City of Forest Grove	Wanapum	SCS	FY2022&FY2023	N/A	1.600	1.600	$ -	$ -	$ -
7	The City of McMinnville, a municipal corporation of the State of Oregon, acting by and through its Water and Light Commission	Priest Rapids	SCS	FY2022&FY2023	N/A	1.577	1.577	$ -	$ -	$ -
8	The City of McMinnville, a municipal corporation of the State of Oregon, acting by and through its Water and Light Commission	Wanapum	SCS	FY2022&FY2023	N/A	1.600	1.600	$ -	$ -	$ -
9	The City of McMinnville, a municipal corporation of the State of Oregon, acting by and through its Water and Light Commission	Riverbend Biogas	DFS FOR RSC	FY2022&FY2023	2.280	4.069	4.015	$ 0.17	$ 4,022	$ 2.41
10	City of Milton-Freewater	Priest Rapids	SCS	FY2022&FY2023	N/A	1.577	1.577	$ -	$ -	$ -
11	City of Milton-Freewater	Wanapum	SCS	FY2022&FY2023	N/A	1.600	1.600	$ -	$ -	$ -
12	Public Utility District No. 1 of Clallam County	Packwood	DFS FOR TSS TCMS RSC	FY2022&FY2023	1.045	0.673	0.673	$ 1.34	$ 6,236	$ 8.15
13	Columbia REA	Walla Walla Hydro	DFS FOR RSC	FY2022&FY2023	0.954	1.231	0.306	$ 0.38	$ 2,319	$ 3.32
14	Flathead Electric Cooperative, Inc.	Flathead LFGTE	DFS FOR RSC	FY2022&FY2023	1.392	1.077	1.077	$ 0.12	$ 3,872	$ 3.80
15	Flathead Electric Cooperative, Inc.	Stoltze Lumber	DFS FOR RSC	FY2022&FY2023	2.456	2.500	2.500	$ 0.14	$ 4,741	$ 2.64
16	Northern Wasco County People's Utility District	NLSL Unspecified Resource Amoun	TSS TCMS	FY2022&FY2023	N/A	85.853	104.250	$ -	$ -	$ -
17	Public Utility District No. 1 of Kittitas County	Priest Rapids	SCS	FY2022&FY2023	N/A	0.526	0.526	$ -	$ -	$ -
18	Public Utility District No. 1 of Kittitas County	Wanapum	SCS	FY2022&FY2023	N/A	0.533	0.533	$ -	$ -	$ -
19	Richland	Horn Rapids Solar	DFS TSS TCMS RSC	FY2022&FY2023	0.606	0.582	0.582	$ 3.22	$ 5,861	$ 13.21
20	Public Utility District No. 3 of Mason County	Packwood	SCS TSS TCMS	FY2022&FY2023	N/A	0.656	0.656	$ -	$ -	$ -
21	Public Utility District No. 3 of Mason County	Nine Canyon Wind	DFS TSS TCMS RSC	FY2022&FY2023	0.854	0.809	0.809	$ 3.23	$ 7,941	$ 12.71
22	Public Utility District No. 3 of Mason County	White Creek Wind	DFS TSS TCMS RSC	FY2022&FY2023	1.072	0.920	0.920	$ 2.95	$ 10,005	$ 12.75
23	PNGC	Lake Creek	SCS	FY2022&FY2023	N/A	1.530	1.530	$ -	$ -	$ -
24	PNGC	Chester Hydro	DFS FOR RSC	FY2022&FY2023	0.777	0.967	0.967	$ 0.33	$ 4,837	$ 8.50
25	PNGC	Island Park	SCS	FY2022&FY2023	N/A	0.992	0.992	$ -	$ -	$ -
27	Northern Wasco County People's Utility District	McNary Fishway	GMS TSS	FY2022&FY2023	N/A	4.404	4.404	$ -	$ -	$ -
28	Klickitat	McNary Fishway	SCS TSS TCMS	FY2022&FY2023	N/A	4.222	4.222	$ -	$ -	$ -
29	Klickitat	Packwood	SCS TSS TCMS	FY2022&FY2023	N/A	0.197	0.197	$ -	$ -	$ -
30	Klickitat	Unspecified Resource Amounts	TSS TCMS	FY2022&FY2023	N/A	10.000	10.000	$ -	$ -	$ -
31	Mission Valley Power	Kerr	TSS TCMS	FY2022&FY2023	N/A	9.657	9.657	$ -	$ -	$ -
32	PNGC	Lake Creek	SCS	FY2022&FY2023	N/A	1.530	1.530	$ -	$ -	$ -
33	PNGC	Chester Hydro	DFS FOR RSC	FY2022&FY2023	0.777	0.967	0.967	$ 0.33	$ 4,837	$ 8.50
34	PNGC	Island Park	SCS	FY2022&FY2023	N/A	0.992	0.992	$ -	$ -	$ -
35	Northern Wasco County People's Utility District	Unspecified Resource Amounts	TSS TCMS	FY2022&FY2023	N/A	7.000	9.000	$ -	$ -	$ -
36	Northern Wasco County People's Utility District	McNary Fishway	GMS TSS	FY2022&FY2023	N/A	4.404	4.404	$ -	$ -	$ -
37	Klickitat	McNary Fishway	SCS TSS TCMS	FY2022&FY2023	N/A	4.222	4.222	$ -	$ -	$ -
38	Klickitat	Packwood	SCS TSS TCMS	FY2022&FY2023	N/A	0.197	0.197	$ -	$ -	$ -
39	Klickitat	Unspecified Resource Amounts	TSS TCMS	FY2022&FY2023	N/A	10.000	10.000	$ -	$ -	$ -
40	Cheney	Unspecified Resource Amounts	TSS TCMS	FY2022&FY2023	N/A	2.000	2.000	$ -	$ -	$ -
41	Kootenai	Unspecified Resource Amounts	TSS TCMS	FY2022&FY2023	N/A	10.000	10.000	$ -	$ -	$ -
42	Lower Valley	Unspecified Resource Amounts	TSS TCMS	FY2022&FY2023	N/A	13.000	14.000	$ -	$ -	$ -
43	United	Unspecified Resource Amounts	TSS TCMS	FY2022&FY2023	N/A	3.000	3.000	$ -	$ -	$ -
44	Wells	Unspecified Resource Amounts	TSS TCMS	FY2022&FY2023	N/A	5.000	5.000	$ -	$ -	$ -

Table 3.11 Continued
RSS and Related Charges for FY 2022 and FY 2023

	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 FY2022	Revenue Credit to Non-Slice Cost Pool FY2022	Revenue Credit to Composite Cost Pool FY2023	Revenue Credit to Non-Slice Cost Pool FY2023	Forecast Total $/MWh Equivalent Rate
1	$ (29,006)	$ (2.29)	$ -	$ -	$ 1,019	$ 0.08	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,010,243	$ 75,687	$ 2,010,243	$ 75,687	$ 13.72
2	$ -	$ -	$ -	$ -	$ 648	$ 0.11	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,775	$ -	$ 7,775	$ -	$ 0.11
3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 782	$ 0.57	$ 9,381	$ -	$ 9,381	$ -	$ 0.57
4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,421	$ 0.66	$ 41,047	$ -	$ 41,047	$ -	$ 0.66
5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 777	$ 0.67	$ -	$ -	$ 9,323	$ -	$ 9,323	$ -	$ 0.67
6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 788	$ 0.67	$ -	$ -	$ 9,450	$ -	$ 9,450	$ -	$ 0.67
7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 777	$ 0.67	$ -	$ -	$ 9,323	$ -	$ 9,323	$ -	$ 0.67
8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 788	$ 0.67	$ -	$ -	$ 9,450	$ -	$ 9,450	$ -	$ 0.67
9	$ 35,422	$ 21.22	$ 1,236	$ 0.74	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 63,096	$ 428,372	$ 63,096	$ 428,372	$ 24.54
10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 777	$ 0.67	$ -	$ -	$ 9,323	$ -	$ 9,323	$ -	$ 0.67
11	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 788	$ 0.67	$ -	$ -	$ 9,450	$ -	$ 9,450	$ -	$ 0.67
12	$ (7,429)	$ (9.71)	$ 162	$ 0.21	$ 71	$ 0.09	$ -	$ -	$ -	$ -	$ -	$ -	$ 77,620	$ (76,866)	$ 77,620	$ (76,866)	$ 0.08
13	$ (6,460)	$ (9.25)	$ 356	$ 0.51	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 32,104	$ (74,336)	$ 32,104	$ (74,336)	$ (5.04)
14	$ (7,513)	$ (7.37)	$ 665	$ 0.65	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 54,448	$ (88,727)	$ 54,448	$ (88,727)	$ (2.80)
15	$ (1,218)	$ (0.68)	$ 1,526	$ 0.85	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 75,200	$ (11,653)	$ 75,200	$ (11,653)	$ 2.95
16	$ -	$ -	$ -	$ -	$ 1,008	$ 0.01	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,098	$ -	$ 12,098	$ -	$ 0.01
17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 259	$ 0.67	$ -	$ -	$ 3,107	$ -	$ 3,107	$ -	$ 0.67
18	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 262	$ 0.67	$ -	$ -	$ 3,149	$ -	$ 3,149	$ -	$ 0.67
19	$ (304)	$ (0.69)	$ -	$ -	$ 63	$ 0.14	$ -	$ -	$ -	$ -	$ -	$ -	$ 71,093	$ 13,503	$ 71,093	$ 13,503	$ 15.88
20	$ -	$ -	$ -	$ -	$ 58	$ 0.12	$ -	$ -	$ 301	$ 0.63	$ -	$ -	$ 4,313	$ -	$ 4,313	$ -	$ 0.75
21	$ (839)	$ (1.34)	$ -	$ -	$ 70	$ 0.11	$ -	$ -	$ -	$ -	$ -	$ -	$ 96,138	$ 14,127	$ 96,138	$ 14,127	$ 14.71
22	$ (2,600)	$ (3.31)	$ -	$ -	$ 79	$ 0.10	$ -	$ -	$ -	$ -	$ -	$ -	$ 121,013	$ (3,437)	$ 121,013	$ (3,437)	$ 12.49
23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 613	$ 0.55	$ -	$ -	$ 7,354	$ -	$ 7,354	$ -	$ 0.55
24	$ 2,738	$ 4.81	$ 94	$ 0.16	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 59,169	$ 35,119	$ 59,169	$ 35,119	$ 13.80
25	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 446	$ 0.62	$ -	$ -	$ 5,347	$ -	$ 5,347	$ -	$ 0.62
27	$ -	$ -	$ -	$ -	$ 359	$ 0.11	$ -	$ -	$ -	$ -	$ 2,117	$ 0.66	$ 29,709	$ -	$ 29,709	$ -	$ 0.77
28	$ -	$ -	$ -	$ -	$ 345	$ 0.11	$ -	$ -	$2,029	$ 0.66	$ -	$ -	$ 28,485	$ -	$ 28,485	$ -	$ 0.77
29	$ -	$ -	$ -	$ -	$ 21	$ 0.15	$ -	$ -	$ 90	$ 0.63	$ -	$ -	$ 1,339	$ -	$ 1,339	$ -	$ 0.78
30	$ -	$ -	$ -	$ -	$ 809	$ 0.11	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,703	$ -	$ 9,703	$ -	$ 0.11
31	$ -	$ -	$ -	$ -	$ 792	$ 0.11	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,505	$ -	$ 9,505	$ -	$ 0.11
32	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 613	$ 0.55	$ -	$ -	$ 7,354	$ -	$ 7,354	$ -	$ 0.55
33	$ 2,738	$ 4.81	$ 94	$ 0.16	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 59,169	$ 35,119	$ 59,169	$ 35,119	$ 13.80
34	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 446	$ 0.62	$ -	$ -	$ 5,347	$ -	$ 5,347	$ -	$ 0.62
35	$ -	$ -	$ -	$ -	$ 648	$ 0.11	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,775	$ -	$ 7,775	$ -	$ 0.11
36	$ -	$ -	$ -	$ -	$ 359	$ 0.11	$ -	$ -	$ -	$ -	$ 2,117	$ 0.66	$ 29,709	$ -	$ 29,709	$ -	$ 0.77
37	$ -	$ -	$ -	$ -	$ 345	$ 0.11	$ -	$ -	$2,029	$ 0.66	$ -	$ -	$ 28,485	$ -	$ 28,485	$ -	$ 0.77
38	$ -	$ -	$ -	$ -	$ 21	$ 0.15	$ -	$ -	$ 90	$ 0.63	$ -	$ -	$ 1,339	$ -	$ 1,339	$ -	$ 0.78
39	$ -	$ -	$ -	$ -	$ 809	$ 0.11	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,703	$ -	$ 9,703	$ -	$ 0.11
40	$ -	$ -	$ -	$ -	$ 166	$ 0.11	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,994	$ -	$ 1,994	$ -	$ 0.11
41	$ -	$ -	$ -	$ -	$ 809	$ 0.11	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,703	$ -	$ 9,703	$ -	$ 0.11
42	$ -	$ -	$ -	$ -	$ 1,008	$ 0.10	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,098	$ -	$ 12,098	$ -	$ 0.10
43	$ -	$ -	$ -	$ -	$ 246	$ 0.11	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,957	$ -	$ 2,957	$ -	$ 0.11
44	$ -	$ -	$ -	$ -	$ 407	$ 0.11	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,885	$ -	$ 4,885	$ -	$ 0.11

Table 3.12
PF Load Forecast Deviation Liquidated Damages

	A	B	C
1		FY 2022	FY 2023
2	Forecast of Annual Consumer Load MWh	1,051,200	1,051,200
3	Actual Annual Consumer Load MWh	1,226,400	1,226,400
4	Actual Annual Consumer Load Above Forecast Amount MWh	175,200	175,200
5	Absolute Value of Load Shaping True-Up Rate	$ 6.11	$ 6.11
6	Annual Liquidated Damages Charge	$ 1,070,472	$ 1,070,472

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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**	**Load Shaping Rate HLH $/MWh**	**Demand Shaping Factor**	**Monthly Demand Rate $/kW/mo**
2	Start Year of Operation (FY)	2022		2015	104.624		Oct	29.92	8.50%	$ 9.87
3	Cost of Debt	2.42%	/1	2016	105.722		Nov	31.71	9.01%	$ 10.46
4				2017	107.710		Dec	38.76	11.01%	$ 12.78
5	Inflation Rate	1.66%		2018	110.296		Jan	34.29	9.74%	$ 11.31
6	Insurance Rate	0.25%	/2	2019	112.265		Feb	34.79	9.88%	$ 11.47
7				2020	113.625		Mar	27.57	7.83%	$ 9.09
8	Debt Finance Period (years)	30	/2				Apr	20.71	5.88%	$ 6.83
9	Plant Lifecycle (years)	30	/2		101.66%	5-year Ave.	May	16.28	4.62%	$ 5.36
10							Jun	17.15	4.87%	$ 5.65
11	Plant in service 2022 Vintaged Heat Rate Btu/kWh	8,541	/3	Chained GDP IPD from BEA -- Table 1.1.9. Implicit Price Deflators for Gross Domestic Product (2012 Base year) - Last Revised April 29, 2021			Jul	36.83	10.46%	$ 12.14
12							Aug	35.87	10.19%	$ 11.83
13	Eastside Fixed Fuel $/kW/yr with 10000 Heat Rate 2012$	$ 41.42	/3				Sep	28.15	8.00%	$ 9.29
14	Westside Fixed Fuel $/kW/yr with 10000 Heat Rate 2012$	$ 46.03	/3				**Average $/kW/mo**			**$ 9.67**
15	Eastside Fixed Fuel $/kW/yr with 10000 Heat Rate 2022$	$ 48.85								
16	Westside Fixed Fuel $/kW/yr with 10000 Heat Rate 2022$	$ 54.29								
17	Average of Existing Eastside and Westside with 10000 Heat Rate 2022$	$ 51.57								
18	Average of Existing Eastside and Westside with 8541 Heat Rate 2022$	$ 44.05								
19										
20	All-in Nominal Capital Cost LMS100 $/kW	$ 1,179.47	/4	**End of Fiscal Year**	**Midyear Assessed Value**	**Debt Payment**	**Fixed O&M**	**Insurance**	**Fixed Fuel**	**Cash Expense Each Year**
21	Fixed O&M $/kW/yr 2022$	12.97	/5	2022	$ 1,159.81	$55.75	$ 12.97	$ 2.90	$ 44.05	$ 115.67
22	Fixed Fuel $/kW/yr	$ 44.05		2023	$ 1,120.50	$55.75	$ 13.19	$ 2.80	$ 44.78	$ 116.52
23							**Rate Period Average Expense $/kW/year**			**$ 116.10**
24										
25	/1 Source BPA FY 2021 Third-Party Tax-Exempt Borrowing Rate Forecast 30-year									
26	/2 Source NWPCC 7th Power Plan Appendix H.									
27	/3 Source NWPCC Microfin Model, Version 15.0.5									
28	/4 Source NWPCC Microfin Model assumption of $1000/kW in 2012$, with 100% PUD ownership at 3.75% with plant in service 2022.									
29	/5 Source NWPCC Microfin Model assumption of $11/kW/yr in 2012$.									

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-21	30.65	27.46		October	29.92	28.27
4	Nov-21	32.01	28.85		November	31.71	29.14
5	Dec-21	39.64	32.29		December	38.76	32.05
6	Jan-22	35.33	26.69		January	34.29	25.85
7	Feb-22	35.32	28.38		February	34.79	28.29
8	Mar-22	27.79	27.20		March	27.57	28.44
9	Apr-22	21.12	24.59		April	20.71	25.66
10	May-22	15.82	15.09		May	16.28	16.30
11	Jun-22	17.36	9.77		June	17.15	10.62
12	Jul-22	38.34	21.90		July	36.83	21.36
13	Aug-22	37.21	29.00		August	35.87	26.85
14	Sep-22	29.33	29.86		September	28.15	28.95
15	Oct-22	29.18	29.08				
16	Nov-22	31.41	29.42				$/MWh
17	Dec-22	37.88	31.80	**FY2022 Aurora Flat Annual Block**			27.82
18	Jan-23	33.26	25.02	**FY2023 Aurora Flat Annual Block**			27.13
19	Feb-23	34.26	28.21				
20	Mar-23	27.35	29.68				
21	Apr-23	20.29	26.73				
22	May-23	16.73	17.50				
23	Jun-23	16.94	11.47				
24	Jul-23	35.32	20.83				
25	Aug-23	34.52	24.71				
26	Sep-23	26.97	28.05				

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_FY2022	LG.1.2012_2028	FY2022	13.823	14.267
3	LG.1.2012_2028_FY2023	LG.1.2012_2028	FY2023	13.973	14.422
4	ST.3.2020_2024_FY2022	ST.3.2020_2024	FY2022	142.767	147.350
5	ST.3.2020_2024_FY2023	ST.3.2020_2024	FY2023	159.228	164.339
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 2018	FY 2019	FY 2020	Average			kW	Hours	
4	October	490,000	422,000	412,000	441,333		October	191,667	744	
5	November	462,000	407,000	413,000	427,333		November	203,667	721	
6	December	495,000	436,000	523,000	484,667		December	238,667	744	
7	January	493,000	474,000	476,000	481,000		January	259,333	744	
8	February	505,000	469,000	510,000	494,667		February	260,667	680	
9	March	501,000	413,000	511,000	475,000		March	237,333	743	
10	April	490,000	430,000	468,000	462,667		April	239,000	720	
11	May	500,000	439,000	499,000	479,333		May	269,000	744	
12	June	497,000	472,000	491,000	486,667		June	255,000	720	
13	July	541,000	512,000	531,000	528,000		July	270,000	744	
14	August	525,000	528,000	555,000	536,000		August	276,667	744	
15	September	477,000	517,000	505,000	499,667		September	245,667	720	
16										
17		Minimum Hourly Amount (kW)					Average Annual Power (kWh)		2,152,963,667	
18		FY 2018	FY 2019	FY 2020	Average		Capacity Cost Comp$_2$		$2,152,964	
19	October	202,000	171,000	202,000	191,667					
20	November	179,000	203,000	229,000	203,667		**Capacity Cost of Real Power Losses:**			
21	December	269,000	213,000	234,000	238,667		Sum of Capacity Cost Comp$_1$ and Comp$_2$			$17,170,707
22	January	262,000	256,000	260,000	259,333		Average Annual Amount of Losses (MWh)			3,112,095
23	February	307,000	193,000	282,000	260,667		FPS Real Power Losses Capacity Rate $/MWh			$5.52
24	March	280,000	198,000	234,000	237,333					
25	April	269,000	235,000	213,000	239,000					
26	May	295,000	243,000	269,000	269,000					
27	June	285,000	212,000	268,000	255,000					
28	July	248,000	249,000	313,000	270,000					
29	August	231,000	274,000	325,000	276,667					
30	September	214,000	291,000	232,000	245,667					
31										
32	Annual Sum of Monthly Capacity$_{inc}$				2,849,667					
33	Capacity Cost Comp$_1$				$15,017,743					

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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	6.00%	4,974.051
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	6.00%	2,489.359
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	3.00%	173.085
23	10338	Riverside	528.123	986.578	1,167.444	906.478	566.587	4,155.210	3.50%	145.432
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	5.00%	11,438.621
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	7.00%	501.994
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	5.50%	1,011.286
33								**Wt. LDD**	**4.8%**	

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

	A	B	C	D	E	F
1	**FY 2022**					
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	4.069	35,644	32.13	$1,145,256	$95,438
4	Mason County PUD #3	0.079	692	32.13	$22,235	$1,853
5	Total	4.148	36,336		$1,167,491	$97,291
6	**FY 2023**					
7	**Customers receiving remarketing credits for non-Federal resource(s) with DFS**	**Remarketing Amount (aMW)**	**Remarketing Amount (MWh)**	**Remarketing Value ($/MWh)**	**Annual Remarketing Credit**	**Monthly Remarketing Credit**
8	McMinnville, City of	4.015	35,171	30.73	$1,080,817	$90,068
9	Mason County PUD #3	0.000	0	30.73	$0	$0
10	Total	4.015	35,171		$1,080,817	$90,068

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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	0.0204	
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 2020	801,683	942,943	1,111,014	1,094,315	952,184	907,851	828,116	840,313	894,476	976,167	937,054	807,956
FY 2021	809,299	950,769	1,118,985	1,103,375	960,559	916,469	836,458	848,862	902,950	984,894	945,668	816,305
Total	1,610,982	1,893,712	2,229,999	2,197,690	1,912,743	1,824,320	1,664,574	1,689,175	1,797,426	1,961,062	1,882,723	1,624,261

2022 Rate recovery ($1000s)	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
Spin	136	159	188	185	161	154	140	142	151	165	158	137	1,876
Supp	89	104	123	121	105	100	92	93	99	108	104	89	1,226
Reg & Freq	369	434	511	503	438	418	381	387	411	449	431	372	5,103
WECC Fee	25	25	25	25	25	25	25	25	25	25	25	25	297
Total	618	722	847	834	729	696	637	646	686	747	718	622	8,503

2023 Rate recovery ($1000s)	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
Spin	137	161	189	187	162	155	141	144	153	167	160	138	1,893
Supp	89	105	124	122	106	101	92	94	100	109	105	90	1,237
Reg & Freq	372	437	515	508	442	422	385	390	415	453	435	376	5,150
WECC Fee	25	25	25	25	25	25	25	25	25	25	25	25	297
Total	623	728	852	841	735	703	643	653	693	753	724	629	8,577

Delivery Charge (using FY18-19 actuals)

Distribution and Low Voltage Costs	3,118,355	$
BPA Customer System Peak	2,451,443	Peak kW
Proposed Rate	$ 1.27	Per kW

SECTION 7: SLICE

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SECTION 8: AVERAGE SYSTEM COSTS

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Table Descriptions

Table 8.1
Forecast Average System Costs (ASCs)
Table lists the Fiscal Year Forecast ASCs in $/MWh as determined through the ASC review process.

Table 8.2
IOUs' Exchange Loads and COUs' Forecast Exchange Loads (MWh)
Table lists the monthly two-year average IOU Exchange Loads based on actual loads as submitted by Exchanging Utilities, and the monthly Forecast COU Exchange Loads.

Table 8.1

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

	A	B	C
1		**FY 2022**	**FY 2023**
2	Avista	$ 62.93	$ 62.93
3	Idaho Power	$ 58.17	$ 58.17
4	NorthWestern	$ 68.34	$ 68.34
5	PacifiCorp	$ 77.61	$ 77.61
6	PGE	$ 70.09	$ 70.09
7	Puget Sound Energy	$ 67.28	$ 67.28
8	Clark	$ 42.14	$ 42.14
9	Snohomish	$ 55.83	$ 55.83
10			
11	Note: Rate Period ASCs are determined through the ASC review process		

Table 8.2

IOUs FY 2022 - 2023 Residential Loads
(MWh)

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1		**Oct-21**	**Nov-21**	**Dec-21**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**FY 2022**
2	Avista	430,208	396,229	422,302	321,131	260,985	251,591	272,463	311,984	290,831	260,373	326,963	426,399	**3,971,458**
3	Idaho Power	619,849	581,817	542,521	458,192	488,575	530,993	654,648	767,198	676,694	474,145	477,209	585,231	**6,857,072**
4	NorthWestern	75,258	68,548	70,040	59,323	50,780	49,460	51,988	58,493	53,934	48,500	58,449	69,349	**714,123**
5	PacifiCorp	964,347	891,813	848,939	690,494	580,060	631,520	715,187	797,533	713,043	593,932	734,342	985,951	**9,147,160**
6	PGE	1,279,182	1,175,005	1,168,115	992,429	843,835	868,651	905,098	1,004,725	985,192	850,292	1,010,800	1,308,440	**12,391,765**
7	Puget Sound Energy	1,293,470	1,286,740	1,283,103	1,028,327	850,106	790,291	758,383	777,650	786,254	814,426	986,271	1,297,422	**11,952,444**
8														
9		**Oct-22**	**Nov-22**	**Dec-22**	**Jan-23**	**Feb-23**	**Mar-23**	**Apr-23**	**May-23**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**FY 2023**
10	Avista	430,208	396,229	422,302	321,131	260,985	251,591	272,463	311,984	290,831	260,373	326,963	426,399	**3,971,458**
11	Idaho Power	619,849	581,817	542,521	458,192	488,575	530,993	654,648	767,198	676,694	474,145	477,209	585,231	**6,857,072**
12	NorthWestern	75,258	68,548	70,040	59,323	50,780	49,460	51,988	58,493	53,934	48,500	58,449	69,349	**714,123**
13	PacifiCorp	964,347	891,813	848,939	690,494	580,060	631,520	715,187	797,533	713,043	593,932	734,342	985,951	**9,147,160**
14	PGE	1,279,182	1,175,005	1,168,115	992,429	843,835	868,651	905,098	1,004,725	985,192	850,292	1,010,800	1,308,440	**12,391,765**
15	Puget Sound Energy	1,293,470	1,286,740	1,283,103	1,028,327	850,106	790,291	758,383	777,650	786,254	814,426	986,271	1,297,422	**11,952,444**
16														
17														
18						COUs FY 2022 - 2023 Forecast Exchange Loads								
19						(MWh)								
20														
21		**Oct-21**	**Nov-21**	**Dec-21**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**FY 2022**
22	Clark	187,291	248,534	321,915	301,752	242,583	240,139	190,265	177,139	156,825	184,553	184,417	150,897	**2,586,310**
23	Snohomish	281,981	319,922	378,546	374,981	318,605	324,418	276,391	258,113	245,586	256,814	255,278	247,411	**3,538,046**
24														
25		**Oct-22**	**Nov-22**	**Dec-22**	**Jan-23**	**Feb-23**	**Mar-23**	**Apr-23**	**May-23**	**Jun-23**	**Jul-23**	**Aug-23**	**Sep-23**	**FY 2023**
26	Clark	188,208	249,672	322,977	302,668	243,494	241,024	190,781	178,062	157,857	185,980	185,869	151,793	**2,598,384**
27	Snohomish	280,508	318,251	376,568	372,620	316,599	322,376	274,651	256,487	244,039	255,197	253,671	245,853	**3,516,820**

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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
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 9.4
Balancing Reserve Capacity Quantity Forecast for FY 2022-2023
The forecast quantities of balancing reserves needed on a monthly basis to support the 99.7 percent planning standard.

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**													**2021**	
2	**Category**	**202010**	**202011**	**202012**	**202101**	**202102**	**202103**	**202104**	**202105**	**202106**	**202107**	**202108**	**202109**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 183,932	$ 183,932	$ 183,932	$ 183,932	$ 183,932	$ 184,226	$ 184,226	$ 184,226	$ 184,226	$ 184,226	$ 184,226	$ 184,226	$ 2,209,243	4,959
4	Non-Slice Revenue	$ (14,127)	$ (14,127)	$ (14,127)	$ (14,127)	$ (14,127)	$ (14,157)	$ (14,157)	$ (14,157)	$ (14,157)	$ (14,157)	$ (14,157)	$ (14,157)	$ (169,732)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	2,689
6	Load Shaping Revenue	$ 1,357	$ (5,143)	$ 10,791	$ 23,294	$ 24,076	$ 6,680	$ 7,511	$ (7,940)	$ (14,404)	$ (6,563)	$ (5,889)	$ (1,736)	$ 32,034	53
7	Demand Revenue	$ 9,981	$ 2,990	$ 4,914	$ 4,613	$ 4,877	$ 5,404	$ 4,086	$ 1,916	$ 2,297	$ 5,495	$ 6,041	$ 5,343	$ 57,956	-
8	Irrigation Rate Discount	$ -	$ 20	$ -	$ -	$ -	$ -	$ -	$ (3,222)	$ (4,816)	$ (5,546)	$ (4,551)	$ (2,769)	$ (20,885)	-
9	Low Density Discount	$ (3,500)	$ (2,924)	$ (3,400)	$ (3,620)	$ (3,752)	$ (3,251)	$ (3,422)	$ (3,109)	$ (3,016)	$ (3,473)	$ (3,483)	$ (3,291)	$ (40,240)	-
10	Tier 2	$ 1,559	$ 1,511	$ 1,559	$ 1,559	$ 1,408	$ 1,691	$ 1,640	$ 1,686	$ 1,637	$ 1,681	$ 1,686	$ 1,623	$ 19,239	58
11	RSS (Non-Federal) and Other	$ (61)	$ (132)	$ (176)	$ (122)	$ (76)	$ 76	$ 76	$ 76	$ 76	$ 76	$ 76	$76	$ (38)	-
12	**PF customers (TRM) sub-total**	**$ 179,140**	**$ 166,126**	**$ 183,492**	**$ 195,529**	**$ 196,338**	**$ 180,670**	**$ 179,961**	**$ 159,476**	**$ 151,843**	**$ 161,740**	**$ 163,949**	**$ 169,315**	**$ 2,087,577**	**7,759**
13	**NR sub-total**	**$ (145)**	**$ (119)**	**$ (139)**	**$ (107)**	**$ (238)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ (749)**	**-**
14	**DSIs sub-total**	**$ 342**	**$ 355**	**$ 373**	**$ 357**	**$ 318**	**$ 251**	**$ 329**	**$ 276**	**$ 245**	**$ 360**	**$ 398**	**$ 383**	**$ 3,987**	**11**
15	**FPS sub-total**	**$ 522**	**$ 598**	**$ 704**	**$ 684**	**$ 632**	**$ 991**	**$ 932**	**$ 942**	**$ 989**	**$ 1,060**	**$ 1,023**	**$ 914**	**$ 9,989**	**-**
16	**Short-term market sales sub-total**	**$ 35,018**	**$ 38,938**	**$ 46,731**	**$ 57,646**	**$ 59,335**	**$ 45,856**	**$ 18,582**	**$ 36,123**	**$ 36,861**	**$ 52,206**	**$ 34,976**	**$ 21,502**	**$ 483,775**	**1,835**
17	**Long Term Contractual Obligations sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**468**
19	**Other Sales sub-total**	**$ 30**	**$ 13**	**$ 23**	**$ 0**	**$ 1**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 19,774**	**$ 19,841**	**-**
20	**Gross Sales**	**$214,907**	**$205,912**	**$231,183**	**$254,109**	**$256,386**	**$227,768**	**$199,803**	**$196,817**	**$189,938**	**$215,366**	**$200,346**	**$211,887**	**$2,604,421**	**10,068**
21	Transfer Service Delivery charge	$ 286	$ 284	$ 294	$ 294	$ 330	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 1,663	-
22	Energy Efficiency Revenues	$ (91)	$ (56)	$ 50	$ (53)	$ 180	$ 544	$ 544	$ 544	$ 544	$ 544	$ 544	$ 544	$ 3,836	-
23	Irrigation Pumping Power	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 1,278	15
24	Reserve Energy	$ 882	$ 882	$ 882	$ 882	$ 882	$ 812	$ 812	$ 812	$ 812	$ 812	$ 812	$ 812	$ 10,098	160
25	USBR Owyhee Wheeling Project	$ 139	$ 139	$ 139	$ 139	$ 139	$ 137	$ 137	$ 137	$ 137	$ 137	$ 137	$ 137	$ 1,652	-
26	Downstream Benefits	$ 729	$ 634	$ 1,730	$ 3,113	$ 634	$ 611	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 10,801	-
27	Upper Baker Revenues	$ -	$ 82	$ 96	$ 87	$ 82	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 347	-
28	**Miscellaneous Revenue**	**$2,052**	**$2,072**	**$3,298**	**$4,570**	**$2,355**	**$2,234**	**$2,182**	**$2,182**	**$2,182**	**$2,182**	**$2,182**	**$2,182**	**$29,675**	**175**
29	Balancing Reserve Capacity	$ 5,688	$ 6,055	$ 5,688	$ 5,850	$ 5,850	$ 5,850	$ 5,850	$ 5,850	$ 5,850	$ 5,850	$ 5,850	$ 5,850	$ 70,079	-
30	ACS Risk Share	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
31	Risk Mitigation Tool	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
32	Imbalance Adjustment for Third-Party Deployed Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
33	Operating Reserve - Spinning	$ 1,138	$ 1,300	$ 1,375	$ 1,499	$ 1,539	$ 1,368	$ 1,427	$ 1,533	$ 1,655	$ 1,540	$ 1,427	$ 1,299	$ 17,100	-
34	Operating Reserve - Supplemental	$ 1,138	$ 1,300	$ 1,375	$ 1,499	$ 1,539	$ 1,368	$ 1,427	$ 1,533	$ 1,655	$ 1,540	$ 1,427	$ 1,299	$ 17,100	-
35	Operating Reserve - Spinning Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
36	Operating Reserve - Supplemental Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
37	Synchronous Condensing	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 831	-
38	Generation Dropping	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 498	-
39	Redispatch	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 250	-
40	Segmentation of COE/Reclamation Network and Delivery Facilities	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 8,806	-
41	Station Service	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 1,660	9
42	Energy Imbalance	$ 18	$ 38	$ 23	$ 33	$ 196	$ 51	$ 47	$ 64	$ 91	$ 14	$ 40	$ 6	$ 621	-
43	Generation Imbalance	$ 431	$ 727	$ 195	$ 183	$ 1,030	$ 14	$ 51	$ 159	$ 95	$ (73)	$ 67	$ 210	$ 3,090	-
44	Energy Imbalance Persistent Deviation	$ 15	$ 184	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 199	-
45	Generation Imbalance Persistent Deviation	$ 11	$ -	$ 18	$ 8	$ 9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 46	-
46	Operating Reserve - Energy	$ 11	$ 35	$ 57	$ 25	$ 78	$ 28	$ 27	$ 20	$ 3	$ 32	$ 26	$ 25	$ 368	-
47	**Generation Inputs / Inter-business line**	**$ 9,453**	**$ 10,643**	**$ 9,734**	**$ 10,101**	**$ 11,245**	**$ 9,683**	**$ 9,833**	**$ 10,163**	**$ 10,353**	**$ 9,907**	**$ 9,841**	**$ 9,693**	**$ 120,648**	**9**
48	4(h)(10)(c)	$ 10,343	$ 5,134	$ 7,520	$ 7,132	$ 4,757	$ 8,544	$ 8,862	$ 6,490	$ 6,078	$ 5,517	$ 5,884	$ 6,934	$ 83,195	-
49	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
50	**Treasury Credits**	**$ 10,726**	**$ 5,517**	**$ 7,903**	**$ 7,515**	**$ 5,140**	**$ 8,927**	**$ 9,245**	**$ 6,873**	**$ 6,461**	**$ 5,901**	**$ 6,267**	**$ 7,317**	**$ 87,795**	**-**
51	Augmentation Power Purchase sub-total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
52	Balancing Power Purchase sub-total	$ 20,552	$ 9,850	$ 22,127	$ 13,649	$ 22,588	$ 23,219	$ 5,129	$ 3,161	$ 3,110	$ 186	$ 1,770	$ 226	$ 125,568	411
53	Other Power Purchase sub-total	$ 813	$ 168	$ 599	$ 1,773	$ 2,656	$ (169)	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,840	-
54	**Power Purchases**	**$ 21,365**	**$ 10,018**	**$ 22,726**	**$ 15,423**	**$ 25,244**	**$ 23,051**	**$ 5,129**	**$ 3,161**	**$ 3,110**	**$ 186**	**$ 1,770**	**$ 226**	**$ 131,408**	**411**

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**													**2022**	
2	**Category**	**202110**	**202111**	**202112**	**202201**	**202202**	**202203**	**202204**	**202205**	**202206**	**202207**	**202208**	**202209**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 187,620	$ 187,620	$ 187,620	$ 187,620	$ 187,620	$ 187,620	$ 187,620	$ 187,620	$ 187,620	$ 187,620	$ 187,620	$ 187,620	$ 2,251,441	4,854
4	Non-Slice Revenue	$ (14,500)	$ (14,500)	$ (14,500)	$ (14,500)	$ (14,500)	$ (14,500)	$ (14,500)	$ (14,500)	$ (14,500)	$ (14,500)	$ (14,500)	$ (14,500)	$ (174,001)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	1,521
6	Load Shaping Revenue	$ (2,616)	$ (11,230)	$ 10,746	$ 26,207	$ 19,009	$ 4,697	$ 7,545	$ (9,222)	$ (11,150)	$ (8,813)	$ (7,759)	$ (7,572)	$ 9,842	(21)
7	Demand Revenue	$ 2,748	$ 3,758	$ 8,909	$ 6,208	$ 4,053	$ 5,047	$ 4,342	$ 1,853	$ 2,645	$ 5,034	$ 7,699	$ 5,678	$ 57,974	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,222)	$ (4,816)	$ (5,546)	$ (4,551)	$ (2,769)	$ (20,905)	-
9	Low Density Discount	$ (3,234)	$ (3,234)	$ (3,234)	$ (3,234)	$ (3,234)	$ (3,234)	$ (3,234)	$ (3,234)	$ (3,234)	$ (3,234)	$ (3,234)	$ (3,234)	$ (38,806)	-
10	Tier 2	$ 3,439	$ 3,333	$ 3,439	$ 3,439	$ 3,106	$ 3,434	$ 3,328	$ 3,439	$ 3,328	$ 3,439	$ 3,439	$ 3,328	$ 40,489	157
11	RSS (Non-Federal) and Other	$ 73	$ 73	$ 73	$ 73	$ 73	$ 73	$ 73	$ 73	$ 73	$ 73	$ 73	$ 73	$ 871	-
12	**PF customers (TRM) sub-total**	**$ 173,529**	**$ 165,820**	**$ 193,053**	**$ 205,812**	**$ 196,126**	**$ 183,137**	**$ 185,174**	**$ 162,806**	**$ 159,966**	**$ 164,073**	**$ 168,787**	**$ 168,623**	**$ 2,126,906**	**6,511**
13	**NR sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
14	**DSIs sub-total**	**$ 387**	**$ 392**	**$ 425**	**$ 393**	**$ 353**	**$ 352**	**$ 328**	**$ 276**	**$ 245**	**$ 359**	**$ 399**	**$ 381**	**$ 4,290**	**12**
15	**FPS sub-total**	**$ 618**	**$ 722**	**$ 847**	**$ 834**	**$ 729**	**$ 696**	**$ 637**	**$ 646**	**$ 686**	**$ 747**	**$ 718**	**$ 622**	**$ 8,503**	**-**
16	**Short-term market sales sub-total**	**$ 21,117**	**$ 34,879**	**$ 39,547**	**$ 60,308**	**$ 60,891**	**$ 43,528**	**$ 25,828**	**$ 41,295**	**$ 43,626**	**$ 65,582**	**$ 45,590**	**$ 21,665**	**$ 503,856**	**1,870**
17	**Long Term Contractual Obligations sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**462**
19	**Other Sales sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,070**	**$ 1,070**	**-**
20	**Gross Sales**	**$195,650**	**$201,813**	**$233,871**	**$267,348**	**$258,098**	**$227,713**	**$211,967**	**$205,024**	**$204,523**	**$230,761**	**$215,494**	**$192,363**	**$2,644,625**	**8,855**
21	Transfer Service Delivery charge	$ 217	$ 222	$ 315	$ 346	$ 300	$ 248	$ 222	$ 233	$ 243	$ 264	$ 258	$ 233	$ 3,100	-
22	Energy Efficiency Revenues	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 8,000	-
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	$ -	$ 92	$ 115	$ 104	$ 100	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 411	-
28	**Miscellaneous Revenue**	**$2,605**	**$2,702**	**$2,819**	**$2,838**	**$2,788**	**$2,636**	**$2,611**	**$2,621**	**$2,631**	**$2,652**	**$2,647**	**$2,621**	**$32,173**	**175**
29	Balancing Reserve Capacity	$ 4,563	$ 4,395	$ 4,395	$ 4,395	$ 4,395	$ 4,395	$ 4,395	$ 4,395	$ 4,395	$ 4,395	$ 4,395	$ 4,395	$ 52,913	-
30	ACS Risk Share	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
31	Risk Mitigation Tool	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
32	Imbalance Adjustment for Third-Party Deployed Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
33	Operating Reserve - Spinning	$ 1,515	$ 1,708	$ 1,817	$ 1,959	$ 1,908	$ 1,969	$ 2,172	$ 1,818	$ 2,167	$ 2,051	$ 2,134	$ 1,615	$ 22,834	-
34	Operating Reserve - Supplemental	$ 989	$ 1,116	$ 1,187	$ 1,280	$ 1,246	$ 1,286	$ 1,418	$ 1,187	$ 1,415	$ 1,339	$ 1,394	$ 1,055	$ 14,911	-
35	Operating Reserve - Spinning Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
36	Operating Reserve - Supplemental Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
37	Synchronous Condensing	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 923	-
38	Generation Dropping	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 365	-
39	Redispatch	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 370	-
40	Segmentation of COE/Reclamation Network and Delivery Facilities	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 9,502	-
41	Station Service	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 2,295	9
42	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
43	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
44	Energy Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
45	Generation Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	**Generation Inputs / Inter-business line**	**$ 8,188**	**$ 8,341**	**$ 8,521**	**$ 8,756**	**$ 8,671**	**$ 8,771**	**$ 9,107**	**$ 8,522**	**$ 9,099**	**$ 8,907**	**$ 9,044**	**$ 8,186**	**$ 104,113**	**9**
48	4(h)(10)(c)	$ 10,194	$ 6,934	$ 9,605	$ 9,551	$ 7,756	$ 8,006	$ 9,398	$ 7,460	$ 6,636	$ 6,252	$ 5,642	$ 6,736	$ 94,171	-
49	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
50	**Treasury Credits**	**$ 10,578**	**$ 7,317**	**$ 9,988**	**$ 9,934**	**$ 8,139**	**$ 8,389**	**$ 9,782**	**$ 7,844**	**$ 7,020**	**$ 6,635**	**$ 6,025**	**$ 7,119**	**$ 98,771**	**-**
51	Augmentation Power Purchase sub-total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
52	Balancing Power Purchase sub-total	$ 6,295	$ 2,086	$ 8,305	$ 7,976	$ 5,329	$ 2,044	$ 4,210	$ 449	$ 279	$ 2,177	$ 2,502	$ 1,614	$ 43,266	150
53	Other Power Purchase sub-total	$ 3,693	$ 3,693	$ 3,693	$ 3,693	$ 3,693	$ 3,693	$ 3,693	$ 3,693	$ 3,693	$ 3,693	$ 3,693	$ 3,693	$ 44,321	162
54	**Power Purchases**	**$ 9,989**	**$ 5,780**	**$ 11,998**	**$ 11,669**	**$ 9,022**	**$ 5,737**	**$ 7,904**	**$ 4,142**	**$ 3,973**	**$ 5,870**	**$ 6,196**	**$ 5,308**	**$ 87,587**	**311**

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**													**2023**	
2	**Category**	**202210**	**202211**	**202212**	**202301**	**202302**	**202303**	**202304**	**202305**	**202306**	**202307**	**202308**	**202309**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 188,236	$ 188,236	$ 188,236	$ 188,236	$ 188,236	$ 188,236	$ 188,236	$ 188,236	$ 188,236	$ 188,236	$ 188,236	$ 188,236	$ 2,258,827	6,381
4	Non-Slice Revenue	$ (14,562)	$ (14,562)	$ (14,562)	$ (14,562)	$ (14,562)	$ (14,562)	$ (14,562)	$ (14,562)	$ (14,562)	$ (14,562)	$ (14,562)	$ (14,562)	$ (174,748)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	1,491
6	Load Shaping Revenue	$ (2,324)	$ (10,588)	$ 11,642	$ 27,096	$ 19,781	$ 5,292	$ 7,991	$ (8,769)	$ (10,985)	$ (8,310)	$ (7,092)	$ (6,688)	$ 17,047	21
7	Demand Revenue	$ 2,988	$ 3,896	$ 9,071	$ 6,339	$ 4,168	$ 5,130	$ 3,919	$ 2,237	$ 2,685	$ 5,117	$ 7,793	$ 5,565	$ 58,908	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,222)	$ (4,816)	$ (5,546)	$ (4,551)	$ (2,769)	$ (20,905)	-
9	Low Density Discount	$ (3,234)	$ (3,234)	$ (3,234)	$ (3,234)	$ (3,234)	$ (3,234)	$ (3,234)	$ (3,234)	$ (3,234)	$ (3,234)	$ (3,234)	$ (3,234)	$ (38,806)	-
10	Tier 2	$ 4,154	$ 4,025	$ 4,154	$ 4,154	$ 3,752	$ 4,148	$ 4,020	$ 4,154	$ 4,020	$ 4,154	$ 4,154	$ 4,020	$ 48,909	173
11	RSS (Non-Federal) and Other	$ 73	$ 73	$ 73	$ 73	$ 73	$ 73	$ 73	$ 73	$ 73	$ 73	$ 73	$ 73	$ 871	-
12	**PF customers (TRM) sub-total**	**$ 175,330**	**$ 167,845**	**$ 195,379**	**$ 208,101**	**$ 198,214**	**$ 185,082**	**$ 186,442**	**$ 164,912**	**$ 161,415**	**$ 165,926**	**$ 170,816**	**$ 170,640**	**$ 2,150,102**	**8,067**
13	**NR sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
14	**DSIs sub-total**	**$ 387**	**$ 392**	**$ 425**	**$ 393**	**$ 353**	**$ 352**	**$ 328**	**$ 276**	**$ 245**	**$ 359**	**$ 399**	**$ 381**	**$ 4,290**	**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**	**$ 16,014**	**$ 31,605**	**$ 36,912**	**$ 54,487**	**$ 56,062**	**$ 39,783**	**$ 21,823**	**$ 34,501**	**$ 36,998**	**$ 60,186**	**$ 40,698**	**$ 18,827**	**$ 447,898**	**1,815**
17	**Long Term Contractual Obligations sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**462**
19	**Other Sales sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,070**	**$ 1,070**	**-**
20	**Gross Sales**	**$192,354**	**$200,569**	**$233,569**	**$263,823**	**$255,364**	**$225,920**	**$209,237**	**$200,342**	**$199,351**	**$227,225**	**$212,637**	**$191,548**	**$2,611,938**	**10,357**
21	Transfer Service Delivery charge	$ 217	$ 222	$ 315	$ 346	$ 300	$ 248	$ 222	$ 233	$ 243	$ 264	$ 258	$ 233	$ 3,100	-
22	Energy Efficiency Revenues	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 8,000	-
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**	**$2,605**	**$2,702**	**$2,816**	**$2,835**	**$2,786**	**$2,636**	**$2,611**	**$2,621**	**$2,631**	**$2,652**	**$2,647**	**$2,621**	**$32,163**	**175**
29	Balancing Reserve Capacity	$ 4,407	$ 4,407	$ 4,407	$ 4,407	$ 4,407	$ 4,407	$ 4,407	$ 4,407	$ 4,407	$ 4,407	$ 4,407	$ 4,407	$ 52,879	-
30	ACS Risk Share	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
31	Risk Mitigation Tool	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
32	Imbalance Adjustment for Third-Party Deployed Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
33	Operating Reserve - Spinning	$ 1,255	$ 1,402	$ 1,519	$ 1,550	$ 1,699	$ 1,472	$ 1,785	$ 1,559	$ 1,851	$ 1,784	$ 1,767	$ 1,376	$ 19,022	-
34	Operating Reserve - Supplemental	$ 1,255	$ 1,402	$ 1,519	$ 1,550	$ 1,699	$ 1,472	$ 1,785	$ 1,559	$ 1,851	$ 1,784	$ 1,767	$ 1,376	$ 19,022	-
35	Operating Reserve - Spinning Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
36	Operating Reserve - Supplemental Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
37	Synchronous Condensing	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 923	-
38	Generation Dropping	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 365	-
39	Redispatch	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 370	-
40	Segmentation of COE/Reclamation Network and Delivery Facilities	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 9,502	-
41	Station Service	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 2,295	9
42	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
43	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
44	Energy Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
45	Generation Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	**Generation Inputs / Inter-business line**	**$ 8,038**	**$ 8,332**	**$ 8,566**	**$ 8,628**	**$ 8,927**	**$ 8,473**	**$ 9,099**	**$ 8,647**	**$ 9,230**	**$ 9,097**	**$ 9,062**	**$ 8,280**	**$ 104,377**	**9**
48	4(h)(10)(c)	$ 10,247	$ 6,907	$ 9,452	$ 9,253	$ 7,723	$ 8,196	$ 9,667	$ 7,661	$ 6,673	$ 6,243	$ 5,605	$ 6,588	$ 94,216	-
49	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
50	**Treasury Credits**	**$ 10,630**	**$ 7,290**	**$ 9,836**	**$ 9,636**	**$ 8,106**	**$ 8,579**	**$ 10,050**	**$ 8,044**	**$ 7,056**	**$ 6,627**	**$ 5,989**	**$ 6,971**	**$ 98,816**	**-**
51	Augmentation Power Purchase sub-total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
52	Balancing Power Purchase sub-total	$ 3,903	$ 1,339	$ 7,638	$ 6,107	$ 4,977	$ 2,081	$ 4,724	$ 1,149	$ 908	$ 1,924	$ 1,947	$ 1,391	$ 38,088	133
53	Other Power Purchase sub-total	$ 3,920	$ 3,920	$ 3,920	$ 3,920	$ 3,920	$ 3,920	$ 3,920	$ 3,920	$ 3,920	$ 3,920	$ 3,920	$ 3,920	$ 47,041	179
54	**Power Purchases**	**$ 7,823**	**$ 5,259**	**$ 11,558**	**$ 10,027**	**$ 8,897**	**$ 6,001**	**$ 8,644**	**$ 5,069**	**$ 4,828**	**$ 5,844**	**$ 5,867**	**$ 5,311**	**$ 85,128**	**312**

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**													**2021**	
2	**Category**	**202010**	**202011**	**202012**	**202101**	**202102**	**202103**	**202104**	**202105**	**202106**	**202107**	**202108**	**202109**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 183,932	$ 183,932	$ 183,932	$ 183,932	$ 183,932	$ 184,226	$ 184,226	$ 184,226	$ 184,226	$ 184,226	$ 184,226	$ 184,226	$ 2,209,243	4,959
4	Non-Slice Revenue	$ (14,127)	$ (14,127)	$ (14,127)	$ (14,127)	$ (14,127)	$ (14,157)	$ (14,157)	$ (14,157)	$ (14,157)	$ (14,157)	$ (14,157)	$ (14,157)	$ (169,732)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	2,689
6	Load Shaping Revenue	$ 1,357	$ (5,143)	$ 10,791	$ 23,294	$ 24,076	$ 6,680	$ 7,511	$ (7,940)	$ (14,404)	$ (6,563)	$ (5,889)	$ (1,736)	$ 32,034	53
7	Demand Revenue	$ 9,981	$ 2,990	$ 4,914	$ 4,613	$ 4,877	$ 5,404	$ 4,086	$ 1,916	$ 2,297	$ 5,495	$ 6,041	$ 5,343	$ 57,956	-
8	Irrigation Rate Discount	$ -	$ 20	$ -	$ -	$ -	$ -	$ -	$ (3,222)	$ (4,816)	$ (5,546)	$ (4,551)	$ (2,769)	$ (20,885)	-
9	Low Density Discount	$ (3,500)	$ (2,924)	$ (3,400)	$ (3,620)	$ (3,752)	$ (3,251)	$ (3,422)	$ (3,109)	$ (3,016)	$ (3,473)	$ (3,483)	$ (3,291)	$ (40,240)	-
10	Tier 2	$ 1,559	$ 1,511	$ 1,559	$ 1,559	$ 1,408	$ 1,691	$ 1,640	$ 1,686	$ 1,637	$ 1,681	$ 1,686	$ 1,623	$ 19,239	58
11	RSS (Non-Federal) and Other	$ (61)	$ (132)	$ (176)	$ (122)	$ (76)	$ 76	$ 76	$ 76	$ 76	$ 76	$ 76	$76	$ (38)	-
12	**PF customers (TRM) sub-total**	**$ 179,140**	**$ 166,126**	**$ 183,492**	**$ 195,529**	**$ 196,338**	**$ 180,670**	**$ 179,961**	**$ 159,476**	**$ 151,843**	**$ 161,740**	**$ 163,949**	**$ 169,315**	**$ 2,087,577**	**7,759**
13	**NR sub-total**	**$ (145)**	**$ (119)**	**$ (139)**	**$ (107)**	**$ (238)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ (749)**	**-**
14	**DSIs sub-total**	**$ 342**	**$ 355**	**$ 373**	**$ 357**	**$ 318**	**$ 251**	**$ 329**	**$ 276**	**$ 245**	**$ 360**	**$ 398**	**$ 383**	**$ 3,987**	**11**
15	**FPS sub-total**	**$ 522**	**$ 598**	**$ 704**	**$ 684**	**$ 632**	**$ 991**	**$ 932**	**$ 942**	**$ 989**	**$ 1,060**	**$ 1,023**	**$ 914**	**$ 9,989**	**-**
16	**Short-term market sales sub-total**	**$ 35,018**	**$ 38,938**	**$ 46,731**	**$ 57,646**	**$ 59,335**	**$ 45,856**	**$ 18,582**	**$ 36,123**	**$ 36,861**	**$ 52,206**	**$ 34,976**	**$ 21,502**	**$ 483,775**	**1,835**
17	**Long Term Contractual Obligations sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**462**
19	**Other Sales sub-total**	**$ 30**	**$ 13**	**$ 23**	**$ 0**	**$ 1**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 19,774**	**$ 19,841**	**-**
20	**Gross Sales**	**$214,907**	**$205,912**	**$231,183**	**$254,109**	**$256,386**	**$227,768**	**$199,803**	**$196,817**	**$189,938**	**$215,366**	**$200,346**	**$211,887**	**$2,604,421**	**10,068**
21	Transfer Service Delivery charge	$ 286	$ 284	$ 294	$ 294	$ 330	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 25	$ 1,663	-
22	Energy Efficiency Revenues	$ (91)	$ (56)	$ 50	$ (53)	$ 180	$ 544	$ 544	$ 544	$ 544	$ 544	$ 544	$ 544	$ 3,836	-
23	Irrigation Pumping Power	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 1,278	15
24	Reserve Energy	$ 882	$ 882	$ 882	$ 882	$ 882	$ 812	$ 812	$ 812	$ 812	$ 812	$ 812	$ 812	$ 10,098	160
25	USBR Owyhee Wheeling Project	$ 139	$ 139	$ 139	$ 139	$ 139	$ 137	$ 137	$ 137	$ 137	$ 137	$ 137	$ 137	$ 1,652	-
26	Downstream Benefits	$ 729	$ 634	$ 1,730	$ 3,113	$ 634	$ 611	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 10,801	-
27	Upper Baker Revenues	$ -	$ 82	$ 96	$ 87	$ 82	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 347	-
28	**Miscellaneous Revenue**	**$2,052**	**$2,072**	**$3,298**	**$4,570**	**$2,355**	**$2,234**	**$2,182**	**$2,182**	**$2,182**	**$2,182**	**$2,182**	**$2,182**	**$29,675**	**175**
29	Balancing Reserve Capacity	$ 5,688	$ 6,055	$ 5,688	$ 5,850	$ 5,850	$ 5,850	$ 5,850	$ 5,850	$ 5,850	$ 5,850	$ 5,850	$ 5,850	$ 70,079	-
30	ACS Risk Share	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
31	Risk Mitigation Tool	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
32	Imbalance Adjustment for Third-Party Deployed Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
33	Operating Reserve - Spinning	$ 1,138	$ 1,300	$ 1,375	$ 1,499	$ 1,539	$ 1,368	$ 1,427	$ 1,533	$ 1,655	$ 1,540	$ 1,427	$ 1,299	$ 17,100	-
34	Operating Reserve - Supplemental	$ 1,138	$ 1,300	$ 1,375	$ 1,499	$ 1,539	$ 1,368	$ 1,427	$ 1,533	$ 1,655	$ 1,540	$ 1,427	$ 1,299	$ 17,100	-
35	Operating Reserve - Spinning Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
36	Operating Reserve - Supplemental Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
37	Synchronous Condensing	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 69	$ 831	-
38	Generation Dropping	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 41	$ 498	-
39	Redispatch	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 21	$ 250	-
40	Segmentation of COE/Reclamation Network and Delivery Facilities	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 734	$ 8,806	-
41	Station Service	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 138	$ 1,660	9
42	Energy Imbalance	$ 18	$ 38	$ 23	$ 33	$ 196	$ 51	$ 47	$ 64	$ 91	$ 14	$ 40	$ 6	$ 621	-
43	Generation Imbalance	$ 431	$ 727	$ 195	$ 183	$ 1,030	$ 14	$ 51	$ 159	$ 95	$ (73)	$ 67	$ 210	$ 3,090	-
44	Energy Imbalance Persistent Deviation	$ 15	$ 184	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 199	-
45	Generation Imbalance Persistent Deviation	$ 11	$ -	$ 18	$ 8	$ 9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 46	-
46	Operating Reserve - Energy	$ 11	$ 35	$ 57	$ 25	$ 78	$ 28	$ 27	$ 20	$ 3	$ 32	$ 26	$ 25	$ 368	-
47	**Generation Inputs / Inter-business line**	**$ 9,453**	**$ 10,643**	**$ 9,734**	**$ 10,101**	**$ 11,245**	**$ 9,683**	**$ 9,833**	**$ 10,163**	**$ 10,353**	**$ 9,907**	**$ 9,841**	**$ 9,693**	**$ 120,648**	**8**
48	4(h)(10)(c)	$ 10,343	$ 5,134	$ 7,520	$ 7,132	$ 4,757	$ 8,544	$ 8,862	$ 6,490	$ 6,078	$ 5,517	$ 5,884	$ 6,934	$ 83,195	-
49	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
50	**Treasury Credits**	**$ 10,726**	**$ 5,517**	**$ 7,903**	**$ 7,515**	**$ 5,140**	**$ 8,927**	**$ 9,245**	**$ 6,873**	**$ 6,461**	**$ 5,901**	**$ 6,267**	**$ 7,317**	**$ 87,795**	**-**
51	Augmentation Power Purchase sub-total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
52	Balancing Power Purchase sub-total	$ 20,552	$ 9,850	$ 22,127	$ 13,649	$ 22,588	$ 23,219	$ 5,129	$ 3,161	$ 3,110	$ 186	$ 1,770	$ 226	$ 125,568	411
53	Other Power Purchase sub-total	$ 813	$ 168	$ 599	$ 1,773	$ 2,656	$ (169)	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,840	-
54	**Power Purchases**	**$ 21,365**	**$ 10,018**	**$ 22,726**	**$ 15,423**	**$ 25,244**	**$ 23,051**	**$ 5,129**	**$ 3,161**	**$ 3,110**	**$ 186**	**$ 1,770**	**$ 226**	**$ 131,408**	**411**

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**													**2022**	
2	**Category**	**202110**	**202111**	**202112**	**202201**	**202202**	**202203**	**202204**	**202205**	**202206**	**202207**	**202208**	**202209**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 189,312	$ 189,312	$ 189,312	$ 189,312	$ 189,312	$ 189,312	$ 189,312	$ 189,312	$ 189,312	$ 189,312	$ 189,312	$ 189,312	$ 2,271,748	4,854
4	Non-Slice Revenue	$ (23,878)	$ (23,878)	$ (23,878)	$ (23,878)	$ (23,878)	$ (23,878)	$ (23,878)	$ (23,878)	$ (23,878)	$ (23,878)	$ (23,878)	$ (23,878)	$ (286,530)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	1,521
6	Load Shaping Revenue	$ (2,775)	$ (14,242)	$ 14,773	$ 35,486	$ 27,372	$ 7,552	$ 10,759	$ (12,544)	$ (18,174)	$ (16,008)	$ (11,220)	$ (8,265)	$ 12,713	(21)
7	Demand Revenue	$ 2,375	$ 3,257	$ 8,466	$ 5,803	$ 3,987	$ 4,992	$ 3,445	$ 1,773	$ 2,965	$ 5,951	$ 7,528	$ 4,429	$ 54,969	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,161)	$ (4,725)	$ (5,441)	$ (4,465)	$ (2,717)	$ (20,509)	-
9	Low Density Discount	$ (2,988)	$ (2,570)	$ (3,602)	$ (3,953)	$ (3,725)	$ (3,182)	$ (3,448)	$ (2,953)	$ (2,984)	$ (3,451)	$ (3,564)	$ (3,063)	$ (39,482)	-
10	Tier 2	$ 3,834	$ 3,834	$ 3,834	$ 3,834	$ 3,834	$ 3,834	$ 3,834	$ 3,834	$ 3,834	$ 3,834	$ 3,834	$ 3,834	$ 46,009	157
11	RSS (Non-Federal) and Other	$ 73	$ 73	$ 73	$ 73	$ 73	$ 73	$ 73	$ 73	$ 73	$ 73	$ 73	$ 73	$ 879	-
12	**PF customers (TRM) sub-total**	**$ 165,954**	**$ 155,787**	**$ 188,979**	**$ 206,678**	**$ 196,976**	**$ 178,705**	**$ 180,097**	**$ 152,458**	**$ 146,424**	**$ 150,393**	**$ 157,620**	**$ 159,726**	**$ 2,039,797**	**6,511**
13	**NR sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
14	**DSIs sub-total**	**$ 379**	**$ 379**	**$ 437**	**$ 390**	**$ 364**	**$ 367**	**$ 312**	**$ 264**	**$ 238**	**$ 384**	**$ 404**	**$ 361**	**$ 4,279**	**12**
15	**FPS sub-total**	**$ 618**	**$ 722**	**$ 847**	**$ 834**	**$ 729**	**$ 696**	**$ 637**	**$ 646**	**$ 686**	**$ 747**	**$ 718**	**$ 622**	**$ 8,503**	**-**
16	**Short-term market sales sub-total**	**$ 21,117**	**$ 34,879**	**$ 39,547**	**$ 60,308**	**$ 60,891**	**$ 43,528**	**$ 25,828**	**$ 41,295**	**$ 43,626**	**$ 65,582**	**$ 45,590**	**$ 21,665**	**$ 503,856**	**1,870**
17	**Long Term Contractual Obligations sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**462**
19	**Other Sales sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,070**	**$ 1,070**	**-**
20	**Gross Sales**	**$188,068**	**$191,767**	**$229,808**	**$268,210**	**$258,960**	**$223,297**	**$206,874**	**$194,663**	**$190,974**	**$217,106**	**$204,333**	**$183,445**	**$2,557,504**	**8,855**
21	Transfer Service Delivery charge	$ 217	$ 222	$ 315	$ 346	$ 300	$ 248	$ 222	$ 233	$ 243	$ 264	$ 258	$ 233	$ 3,100	-
22	Energy Efficiency Revenues	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 8,000	-
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	$ -	$ 92	$ 115	$ 104	$ 100	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 411	-
28	**Miscellaneous Revenue**	**$2,605**	**$2,702**	**$2,819**	**$2,838**	**$2,788**	**$2,636**	**$2,611**	**$2,621**	**$2,631**	**$2,652**	**$2,647**	**$2,621**	**$32,173**	**175**
29	Balancing Reserve Capacity	$ 4,563	$ 4,395	$ 4,395	$ 4,395	$ 4,395	$ 4,395	$ 4,395	$ 4,395	$ 4,395	$ 4,395	$ 4,395	$ 4,395	$ 52,913	-
30	ACS Risk Share	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
31	Risk Mitigation Tool	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
32	Imbalance Adjustment for Third-Party Deployed Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
33	Operating Reserve - Spinning	$ 1,515	$ 1,708	$ 1,817	$ 1,959	$ 1,908	$ 1,969	$ 2,172	$ 1,818	$ 2,167	$ 2,051	$ 2,134	$ 1,615	$ 22,834	-
34	Operating Reserve - Supplemental	$ 989	$ 1,116	$ 1,187	$ 1,280	$ 1,246	$ 1,286	$ 1,418	$ 1,187	$ 1,415	$ 1,339	$ 1,394	$ 1,055	$ 14,911	-
35	Operating Reserve - Spinning Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
36	Operating Reserve - Supplemental Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
37	Synchronous Condensing	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 923	-
38	Generation Dropping	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 365	-
39	Redispatch	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 370	-
40	Segmentation of COE/Reclamation Network and Delivery Facilities	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 9,502	-
41	Station Service	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 2,295	9
42	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
43	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
44	Energy Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
45	Generation Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	**Generation Inputs / Inter-business line**	**$ 8,188**	**$ 8,341**	**$ 8,521**	**$ 8,756**	**$ 8,671**	**$ 8,771**	**$ 9,107**	**$ 8,522**	**$ 9,099**	**$ 8,907**	**$ 9,044**	**$ 8,186**	**$ 104,113**	**9**
48	4(h)(10)(c)	$ 10,194	$ 6,934	$ 9,605	$ 9,551	$ 7,756	$ 8,006	$ 9,398	$ 7,460	$ 6,636	$ 6,252	$ 5,642	$ 6,736	$ 94,171	-
49	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
50	**Treasury Credits**	**$ 10,578**	**$ 7,317**	**$ 9,988**	**$ 9,934**	**$ 8,139**	**$ 8,389**	**$ 9,782**	**$ 7,844**	**$ 7,020**	**$ 6,635**	**$ 6,025**	**$ 7,119**	**$ 98,771**	**-**
51	Augmentation Power Purchase sub-total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
52	Balancing Power Purchase sub-total	$ 6,295	$ 2,086	$ 8,305	$ 7,976	$ 5,329	$ 2,044	$ 4,210	$ 449	$ 279	$ 2,177	$ 2,502	$ 1,614	$ 43,266	150
53	Other Power Purchase sub-total	$ 3,693	$ 3,693	$ 3,693	$ 3,693	$ 3,693	$ 3,693	$ 3,693	$ 3,693	$ 3,693	$ 3,693	$ 3,693	$ 3,693	$ 44,321	162
54	**Power Purchases**	**$ 9,989**	**$ 5,780**	**$ 11,998**	**$ 11,669**	**$ 9,022**	**$ 5,737**	**$ 7,904**	**$ 4,142**	**$ 3,973**	**$ 5,870**	**$ 6,196**	**$ 5,308**	**$ 87,587**	**311**

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**													**2023**	
2	**Category**	**202210**	**202211**	**202212**	**202301**	**202302**	**202303**	**202304**	**202305**	**202306**	**202307**	**202308**	**202309**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 189,933	$ 189,933	$ 189,933	$ 189,933	$ 189,933	$ 189,933	$ 189,933	$ 189,933	$ 189,933	$ 189,933	$ 189,933	$ 189,933	$ 2,279,201	6,381
4	Non-Slice Revenue	$ (23,980)	$ (23,980)	$ (23,980)	$ (23,980)	$ (23,980)	$ (23,980)	$ (23,980)	$ (23,980)	$ (23,980)	$ (23,980)	$ (23,980)	$ (23,980)	$ (287,761)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	1,491
6	Load Shaping Revenue	$ (2,387)	$ (13,412)	$ 16,001	$ 36,690	$ 28,486	$ 8,487	$ 11,753	$ (12,062)	$ (17,825)	$ (15,205)	$ (10,296)	$ (7,149)	$ 23,082	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	$ (3,029)	$ (2,609)	$ (3,651)	$ (4,003)	$ (3,775)	$ (3,224)	$ (3,472)	$ (3,002)	$ (3,023)	$ (3,499)	$ (3,615)	$ (3,109)	$ (40,009)	-
10	Tier 2	$ 4,081	$ 4,081	$ 4,081	$ 4,081	$ 4,081	$ 4,081	$ 4,081	$ 4,081	$ 4,081	$ 4,081	$ 4,081	$ 4,081	$ 48,975	173
11	RSS (Non-Federal) and Other	$ 73	$ 73	$ 73	$ 73	$ 73	$ 73	$ 73	$ 73	$ 73	$ 73	$ 73	$ 73	$ 879	-
12	**PF customers (TRM) sub-total**	**$ 167,274**	**$ 157,463**	**$ 191,077**	**$ 208,721**	**$ 198,920**	**$ 180,446**	**$ 181,498**	**$ 154,024**	**$ 147,545**	**$ 152,011**	**$ 159,351**	**$ 161,475**	**$ 2,059,803**	**8,067**
13	**NR sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
14	**DSIs sub-total**	**$ 379**	**$ 379**	**$ 437**	**$ 390**	**$ 364**	**$ 367**	**$ 312**	**$ 264**	**$ 238**	**$ 384**	**$ 404**	**$ 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**	**$ 16,014**	**$ 31,605**	**$ 36,912**	**$ 54,487**	**$ 56,062**	**$ 39,783**	**$ 21,823**	**$ 34,501**	**$ 36,998**	**$ 60,186**	**$ 40,698**	**$ 18,827**	**$ 447,898**	**1,815**
17	**Long Term Contractual Obligations sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**462**
19	**Other Sales sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,070**	**$ 1,070**	**-**
20	**Gross Sales**	**$184,291**	**$190,175**	**$229,278**	**$264,439**	**$256,082**	**$221,298**	**$204,277**	**$189,441**	**$185,474**	**$213,334**	**$201,178**	**$182,361**	**$2,521,628**	**10,357**
21	Transfer Service Delivery charge	$ 217	$ 222	$ 315	$ 346	$ 300	$ 248	$ 222	$ 233	$ 243	$ 264	$ 258	$ 233	$ 3,100	-
22	Energy Efficiency Revenues	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 8,000	-
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**	**$2,605**	**$2,702**	**$2,816**	**$2,835**	**$2,786**	**$2,636**	**$2,611**	**$2,621**	**$2,631**	**$2,652**	**$2,647**	**$2,621**	**$32,163**	**175**
29	Balancing Reserve Capacity	$ 4,407	$ 4,407	$ 4,407	$ 4,407	$ 4,407	$ 4,407	$ 4,407	$ 4,407	$ 4,407	$ 4,407	$ 4,407	$ 4,407	$ 52,879	-
30	ACS Risk Share	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
31	Risk Mitigation Tool	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
32	Imbalance Adjustment for Third-Party Deployed Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
33	Operating Reserve - Spinning	$ 1,255	$ 1,402	$ 1,519	$ 1,550	$ 1,699	$ 1,472	$ 1,785	$ 1,559	$ 1,851	$ 1,784	$ 1,767	$ 1,376	$ 19,022	-
34	Operating Reserve - Supplemental	$ 1,255	$ 1,402	$ 1,519	$ 1,550	$ 1,699	$ 1,472	$ 1,785	$ 1,559	$ 1,851	$ 1,784	$ 1,767	$ 1,376	$ 19,022	-
35	Operating Reserve - Spinning Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
36	Operating Reserve - Supplemental Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
37	Synchronous Condensing	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 77	$ 923	-
38	Generation Dropping	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 30	$ 365	-
39	Redispatch	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 370	-
40	Segmentation of COE/Reclamation Network and Delivery Facilities	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 792	$ 9,502	-
41	Station Service	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 2,295	9
42	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
43	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
44	Energy Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
45	Generation Imbalance Persistent Deviation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	**Generation Inputs / Inter-business line**	**$ 8,038**	**$ 8,332**	**$ 8,566**	**$ 8,628**	**$ 8,927**	**$ 8,473**	**$ 9,099**	**$ 8,647**	**$ 9,230**	**$ 9,097**	**$ 9,062**	**$ 8,280**	**$ 104,377**	**9**
48	4(h)(10)(c)	$ 10,247	$ 6,907	$ 9,452	$ 9,253	$ 7,723	$ 8,196	$ 9,667	$ 7,661	$ 6,673	$ 6,243	$ 5,605	$ 6,588	$ 94,216	-
49	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
50	**Treasury Credits**	**$ 10,630**	**$ 7,290**	**$ 9,836**	**$ 9,636**	**$ 8,106**	**$ 8,579**	**$ 10,050**	**$ 8,044**	**$ 7,056**	**$ 6,627**	**$ 5,989**	**$ 6,971**	**$ 98,816**	**-**
51	Augmentation Power Purchase sub-total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
52	Balancing Power Purchase sub-total	$ 3,903	$ 1,339	$ 7,638	$ 6,107	$ 4,977	$ 2,081	$ 4,724	$ 1,149	$ 908	$ 1,924	$ 1,947	$ 1,391	$ 38,088	133
53	Other Power Purchase sub-total	$ 3,920	$ 3,920	$ 3,920	$ 3,920	$ 3,920	$ 3,920	$ 3,920	$ 3,920	$ 3,920	$ 3,920	$ 3,920	$ 3,920	$ 47,041	179
54	**Power Purchases**	**$ 7,823**	**$ 5,259**	**$ 11,558**	**$ 10,027**	**$ 8,897**	**$ 6,001**	**$ 8,644**	**$ 5,069**	**$ 4,828**	**$ 5,844**	**$ 5,867**	**$ 5,311**	**$ 85,128**	**312**

9.3 Inter-Business Line Allocations

	A	B	C	D
	Generation Inputs	Annual Average for FY 2022-2023 Forecast Quantity (MW)	Average Capacity Unit Cost ($/kW/mo)	Annual Average for FY 2022-2023 Revenue Forecast ($)
1	Balancing Reserve Capacity	657.0	6.71	**$ 52,895,823**
2	Operating Reserve Capacity	473.4	6.67	**$ 37,894,455**
3	Synchronous Condensing			**$ 922,844**
4	Generation Dropping			**$ 364,955**
5	Redispatch			**$ 370,000**
6	Segmentation of COE/Reclamation Network and Delivery Facilities			**$ 9,502,000**
7	Station Service			**$ 2,295,181**
8	**Generation Inputs Total**			**$ 104,245,257**

Table 9.4 Balancing Reserve Capacity Quantity Forecast FY 2022-2023

Table 9.4

Total Balancing Reserve Capacity Requirement (Values in MW)
for FY2022-2023 Balancing Reserve Capacity Quantity Forecast

		INSTALLED CAPACITY				BALANCING RESERVE BY TYPE				BALANCING RESERVE TOTAL (FEDERAL VS. NON-FEDERAL)			
		WIND	SOLAR	FCRPS	NON-FEDERAL DISPATCHABLE	REGULATION		NON-REGULATION		TOTAL FEDERAL		TOTAL NON-FEDERAL	
						INC	DEC	INC	DEC	INC	DEC	INC	DEC
	A	B	C	D	E	F	G	H	I	J	K	L	M
1	Oct-21	2,930	89	3,739	1,548	309.6	-332.0	397.2	-529.1	22.5	-24.1	684.4	-836.9
2	Nov-21	2,830	89	3,739	1,548	307.9	-326.9	370.2	-498.3	23.0	-24.4	655.1	-800.8
3	Dec-21	2,830	89	3,739	1,548	307.9	-326.9	370.2	-498.3	23.0	-24.4	655.1	-800.8
4	Jan-22	2,830	89	3,739	1,548	307.9	-326.9	370.2	-498.3	23.0	-24.4	655.1	-800.8
5	Feb-22	2,830	89	3,739	1,548	307.9	-326.9	370.2	-498.3	23.0	-24.4	655.1	-800.8
6	Mar-22	2,830	89	3,739	1,548	307.9	-326.9	370.2	-498.3	23.0	-24.4	655.1	-800.8
7	Apr-22	2,830	89	3,739	1,548	307.9	-326.9	370.2	-498.3	23.0	-24.4	655.1	-800.8
8	May-22	2,830	89	3,739	1,548	307.9	-326.9	370.2	-498.3	23.0	-24.4	655.1	-800.8
9	Jun-22	2,830	89	3,739	1,548	307.9	-326.9	370.2	-498.3	23.0	-24.4	655.1	-800.8
10	Jul-22	2,830	89	3,739	1,548	307.9	-326.9	370.2	-498.3	23.0	-24.4	655.1	-800.8
11	Aug-22	2,830	89	3,739	1,548	307.9	-326.9	370.2	-498.3	23.0	-24.4	655.1	-800.8
12	Sep-22	2,830	89	3,739	1,548	307.9	-326.9	370.2	-498.3	23.0	-24.4	655.1	-800.8
13	Oct-22	2,830	109	3,739	1,548	309.1	-327.4	370.5	-498.0	23.0	-24.3	656.6	-801.0
14	Nov-22	2,830	109	3,739	1,548	309.1	-327.4	370.5	-498.0	23.0	-24.3	656.6	-801.0
15	Dec-22	2,830	109	3,739	1,548	309.1	-327.4	370.5	-498.0	23.0	-24.3	656.6	-801.0
16	Jan-23	2,830	109	3,739	1,548	309.1	-327.4	370.5	-498.0	23.0	-24.3	656.6	-801.0
17	Feb-23	2,830	109	3,739	1,548	309.1	-327.4	370.5	-498.0	23.0	-24.3	656.6	-801.0
18	Mar-23	2,830	109	3,739	1,548	309.1	-327.4	370.5	-498.0	23.0	-24.3	656.6	-801.0
19	Apr-23	2,830	109	3,739	1,548	309.1	-327.4	370.5	-498.0	23.0	-24.3	656.6	-801.0
20	May-23	2,830	109	3,739	1,548	309.1	-327.4	370.5	-498.0	23.0	-24.3	656.6	-801.0
21	Jun-23	2,830	109	3,739	1,548	309.1	-327.4	370.5	-498.0	23.0	-24.3	656.6	-801.0
22	Jul-23	2,830	109	3,739	1,548	309.1	-327.4	370.5	-498.0	23.0	-24.3	656.6	-801.0
23	Aug-23	2,830	109	3,739	1,548	309.1	-327.4	370.5	-498.0	23.0	-24.3	656.6	-801.0
24	Sep-23	2,830	109	3,739	1,548	309.1	-327.4	370.5	-498.0	23.0	-24.3	656.6	-801.0
25	**BP-22 AVG**	**2,834**	**99**	**3,739**	**1,548**	**308.5**	**-327.3**	**371.5**	**-499.4**	**23.0**	**-24.4**	**657.0**	**-802.4**

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