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-18 Rate Proceeding

Final Proposal

Power Rates Study Documentation

BP-18-FS-BPA-01A

July 2017

BP-18 POWER RATES STUDY DOCUMENTATION

TABLE OF CONTENTS

COMMONLY USED ACRONYMS AND SHORT FORMS

AAC	Anticipated Accumulation of Cash
ACNR	Accumulated Calibrated Net Revenue
ACS	Ancillary and Control Area Services
AF	Advance Funding
AFUDC	Allowance for Funds Used During Construction
aMW	average megawatt(s)
ANR	Accumulated Net Revenues
ASC	Average System Cost
BAA	Balancing Authority Area
BiOp	Biological Opinion
BPA	Bonneville Power Administration
Bps	basis points
Btu	British thermal unit
CIP	Capital Improvement Plan
CIR	Capital Investment Review
CDQ	Contract Demand Quantity
CGS	Columbia Generating Station
CHWM	Contract High Water Mark
CNR	Calibrated Net Revenue
COB	California-Oregon border
COE	U.S. Army Corps of Engineers
COI	California-Oregon Intertie
Commission	Federal Energy Regulatory Commission
Corps	U.S. Army Corps of Engineers
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council	Northwest Power and Conservation Council
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CSP	Customer System Peak
CT	combustion turbine
CY	calendar year (January through December)
DD	Dividend Distribution
DDC	Dividend Distribution Clause
dec	decrease, decrement, or decremental
DERBS	Dispatchable Energy Resource Balancing Service
DFS	Diurnal Flattening Service
DNR	Designated Network Resource
DOE	Department of Energy
DOI	Department of Interior
DSI	direct-service industrial customer or direct-service industry
DSO	Dispatcher Standing Order

EE	Energy Efficiency
EIM	Energy imbalance market
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.
ESA	Endangered Species Act
ESS	Energy Shaping Service
e-Tag	electronic interchange transaction information
FBS	Federal base system
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FELCC	firm energy load carrying capability
FOIA	Freedom Of Information Act
FORS	Forced Outage Reserve Service
FPS	Firm Power and Surplus Products and Services
FPT	Formula Power Transmission
FY	fiscal year (October through September)
G&A	general and administrative (costs)
GARD	Generation and Reserves Dispatch (computer model)
GMS	Grandfathered Generation Management Service
GSP	Generation System Peak
GSR	Generation Supplied Reactive
GRSPs	General Rate Schedule Provisions
GTA	General Transfer Agreement
GWh	gigawatthour
HLH	Heavy Load Hour(s)
HOSS	Hourly Operating and Scheduling Simulator (computer model)
HYDSIM	Hydrosystem Simulator (computer model)
IE	Eastern Intertie
IM	Montana Intertie
inc	increase, increment, or incremental
IOU	investor-owned utility
IP	Industrial Firm Power
IPR	Integrated Program Review
IR	Integration of Resources
IRD	Irrigation Rate Discount
IRM	Irrigation Rate Mitigation
IRPL	Incremental Rate Pressure Limiter
IS	Southern Intertie
kcfs	thousand cubic feet per second
kW	kilowatt
kWh	kilowatthour
LDD	Low Density Discount
LGIA	Large Generator Interconnection Agreement
LLH	Light Load Hour(s)
LPP	Large Project Program
LPTAC	Large Project Targeted Adjustment Charge

LTF	Long-term Form
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)
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NP-15	North of Path 15
NPCC	Pacific Northwest Electric Power and Conservation Planning Council
NPV	net present value
NR	New Resource Firm Power
NRFS	NR Resource Flattening Service
NT	Network Integration
NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation
NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff
O&M	operation and maintenance
OATI	Open Access Technology International, Inc.
OS	Oversupply
OY	operating year (August through July)
PDCI	Pacific DC Intertie
Peak	Peak Reliability (assessment/charge)
PF	Priority Firm Power
PFp	Priority Firm Public
PFx	Priority Firm Exchange
PNCA	Pacific Northwest Coordination Agreement
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration or Point of Interconnection
POR	Point of Receipt
Project Act	Bonneville Project Act

PS	Power Services
PSC	power sales contract
PSW	Pacific Southwest
PTP	Point to Point
PUD	public or people's utility district
PW	WECC and Peak Service
RAM	Rate Analysis Model (computer model)
RCD	Regional Cooperation Debt
RD	Regional Dialogue
REC	Renewable Energy Certificate
Reclamation	U.S. Bureau of Reclamation
RDC	Reserves Distribution Clause
REP	Residential Exchange Program
REPSIA	REP Settlement Implementation Agreement
RevSim	Revenue Simulation Model
RFA	Revenue Forecast Application (database)
RHWM	Rate Period High Water Mark
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RR	Resource Replacement
RRS	Resource Remarketing Service
RSC	Resource Shaping Charge
RSS	Resource Support Services
RT1SC	RHWM Tier 1 System Capability
SCD	Scheduling, System Control, and Dispatch rate
SCS	Secondary Crediting Service
SDD	Short Distance Discount
SILS	Southeast Idaho Load Service
Slice	Slice of the System (product)
T1SFCO	Tier 1 System Firm Critical Output
TCMS	Transmission Curtailment Management Service
TGT	Townsend-Garrison Transmission
TOCA	Tier 1 Cost Allocator
TPP	Treasury Payment Probability
TRAM	Transmission Risk Analysis Model
Transmission System Act	Federal Columbia River Transmission System Act
Treaty	Columbia River Treaty
TRL	Total Retail Load
TRM	Tiered Rate Methodology
TS	Transmission Services
TSS	Transmission Scheduling Service
UAI	Unauthorized Increase
UFT	Use of Facilities Transmission
UIC	Unauthorized Increase Charge
ULS	Unanticipated Load Service
USACE	U.S. Army Corps of Engineers

USBR	U.S. Bureau of Reclamation
USFWS	U.S. Fish & Wildlife Service
VERBS	Variable Energy Resources 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

This page intentionally left blank.

DOCUMENTATION FOR THE
BP-18 POWER RATES STUDY

INTRODUCTION

The Documentation for the Power Rates Study (PRS) shows the details of the calculation of the final 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: Ratesetting Methodology and Process contains ratemaking tables that are the output of the Rate Analysis Model (RAM2018). The RAM2018 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 RAM2018 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 PRS cost of service analysis (COSA). A series of tables show the initial allocation of the revenue requirement over the billing determinants. Next, tables present the rate design steps, incorporating statutory directives from section 7 of the Northwest Power Act. The final table shows the calculation of the resource cost contributions that appear in GRSP II.Z.

Section 3: Rate Design documents the calculations of the Demand rate and Load Shaping rates, including 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. A table on the Product Conversion Adjustment calculation and charges is provided.

Section 4: Power Rate Schedules are documented for the most part in Section 3. However, this section includes tables for Load Shaping Rates, Demand Rates, and Tier 2 billing determinant assumptions.

Section 5: Power General Rate Schedule Provisions (GRSPs) are documented for the most part in Section 3, but this section includes tables for Irrigation Rate Discount and Low Density Discount programs.

Section 6: Transfer Service shows calculations for WECC assessment charge, and information on the five-year market purchases for Southeast Idaho transfer load service (SILS).

Section 7: Slice *No documentation*

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

Section 9: The Revenue Forecast documents revenue forecasts at both current and final rates for the rate period, FY 2018–2019, and at current rates for the fiscal year immediately preceding the two-year rate period, FY 2017.

SECTION 1: BACKGROUND

This page intentionally left blank.

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-18-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 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 2018–2019.

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

Atmospheric Administration (NOAA) Fisheries FCRPS Biological Opinion (BiOp) regarding salmon and steelhead, published May 5, 2008; the NOAA Fisheries FCRPS Supplemental BiOp, published May 20, 2010; the NOAA Fisheries FCRPS Supplemental BiOp, published January 17, 2014; the U.S. Fish and Wildlife Service (USFWS) FCRPS BiOp regarding bull trout, published December 20, 2000; the USFWS Libby BiOp regarding bull trout and Kootenai River white sturgeon, published February 18, 2006; relevant operations described in the Northwest Power and Conservation Council's (NPCC) Fish and Wildlife Program; and other fish mitigation measures. 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 efficiency requirements. Additionally, HYDSIM uses hydro plant operating characteristics in combination with power and non-power requirements to simulate the coordinated operation of the hydro system. 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-18-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-18-FS-BPA-04):

The risk portion of the Power Risk and Market Price Forecast Study has been removed from the Power Market Price Study and now is included in the Power and Transmission Risk Study, BP-18-FS-BPA-05.

The Power Market Price Study is comprised 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 Tier 2 Balancing Credit
- 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-18-FS-BPA-05.

The tool used to calculate electric energy prices is a model of the Western Electricity Coordinating Council (WECC) power system called AURORAxmp®. AURORAxmp® 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.

AURORAxmp® produces a single electricity price forecast as a function of its inputs. Thus, to produce a given number of price forecasts requires that AURORAxmp® be run that same number of times using different inputs. Risk models provide inputs to AURORAxmp®, 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-18-FS-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-18-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-18 rate case (RAM2018).

Results Provided for Input into RAM2018 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 results from two hydroregulation models, HYDSIM and the Hourly Operating and Scheduling Simulator (HOSS), plus load forecasts, 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 AURORAxmp®

model (*see* the Power Market Price Study subsection above for a description of the AURORAxmp® 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 AURORAxmp® prices under 1937 hydro conditions. As described in the Power Rates Study below, RAM2018 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 AURORAxmp® 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.

The 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 AURORAxmp® and the Power Non-Operating Risk Model (P-NORM) are used to quantify Power's 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 AURORAxmp®. 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-18-FS-BPA-01)

Rate Analysis Model (RAM2018)

RAM2018 is a group of computer applications that perform most of the computations that determine BPA's proposed power rates. RAM Core, a spreadsheet-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 RAM2018 performs these rate adjustments. The amount of PF Public rate protection and the levels of the IP and NR rates are set incorporating the 2012 settlement of the 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 have 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 to 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 between the differences between COSA allocations and TRM allocations, the mapping for each is shown in RAM2018 using unique database keys.

RAM2018 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 Desources. RAM2018 designs rates for each rate pool.

Resource Support Services Module of RAM2018

The Resource Support Services (RSS) module of RAM2018, 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 RAM2018); 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 RAM2018

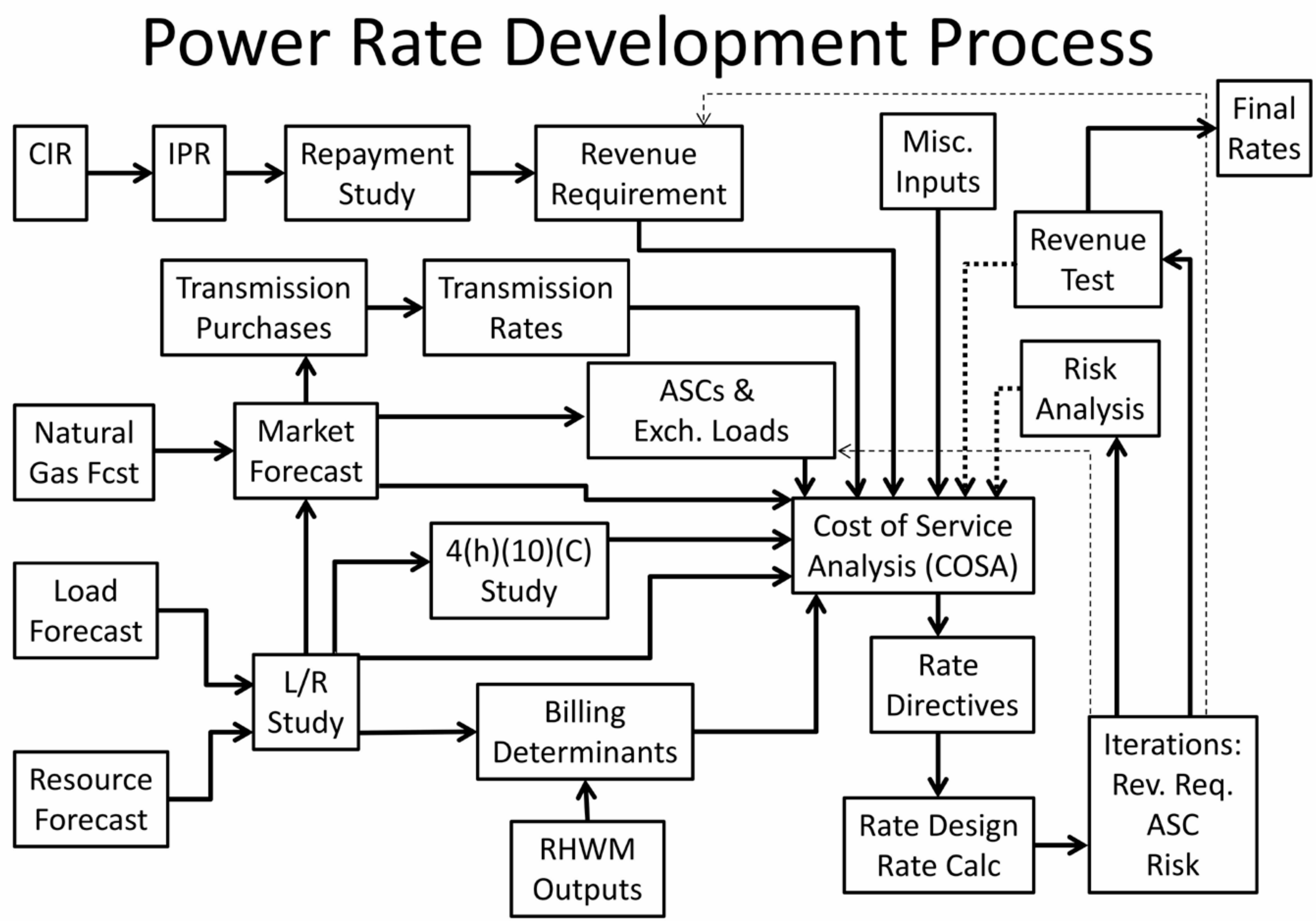
The Tier 2 module of RAM2018, a spreadsheet-based model, calculates Tier 2 rates and the applicable Tier 2 revenue credits and adjustments used in RAM Core that are not already accounted for in the RSS module of RAM2018. This module also calculates customer remarketing credits for amounts of Tier 2 service, 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 2018-2019 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-18 rates, BPA is using the ASC Reports published by BPA on November 17, 2016.

Revenue and Power Purchase Expense Forecast

The Revenue Forecast presents BPA's expected level of revenue and power purchase expense for FY 2017–2019. FY 2017 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, 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
CIR
IPR
Repayment Study
Revenue Requirement
Misc. Inputs
Final Rates
Revenue Test
Transmission Purchases
Transmission Rates
Risk Analysis
ASCs & Exch. Loads
Natural Gas Fcst
Market Forecast
Cost of Service Analysis (COSA)
4(h)(10)(C) Study
Load Forecast
L/R Study
Rate Directives
Billing Determinants
Iterations: Rev. Req. ASC Risk
Resource Forecast
Rate Design Rate Calc
RHWM Outputs

This page intentionally left blank.

SECTION 2: RATESETTING METHODOLOGY AND PROCESS

This page intentionally left blank.

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
Residential Exchange Summary (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 date from their input worksheets.

Table 2.2.2
Aggregated Loads and Resources (EAF 02)
Worksheet added 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 is the Residential Exchange Program costs.

Table 2.3.3
Computation of Low Density and Irrigation Rate Discount Costs (COSA 03)
Worksheet calculates the foregone revenue due to the Low Density Discount and the Irrigation Rate Discount. The foregone 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 FBS Costs and LDD/IRD Costs (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 foregone revenue associated with the LDD and IRD rate discounts are allocated to PF load.

Table 2.3.4.2
Allocation of New Resource Costs and Exchange Resource Costs (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 Conservation, BPA Program and Transmission Costs (COSA 04-5)
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
Revenue Credits Allocated to FBS Costs (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 Transmission Related Revenue Credits (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
Revenue Credits Allocated to New Resource Costs (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
Revenue Credits Allocated to Conservation Costs (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 Generation Input Related Revenue Credits (COSA 07-5)
Worksheet allocates revenue credits associated with providing generation inputs as directed by section 7(g) of the Northwest Power Act.

Table 2.3.7.6
Allocation of Non-Federal RSS/RCS Related Revenue Credits (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 is 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 resultant 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 to 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 (7b and 7f 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 rate-making 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 Unconstrained 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)
Table 2.4.11 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 balances 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 load 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 resultant 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)
This worksheet does a comparison of 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 percent 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 percent 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 percent 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 Contribution
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.

Rate Data Input
Disaggregated Loads
Test Period October 2017 - September 2019
(MWh)

	A	B	C	E	F
4				2018	2019
5	Preference			59,966,424	60,497,894
6		Block		4,475,037	4,512,731
7		Slice Block		12,772,729	13,271,002
8		Slice		14,017,964	13,701,415
9		Load Following		27,813,788	27,987,125
10		Tier 2 (Block net remarketing)		886,906	1,025,621
11	Industrial			531,822	767,447
12		Smelter		421,375	657,000
13		Other Industrial		110,447	110,447
14	New Resource			9	9
15	Firm Power and Services			6,550,572	6,321,396
16		Intraregional Transfer		505,326	505,326
17			WNP3	406,900	406,900
18			Dittmer Station Service	82,668	82,668
19			Transfer Gen Losses	15,758	15,758
27		FBS Obligation		5,770,918	5,717,820
28			Canadian Entitlement	4,103,985	4,050,924
29			USBR Pump Load	1,575,931	1,575,931
30			Hungry Horse	0	0
31			Upper Baker	11,228	11,228
32			Non-Treaty Storage	79,774	79,738
33			Libby Coordination	0	0
38		Seasonal or Capacity Exchange		274,328	98,249
39			Riverside Capacity	0	0
40			Riverside Seasonal	0	0
41			Pasadena Capacity	0	0
42			Pasadena Seasonal	0	0
43			PG&E	229,255	58,248
44			Intertie Losses	6,878	1,747
45			PacifiCorp	38,194	38,254
49	Presale of Secondary			0	0
50	Irrigation Mitigation			0	0
51	Conservation			0	0
52					
53					
54	Loss Percentage			3.061%	3.061%

Rate Data Input
Disaggregated Resources
Test Period October 2017 - September 2019
(MWh)

	A	B	C	E	F
5				2018	2019
6	Hydro			59,075,664	59,044,163
7		Regulated		54,831,406	54,793,953
8		Independent		3,052,662	3,052,662
9			Cowlitz Falls	232,343	232,343
10			Idaho Falls	0	0
11			PreAct	2,820,319	2,820,319
19		Hydro Other		1,191,596	1,197,548
20			Canadian Entitlement	1,191,596	1,197,548
21			Libby Coordination	0	0
22			Other	0	0
30	Non Hydro			10,063,328	8,637,728
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		9,636,000	8,210,400
43			Columbia Generating Station	9,636,000	8,210,400
53		Wind		404,259	404,259
54			Foote Creek 1	31,593	31,593
55			Foote Creek 2	0	0
56			Foote Creek 4	34,650	34,650
57			Stateline Wind Project	185,808	185,808
58			Condon Wind Project	102,710	102,710
59			Klondike I	49,499	49,499
64		Renewable		30	30
65			Georgia-Pacific Paper (Wauna)	0	0
66			Fourmile Hill Geothermal	0	0
67			Ashland Solar Project	30	30
68			White Bluffs Solar	0	0

Rate Data Input
Disaggregated Resources
Test Period October 2017 - September 2019
(MWh)

	A	B	C	E	F
5				2018	2019
75	Contracts			539,573	358,292
76		Imports		275,345	269,326
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	266,585	260,566
87		Seasonal or Capacity Exchange		264,228	88,966
88			Riverside Capacity	0	0
89			Riverside Seasonal	0	0
90			Pasadena Capacity	0	0
91			Pasadena Seasonal	0	0
92			PG&E	226,026	50,713
93			PacifiCorp	38,202	38,253
109	Augmentation and Balancing			105,505	105,505
110		System Augmentation		0	0
111		Balancing		0	0
112		Tier 1 Resources		105,505	105,505
113			Klondike III	103,302	103,302
114			Rocky Brook	2,203	2,203
115					
116	Transmission Losses			(2,088,345)	(2,053,132)

Rate Data Input
Exchange ASCs, Loads, and Gross Costs
Test Period October 2017 - September 2019

	B	D		E	
7	**Exchange ASCs ($/MWh)**		**2018**		**2019**
8					
9	Avista Corporation	$	54.67	$	54.67
10	Idaho Power Company	$	63.09	$	63.09
11	NorthWestern Energy, LLC	$	78.46	$	78.46
12	PacifiCorp	$	79.55	$	79.55
13	Portland General Electric Company	$	75.76	$	75.76
14	Puget Sound Energy, Inc.	$	71.13	$	71.13
15	Clark Public Utilities	$	56.48	$	56.48
17	Snohomish County PUD No 1	$	52.66	$	53.99
18					
19	**Exchange Loads (GWh)**		**2018**		**2019**
20					
21	Avista Corporation		3,728		3,728
22	Idaho Power Company		6,474		6,474
23	NorthWestern Energy, LLC		665		665
24	PacifiCorp		8,691		8,691
25	Portland General Electric Company		8,154		8,154
26	Puget Sound Energy, Inc.		11,209		11,209
27	Clark Public Utilities		2,535		2,535
29	Snohomish County PUD No 1		3,715		3,731
30			45,170		45,186
31					
32	**Exchange Resource Cost ($000)**		**2018**		**2019**
33					
34	Avista Corporation	$	203,806	$	203,806
35	Idaho Power Company	$	408,452	$	408,452
36	NorthWestern Energy, LLC	$	52,164	$	52,164
37	PacifiCorp	$	691,333	$	691,333
38	Portland General Electric Company	$	617,734	$	617,734
39	Puget Sound Energy, Inc.	$	797,322	$	797,322
40	Clark Public Utilities	$	143,173	$	143,183
42	Snohomish County PUD No 1	$	195,609	$	201,413
43		$	3,109,594	$	3,115,409

Table 2.2.1.1

Energy Allocation Factor
Power Sales and Resources
Test Period October 2017 - September 2019
(aMW)

	B	C	E	F
4			**2018**	**2019**
5	**Sales**			
6	Public			
7		Load Following	3,175	3,195
8		Tier 2 (block net of remarketing)	101	117
9		Slice (output energy)	1,600	1,564
10		Block	1,969	2,030
12	Exports			
13		BC Hydro (Cdn Entitlement)	468	462
14		Non-Treaty Storage	9	9
15		Libby Coordination	0	0
16		Pasadena Capacity	0.0	0
17		Pasadena Seasonal	0.0	0
18		Riverside Capacity	0	0
19		Riverside Seasonal	0	0
20		PacifiCorp	4	4
21		PG&E	26	7
22		Federal Generation Transmission Losses	2	2
23		Intertie Losses	1	0
24	Intra-regional Transfers			
25		Avista (WNP#3 Settle.)	46	46
26		Dittmer/Substration Sale	9	9
27	Other Loads			
28		USBR Pump Load	180	180
29		Hungry Horse	0	0
30		Upper Baker	1	1
31		Direct Service Industries	61	88
32		New Resource	0.0	0
33	Total Firm Obligations		**7,654**	**7,715**
34				
35	**Resources**			
36	Hydro			
37		Regulated	6,259	6,255
38		Independent		
39		Cowlitz Falls	27	27
40		Idaho Falls	0	0
41		PreAct	322	322
42		Non-Fed CER (Canada)	136	137
43		Libby Coordination	0	0
44	Other Hydro Resources			
45				

Energy Allocation Factor
Power Sales and Resources
Test Period October 2017 - September 2019
(aMW)

	B	C	E	F
4			**2018**	**2019**
46	Combustion Turbines			
47	Renewables			
48		Foote Creek 1	4	4
49		Foote Creek 2	0	0
50		Foote Creek 4	4	4
51		Stateline Wind Project	21	21
52		Condon Wind Project	12	12
53		Klondike I	6	6
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	30	30
69	Regional Transfers (In)			
70		PG&E	26	6
71		PacifiCorp	4	4
72	Large Thermal		1,100	937
73	Non-Utility Generation			
74		Dworshak/Clearwater Small Hydropower	3	3
75		Elwha Hydro	0	0
76		Glines Canyon Hydro	0	0
77		Rocky Brook	0.25	0.25
78	Augmentation Purchases		0	0
79	Tier 2 Purchases		104	121
80	Federal Trans. Losses		(238)	(234)
81	Total Net Resources		**7,832**	**7,665**
82				
83	Total Firm Surplus/Deficit		**176**	**(52)**

Table 2.2.2.1

Energy Allocation Factor
Aggregated Loads and Resources
Test Period October 2017 - September 2019
(aMW)

	B	C	D	E
4			**2018**	**2019**
7	**Loads**			
8	Priority Firm - 7(b) Loads			
9		Block	2,029	2,092
10		Load Following	3,272	3,293
11		Slice (output energy)	1,649	1,612
12		Tier 2	104	121
14		5(c) Exchange	5,314	5,316
15	Industrial Firm - 7(c) Loads			
16		Direct Service Industries	63	90
17	New Resources - 7(f) Loads			
18		NR	0.001	0.001
19	Surplus Firm - SP Loads			
20		Avista & Puget (WNP#3 Settle.)	48	48
21		Dittmer/Substation Sale	10	10
22	Total Loads		**12,489**	**12,582**
23				
24	**Resources**			
25	Federal Base System			
26		Hydro	6,717	6,714
27		Other Resources		
28		Small Thermal & Misc.		
29		Combustion Turbines		
30		Renewables	0	0
31		Cogeneration		
32		Imports	1	1
33		Regional Transfers (In)	30	10
34		Large Thermal	1,100	937
35		Non-Utility Generation	0	0
36		Slice Loss Return	30	30
37		Augmentation Purchases	0	52
38		Tier 2 Purchases	104	121

Energy Allocation Factor
Aggregated Loads and Resources
Test Period October 2017 - September 2019
(aMW)

	B	C	D	E
4			**2018**	**2019**
39	less: FBS Obligations			
40		BC Hydro (Cdn Entitlement)	(483)	(477)
41		Non-Treaty Storage	(9)	(9)
42		Libby Coordination	0	0
43		Hungry Horse	0	0
44		Upper Baker	(1)	(1)
45		USBR Pump Load	(185)	(185)
46	less: FBS Uses			
47		Pasadena	0	0
48		Riverside	0	0
49		PacifiCorp	(4)	(5)
50		PG&E	(27)	(7)
51		Federal Generation Transmission Losses	(2)	(2)
52		Intertie Losses	(1)	(0)
53	Exchange Resources			
54		5(c) Exchange	5,314	5,316
55	New Resources			
56		Cowlitz Falls	27	27
57		Idaho Falls	0	0
58		Foote Creek 1	4	4
59		Foote Creek 2	0	0
60		Foote Creek 4	4	4
61		Stateline Wind Project	21	21
62		Condon Wind Project	12	12
63		Klondike I	6	6
64		Klondike III	12	12
65		Georgia-Pacific Paper (Wauna)	0	0
66		Fourmile Hill Geothermal	0	0
67		Ashland Solar Project	0	0
68		White Bluffs Solar	0	0
69		Dworshak/Clearwater Small Hydropower	3	3
70		Elwha Hydro	0	0
71		Glines Canyon Hydro	0	0
72		Rocky Brook	0	0
73	Total Resources		**12,672**	**12,582**

Energy Allocation Factor
Calculation of Energy Allocation Factors
Test Period October 2017 - September 2019

	B	C	D
4		**2018**	**2019**
5			
6	**Loads (after adjustments)**		
7	Public	7,055	7,118
8	Exchange	5,314	5,316
9	DSI	63	90
10	NR	0.001	0.001
11	FPS	240	58
12			
13	Load Pools -- Program Case		
14	Priority Firm - 7(b) Loads	12,369	12,434
15	Industrial Firm - 7(c) Loads	63	90
16	New Resources - 7(f) Loads	0.001	0.001
17	Surplus Firm - SP Loads	240	58
18	Total Firm Loads	12,672	12,582
19	Secondary	2,405	2,387
20	Surplus Firm - SP Loads (for rate protection)	240	58
21			
22	**Resources (after adjustments)**		
23	Federal Base System	7,270	7,178
24	Exchange Resources	5,314	5,316
25	New Resources	87	87
26	Total Firm Resources	12,672	12,582
27			
28	Allocators -- Program Case		
29	Federal Base System		
30	Priority Firm - 7(b) Loads	7,270	7,178
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	5,099	5,256
36	Industrial Firm - 7(c) Loads	45	37
37	New Resources - 7(f) Loads	0.0007	0.0004
38	Surplus Firm - SP Loads	171	24
39	New Resources		
40	Priority Firm - 7(b) Loads	0	0
41	Industrial Firm - 7(c) Loads	18	53
42	New Resources - 7(f) Loads	0	0
43	Surplus Firm - SP Loads	69	34

Energy Allocation Factor
Calculation of Energy Allocation Factors
Test Period October 2017 - September 2019

	B	C	D
4		**2018**	**2019**
44			
45	**Allocation Factors -- Program Case with Exchange**		
46	Federal Base System + NR		
47	Priority Firm - 7(b) Loads	0.9881	0.9880
48	Industrial Firm - 7(c) Loads	0.0025	0.0073
49	New Resources - 7(f) Loads	0.0000	0.0000
50	Surplus Firm - SP Loads	0.0094	0.0047
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	0.9595	0.9886
58	Industrial Firm - 7(c) Loads	0.0084	0.0070
59	New Resources - 7(f) Loads	0.0000	0.0000
60	Surplus Firm - SP Loads	0.0321	0.0044
61	New Resources		
62	Priority Firm - 7(b) Loads	0.0000	0.0000
63	Industrial Firm - 7(c) Loads	0.2068	0.6105
64	New Resources - 7(f) Loads	0.0000	0.0000
65	Surplus Firm - SP Loads	0.7932	0.3895
66	Conservation & General		
67	Priority Firm - 7(b) Loads	0.9761	0.9882
68	Industrial Firm - 7(c) Loads	0.0049	0.0072
69	New Resources - 7(f) Loads	0.0000	0.0000
70	Surplus Firm - SP Loads	0.0189	0.0046
81	Surplus Deficit		
82	Priority Firm - 7(b) Loads	0.9950	0.9928
83	Industrial Firm - 7(c) Loads	0.0050	0.0072
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	0.6625	0.6771
91	Industrial Firm - 7(c) Loads	0.0078	0.0115
92	New Resources - 7(f) Loads	0.0000	0.0000
93	Secondary Sales	0.3297	0.3114

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2017 - September 2019
($ 000)

	B	D	E
4		**2018**	**2019**
5	**Power System Generation Resources**		
6	**Operating Generation**		
7	Columbia Generating Station (WNP-2)	270,146	327,354
8	Bureau of Reclamation	164,609	162,623
9	Corps of Engineers	256,057	256,057
10	Billing Credits Generation	5,300	5,300
11	Cowlitz Falls O&M	4,948	5,990
12	Idaho Falls Bulb Turbine	-	-
13	Clearwater Hatchery Generation	1,300	1,350
14	New Resources Integration Wheeling	1,047	1,047
15			
16	**Operating Generation Settlement Payment**		
17	Operating Generation Settlement Payment (Colville)	22,612	22,997
18			
19	**Non-Operating Generation**		
20	Trojan Decomissioning	1,000	1,000
21	WNP-1&3 Decomissioning	500	534
22			
23	**Contracted and Augmentation Power Purchases**		
24	Augmentation Power Purchases	-	12,211
25	Balancing Purchases	21,877	15,743
26	PNCA Headwater Benefits	3,100	3,100
27	Tier 1 Augmentation Resources (Klondike III)	10,048	10,158
28	Hedging/Mitigation	38,382	38,441
29	Other Committed Purchase (excl. Hedging)	225	225
30	Bookout Adj to Contracted Power Purchases	-	-
31			
32	**Exchanges and Settlements**		
33	Residential Exchange (IOU)	232,200	232,200
34	Residential Exchange (COU)	9,164	9,178
35	Residential Exchange (Refund)	76,538	76,538
36	Residential Exchange Program Support	1,008	733
37	Residential Exchange Interest Accrual	-	-
38			
39	**Renewable and Conservation Generation**		
40	Renewables R&D	-	-
41	Renewable Generation	28,284	28,902
42	Conservation Infrastructure	27,149	27,283
43	Generation Conservation R&D	2,923	2,858
44	DR & Smart Grid	856	854
45	Conservation Acquisition	71,785	71,785
46	Energy Efficiency Initiative	-	-
47	BPA Managed EE	-	-
48	Low Income Energy Efficiency	5,523	5,627
49	Reimbursable Energy Efficiency Development	8,000	8,000
50	Legacy Conservation	590	590
51	Market Transformation	12,364	12,049

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2017 - September 2019
($ 000)

	B	D	E
4		**2018**	**2019**
52			
53	**Transmission Acquisition and Ancillary Services**		
54	Trans & Ancillary Svcs	74,698	71,274
55	Trans & Ancillary Svcs (sys oblig)	33,857	32,924
56	Third Party GTA Wheeling	91,759	92,516
57	Power 3rd Party Trans & Ancillary Svcs (Non-Slice Cost)	-	-
58	Power 3rd Party Trans & Ancillary Svcs (Composite Cost)	2,251	2,292
59	Trans Acq Generation Integration	12,480	12,634
60	Power Telemetering/Equipment Replacement	-	-
61			
62	**Power Non-Generation Operations**		
63	Efficiencies Program	-	-
64	Information Technology	6,976	7,294
65	Generation Project Coordination	6,174	6,409
66	Slice costs Charged to Slice Customers	-	-
67	Slice Implementation	1,024	1,061
68			
69	**PS Scheduling**		
70	Operations Scheduling	10,054	10,404
71	Operations Planning	8,528	8,416
72			
73	**PS Marketing and Business Support**		
74	Sales and Support	22,885	23,485
75	Strategy, Finance & Risk Mgmt	12,016	13,310
76	Executive and Administrative Svcs	4,119	4,204
77	Conservation Support	9,094	9,409
78	Power R&D	1,782	1,742
79	KSI Asset Management Expense	500	-
80	KSI LT Finance & Rates Expense	-	-
81	KSI Commercial Operations Expense	3,330	4,995
82			
83	**Fish and Wildlife/USF&W/Planning Council/Env Req.**		
84	Fish and Wildlife	276,713	276,704
85	USF&W Lower Snake Hatcheries	33,483	33,483
86	Planning Council	11,624	11,914
87	Environmental Requirements	-	-
88			
89	**BPA Internal Support**		
90	Additional Post-Retirement Contribution	14,962	15,620
91	Agency Svs for Power for Rev Req schedule	40,065	41,000
92	F&W Corporate Support - G&A	11,369	11,627
93	Agency Svs for Energy Efficiency for Rev Req schedule	12,958	13,170

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2017 - September 2019
($ 000)

	B	D	E
4		**2018**	**2019**
94			
95	**Bad Debt Expense/Other**		
96	Bad Debt Expense (composite)	-	-
97	Bad Debt Expense (non-slice)	-	-
98	Other Income & Expense (composite) - IPR undistrib reduction	(10,000)	(10,000)
99	Other Income & Expense (composite) - RCD Effect	11,772	(3,668)
100	Other Income & Expense (non-slice) - RCD Offset	(70,000)	-
101	Other Income & Expense (composite) - Expense Offset (EE)	(60,500)	(60,500)
102			
103	**Non-Federal Debt Service**		
104	**Energy Northwest Debt Service**		
105	CGS Debt Service	184,737	338,592
106	WNP-1 Debt Service	60,431	40,738
107	WNP-3 Debt Service	236,158	32,139
108			
109	**Non-Energy Northwest Debt Service**		
110	Cowlitz Falls (Lewis County) Debt Service	7,302	7,304
111	Northern Wasco Debt Service	1,934	1,932
112			
113	**Depreciation and Amortization**		
114	**Depreciation**		
115	Depreciation - BPA	18,080	13,609
116	Depreciation - Corps	97,725	100,816
117	Depreciation - Bureau	28,287	29,641
118			
119	**Amortization**		
120	Amortization - Legacy Conservation	923	367
121	Amortization - Conservation Acquisitions	40,145	40,145
122	Amortization - CRFM	10,398	10,398
123	Amortization - Fish & Widlife	35,330	36,548
124			
125	**Interest Expense**		
126	**Net Interest**		
127	Interest On Appropriated Funds	83,294	82,687
128	Capitalization Adjustment	(45,937)	(45,937)
129	Interest On Treasury Bonds	56,449	63,302
130	Non Federal Interest (Prepay)	11,628	10,747
131	Capitalized Bond Premium	-	-
132	AFUDC	(8,379)	(8,307)
133	Interest Earned on BPA Fund for Power (composite)	(2,543)	(3,781)
134	Prepay Offset Credit	-	-
135	Interest Earned on BPA Fund for Power (non-slice)	1,151	1,576

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2017 - September 2019
($ 000)

	B	D	E
4		**2018**	**2019**
136			
137	**Net Interest into Cost Pools**		
138	Power Net Interest - Hydro Allocation	76,103	79,386
139	Power Net Interest - Fish & Wildlife Allocation	9,560	10,984
140	Power Net Interest - Conservation Allocation	8,539	8,635
141	Power Net Interest - BPA Programs Allocation	1,460	1,282
142			
143	**Net Interest into Cost Pools 7b2**		
144	Power Net Interest Hydro 7b2 Allocation	76,103	79,386
145	Power Net Interest Fish & Wildlife 7b2 Allocation	9,560	10,984
146	Power Net Interest BPA Programs 7b2 Allocation	9,999	9,917
147			
148	**Net Revenue**		
149	**Minimum Required Net Revenue**		
150	Repayment of Treasury Borrowings	44,150	156,250
151	Payment of Irrigation Assistance	27,234	56,573
152	Depreciation (MRNR - Reverse sign)	(144,092)	(144,065)
153	Amortization (MRNR - Reverse sign)	(86,796)	(87,458)
154	Non Federal Interest (Prepay) (MRNR - Reverse Sign)	(11,628)	(10,747)
155	Capitalization Adjustment (MRNR - Reverse Sign)	45,937	45,937
156	Capitalized Bond Premium (Reverse Sign)	-	-
157	Repayment of Federal Appropriations	91,070	17,371
158	PGE WNP #3 Settlement	3,524	3,524
159	Accrual Revenues (MRNR Adjustment - Reverse Sign)	-	-
160	Prepay Revenue Credits (MRNR - Reverse Sign)	30,600	30,600
161	Non-Cash Expenses	-	-
162	Repayment of Non-Federal Obligations	220,252	-
163	Customer Proceeds	-	-
164	Revenue Financing Requirement	-	-
165	Depreciation Exceeds Cash Expense	(220,252)	(67,984)
166			
167	**Minimum Net Revenue into Cost Pools**		
168	Power MNetRev - Hydro Allocation	175,221	53,815
169	Power MNetRev - Fish & Wildlife Allocation	22,009	7,446
170	Power MNetRev - Conservation Allocation	19,660	5,853
171	Power MNetRev - BPA Programs Allocation	3,362	869
172			
173	**Minimum Net Revenue into Cost Pools 7b2**		
174	Power MNetRev - Hydro 7b2 Allocation	175,221	53,815
175	Power MNetRev - Fish & Wildlife 7b2 Allocation	22,009	7,446
176	Power MNetRev - PBA Programs 7b2 Allocation	23,022	6,722
177			
178	**Planned Net Revenues for Risk into Cost Pools**		
179	Power PNetRev - Hydro Allocation	15,911	15,832
180	Power PNetRev - Fish & Wildlife Allocation	1,999	2,191
181	Power PNetRev - Conservation Allocation	1,785	1,722
182	Power PNetRev - BPA Programs Allocation	305	256
183			
184	**Planned Net Revenues for Risk into Cost Pools 7b2**		
185	Power PNetRev - Hydro 7b2 Allocation	15,911	15,832
186	Power PNetRev - Fish & Wildlife 7b2 Allocation	1,999	2,191
187	Power PNetRev - BPA Programs 7b2 Allocation	2,090	1,978

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2017 - September 2019
($ 000)

	B	D	E
4		**2018**	**2019**
188			
189	**Internally Computed Line Items**		
190	Augmentation Power Purchases	-	12,211
191	Balancing Purchases	60,259	54,184
192	Secondary Energy Credit	(378,878)	(343,895)
193	Low Density Discount Costs	41,010	41,971
194	Irrigation Rate Mitigation Costs	22,128	22,128
195	**Charges/Credits to Tiered Rate Pools**		
196	Firm Surplus and Secondary Credit (from unused RHWM)	(30,246)	(13,324)
197	Balancing Augmentation	1,364	(8,511)
198	Transmission Loss Adjustment	(31,568)	(32,060)
199	Demand Revenue	48,363	47,951
200	Load Shaping Revenue	22,842	31,941
201	**Tier 2 and RSS Charges/Credits to Tiered Rate Pools**		
202	Augmentation RSS & RSC Adder	2,345	2,345
203	Tier 2 Purchase Costs	37,050	42,112
204	Tier 2 Rate Design Adjustments (Cost)	1,215	1,434
205	Tier 2 Other Costs	-	-
206			
207	**Revenue Credits / Rate Design Adjustments**		
208	Downstream Benefits and Pumping Power	(16,829)	(16,829)
209	Generation Inputs for Ancillary and Other Services Revenue	(108,430)	(101,519)
210	4(h)(10)(C)	(93,172)	(91,526)
211	Colville and Spokane Settlements	(4,600)	(4,600)
212	Green Tags (FBS resources)	-	-
213	Green Tags (New resources)	-	-
214	Energy Efficiency Revenues	(8,000)	(8,000)
215	Large Project Revenues	-	-
216	Miscellaneous Credits (incl. GTA)	(7,200)	(7,200)
217	Pre-sub/Hungry Horse	-	-
218	Other Locational/Seasonal Exchange	(565)	(129)
219	Upper Baker	(395)	(395)
220	WNP3 Settlement	(15,959)	(15,959)
221	Other Long-Term Contracts	-	-
222	Network Wind Integration & Shaping	-	-
223	Product Conversion Adjustment Revenues	(2,033)	(2,033)
224	NR Revenues from ESS energy and capacity charges	-	-
225	**Tier 2**		
226	Composite Augmentation RSS Revenue Debit/(Credit)	(1,619)	(1,619)
227	Composite Tier 2 RSS Revenue Debit/(Credit)	(139)	(161)
228	Composite Tier 2 Rate Design Adjustment Debit/(Credit)	(1,076)	(1,273)
229	Composite Non-Federal RSS Revenue Debit/(Credit)	(1,323)	(1,322)
230	Non-Slice Augmentation RSC Revenue Debit/(Credit)	(726)	(726)
231	Non-Slice Tier 2 RSC Revenue Debit/(Credit)	-	-
232	Non-Slice Tier 2 Rate Design Debit/(Credit)	-	-
233	Non-Slice Non-Federal RSC Revenue Debit/(Credit)	113	113

Cost of Service Analysis
Cost Pool Aggregation
Test Period October 2017 - September 2019
($ 000)

	B	D	E
3		**2018**	**2019**
4			
5	**Federal Base System**	**2,103,831**	**1,976,084**
6	Hydro	883,506	768,148
7	Operating Expense	616,272	619,115
8	Net Interest	76,103	79,386
9	PNRR	15,911	15,832
10	MRNR	175,221	53,815
11	BPA Fish and Wildlife Program	368,604	357,414
12	Operating Expense	335,036	336,793
13	Net Interest	9,560	10,984
14	PNRR	1,999	2,191
15	MRNR	22,009	7,446
16	Trojan	1,000	1,000
17	WNP #1	60,931	41,272
18	WNP #2	454,883	665,946
19	WNP #3	236,158	32,139
20	System Augmentation	-	12,211
21	Balancing	60,484	54,409
22	Tier 2 Costs	38,265	43,545
23			
24	**New Resources**	**54,863**	**56,683**
25	Idaho Falls	-	-
26	Tier 1 Aug (Klondike III)	10,048	10,158
27	Cowlitz Falls	12,250	13,293
28	Other NR	32,565	33,231
29			
30	**Residential Exchange**	**3,110,602**	**3,116,142**
31			
32	**Conservation**	**167,093**	**153,145**
33	Operating Expense	137,109	136,935
34	Net Interest	8,539	8,635
35	PNRR	1,785	1,722
36	MRNR	19,660	5,853
37			
38	**BPA Programs**	**87,392**	**140,287**
39	Operating Expense	82,265	137,880
40	Net Interest	1,460	1,282
41	PNRR	305	256
42	MRNR	3,362	869
43			
44			
45	**Transmission**	**215,044**	**211,640**
46	TBL Transmission/Ancillary Services	123,285	119,124
47	3Rd Party Trans/Ancillary Services	-	-
48	General Transfer Agreements	91,759	92,516
49			
50	**Total PBL Revenue Requirement**	**5,738,826**	**5,653,981**

Cost of Service Analysis
Computation of Low Density and Irrigation Rate Discount Costs
Test Period October 2017 - September 2019
($ 000)

	B		D		E	F	G	H
18	**Program Totals**		**2018**		**2019**			
19	**Low Density Discount Expenses........................**	**$**	**41,010**	**$**	**41,971**			
20	**Irrigation Rate Discount....................................**	**$**	**22,128**	**$**	**22,128**			
21								
22								
23	**TRM Costs after Adjustments**		**2018**		**2019**			
24	**Composite...**	$	2,462,544	$	2,477,578			
25	**Non-Slice...**	$	(264,902)	$	(267,017)			
26	**Slice...**	$	-	$	-			
27	**Tier 2...**	$	38,265	$	43,545			
28	**Total Costs**	$	2,235,907	$	2,254,107			
29								
30	**Low Density Discount**							
31	**Customer Charge LDD**		**2018**		**2019**			
32	**TOCA LDD Offest %.......................................**		1.71%		1.72%			
33	**LDD Customer Charge ($000).........................**	$	37,501	$	38,019			
34								
35	**Irrigation Rate Discount**							
36	**IRD Percentage..**		37.06%					
37	**Total Irrigation Load (MWh).........................**		1,881,605					
38	**RT1SC...**		6,945					
39	**Irrigation Load Weighted LDD.......................**		4.9%					
40								
41			**2018**		**2019**			
42	**Hours...**		8760		8760			
43	**IRD TOCA...**		3.09287%		3.09287%			
44	**Composite Revenue...**	$	78,798,106	$	78,798,106			
45	**Non-Slice Revenue...**	$	(11,083,643)	$	(11,083,643)			
46	**Load Shaping Revenue.......................................**	$	(4,956,637)	$	(4,956,637)			
47	**Total after LDD...**	$	59,682,693	$	59,682,693			
48								
49	**Irrigation Rate Discount...................................**		**11.76**					
50								
51								

Cost of Service Analysis
Computation of Low Density and Irrigation Rate Discount Costs
Test Period October 2017 - September 2019
($ 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-17	17,126	(5,766)	$ 10.45	$ 26.74	$ 24,786
54	Oct-17	-	1,214	$ 10.45	$ 22.49	$ 27,308
55	Nov-17	18,741	(11,647)	$ 10.65	$ 27.27	$ (118,051)
56	Nov-17	-	(1,244)	$ 10.65	$ 24.74	$ (30,776)
57	Dec-17	29,677	(1,033)	$ 11.83	$ 30.28	$ 319,792
58	Dec-17	-	5,940	$ 11.83	$ 26.60	$ 158,025
59	Jan-18	31,889	7,456	$ 11.45	$ 29.30	$ 583,591
60	Jan-18	-	9,084	$ 11.45	$ 23.94	$ 217,495
61	Feb-18	19,038	8,113	$ 11.15	$ 28.54	$ 443,846
62	Feb-18	-	8,680	$ 11.15	$ 23.94	$ 207,800
63	Mar-18	29,262	(1,738)	$ 9.28	$ 23.75	$ 230,259
64	Mar-18	-	1,875	$ 9.28	$ 20.80	$ 38,994
65	Apr-18	23,183	(2,466)	$ 7.68	$ 19.67	$ 129,523
66	Apr-18	-	3,150	$ 7.68	$ 17.54	$ 55,255
67	May-18	20,743	(22,607)	$ 6.49	$ 16.63	$ (241,296)
68	May-18	-	(7,403)	$ 6.49	$ 11.25	$ (83,319)
69	Jun-18	24,426	(3,888)	$ 6.92	$ 17.71	$ 100,167
70	Jun-18	-	2,975	$ 6.92	$ 9.31	$ 27,706
71	Jul-18	24,283	7,898	$ 9.63	$ 24.66	$ 428,592
72	Jul-18	-	13,223	$ 9.63	$ 19.05	$ 251,956
73	Aug-18	30,753	1,071	$ 10.98	$ 28.11	$ 367,761
74	Aug-18	-	6,911	$ 10.98	$ 22.61	$ 156,296
75	Sep-18	19,348	(2,539)	$ 10.91	$ 27.94	$ 140,127
76	Sep-18	-	3,287	$ 10.91	$ 22.19	$ 72,947
77	**Total**					**$ 3,508,785**

Cost of Service Analysis
Computation of Low Density and Irrigation Rate Discount Costs
Test Period October 2017 - September 2019
($ 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-18	22,831	(4,446)	$ 10.45	$ 26.74	$ 119,699
80	Oct-18	-	(274)	$ 10.45	$ 22.49	$ (6,154)
81	Nov-18	21,424	(10,801)	$ 10.65	$ 27.27	$ (66,417)
82	Nov-18	-	(2,328)	$ 10.65	$ 24.74	$ (57,598)
83	Dec-18	32,376	47	$ 11.83	$ 30.28	$ 384,418
84	Dec-18	-	4,746	$ 11.83	$ 26.60	$ 126,269
85	Jan-19	34,679	8,826	$ 11.45	$ 29.30	$ 655,671
86	Jan-19	-	7,923	$ 11.45	$ 23.94	$ 189,693
87	Feb-19	22,872	9,433	$ 11.15	$ 28.54	$ 524,275
88	Feb-19	-	7,501	$ 11.15	$ 23.94	$ 179,575
89	Mar-19	28,675	(708)	$ 9.28	$ 23.75	$ 249,282
90	Mar-19	-	889	$ 9.28	$ 20.80	$ 18,486
91	Apr-19	29,100	(396)	$ 7.68	$ 19.67	$ 215,699
92	Apr-19	-	1,088	$ 7.68	$ 17.54	$ 19,091
93	May-19	23,569	(21,139)	$ 6.49	$ 16.63	$ (198,551)
94	May-19	-	(9,116)	$ 6.49	$ 11.25	$ (102,598)
95	Jun-19	23,316	(2,639)	$ 6.92	$ 17.71	$ 114,612
96	Jun-19	-	1,743	$ 6.92	$ 9.31	$ 16,230
97	Jul-19	31,144	10,459	$ 9.63	$ 24.66	$ 557,808
98	Jul-19	-	10,891	$ 9.63	$ 19.05	$ 207,521
99	Aug-19	32,819	2,986	$ 10.98	$ 28.11	$ 444,299
100	Aug-19	-	5,086	$ 10.98	$ 22.61	$ 115,026
101	Sep-19	21,554	(771)	$ 10.91	$ 27.94	$ 213,624
102	Sep-19	-	1,408	$ 10.91	$ 22.19	$ 31,250
103	**Total**					**$ 3,951,212**

Cost of Service Analysis
Allocation of Costs
Test Period October 2017 - September 2019
($ 000)

	B	C		D	
4	**Costs ($000)**		**2018**		**2019**
5	**FBS...**	$	2,103,831	$	1,976,084
6	**New Resources......................................**	$	54,863	$	56,683
7	**Residential Exchange...........................**	$	3,110,602	$	3,116,142
8	**Conservation..**	$	167,093	$	153,145
9	**BPAPrograms......................................**	$	87,392	$	140,287
10	**Transmission..**	$	215,044	$	211,640
11	**Irrigation/Low Density Discounts.......**	$	63,137	$	64,098
12	Total..	$	5,801,964	$	5,718,079
13					
14	**Cost Allocation**				
15					
16	**FBS...**	$	2,103,831	$	1,976,084
17					
18	**Federal Base System Allocators...........**		**2018**		**2019**
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............................**		**2018**		**2019**
26	Priority Firm - 7(b) Loads.....................	$	2,103,831	$	1,976,084
27	Industrial Firm - 7(c) Loads..................	$	-	$	-
28	New Resources - 7(f) Loads..................	$	-	$	-
29	Surplus Firm - SP Loads.......................	$	-	$	-
30	Total..	$	2,103,831	$	1,976,084
31					
32					
33	**Irrigation/Low Density Discounts.......**	$	63,137	$	64,098
34					
35	**Irrigation/LDD Allocators..................**		**2018**		**2019**
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...........**		**2018**		**2019**
43	Priority Firm - 7(b) Loads.....................	$	63,137	$	64,098
44	Industrial Firm - 7(c) Loads..................	$	-	$	-
45	New Resources - 7(f) Loads..................	$	-	$	-
46	Surplus Firm - SP Loads.......................	$	-	$	-
47	Total..	$	63,137	$	64,098

Cost of Service Analysis
Allocation of Costs
Test Period October 2017 - September 2019
($ 000)

	B	C		D	
4	**Costs ($000)**		**2018**		**2019**
5	**FBS...**	$	2,103,831	$	1,976,084
6	**New Resources......................................**	$	54,863	$	56,683
7	**Residential Exchange............................**	$	3,110,602	$	3,116,142
8	**Conservation...**	$	167,093	$	153,145
9	**BPAPrograms.......................................**	$	87,392	$	140,287
10	**Transmission...**	$	215,044	$	211,640
11	**Irrigation/Low Density Discounts.........**	$	63,137	$	64,098
12	Total...	$	5,801,964	$	5,718,079
13					
14	**Cost Allocation (continued)**				
15					
16	**New Resources......................................**	$	54,863	$	56,683
17					
18	**New Resources Allocators**		**2018**		**2019**
19	Priority Firm - 7(b) Loads......................		0.0000		0.0000
20	Industrial Firm - 7(c) Loads....................		0.2068		0.6105
21	New Resources - 7(f) Loads...................		0.00000341		0.00000697
22	Surplus Firm - SP Loads.........................		0.7932		0.3895
23	Total...		1.0000		1.0000
24					
25	**New Resources Cost Allocation...........**		**2018**		**2019**
26	Priority Firm - 7(b) Loads......................	$	-	$	-
27	Industrial Firm - 7(c) Loads....................	$	11,347	$	34,606
28	New Resources - 7(f) Loads...................	$	0.1869	$	0.3950
29	Surplus Firm - SP Loads.........................	$	43,516	$	22,076
30	Total...	$	54,863	$	56,683
31					
32					
33	**Residential Exchange............................**	$	3,110,602	$	3,116,142
34	Costs Functionalized to Transmission.....	$	(213,203)	$	(213,279)
35	Costs Functionalized to Generation.........	$	2,897,399	$	2,902,863
36					
37	**Residential Exchange Allocators**		**2018**		**2019**
38	Priority Firm - 7(b) Loads......................		0.9595		0.9886
39	Industrial Firm - 7(c) Loads....................		0.0084		0.0070
40	New Resources - 7(f) Loads...................		0.00000014		0.00000008
41	Surplus Firm - SP Loads.........................		0.0321		0.0044
42	Total...		1.0000		1.0000
43					
44	**Residential Exchange Cost Allocation**		**2018**		**2019**
45	Priority Firm - 7(b) Loads......................	$	2,780,081	$	2,869,803
46	Industrial Firm - 7(c) Loads....................	$	24,264	$	20,184
47	New Resources - 7(f) Loads...................	$	0.400	$	0.230
48	Surplus Firm - SP Loads.........................	$	93,054	$	12,876
49	Total...	$	2,897,399	$	2,902,863

Cost of Service Analysis
Allocation of Costs
Test Period October 2017 - September 2019
($ 000)

	B	C		D	
4	**Costs ($000)**		**2018**		**2019**
5	**FBS..**	$	2,103,831	$	1,976,084
6	**New Resources................................**	$	54,863	$	56,683
7	**Residential Exchange.......................**	$	3,110,602	$	3,116,142
8	**Conservation....................................**	$	167,093	$	153,145
9	**BPAPrograms..................................**	$	87,392	$	140,287
10	**Transmission...................................**	$	215,044	$	211,640
11	**Irrigation/Low Density Discounts...**	$	63,137	$	64,098
12	Total..	$	5,801,964	$	5,718,079
13					
14	**Cost Allocation (continued)**				
15					
16	**Conservation....................................**	$	167,093	$	153,145
17					
18	**BPAPrograms..................................**	$	87,392	$	140,287
19					
20	**Transmission...................................**	$	215,044	$	211,640
21					
22					
23	**Conservation & General Allocators**		**2018**		**2019**
24	Priority Firm - 7(b) Loads.................		0.9761		0.9882
25	Industrial Firm - 7(c) Loads..............		0.0049		0.0072
26	New Resources - 7(f) Loads..............		0.0000		0.0000
27	Surplus Firm - SP Loads...................		0.0189		0.0046
28	Total..		1.0000		1.0000
29					
30	**Conservation Cost Allocation..........**		**2018**		**2019**
31	Priority Firm - 7(b) Loads.................	$	163,104	$	151,345
32	Industrial Firm - 7(c) Loads..............	$	825	$	1,099
33	New Resources - 7(f) Loads..............	$	0	$	0
34	Surplus Firm - SP Loads...................	$	3,164	$	701
35	Total..	$	167,093	$	153,145
36					
37	**BPA Programs Cost Allocation.......**		**2018**		**2019**
38	Priority Firm - 7(b) Loads.................	$	85,306	$	138,638
39	Industrial Firm - 7(c) Loads..............	$	432	$	1,007
40	New Resources - 7(f) Loads..............	$	0	$	0
41	Surplus Firm - SP Loads...................	$	1,655	$	642
42	Total..	$	87,392	$	140,287
43					
44	**Transmission Cost Allocation..........**		**2018**		**2019**
45	Priority Firm - 7(b) Loads.................	$	209,910	$	209,152
46	Industrial Firm - 7(c) Loads..............	$	1,062	$	1,519
47	New Resources - 7(f) Loads..............	$	0	$	0
48	Surplus Firm - SP Loads...................	$	4,072	$	969
49	Total..	$	215,044	$	211,640

Cost of Service Analysis
Allocation of Costs Summary
Test Period October 2017 - September 2019
($ 000)

	B	C		D	
4	**Costs ($000)**		**2018**		**2019**
5	**FBS..**	$	2,103,831	$	1,976,084
6	**New Resources......................................**	$	54,863	$	56,683
7	**Residential Exchange...........................**	$	3,110,602	$	3,116,142
8	**Conservation...**	$	167,093	$	153,145
9	**BPAPrograms..**	$	87,392	$	140,287
10	**Transmission...**	$	215,044	$	211,640
11	**Irrigation/Low Density Discounts........**	$	63,137	$	64,098
12	Total...	$	5,801,964	$	5,718,079
13					
14	**Cost Allocation (continued)**				
15					
16					
17	**Initial Cost Allocation (Costs /$1000)**		**2018**		**2019**
18	Priority Firm - 7(b) Loads.......................	$	5,405,370	$	5,409,120
19	Industrial Firm - 7(c) Loads....................	$	37,929	$	58,415
20	New Resources - 7(f) Loads....................	$	0.62	$	0.67
21	Surplus Firm - SP Loads.........................	$	145,461	$	37,264
22	Total Costs Functionalized to Power......	$	5,588,760	$	5,504,799
23					
24					
25					
26	REP Cost Functionalized to Transmissioı	$	213,203	$	213,279
27					
28	Total COSA Revenue Requirement	$	5,801,964	$	5,718,079

Cost of Service Analysis
General Revenue Credits
Test Period October 2017 - September 2019
($ 000)

	B	C		D	
5	**General Revenue Credits ($000))**		**2018**		**2019**
6					
7	**FBS**	**$**	**(115,816)**	**$**	**(114,389)**
8	Hydro and Renewable	$	(21,429)	$	(21,429)
9	Downstream Benefits and Pumping Power	$	(16,829)	$	(16,829)
10	Colville and Spokane Settlements	$	(4,600)	$	(4,600)
11	Green Tags (FBS resources)	$	-	$	-
12	Fish and Wildlife	$	(93,172)	$	(91,526)
13	4(h)(10)(c)	$	(93,172)	$	(91,526)
14	Tier 2 Adjustment	$	(1,215)	$	(1,434)
15	**Contract Obligations**	**$**	**(960)**	**$**	**(524)**
16	Pre-sub/Hungry Horse	$	-	$	-
17	Other Locational/Seasonal Exchange	$	(565)	$	(129)
18	Upper Baker	$	(395)	$	(395)
19	**New Resources**	**$**	**-**	**$**	**-**
20	Green Tags (New resources)	$	-	$	-
21	**Conservation**	**$**	**(8,000)**	**$**	**(8,000)**
22	Energy Efficiency Revenues	$	(8,000)	$	(8,000)
23	Large Project Revenues	$	-	$	-
24	**BPAPrograms**	**$**	**-**	**$**	**-**
25	**Transmission**	**$**	**(7,200)**	**$**	**(7,200)**
26	Miscellaneous Credits (incl. GTA)	$	(7,200)	$	(7,200)
27					
28	**Other Revenue Credits ($ 000))**		**2018**		**2019**
29	Secondary Revenue	**$**	**(437,427)**	**$**	**(438,258)**
30	Incl. Slice	$	(437,427)	$	(438,258)
31	Generation Inputs for Ancillary and Other Services Revenue	**$**	**(108,430)**	**$**	**(101,519)**
32	Composite Non-Federal RSS Revenue Debit/(Credit)	**$**	**(1,323)**	**$**	**(1,322)**
33	Non-Slice Non-Federal RSC Revenue Debit/(Credit)	**$**	**113**	**$**	**113**
34	NR Revenues from ESS energy and capacity charges	**$**	**-**	**$**	**-**
35	Product Conversion Adjustment Revenues	$	(2,033)	$	(2,033)
36	**Firm Surplus and from Other Long-term Sales**	**$**	**(52,307)**	**$**	**(15,959)**
37	WNP3 Settlement	$	(15,959)	$	(15,959)
38	Other Long-Term Contracts	$	-	$	-
39	Firm Surplus Secondary Sales	$	(36,348)	$	-
40					
41	**Total Revenue Credits**	$	(733,383)	$	(689,091)

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2017 - September 2019
($ 000)

	B		C		D
4	**Allocation of Revenue Requirement**		**2018**		**2019**
5	Priority Firm - 7(b) Loads..	$	5,405,370	$	5,409,120
6	Industrial Firm - 7(c) Loads....................................	$	37,929	$	58,415
7	New Resources - 7(f) Loads....................................	$	1	$	1
8	Surplus Firm - SP Loads...	$	145,461	$	37,264
9	Total...	$	5,588,760	$	5,504,799
10					
11	**General Revenue Credits ($000))**		**2018**		**2019**
12					
13	**FBS..**	**$**	**(116,776)**	**$**	**(114,913)**
14	Hydro and Renewable.......................................	$	(21,429)	$	(21,429)
15	Downstream Benefits and Pumping Power..	$	(16,829)	$	(16,829)
16	Colville and Spokane Settlements................	$	(4,600)	$	(4,600)
17	Green Tags (FBS resources)........................	$	-	$	-
18	Fish and Wildlife..	$	(93,172)	$	(91,526)
19	4(h)(10)(c)...	$	(93,172)	$	(91,526)
20	Tier 2 Adjustment...	$	(1,215)	$	(1,434)
21	Contract Obligations...	$	(960)	$	(524)
22	Pre-sub/Hungry Horse.................................	$	-	$	-
23	Other Locational/Seasonal Exchange...........	$	(565)	$	(129)
24	Upper Baker..	$	(395)	$	(395)
25					
26	**Federal Base System Allocators**		**2018**		**2019**
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**		**2018**		**2019**
34	Priority Firm - 7(b) Loads..	$	(116,776)	$	(114,913)
35	Industrial Firm - 7(c) Loads....................................	$	-	$	-
36	New Resources - 7(f) Loads....................................	$	-	$	-
37	Surplus Firm - SP Loads...	$	-	$	-
38	Total...	$	(116,776)	$	(114,913)
39					
40	**Allocation of Revenue Requirement**		**2018**		**2019**
41	Priority Firm - 7(b) Loads..	$	5,288,593	$	5,294,207
42	Industrial Firm - 7(c) Loads....................................	$	37,929	$	58,415
43	New Resources - 7(f) Loads....................................	$	1	$	1
44	Surplus Firm - SP Loads...	$	145,461	$	37,264
45	Total...	$	5,471,984	$	5,389,886

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2017 - September 2019
($ 000)

	B		C		D
40	**Allocation of Revenue Requirement**		**2018**		**2019**
41	Priority Firm - 7(b) Loads.......................................	$	5,288,593	$	5,294,207
42	Industrial Firm - 7(c) Loads....................................	$	37,929	$	58,415
43	New Resources - 7(f) Loads....................................	$	1	$	1
44	Surplus Firm - SP Loads...	$	145,461	$	37,264
45	Total...	$	5,471,984	$	5,389,886
46					
47					
48	**General Revenue Credits (/$1000))**		**2018**		**2019**
49					
50	**Transmission..**	**$**	**(7,200)**	**$**	**(7,200)**
51	Miscellaneous Credits (incl. GTA)...................	$	(7,200)	$	(7,200)
52					
53	**Conservation & General Cost Allocators**		**2018**		**2019**
54	Priority Firm - 7(b) Loads.......................................		0.9761		0.9882
55	Industrial Firm - 7(c) Loads....................................		0.0049		0.0072
56	New Resources - 7(f) Loads....................................		0.0000		0.0000
57	Surplus Firm - SP Loads...		0.0189		0.0046
58	Total...		1.0000		1.0000
59					
60	**Transmission Allocation**		**2018**		**2019**
61	Priority Firm - 7(b) Loads.......................................	$	(7,028)	$	(7,115)
62	Industrial Firm - 7(c) Loads....................................	$	(36)	$	(52)
63	New Resources - 7(f) Loads....................................	$	(0)	$	(0)
64	Surplus Firm - SP Loads...	$	(136)	$	(33)
65	Total...	$	(7,200)	$	(7,200)
66					
67	**Allocation of Revenue Requirement**		**2018**		**2019**
68	Priority Firm - 7(b) Loads.......................................	$	5,281,565	$	5,287,092
69	Industrial Firm - 7(c) Loads....................................	$	37,893	$	58,363
70	New Resources - 7(f) Loads....................................	$	1	$	1
71	Surplus Firm - SP Loads...	$	145,325	$	37,231
72	Total...	$	5,464,784	$	5,382,686

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2017 - September 2019
($ 000)

	B	C		D	
4	**Allocation of Revenue Requirement**		**2018**		**2019**
5	Priority Firm - 7(b) Loads................................	$	5,281,565	$	5,287,092
6	Industrial Firm - 7(c) Loads.............................	$	37,893	$	58,363
7	New Resources - 7(f) Loads............................	$	1	$	1
8	Surplus Firm - SP Loads..................................	$	145,325	$	37,231
9	Total...	$	5,464,784	$	5,382,686
10					
11					
12	**General Revenue Credits ($000))**		**2018**		**2019**
13					
14	**New Resources...**	**$**	**-**	**$**	**-**
15	Green Tags (New resources)......................	$	-	$	-
16					
17					
18	**New Resources Cost Allocators**		**2018**		**2019**
19	Priority Firm - 7(b) Loads................................		0.0000		0.0000
20	Industrial Firm - 7(c) Loads.............................		0.2068		0.6105
21	New Resources - 7(f) Loads............................		0.000003		0.000007
22	Surplus Firm - SP Loads..................................		0.7932		0.3895
23	Total...		1.0000		1.0000
24					
25	**New Resources Allocation**		**2018**		**2019**
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**		**2018**		**2019**
33	Priority Firm - 7(b) Loads................................	$	5,281,565	$	5,287,092
34	Industrial Firm - 7(c) Loads.............................	$	37,893	$	58,363
35	New Resources - 7(f) Loads............................	$	0.624	$	0.666
36	Surplus Firm - SP Loads..................................	$	145,325	$	37,231
37	Total...	$	5,464,784	$	5,382,686
38					

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2017 - September 2019
($ 000)

	B		C		D
32	**Allocation of Revenue Requirement**		**2018**		**2019**
33	Priority Firm - 7(b) Loads................................	$	5,281,565	$	5,287,092
34	Industrial Firm - 7(c) Loads.............................	$	37,893	$	58,363
35	New Resources - 7(f) Loads............................	$	0.624	$	0.666
36	Surplus Firm - SP Loads..................................	$	145,325	$	37,231
37	Total..	$	5,464,784	$	5,382,686
39					
40	**General Revenue Credits (/$1000))**		**2018**		**2019**
41					
42	**Conservation..**	**$**	**(8,000)**	**$**	**(8,000)**
43	Energy Efficiency Revenues.......................	$	(8,000)	$	(8,000)
44	Large Project Revenues.............................	$	-	$	-
45					
46	**Conservation & General Cost Allocators**		**2018**		**2019**
47	Priority Firm - 7(b) Loads................................		0.9761		0.9882
48	Industrial Firm - 7(c) Loads.............................		0.0049		0.0072
49	New Resources - 7(f) Loads............................		0.0000001		0.0000001
50	Surplus Firm - SP Loads..................................		0.0189		0.0046
51	Total..		1.0000		1.0000
52					
53	**Conservation Allocation**		**2018**		**2019**
54	Priority Firm - 7(b) Loads................................	$	(7,809)	$	(7,906)
55	Industrial Firm - 7(c) Loads.............................	$	(40)	$	(57)
56	New Resources - 7(f) Loads............................	$	(0.001)	$	(0.001)
57	Surplus Firm - SP Loads..................................	$	(151)	$	(37)
58	Total..	$	(8,000)	$	(8,000)
59					
60	**Allocation of Revenue Requirement**		**2018**		**2019**
61	Priority Firm - 7(b) Loads................................	$	5,273,756	$	5,279,186
62	Industrial Firm - 7(c) Loads.............................	$	37,854	$	58,305
63	New Resources - 7(f) Loads............................	$	0.624	$	0.666
64	Surplus Firm - SP Loads..................................	$	145,174	$	37,194
65	Total..	$	5,456,784	$	5,374,686

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2017 - September 2019
($ 000)

	B		C		D
4	**Allocation of Revenue Requirement**		**2018**		**2019**
5	Priority Firm - 7(b) Loads..	$	5,273,756	$	5,279,186
6	Industrial Firm - 7(c) Loads..	$	37,854	$	58,305
7	New Resources - 7(f) Loads...	$	0.6235	$	0.6655
8	Surplus Firm - SP Loads...	$	145,174	$	37,194
9	Total..	$	5,456,784	$	5,374,686
10					
11	**General Revenue Credits (/$1000))**		**2018**		**2019**
12					
13	**Generation Inputs..**	**$**	**(108,430)**	**$**	**(101,519)**
14					
15	**NR Revenues from ESS energy and capacity charges.........**	**$**	**-**	**$**	**-**
16					
17	**Product Conversion Adustment Revenues...........................**	**$**	**(2,033)**	**$**	**(2,033)**
19					
20	**Conservation & General Cost Allocators**		**2018**		**2019**
21	Priority Firm - 7(b) Loads..		0.9761		0.9882
22	Industrial Firm - 7(c) Loads..		0.0049		0.0072
23	New Resources - 7(f) Loads...		0.0000001		0.0000001
24	Surplus Firm - SP Loads...		0.0189		0.0046
25	Total..		1.0000		1.0000
26					
27	**Gen Inputs & Wind Integration Credit Allocation**		**2018**		**2019**
28	Priority Firm - 7(b) Loads..	$	(107,826)	$	(102,335)
29	Industrial Firm - 7(c) Loads..	$	(545)	$	(743)
30	New Resources - 7(f) Loads...	$	(0)	$	(0)
31	Surplus Firm - SP Loads...	$	(2,092)	$	(474)
32	Total..	$	(110,463)	$	(103,553)
33					
34	**Allocation of Revenue Requirement**		**2018**		**2019**
35	Priority Firm - 7(b) Loads..	$	5,165,931	$	5,176,851
36	Industrial Firm - 7(c) Loads..	$	37,308	$	57,562
37	New Resources - 7(f) Loads...	$	0.6145	$	0.6570
38	Surplus Firm - SP Loads...	$	143,082	$	36,720
39	Total..	$	5,346,321	$	5,271,134
40					

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2017 - September 2019
($ 000)

	B		C		D
34	**Allocation of Revenue Requirement**		**2018**		**2019**
35	Priority Firm - 7(b) Loads..	$	5,165,931	$	5,176,851
36	Industrial Firm - 7(c) Loads..	$	37,308	$	57,562
37	New Resources - 7(f) Loads...	$	0.6145	$	0.6570
38	Surplus Firm - SP Loads...	$	143,082	$	36,720
39	Total..	$	5,346,321	$	5,271,134
41					
42	**Other Revenue Credits**		**2018**		**2019**
43	Composite Non-Federal RSS Revenue Debit/(Credit)........	$	(1,323)	$	(1,322)
44	Non-Slice Non-Federal RSC Revenue Debit/(Credit).........	$	113	$	113
45					
46					
47	**Conservation & General Cost Allocators**		**2018**		**2019**
48	Priority Firm - 7(b) Loads..		0.9761		0.9882
49	Industrial Firm - 7(c) Loads..		0.0049		0.0072
50	New Resources - 7(f) Loads...		0.0000001		0.0000001
51	Surplus Firm - SP Loads...		0.0189		0.0046
52	Total..		1.0000		1.0000
53					
54	**Non-Federal RSS Revenues**		**2018**		**2019**
55	Priority Firm - 7(b) Loads..	$	(1,181)	$	(1,195)
56	Industrial Firm - 7(c) Loads..	$	(6)	$	(9)
57	New Resources - 7(f) Loads...	$	(0.0001)	$	(0.0001)
58	Surplus Firm - SP Loads...	$	(23)	$	(6)
59	Total..	$	(1,210)	$	(1,209)
60					
61	**Allocation of Revenue Requirement**		**2018**		**2019**
62	Priority Firm - 7(b) Loads..	$	5,164,749	$	5,175,656
63	Industrial Firm - 7(c) Loads..	$	37,302	$	57,554
64	New Resources - 7(f) Loads...	$	0.6144	$	0.6569
65	Surplus Firm - SP Loads...	$	143,059	$	36,715
66	Total..	$	5,345,111	$	5,269,925

Cost of Service Analysis
Calculation and Allocation of Secondary Revenue Credit
Test Period October 2017 - September 2019
(aMW, $ 000)

	C	D	E
4	**General Revenue Credits ($000))**	**2018**	**2019**
9			
10	BPA Secondary Sales Post-Slice (aMW)	1943	1945
11			
12	Slice Percentage	22.7358%	22.7358%
13			
14	Secondary Sales Pre-Slice, aMW	2405	2387
15			
16	aMW to GWh Multiplier	8.760	8.760
17			
18	Secondary Sales Price (Weighted Average, $/MWh)	$ 19.35	$ 19.62
19			
20	BPA Secondary Sales Post-Slice GWh	$ 329,349	$ 334,245
21	CAISO Addition to Secondary (includes other commited sales)	$ 13,181	$ 9,650
22			
23	Firm Surplus Serving Tier 2	$ 6,015	$ -
24	Firm Surplus Sold @ Average Market	$ 30,334	$ -
25	Total Firm Surplus Secondary Sales	$ 36,348	$ -
26			
27	Slice Secondary Sales	$ 94,898	$ 94,364
28			
29	BPA Secondary Sales Pre-Slice $000 (incl. CAISO Adjust, excl. Firm Surplus)	$ 437,427	$ 438,258
30			
35			
36	**Federal Base System + NR Cost Allocators**	**2018**	**2019**
37	Priority Firm - 7(b) Loads..	0.9881	0.9880
38	Industrial Firm - 7(c) Loads..	0.0025	0.0073
39	New Resources - 7(f) Loads..	0.0000	0.0000
40	Surplus Firm - SP Loads..	0.0094	0.0047
41	Total...	1.0000	1.0000
42			
43			
44	**Allocation of Secondary Revenues Credit**	**2018**	**2019**
45	Priority Firm - 7(b) Loads..	$ (432,234)	$ (432,990)
46	Industrial Firm - 7(c) Loads..	$ (1,074)	$ (3,217)
47	New Resources - 7(f) Loads..	$ (0.0177)	$ (0.0367)
48	Surplus Firm - SP Loads..	$ (4,119)	$ (2,052)
49	Total...	$ (437,427)	$ (438,258)
50			
51	**Allocation of Revenue Requirement**	**2018**	**2019**
52	Priority Firm - 7(b) Loads..	$ 4,732,515	$ 4,742,667
53	Industrial Firm - 7(c) Loads..	$ 36,228	$ 54,337
54	New Resources - 7(f) Loads..	$ 0.5967	$ 0.6202
55	Surplus Firm - SP Loads..	$ 138,940	$ 34,663
56	Total...	$ 4,907,684	$ 4,831,667

Cost of Servise Analysis
Calculation and Allocation of FPS Revenue Deficiency Delta
Test Period October 2017 - September 2019
($ 000)

	B		C		D
5	**Allocation of Revenue Requirement**		2018		2019
6	Priority Firm - 7(b) Loads	$	4,732,515	$	4,742,667
7	Industrial Firm - 7(c) Loads	$	36,228	$	54,337
8	New Resources - 7(f) Loads	$	0.5967	$	0.6202
9	Surplus Firm - SP Loads	$	138,940	$	34,663
10	Total	$	4,907,684	$	4,831,667
11					
12	**Firm Surplus and from Other Long-term Sales**	**$**	**(52,307)**	**$**	**(15,959)**
13	WNP3 Settlement	$	(15,959)	$	(15,959)
14	Other Long-Term Contracts	$	-	$	-
15	Firm Surplus Secondary Sales	$	(36,348)	$	-
16					
17	**Calculation of FPS Revenue Deficiency**		2018		2019
18	Surplus Firm - SP Loads	$	138,940	$	34,663
19					
20	**Deficiency**	**$**	**86,633**	**$**	**18,704**
21					
22					
23					
24	**Surplus Deficit Cost Allocators**		2018		2019
25	Priority Firm - 7(b) Loads		0.9950		0.9928
26	Industrial Firm - 7(c) Loads		0.0050		0.0072
27	New Resources - 7(f) Loads		0.0000001		0.0000001
28	Surplus Firm - SP Loads		-1.0000		-1.0000
29	Total		0.0000		0.0000
30					
31	**Surplus Deficit Cost Allocation**		2018		2019
32	Priority Firm - 7(b) Loads	$	86,197	$	18,569
33	Industrial Firm - 7(c) Loads	$	436	$	135
34	New Resources - 7(f) Loads	$	0.0072	$	0.0015
35	Surplus Firm - SP Loads	$	(86,633)	$	(18,704)
36	Total	$	-	$	-
37					
38					
39	**Initial Allocation of Net Revenue Requirement**		2018		2019
40	Priority Firm - 7(b) Loads	$	4,818,712	$	4,761,236
41	Industrial Firm - 7(c) Loads	$	36,664	$	54,472
42	New Resources - 7(f) Loads	$	0.6039	$	0.6218
43	Surplus Firm - SP Loads	$	52,307	$	15,959
44	Total	$	4,907,684	$	4,831,667

Cost of Service Analysis
Calculation of Initial Allocation Power Rates
Test Period October 2017 - September 2019
($ 000, aMW, $/MWh)

	B	C		D	
5	**Initial Allocation of Net Revenue Requirement ($000)**	**2018**		**2019**	
6	Unbifurcated Priority Firm - 7(b) Loads.......................................	$	4,818,712	$	4,761,236
7	Industrial Firm - 7(c) Loads...	$	36,664	$	54,472
8	New Resources - 7(f) Loads...	$	0.6039	$	0.6218
9	Surplus Firm - SP Loads...	$	52,307	$	15,959
10	Total..	$	4,907,684	$	4,831,667
11					
12					
13	**Energy Billing Determinants (aMW)**	**2018**		**2019**	
14					
15	Unbifurcated Priority Firm - 7(b) Loads.......................................		12,002		12,064
16	Industrial Firm - 7(c) Loads...		61		88
17	New Resources - 7(f) Loads...		0.001		0.001
18					
19					
20	**Average Power Rates ($/MWh)**	**2018**		**2019**	
21					
22	Unbifurcated Priority Firm - 7(b) Loads.......................................		45.83		45.05
23	Industrial Firm - 7(c) Loads...		68.94		70.98
24	New Resources - 7(f) Loads...		68.94		70.98

Rate Directive Step
Calculation of DSI VOR and Net Industrial Margin
Test Period October 2017 - September 2019

	B	C	D	E	F	G	H	I
5								
6	Operating Reserves - Supplemental							
8			Embedded Cost $/kW/Mo			$ 7.12		
9								
10	1) Assumed DSI sale					74	aMW	
11	Assumed Wheel Turning Load					6	aMW	
12	Interruptible Load					68		
13	percent of DSI sale that is interruptible					10%		
14	MWs of interruptible load					7	MW	
15								
16	Total value of Operating Reserves per year					$ 582,352	per year	
17	Value converted to $/MWh on total load					$ 0.896	$/MWh	
18								
19					industrial margin	0.754		
20								
21					**net industrial margin**	**$ (0.142)**		

Rate Directive Step
Calculation of Annual Energy Rate Scalars for First IP-PF Link Calculation
Test Period October 2017 - September 2019

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	R	S	T
6		**Load Shaping Rate**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
7		HLH (mills/kWh)	26.74	27.27	30.28	29.30	28.54	23.75	19.67	16.63	17.71	24.66	28.11	27.94				
8		LLH (mills/kWh)	22.49	24.74	26.60	23.94	23.94	20.80	17.54	11.25	9.31	19.05	22.61	22.19				
9		Demand Rate ($/kW/mo)	10.45	10.65	11.83	11.45	11.15	9.28	7.68	6.49	6.92	9.63	10.98	10.91				
10																		
11																		
12		**Unbifurcated PF+NR Load**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			**2018**	
13	**2018**	HLH	4839	5698	6198	5987	5332	5499	4742	5180	4853	4982	5307	4694			Energy (GWH)	105137
14		LLH	3115	3897	4416	4176	3500	3527	3115	3363	2976	3374	3146	3219			Allocated Cost	**$ 4,832,558**
15		Demand	512	495	932	1060	585	969	643	580	618	644	904	585			Rate Scalar	**21.69**
16		Revenue at marginal Rates	$ 204,794	$ 257,106	$ 316,170	$ 287,530	$ 242,510	$ 212,967	$ 152,881	$ 127,731	$ 117,934	$ 193,314	$ 230,231	$ 208,990		**$ 2,552,158**		
17			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			**2019**	
18	**2019**	HLH	4994	5781	6287	6079	5411	5507	4913	5107	4711	5132	5401	4781			Energy (GWH)	105684
19		LLH	3043	3906	4430	4199	3512	3615	3037	3306	2897	3281	3141	3214			Allocated Cost	**$ 4,782,123**
20		Demand	594	502	938	1070	619	792	727	530	520	724	829	543			Rate Scalar	**20.93**
21		Revenue at marginal Rates	$ 208,186	$ 259,650	$ 319,290	$ 290,894	$ 245,431	$ 213,356	$ 155,503	$ 125,558	$ 113,995	$ 196,016	$ 231,911	$ 210,843		**$ 2,570,633**		
43																		
50																		
51		**IP Load**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			**2018**	
52	**2018**	HLH	10	9	9	9	9	37	36	36	35	36	38	33			Energy (GWH)	532
53		LLH	7	7	8	8	7	29	27	29	28	29	27	30			Allocated Cost	**$ 22,819**
54		Demand	0	0	0	0	0	0	0	0	0	0	0	0			Rate Scalar	**21.55**
55		Revenue at marginal Rates	$ 426	$ 429	$ 483	$ 458	$ 402	$ 1,461	$ 1,188	$ 926	$ 880	$ 1,436	$ 1,680	$ 1,589		**$ 11,360**		
56			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			**2019**	
57	**2019**	HLH	38	35	35	36	34	37	36	36	35	36	38	33			Energy (GWH)	767
58		LLH	28	28	31	29	25	29	27	29	28	29	27	30			Allocated Cost	**$ 33,585**
59		Demand	0	0	0	0	0	0	0	0	0	0	0	0			Rate Scalar	**20.78**
60		Revenue at marginal Rates	$ 1,632	$ 1,655	$ 1,864	$ 1,760	$ 1,563	$ 1,461	$ 1,188	$ 926	$ 880	$ 1,436	$ 1,680	$ 1,589		**$ 17,636**		

Rate Directive Step
Calculation of Monthly Energy Rate Scalars for First IP-PF Link Calculation
Test Period October 2017 - September 2019
($/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)		26.74	27.27	30.28	29.30	28.54	23.75	19.67	16.63	17.71	24.66	28.11	27.94				
7	LLH (mills/kWh)		22.49	24.74	26.60	23.94	23.94	20.80	17.54	11.25	9.31	19.05	22.61	22.19				
8	Demand Rate ($/kW/mo)		10.45	10.65	11.83	11.45	11.15	9.28	7.68	6.49	6.92	9.63	10.98	10.91				
9																		
10																		
11	**Unbifurcated PF/NR**		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
12	**2018**	HLH	48.43	48.96	51.97	50.99	50.23	45.44	41.36	38.32	39.40	46.35	49.80	49.63				**2018**
13		LLH	44.18	46.43	48.29	45.63	45.63	42.49	39.23	32.94	31.00	40.74	44.30	43.88				**21.69**
14		Demand	10.45	10.65	11.83	11.45	11.15	9.28	7.68	6.49	6.92	9.63	10.98	10.91				**Scalar**
15			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
16	**2019**	HLH	47.67	48.20	51.21	50.22	49.47	44.68	40.60	37.55	38.64	45.58	49.03	48.87				**2019**
17		LLH	43.42	45.67	47.53	44.87	44.87	41.73	38.47	32.18	30.24	39.98	43.54	43.12				**20.93**
18		Demand	10.45	10.65	11.83	11.45	11.15	9.28	7.68	6.49	6.92	9.63	10.98	10.91				**Scalar**
36																		
42																		
43		**IP**	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
44	**2018**	HLH	48.29	48.82	51.83	50.85	50.09	45.30	41.22	38.18	39.26	46.21	49.66	49.49				**2018**
45		LLH	44.04	46.29	48.15	45.49	45.49	42.35	39.09	32.80	30.86	40.60	44.16	43.74				**21.55**
46		Demand	10.45	10.65	11.83	11.45	11.15	9.28	7.68	6.49	6.92	9.63	10.98	10.91				**Scalar**
47			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
48	**2019**	HLH	47.52	48.06	51.06	50.08	49.33	44.54	40.46	37.41	38.49	45.44	48.89	48.73				**2019**
49		LLH	43.27	45.52	47.38	44.72	44.72	41.58	38.32	32.03	30.09	39.83	43.39	42.97				**20.78**
50		Demand	10.45	10.65	11.83	11.45	11.15	9.28	7.68	6.49	6.92	9.63	10.98	10.91				**Scalar**

Rate Directive Step
Calculation of First IP-PF Link Delta
Test Period October 2017 - September 2019
($ 000)

	B	C	D	E	F	G	H
4						**FY 2018**	**FY 2019**
5							
6	1	IP Allocated Costs				36,664	54,472
7	2	IP Revenues @ Net Margin				(76)	(109)
8	3	adjustment				1,385	887
9	4	IP Marginal Cost Rate Revenues				11,360	17,636
10	5	PF/NR Marginal Cost Rate Revenues				2,552,158	2,570,633
11	6	PF/NR Allocated Energy Costs				4,818,713	4,761,236
12	7	Numerator: 1-2-3-((4/5)*6)				13,907	21,030
13	8						
14	9	PF Allocation Factor for Delta				0.999999917	0.999999917
15	10	NR Allocation Factor for Delta				0.000000083	0.000000083
16	11	Total Allocation Factors for Delta				1.000000000	1.000000000
17	12	Denominator: 1.0 + ((9/11)*(4/5))				1.0045	1.0069
18	13						
19	14	DELTA: (7/12)				**13,845**	**20,886**
20							
21						-0.143	-0.143
22							

Rate Directive Step
Reallocation of First IP-PF Link Delta and Recalculation of Rates
Test Period October 2017 - September 2019
($ 000, aMW, $/MWh)

	B	C		D	
5	**Initial Allocation of Net Revenue Requirement)**		**2018**		**2019**
6	Unbifurcated Priority Firm - 7(b) Loads..............................	$	4,818,712	$	4,761,236
7	Industrial Firm - 7(c) Loads...	$	36,664	$	54,472
8	New Resources - 7(f) Loads..	$	0.6039	$	0.6218
9	Surplus Firm - SP Loads..	$	52,307	$	15,959
10	Total..	$	4,907,684	$	4,831,667
11					
12					
13	**First IP-PF Link Delta**	**$**	**13,845**	**$**	**20,886**
14					
15					
16	**7(c)(2) Delta Cost Allocators**		**2018**		**2019**
17	Unbifurcated Priority Firm - 7(b) Loads..............................		0.999999917		0.999999917
18	Industrial Firm - 7(c) Loads...		-1.000000000		-1.000000000
19	New Resources - 7(f) Loads..		0.000000083		0.000000083
20					
21	**7(c)(2) Delta Cost Allocation**		**2018**		**2019**
22	Unbifurcated Priority Firm - 7(b) Loads..............................	$	13,845	$	20,886
23	Industrial Firm - 7(c) Loads...	$	(13,845)	$	(20,886)
24	New Resources - 7(f) Loads..	$	0.001	$	0.002
25	Total..	$	(0)	$	(0)
26					
27	**Cost Allocation After 7c2 Delta ($ 000)**		**2018**		**2019**
28	Unbifurcated Priority Firm - 7(b) Loads..............................	$	4,832,557	$	4,782,122
29	Industrial Firm - 7(c) Loads...	$	22,819	$	33,585
30	New Resources - 7(f) Loads..	$	0.605	$	0.623
31	Surplus Firm - SP Loads..	$	52,307	$	15,959
32	Total..	$	4,907,684	$	4,831,667
33					
34	**Energy Billing Determinants (aMW)**		**2018**		**2019**
35	Unbifurcated Priority Firm - 7(b) Loads..............................		12,002		12,064
36	Industrial Firm - 7(c) Loads...		60.71030468		87.60814007
37	New Resources - 7(f) Loads..		0.001		0.001
38					
39					
40	**Average Power Rates ($/MWh)**		**2018**		**2019**
41					
42	Unbifurcated Priority Firm - 7(b) Loads..............................		45.97		45.25
43	Industrial Firm - 7(c) Loads...		42.91		43.76
44	New Resources - 7(f) Loads..		69.07		71.18
45					
46					
47	Base PF Exchange Rate w/o Transmission Adder...............		**45.61**		

Rate Directive Step
Calculation of IP Floor Calculation
Test Period October 2017 - September 2019

	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]		680	1,091	657	642	1,771	1,299
18	2	IP-83 Rates		4.62	2.21	14.70	12.20	7.34	
19	3	Revenue		3,141	2,412	9,656	7,837	13,002	36,048
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]		27.74					
36	20	Floor Rate (mills/kWh)[8]		20.62					
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 2017 - September 2019

	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				1,299			
20	2	Floor Rate (mills/kWh)				20.62			
21	3	Value of Reserves Credit (mills/kWh)							
22	4	Revenue at Floor Rate Less VOR Credit				26,787	26,787	20.62	
23	5	IP Revenue Under Proposed Rates					56,405	43.41	
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 2017 - September 2019

	B	C	D	E	F
9		**Cost Allocation After 7c2 Delta**	**2018**	**2019**	Total
10		Unbifurcated Priority Firm - 7(b) Loads.............................	$ 4,832,557	$ 4,782,122	$ 9,614,679
11					
12		Exchange Unbifurcated Costs to 7(b) Loads......................	$ 2,076,227	$ 2,044,643	$ 4,120,870
13					
14					
15					
16					
17		**Energy Billing Determinants (aMW)**	**2018**	**2019**	
18		Unbifurcated Priority Firm - 7(b) Loads.............................	5,156	5,158	
19					
20					
21		**Average Power Rates**	**2018**	**2019**	
22					
23		Unbifurcated Priority Firm - 7(b) Loads.............................	45.96	45.25	
24					
25					
26			(GWh)		
27		Two Year PF Public Load T1	118552		
28		Two Year PF Public Load T2	1913		
29		Two Year IOU PF Exchange Load	77841		
30		Two Year COU PF Exchange Load	12515		
31		Total Two-Year Unbifurcated PF Load	210821		
32					
33					
34		T 2 Costs	$ 81,811		
35		T 1 Costs	$ 9,532,869		
36		Total	$ 9,614,679		
37					
45		Total PF Costs Minus PF T2 Costs	$ 9,532,869		
46		Total PF Load Minus PF T2 Load	208,908		
47		COU Base PF w/o Transmission	45.63		
48		Exchange Transmission Adder	4.72		
49		**COU Base PFx**	**50.35**		
50					
51					
52		Two Year COU PF Exchange Load	12515		
53		Two Year Base PF Public Exchange T2 Revenue	$ 571,091		
54					
55		Total Exchange Costs minus COU Exchange Costs	$ 3,549,779		
56		Total IOU Exchange Loads	77,841		
57		IOU Base PF w/o Transmission	45.60		
58		Exchange Transmission Adder	4.72		
59		**IOU Base PFx**	**50.32**		
60					

Table 2.4.9

Rate Directive Step
Calculation of IOU REP Benefits in Rates
Test Period October 2017 - September 2019

	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		$76,537.617		
16					
17					
18	IOU Scheduled Amount		$232,200		
19	Refund Amount*		$76,538		
20	REP Recovery Amount		$308,738		
21					
26					
27					
28			**2018**		**2019**
29			($000)		($000)
30	IOU Unconstrained Benefits	$	812,217	$	812,217
31	REP Recovery Amount	**$**	**308,738**	**$**	**308,738**
32	Rate Protection Delta	$	503,480	$	503,480
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 2017 - September 2019

	B	C	D	E	F	G	H	I	J	K	L
5	**IOU Base PFx**	**50.32**									
6	**COU Base PFx**	**50.35**		**ASCs**			**Exchange Loads**			**Unconstrained Benefits**	
7										(load * (ASC - Base PFx)	
8				**2018**	**2019**		**2018**	**2019**		**2018**	**2019**
9											
10											
11	Avista Corporation	1		54.67	54.67		3,728	3,728		$ 16,206	$ 16,206
12	Idaho Power Company	1		63.09	63.09		6,474	6,474		$ 82,657	$ 82,657
13	NorthWestern Energy,	1		78.46	78.46		665	665		$ 18,707	$ 18,707
14	PacifiCorp	1		79.55	79.55		8,691	8,691		$ 254,001	$ 254,001
15	Portland General Elect	1		75.76	75.76		8,154	8,154		$ 207,411	$ 207,411
16	Puget Sound Energy, I	1		71.13	71.13		11,209	11,209		$ 233,236	$ 233,236
17	Clark Public Utilities	1		56.48	56.48		2,535	2,535		$ 15,534	$ 15,536
18	Franklin	0		0.00	0.00		0	0		$ -	$ -
19	Snohomish County PU	1		52.66	53.99		3,715	3,731		$ 8,574	$ 13,572
31	Total									**$ 836,325**	**$ 841,325**
32											
33									IOU	**$ 812,217**	**$ 812,217**

Rate Directive Step
Calculation of Utility Specific PF Exchange Rates and REP Benefits
Test Period October 2017 - September 2019

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
4	**Initial Allocations**				**FY 2018**	**FY 2019**	**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	1	54.67	50.32	3,728	3,728	3,728	$ 16,206			$ 10,046	$ 1,527	3.10	53.43	$ 4,633
9	Idaho Power Company	1	63.09	50.32	6,474	6,474	6,474	$ 82,657			$ 51,237	$ 7,789	9.12	59.44	$ 23,630
10	NorthWestern Energy, LLC	1	78.46	50.32	665	665	665	$ 18,707			$ 11,596	$ 1,763	20.09	70.42	$ 5,348
11	PacifiCorp	1	79.55	50.32	8,691	8,691	8,691	$ 254,001			$ 157,451	$ 23,935	20.87	71.19	$ 72,615
12	Portland General Electric Company	1	75.76	50.32	8,154	8,154	8,154	$ 207,411			$ 128,570	$ 19,545	18.17	68.49	$ 59,295
13	Puget Sound	1	71.13	50.32	11,209	11,209	11,209	$ 233,236			$ 144,579	$ 21,978	14.86	65.18	$ 66,678
14	Clark Public Utilities	1	56.48	50.35	2,535	2,535	2,535	$ 15,535			$ 9,630		3.80	54.15	$ 5,905
15	Franklin	0	0	0.00	0	0	0	$ -			$ -		0.00	0.00	$ -
16	Snohomish County PUD No 1	1	52.66	50.35	3,715	3,731	3,723	$ 8,592			$ 5,326		1.43	51.78	$ 3,266
17	Total							$ 836,345	$232,200	$76,538	$ 518,436	$76,538			$ 241,371
18															
19	rounding to	4	places =	$120			IOU Σ(g)	$ 812,217	$232,200	$308,738	$ 503,480	IOU Σ(j)		IOU REP	$ 232,200
20							COU Σ(g)	$ 24,127		$9,171	$ 14,956	COU Σ(j)		COU REP	$ 9,171
21															
22	**IOU Reallocations**														
23			**Interim**				**Final**	**Final**	**Final**		**Final**			**FY 2018**	**FY 2019**
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		$ 4,633	$ 2,005	$ 228	$ 2,857	$ 13,350	3.58	53.90370		$ 2,857		Avista	$ 2,857	$ 2,857
28	Idaho Power Company		$ 23,630	$ 10,255	$ -	$ 13,375	$ 69,281	10.70	61.02400		$ 13,376		Idaho Power	$ 13,376	$ 13,376
29	NorthWestern Energy, LLC		$ 5,348	$ -	$ 667	$ 6,015	$ 12,692	19.09	69.41220		$ 6,015		NorthWestern	$ 6,015	$ 6,015
30	PacifiCorp		$ 72,615	$ 8,443	$ 3,578	$ 67,750	$ 186,251	21.43	71.75420		$ 67,750		PacifiCorp	$ 67,750	$ 67,750
31	Portland General Electric Company		$ 59,295	$ -	$ 7,639	$ 66,934	$ 140,477	17.23	67.55110		$ 66,934		Portland	$ 66,934	$ 66,934
32	Puget Sound		$ 66,678	$ -	$ 8,590	$ 75,268	$ 157,967	14.09	64.41520		$ 75,269		Puget Sound	$ 75,269	$ 75,269
33	Total		$ 232,200	$ 20,702	$ 20,702	$ 232,200	$ 580,017				$ 232,200		IOU REP	$ 232,200	$ 232,200
34															
35													Clark	$ 5,905	$ 5,905
36													Franklin	$ -	$ -
37	**IOU Reallocation Adjustments**												Snohomish	$ 3,259	$ 3,273
38			Avista Corporati	o Power Com	Western Energy	PacifiCorp	eneral Electri	Puget Sound	Total				COU REP	$ 9,164	$ 9,178
39			$ 2,005	$ 10,255	$ -	$ 8,443	$ -	$ -					Total REP	$ 241,364	$ 241,379
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			$ 228	$ -				$ 228				Refund Amt	$ 76,538	$ 76,538
42	Idaho Power Company								$ -				REP Cost	$ 317,902	$ 317,916
43	NorthWestern Energy, LLC		$ 82	$ 242		$ 344	$ -	$ -	$ 667						
44	PacifiCorp			$ 3,578	$ -				$ 3,578						
45	Portland General Electric Company		$ 905	$ 2,922	$ -	$ 3,812			$ 7,639						
46	Puget Sound		$ 1,018	$ 3,285	$ -	$ 4,287	$ -		$ 8,590						
47			$ 2,005	$ 10,255	$ -	$ 8,443	$ -	$ -	$ 20,702						

Rate Directive Step
IOU Reallocation Balances
Test Period October 2017 - September 2019

	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	$ 2,004,778	$ 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	$ 19,299
53	NorthWestern Energy, LLC	$ -	$ -	$ -	$ -	$ -
54	PacifiCorp	$ 4,159,844	$ 187,193	$ 4,159,844	$ 68,013	$ 255,206
55	Portland General Electric Company	$ -	$ -	$ -	$ -	$ -
56						
57						

Rate Directive Step
Calculation and Allocation of the Increase in PF Exchange Revenue Requirement Due to REP Settlement
Test Period October 2017 - September 2019

	B		C		D
4	**Cost Allocation After 7c2 Delta**		**2018**		**2019**
5	Priority Firm Public - 7(b) Loads...	$	2,756,331	$	2,737,479
6	Priority Firm Exchange - 7(b) Loads....................................	$	2,076,227	$	2,044,643
7	Industrial Firm - 7(c) Loads...	$	22,819	$	33,585
8	New Resources - 7(f) Loads...	$	0.605	$	0.623
9	Surplus Firm - SP Loads..	$	52,307	$	15,959
10	Total..	$	4,907,684	$	4,831,667
11					
12					
13	**Calc Rate Protection to PFx Rate**		**2018**		**2019**
14	Unconstrained Benefits	$	836,325	$	841,325
15	REP Recovery Amount plus COU Benefits	$	(317,902)	$	(317,916)
16	delta	$	518,424	$	523,409
17					
18					
19	**Allocation Factors**		**2018**		**2019**
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**		**2018**		**2019**
27	Priority Firm Public - 7(b) Loads...	$	(518,424)	$	(523,409)
28	Priority Firm Exchange - 7(b) Loads....................................	$	518,424	$	523,409
29	Industrial Firm - 7(c) Loads...	$	-	$	-
30	New Resources - 7(f) Loads...	$	-	$	-
31	Total..	$	-	$	-
32					
33					
34	**Cost Allocation After Rate Protection to PFx**		**2018**		**2019**
35	Priority Firm Public - 7(b) Loads...	$	2,237,907	$	2,214,070
36	Priority Firm Exchange - 7(b) Loads....................................	$	2,594,650	$	2,568,052
37	Industrial Firm - 7(c) Loads...	$	22,819	$	33,585
38	New Resources - 7(f) Loads...	$	0.605	$	0.623
39	Surplus Firm - SP Loads..	$	52,307	$	15,959
40	Total..	$	4,907,684	$	4,831,667
41					
42					
43	**Energy Billing Determinants (aMW)**		**2018**		**2019**
44	Priority Firm Public - 7(b) Loads...		6,845		6,906
45	Priority Firm Exchange - 7(b) Loads....................................		5,156		5,158
46	Industrial Firm - 7(c) Loads...		61		88
47	New Resources - 7(f) Loads...		0.001		0.001
48					
50					
51	**Average Power Rates**		**2018**		**2019**
52	Priority Firm Public - 7(b) Loads...		37.32		36.60
53	Priority Firm Exchange - 7(b) Loads....................................		62.16		61.55
54	Industrial Firm - 7(c) Loads...		42.91		43.76
55	New Resources - 7(f) Loads...		69.07		71.18

Rate Directive Step
Calculation of PF, IP and NR Rate Contribution to Net REP Benefit Costs
Test Period October 2017 - September 2019

	B	C		D	
25			**2018**		**2019**
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	$	8.83	$	8.83
30	IP Load		532		767
31	NR Load		0		0
32	REP Surcharge Revenue from IP Rate	$	4,693	$	6,773
33	REP Surcharge Revenue from NR Rate	$	0	$	0
34					
35	Amount of REP Recovery remaining after IP/NR REP Surcharge	$	313,208	$	311,143
36	Remaining REP Recovery in PF, IP and NR Rates ($/MWh)	$	5.18	$	5.08
37					
38	Before Reallocation				
39	IP REP Recovery Amount in Rates	$	7,447	$	10,671
40	NR REP Recovery Amount in Rates	$	0	$	0
41					
42	After Reallocation				
43	IP REP Recovery Amount in Rates	$	4,652	$	6,688
44	NR REP Recovery Amount in Rates	$	0	$	0
45					
46					
47	Reallocation that Should be in Rates		**2018**		**2019**
48	Priority Firm Public - 7(b) Loads..	$	310,455	$	307,245
49	Industrial Firm - 7(c) Loads...	$	7,447	$	10,671
50	New Resources - 7(f) Loads..	$	0.123	$	0.122
51		$	317,902	$	317,916
52					
53	Adjustment Necessary to Achieve Reallocation		**2018**		**2019**
54	Priority Firm Public - 7(b) Loads..	$	(4,652)	$	(6,688)
55	Industrial Firm - 7(c) Loads...	$	4,652	$	6,688
56	New Resources - 7(f) Loads..	$	0.077	$	0.076
57		$	(0)	$	(0)
58					
59			**2018**		**2019**
60	PF Contribution to Net REP Benefits $/MWh.............................		5.18		5.08
61	IP Contribution to Net REP Benefits $/MWh.............................		14.00		13.90
62	NR Contribution to Net REP Benefits $/MWh............................		14.00		13.90

Rate Directive Step
Reallocation of Rate Protection Provided by the IP and NR Rates
Test Period October 2017 - September 2019

	B	C		D	
4	**Cost Allocation After Rate Protection Provided by PFx**		**2018**		**2019**
5	Priority Firm Public - 7(b) Loads..	$	2,237,907	$	2,214,070
6	Priority Firm Exchange - 7(b) Loads...	$	2,594,650	$	2,568,052
7	Industrial Firm - 7(c) Loads..	$	22,819	$	33,585
8	New Resources - 7(f) Loads...	$	0.605	$	0.623
9	Surplus Firm - SP Loads...	$	52,307	$	15,959
10	Total..	$	4,907,684	$	4,831,667
11					
12					
13					
14	**Allocation of Rate Protection Provided by IP and NR**		**2018**		**2019**
15	Priority Firm Public - 7(b) Loads..	$	(4,652)	$	(6,688)
16					
17	Industrial Firm - 7(c) Loads..	$	4,652	$	6,688
18	New Resources - 7(f) Loads...	$	0.077	$	0.076
19	Total..	$	(0)	$	(0)
20					
21					
22	**Cost Allocation After Rate Protection Provided by IP and NR**		**2018**		**2019**
23	Priority Firm Public - 7(b) Loads..	$	2,233,255	$	2,207,381
24	Priority Firm Exchange - 7(b) Loads...	$	2,594,650	$	2,568,052
25	Industrial Firm - 7(c) Loads..	$	27,471	$	40,274
26	New Resources - 7(f) Loads...	$	0.682	$	0.700
27	Surplus Firm - SP Loads...	$	52,307	$	15,959
28	Total..	$	4,907,684	$	4,831,667
29					
30					
31	**Energy Billing Determinants (aMW)**		**2018**		**2019**
32	Priority Firm Public - 7(b) Loads..		6,845		6,906
33	Priority Firm Exchange - 7(b) Loads...		5,156		5,158
34	Industrial Firm - 7(c) Loads..		61		88
35	New Resources - 7(f) Loads...		0.001		0.001
36					
38					
39	**Average Power Rates After Rate Protection Reallocations**		**2018**		**2019**
40	Priority Firm Public - 7(b) Loads..		37.24		36.49
41	Priority Firm Exchange - 7(b) Loads...		62.16		61.55
42	Industrial Firm - 7(c) Loads..		51.66		52.48
43	New Resources - 7(f) Loads...		77.82		79.89

Rate Directive Step
Calculation of Annual Energy Rate Scalars for Second IP-PF Link Calculation
Test Period October 2017 - September 2019

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	PQ	R	S	T
5																		
6	**Load Shaping Rate**		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
7	HLH (mills/kWh)		26.74	27.27	30.28	29.30	28.54	23.75	19.67	16.63	17.71	24.66	28.11	27.94				
8	LLH (mills/kWh)		22.49	24.74	26.60	23.94	23.94	20.80	17.54	11.25	9.31	19.05	22.61	22.19				
9	Demand Rate ($/kW/mo)		10.45	10.65	11.83	11.45	11.15	9.28	7.68	6.49	6.92	9.63	10.98	10.91				
10																		
11		**PF+NR Load**	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep			**2018**	
12	**2018**	HLH	2760	3250	3535	3415	3041	3136	2705	2955	2768	2842	3027	2677			Energy (GWH)	59966
13		LLH	1777	2223	2519	2382	1996	2012	1777	1918	1697	1924	1795	1836			Allocated Cost	$ 2,237,813
14		Demand	292	282	532	605	334	553	367	331	352	367	516	334			Rate Scalar	**13.04**
15	Revenue at marginal Rates		$ 116,808	$ 146,645	$ 180,333	$ 163,998	$ 138,319	$ 121,469	$ 87,199	$ 72,853	$ 67,266	$ 110,260	$ 131,316	$ 119,201		$ 1,455,667		
16			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep			**2019**	
17	**2019**	HLH	2859	3309	3599	3480	3097	3153	2812	2924	2697	2938	3092	2737			Energy (GWH)	60498
18		LLH	1742	2236	2536	2404	2011	2069	1738	1892	1658	1878	1798	1840			Allocated Cost	$ 2,213,938
19		Demand	340	288	537	612	355	453	416	304	298	414	475	311			Rate Scalar	**12.27**
20	Revenue at marginal Rates		$ 119,174	$ 148,634	$ 182,774	$ 166,519	$ 140,494	$ 122,134	$ 89,016	$ 71,874	$ 65,255	$ 112,207	$ 132,755	$ 120,695		$ 1,471,534		
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			**2018**	
26	**2018**	HLH	10	9	9	9	9	37	36	36	35	36	38	33			Energy (GWH)	532
27		LLH	7	7	8	8	7	29	27	29	28	29	27	30			Allocated Cost	$ 22,914
28		Demand	0	0	0	0	0	0	0	0	0	0	0	0			Rate Scalar	**21.73**
29	Revenue at marginal Rates		$ 426	$ 429	$ 483	$ 458	$ 402	$ 1,461	$ 1,188	$ 926	$ 880	$ 1,436	$ 1,680	$ 1,589		$ 11,360		
30			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep			**2019**	
31	**2019**	HLH	38	35	35	36	34	37	36	36	35	36	38	33			Energy (GWH)	767
32		LLH	28	28	31	29	25	29	27	29	28	29	27	30			Allocated Cost	$ 33,718
33		Demand	0	0	0	0	0	0	0	0	0	0	0	0			Rate Scalar	**20.96**
34	Revenue at marginal Rates		$ 1,632	$ 1,655	$ 1,864	$ 1,760	$ 1,563	$ 1,461	$ 1,188	$ 926	$ 880	$ 1,436	$ 1,680	$ 1,589		$ 17,636		
35																		

Rate Directive Step
Calculation of Monthly Energy Rate Scalars for Second IP-PF Link Rate Calculation
Test Period October 2017 - Septmentber 2019

	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)		26.74	27.27	30.28	29.30	28.54	23.75	19.67	16.63	17.71	24.66	28.11	27.94				
7	LLH (mills/kWh)		22.49	24.74	26.60	23.94	23.94	20.80	17.54	11.25	9.31	19.05	22.61	22.19				
8	Demand Rate ($/kW/mo)		10.45	10.65	11.83	11.45	11.15	9.28	7.68	6.49	6.92	9.63	10.98	10.91				
9																		
10																		
11		**PFp /NR**	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
12	**2018**	HLH	39.78	40.32	43.32	42.34	41.59	36.80	32.72	29.67	30.75	37.70	41.15	40.99				**2018**
13		LLH	35.53	37.78	39.64	36.98	36.98	33.84	30.58	24.29	22.35	32.09	35.65	35.23				**13.04**
14		Demand	10.45	10.65	11.83	11.45	11.15	9.28	7.68	6.49	6.92	9.63	10.98	10.91				**Scalar**
15			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
16	**2019**	HLH	39.01	39.54	42.55	41.57	40.81	36.02	31.95	28.90	29.98	36.93	40.38	40.22				**2019**
17		LLH	34.76	37.01	38.87	36.21	36.21	33.07	29.81	23.52	21.58	31.32	34.88	34.46				**12.27**
18		Demand	10.45	10.65	11.83	11.45	11.15	9.28	7.68	6.49	6.92	9.63	10.98	10.91				**Scalar**
19																		
20																		
21		**IP**	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
22	**2018**	HLH	48.47	49.00	52.01	51.02	50.27	45.48	41.40	38.35	39.44	46.38	49.83	49.67				**2010**
23		LLH	44.22	46.47	48.33	45.67	45.67	42.53	39.27	32.98	31.04	40.78	44.34	43.92				**21.73**
24		Demand	10.45	10.65	11.83	11.45	11.15	9.28	7.68	6.49	6.92	9.63	10.98	10.91				**Scalar**
25			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
26	**2019**	HLH	47.70	48.23	51.24	50.25	49.50	44.71	40.63	37.58	38.67	45.61	49.06	48.90				**2011**
27		LLH	43.45	45.70	47.56	44.90	44.90	41.76	38.50	32.21	30.27	40.01	43.57	43.15				**20.96**
28		Demand	10.45	10.65	11.83	11.45	11.15	9.28	7.68	6.49	6.92	9.63	10.98	10.91				**Scalar**

Rate Directive Step
Calculation of Second IP-PF Link Delta
Test Period October 2017 - September 2019

	B	C	D	E	F	G	H
4						**FY 2018**	**FY 2019**
5							
6	1	IP Allocated Costs				22,819	33,585
7	2	IP Revenues @ Net Margin				(76)	(109)
8	3	adjustment				874	606
9	4	IP Marginal Cost Rate Revenues				11,360	17,636
10	5	PF/NR Marginal Cost Rate Revenues				1,455,667	1,471,534
11	6	PF Allocated Energy Costs				2,233,256	2,207,382
12	7	Numerator: 1-2-3-((4/5)*6)				4,593	6,634
13	8						
14	9	PF Allocation Factor for Delta				0.999999917	0.999999917
15	10	NR Allocation Factor for Delta				0.000000083	0.000000083
16	11	Total Allocation Factors for Delta				1.000000000	1.000000000
17	12	Denominator: 1.0 + ((9/11)*(4/5))				1.0078	1.0120
18	13						
19	14	DELTA: (7/12)				**4,557**	**6,556**
20							
21						-0.142	-0.142
22							

Rate Directive Step
Reallocation of IP-PF Link Delta and Recalculation of Rates
Test Period October 2017 - September 2019

	B	C	D	E
4	**Cost Allocation After Rate Protection Provided by IP and NR**	**2018**	**2019**	
5	Priority Firm Public - 7(b) Loads..	$ 2,233,255	$ 2,207,381	
6	Priority Firm Exchange - 7(b) Loads...	$ 2,594,650	$ 2,568,052	
7	Industrial Firm - 7(c) Loads..	$ 27,471	$ 40,274	
8	New Resources - 7(f) Loads..	$ 0.682	$ 0.700	
9	Surplus Firm - SP Loads...	$ 52,307	$ 15,959	
10	Total..	$ 4,907,684	$ 4,831,667	
11				
12				
13	IP-PF Link Delta...	$ 4,557	$ 6,556	
14				
15		**2018**	**2019**	
16	Priority Firm Public - 7(b) Loads..	0.99999985	0.99999986	
17	Industrial Firm - 7(c) Loads..	(1.00000000)	(1.00000000)	
18	New Resources - 7(f) Loads..	0.00000015	0.00000014	
19				
20				
21	**Allocation of Second IP-PF Link Delta**	**2018**	**2019**	
22	Priority Firm Public - 7(b) Loads..	$ 4,557	$ 6,556	
23	Priority Firm Exchange - 7(b) Loads...	$ -	$ -	
24	Industrial Firm - 7(c) Loads..	$ (4,557)	$ (6,556)	
25	New Resources - 7(f) Loads..	$ 0.001	$ 0.001	
26	Total..	$ 0	$ 0	
27				
28				
29	**Cost Allocation After Second IP-PF Link**	**2018**	**2019**	
30	Priority Firm Public - 7(b) Loads..	$ 2,237,812	$ 2,213,937	
31	Priority Firm Exchange - 7(b) Loads...	$ 2,594,650	$ 2,568,052	
32	Industrial Firm - 7(c) Loads..	$ 22,914	$ 33,718	
33	New Resources - 7(f) Loads..	$ 0.682	$ 0.701	
34	Surplus Firm - SP Loads...	$ 52,307	$ 15,959	
35	Total..	$ 4,907,684	$ 4,831,667	
36				
37				
38	**Energy Billing Determinants (aMW)**	**2018**	**2019**	
39	Priority Firm Public - 7(b) Loads..	6,845	6,906	
40	Priority Firm Exchange - 7(b) Loads...	5,156	5,158	
41	Industrial Firm - 7(c) Loads..	61	88	
42	New Resources - 7(f) Loads..	0.001	0.001	
43				
45				
46	**Average Power Rates After Second IP-PF Link**	**2018**	**2019**	Average
47	Priority Firm Public - 7(b) Loads..	37.32	36.60	**36.96**
48	Priority Firm Exchange - 7(b) Loads...	62.16	61.55	**61.86**
49	Industrial Firm - 7(c) Loads..	43.09	43.93	**43.51**
50	New Resources - 7(f) Loads..	77.90	80.00	**78.95**

Rate Design Step
REP Benefit Reconciliation
Test Period October 2017 to September 2019

	B	D	E	F	G	H	I	J	K	L
4		**2018**	**2019**	**Avg**				**2018**	**2019**	**Avg**
5	Resource Costs	3,109,594	3,115,409	3,112,502			PFx Alloc Cost	(2,594,650)	(2,568,052)	
6	PFx Revenues	(2,807,853)	(2,781,332)	(2,794,593)			Exch Tmn Cost	(213,203)	(213,279)	
7	REP Benefits	301,741	334,077	317,909				(2,807,853)	(2,781,332)	(2,794,593)
8										
9	**REP Benefits**						**PFx Revenues**			
10	Avista Corporation	2,857	2,857				Avista Corporation	231,734	229,463	
11	Idaho Power Company	13,376	13,376				Idaho Power Company	402,442	398,498	
12	NorthWestern Energy, LLC	6,015	6,015				NorthWestern Energy, LLC	41,328	40,923	
13	PacifiCorp	67,750	67,750				PacifiCorp	540,219	534,925	
14	Portland General Electric Company	66,934	66,934				Portland General Electric Compa	506,856	501,889	
15	Puget Sound Energy, Inc.	75,269	75,269				Puget Sound Energy, Inc.	696,793	689,965	
16	IOU REP	232,200	232,200	232,200			IOU REP	2,419,373	2,395,663	2,407,518
17										
18	Clark Public Utilities	5,905	5,905				Clark Public Utilities	157,576	156,043	
19	Franklin	-	-				Franklin	-	-	
20	Snohomish County PUD No 1	3,259	3,273				Snohomish County PUD No 1	230,904	229,626	
21	COU REP	9,164	9,178	9,171			COU REP	388,480	385,669	387,074
22										
23	Refund Amounts	76,538	76,538				Refund Amounts	(76,538)	(76,538)	
24	Total REP	317,902	317,916	317,909			Total REP	2,807,853	2,781,332	2,794,593
25				(0)				0	0	0
26										
27	**For Slice True-Up**									100.00%
28	IOU REP	232,200	232,200							
29	COU REP	9,164	9,178							
30	Refund Amounts	76,538	76,538							
31	Total REP	317,902	317,916							

Table 2.5.1

Rate Design Study
Allocated Cost and Unit Cost Priority Firm Rates
Test Period October 2017 - September 2019

	B	C	D	E	F	G	H	I	J	K	L
11											
12			**A**	**B**	**C**		**PF Public**		**PF Exchange**		
13			**ALLOCATED**	**UNIT**	**PERCENT**		**ALLOCATED**		**ALLOCATED**		
14			**COSTS**	**COSTS**	**CONTRIBUTION**		**COSTS**		**COSTS**		
15		GENERATION ENERGY	($ Thousands)	(Mills/kWh)	(Percent)						
16											
17		Federal Base System									
18		Hydro	1,651,654	7.834	17.18%		943,765	7.834	707,889	7.834	
19		Fish & Wildlife	726,018	3.444	7.55%		414,851	3.444	311,167	3.444	
20		Trojan	2,000	0.009	0.02%		1,143	0.009	857	0.009	
21		WNP #1	102,203	0.485	1.06%		58,400	0.485	43,804	0.485	
22		WNP #2	1,120,828	5.316	11.66%		640,448	5.316	480,380	5.316	
23		WNP #3	268,297	1.273	2.79%		153,307	1.273	114,990	1.273	
24		System Augmentation	12,211	0.058	0.13%		6,977	0.058	5,234	0.058	
25		Balancing Power Purchases	114,893	0.545	1.19%		65,651	0.545	49,242	0.545	
26		Tier 2 Costs	81,811	0.388	0.85%		46,747	0.388	35,064	0.388	
27		Total Federal Base System	4,079,915	19.353	42.43%		2,331,289	19.353	1,748,626	19.353	
28		New Resources									
29		Gross Residential Exchange	5,649,884	26.799	58.76%		3,228,379	26.799	2,421,505	26.799	
30		Conservation	314,449	1.492	3.27%		179,678	1.492	134,771	1.492	
31		BPA Programs	223,944	1.062	2.33%		127,963	1.062	95,981	1.062	
32		Power Transmission	419,062	1.988	4.36%		239,455	1.988	179,607	1.988	
33		TOTAL COSA ALLOCATIONS	10,687,255	50.694	111.16%		6,106,764	50.694	4,580,491	50.694	
34											
35											
36		Nonfirm Excess Revenue Credit	(865,224)	-4.104	-9.00%		(494,394)	-4.104	(370,830)	-4.104	
37		Low Density Discount Expense	127,236	0.604	1.32%		72,703	0.604	54,532	0.604	
38		Other Revenue Credits	(474,085)	-2.249	-4.93%		(270,895)	-2.249	(203,190)	-2.249	
39		Irrigation Rate Mitigation Expense									
40		SP Revenue Surplus/Dfct Adj.	104,766	0.497	1.09%		59,864	0.497	44,902	0.497	
41		7(c)(2) Delta Adjustment	34,732	0.165	0.36%		19,846	0.165	14,886	0.165	
42		7(c)(2) Floor Rate Adjustment									
43		TOTAL RATE DESIGN ADJUSTMENTS	(1,072,575)	-5.088	-11.16%		(612,876)	-5.088	(459,699)	-5.088	
44											
45		Total Generation	9,614,679	**45.6059**	100.00%		5,493,888	**45.61**	4,120,792	**45.61**	
46											
47											
48		REP Settlement Rate Protection Adjustment					(1,053,173)	-8.743	1,041,833	1,041,833	
49		7(b)(2) - 7(c)(2) Industrial Adjustment					11,113	0.092	0	0.000	
50		Total Generation					**4,451,828**	**36.96**	5,162,625	**57.14**	
51											
52		Total Transmission							426,483	4.720	
53									5,589,107	**61.86**	
54											

Table 2.5.2

Rate Design Study
Allocated Cost and Unit Costs for Industrial Firm Power Rate
Test Period October 2017 - September 2019

	C	D	E	F
13		**ALLOCATED**	**UNIT**	**PERCENT**
14		**COSTS**	**COSTS**	**CONTRIBUTION**
15	GENERATION ENERGY	($ Thousands)	(Mills/kWh)	(Percent)
16				
17	Federal Base System			
18	Hydro			
19	Fish & Wildlife			
20	Trojan			
21	WNP #1			
22	WNP #2			
23	WNP #3			
24	System Augmentation			
25	Balancing Power Purchases			
26	Total Federal Base System			
27	New Resources	45,953	35.368	81.14%
28	Gross Residential Exchange	44,447	34.210	78.48%
29	Conservation	1,924	1.481	3.40%
30	BPA Programs	1,438	1.107	2.54%
31	Power Transmission	2,581	1.986	4.56%
32	TOTAL COSA ALLOCATIONS	96,343	74.152	170.11%
33				
34	Nonfirm Excess Revenue Credit	(4,291)	-3.302	-7.58%
35				
36	Other Revenue Credits	(1,487)	-1.145	-2.63%
37				
38	SP Revenue Surplus/Dfct Adj.	571	0.439	1.01%
39	7(c)(2) Delta Adjustment	(34,732)	-26.732	-61.33%
40	7(c)(2) Floor Rate Adjustment			
41	TOTAL RATE DESIGN ADJSTMTS	(39,939)	-30.739	-70.52%
42	Total Generation	56,405	43.412	99.59%
43				
55	Total Allocated & Adjusted Costs	56,405	43.412	99.59%
56				
57	Settlement Adjustments			
58	REP Settlement Rate Protection Adjustment	11,340	8.728	20.02%
59	7(b)(2) - 7(c)(2) Industrial Adjustment	(11,113)	-8.553	-19.62%
60		56,632	**43.59**	100.00%
61				
62	Billing Determinants:			
63	Energy (GwH)	1,299		

Table 2.5.3

Rate Design Study
Allocated Costs and Unit Costs for New Resources Firm Power Rate
Test Period October 2017 - September 2019

	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			
18	Fish & Wildlife			
19	Trojan			
20	WNP #1			
21	WNP #2			
22	WNP #3			
23	System Augmentation			
24	Balancing Power Purchases			
25	Total Federal Base System			
26	New Resources	0.5819	33.214	42.07%
27	Gross Residential Exchange	0.6301	35.962	45.55%
28	Conservation	0.0261	1.492	1.89%
29	BPA Programs	0.0534	3.049	3.86%
30	TOTAL COSA ALLOCATIONS	1.2915	73.717	93.37%
31				
32	Nonfirm Excess Revenue Credit	(0.0544)	-3.105	-3.93%
33				
34	Other Revenue Credits	(0.0201)	-1.150	-1.46%
35				
36	SP Revenue Surplus/Dfct Adj.	0.0087	0.498	0.63%
37	7(c)(2) Delta Adjustment	0.0029	0.165	0.21%
38	7(c)(2) Floor Rate Adjustment			
39	TOTAL RATE DESIGN ADJSTMTS	(0.0629)	-3.593	-4.55%
40	Total Generation Energy	1.2286	70.124	88.82%
41				
50				
51	Total Allocated & Adjusted Costs	1.2286	70.124	88.82%
52	Settlement Adjustments			
53	REP Settlement Rate Protection Adjustment	0.1530	8.731	11.06%
54	7(b)(2) - 7(c)(2) Industrial Adjustment	0.0016	0.092	0.12%
55				
56	Total With 7(b)(2) Adjustments	1.3832	**78.95**	100.00%
57				
58	Billing Determinant / Energy (GWh)	0.01752		

Table 2.5.4

Rate Design Study
Resource Cost Percent Contribution to Load Pools
Test Period October 2017 - September 2019

	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	2,331,289	3,228,379		5,559,668		41.93%	58.07%		100.00%
18	Priority Firm - Exchange	1,748,626	2,421,505		4,170,131		41.93%	58.07%		100.00%
19	Priority Firm Power - Total	4,079,915	5,649,884		9,729,799		41.93%	58.07%		100.00%
20	Industrial Firm Power		44,447	45,953	90,400			49.17%	50.83%	100.00%
21	New Resources Firm		0.630	1	1			51.99%	48.01%	100.00%
22	Firm Power Products and Services		105,930	65,592	171,522			61.76%	38.24%	100.00%
23										
24										
25	**TOTALS**	**4,079,915**	**5,800,261**	**111,545**	**9,991,722**		**40.83%**	**58.05%**	**1.12%**	**100.00%**
26										
27					212,120					
28										
29			Average Cost of Resources		47.10					
30										
31			Average Cost to Serve Load Growth		41.41					

SECTION 3: RATE DESIGN

This page intentionally left blank.

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 RAM2018. 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 properly.

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 T1SFCO from the RHWM to 7(i) processes, and values the difference at the system augmentation price when 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 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 Load Shaping True-up Rate (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
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 3.6
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 3.7
Tier 2 VR1-2014 Rate Costing Table
Costing table used to calculate the VR1-2014 rates for each year of the rate period.

Table 3.8
Tier 2 VR1-2016 Rate Costing Table
Costing table used to calculate the VR1-2016 rates for each year of the rate period.

Table 3.9
Tier 2 Overhead Adder Inputs
Table lists inputs to Tier 2 Overhead Cost Adder.

Table 3.10
Tier 2 Rate Revenues
Table summarizes the Tier 2 rate-related revenues and adjustments to Tier 1 cost pools.

Table 3.11
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 3.12
Tier 2 Rate Inputs
Table lists prices used for Tier 2 surplus credit or deficit debit.

Table 3.13
Rates and Charges for RSS and Related Services in FY 2016 and FY 2017
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 what service, during which year, and for what 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 3.14
Calculation of the Product Conversion Charge
This table shows the calculation of the Product Conversion Charge for BP-18 associated with unexpected Regional Cooperation Debt savings in FY 2014-2015, and customers electing to switch PF products under the Regional Dialogue contracts.

Rate Design Step
Cost Aggregation under Tiered Rate Methodology
Test Period October 2017 to September 2019

	A	B	C	D	E	G	H
4						**2018**	**2019**
5		**Composite**					
6			Federal Base System				
7				Hydro			
8					Operating Expense	616,272	619,115
9					Interest	76,103	79,386
10					MRNR	175,221	53,815
11				Fish & Wildlife			
12					Operating Expense	335,036	336,793
13					Interest	9,560	10,984
14					MRNR	22,009	7,446
15				Trojan		1,000	1,000
16				WNP #1		60,931	41,272
17				Columbia Generating Station		454,883	665,946
18				WNP #3		236,158	32,139
19				Augmentation		-	12,211
20			Residentail Exchange Program				
21				REP Net Cost		317,902	317,916
22				Program Support		1,008	733
23				Settlement Interest Accrual		-	-
24			NewResources				
25				Cowlitz		12,250	13,293
26				Idaho		-	-
27				Tier 1 Aug (Klondike III)		12,393	12,503
28				Other		32,565	33,231
29			Conservation				
30				Operating Expense		137,109	136,935
31				Interest		8,539	8,635
32				MRNR		19,660	5,853
33			BPAPrograms				
34				Operating Expense		152,265	137,880
35				Interest		1,460	1,282
36				MRNR		3,362	869
37			Transmission				
38				Transmission and Ancillary Services		48,588	47,850
39				General Transfer Agreements		91,759	92,516
40			Nonslice Interest and MRNR Allocated to Cost Pools				
41				Interest on BPA fund Credit to Nonslice		(1,151)	(1,576)
42				Accrual Revenue (MRNR Adjustment)		-	-
43			**Total**			**2,824,880**	**2,668,029**

Rate Design Step
Cost Aggregation under Tiered Rate Methodology
Test Period October 2017 to September 2019

	A	B	C	D	E	G	H
4						2018	2019
44		**Non-Slice**					
45			FBS				
46				Balancing Purchases from Risk Mod		21,877	15,743
47				Balancing in Revenue Requirement		38,607	38,666
48				PNRR			
49					Hydro	15,911	15,832
50					Fish & Wildlife	1,999	2,191
51			Conservation				
52				PNRR		1,785	1,722
53			BPAPrograms				
54				Hedging Mitigation		-	-
55				RCD Expense Offset Non-Slice		(70,000)	-
56				PNRR		305	256
57			Transmission				
58				Transmission and Ancillary Services		74,698	71,274
59				Third-party T&A		-	-
60			Nonslice Interest and MRNR				
61				BPA Fund		1,151	1,576
62				Non-Slice MRNR Adjustment		-	-
63			**Total**			**86,333**	**147,259**
64		**Slice**					
65			BPAPrograms				
66				Other Slice Costs		-	-
67			**Total**			-	-
68		**Tier 2**					
69			FBS				
70				Tier 2 Purchase Costs		37,050	42,112
71				Tier 2 Rate Design Adjustments		1,215	1,434
72				Tier 2 Other Costs		-	-
73			**Total**			**38,265**	**43,545**

Table 3.1.1

Rate Design Step
Cost Aggregation under Tiered Rate Methodology
Test Period October 2017 to September 2019

	A	B	C	D	E	G	H
4						**2018**	**2019**
74		**Rate Direct/Design Adjustments**					
75			Credits Allocated Against Cost Pools				
76				FBS (excluding T2 Adjustment)		(114,601)	(112,955)
77				Contract Obligations		(395)	(395)
78				New Resources		-	-
79				Conservation		(8,000)	(8,000)
80				BPAPrograms		-	-
81				Transmission		(7,200)	(7,200)
82							
83			Secondary Energy Credit (includes pre-sale and Slice)			(437,427)	(438,258)
84			Firm Surplus Secondary Sales			(36,348)	-
85			Generation Inputs Credit			(108,430)	(101,519)
86			NR Revenues from ESS services			-	-
87			Product Conversion Adjustment Revenues			(2,033)	(2,033)
88			Composite FPS Revenues (excl. secondary)			(15,959)	(15,959)
89			Non-Slice FPS Revenues (excl. secondary)			(565)	(129)
90							
91			Low Density Discount			41,010	41,971
92			Irrigation Rate Mitigation Costs			22,128	22,128
93							
94			Composite Augmentation RSS Revenue Debit/(Credit)			(1,619)	(1,619)
95			Composite Tier 2 RSS Revenue Debit/(Credit)			(139)	(161)
96			Composite Tier 2 Rate Design Adjustment Debit/(Credit)			(1,076)	(1,273)
97			Composite Non-Federal RSS Revenue Debit/(Credit)			(1,323)	(1,322)
98			Non-Slice Augmentation RSC Revenue Debit/(Credit)			(726)	(726)
99			Non-Slice Tier 2 RSC Revenue Debit/(Credit)			-	-
100			Non-Slice Tier 2 Rate Design Debit/(Credit)			-	-
101			Non-Slice Non-Federal RSC Revenue Debit/(Credit)			113	113
102							
103			Firm Surplus and Secondary Credit (from unused RHWM)			(30,246)	(13,324)
104			Demand Revenue			48,363	47,951
105			Load Shaping Revenue			22,842	31,941
106							

Table 3.1.2

Rate Design Step
Unused RHWM (net) Credit Computation
Test Period October 2017 to September 2019

	B	C		D	
4			2018		2019
5	Secondary (aMW)		2,405		2,387
6	T1SFCO (aMW)		6,879		6,879
7	RHWM Augmentation (aMW)		65		65
8	RP Augmentation (aMW)		-		-
9	System Augmentation (aMW)		-		52
10	Firm Surplus (aMW)		182		0
11	IP and NR Loads contributing to avoided cost		63		90
12					
13	Value of Secondary	$	19.35	$	19.62
14	Value of T1SFCO ($/MWh)	$	23.15	$	23.15
15	Value of Augmentation	$	27.26	$	26.99
16					
17	Secondary (MWh)		21,068,280		20,913,965
18	T1SFCO (MWh)		60,263,710		60,263,710
19	RHWM Augmentation (MWh)		573,141		573,141
20	IP and NR Loads (MWh)		548,110		790,947
21					
22	Unused RHWM (MWh)		2,034,238		1,675,234
23					
24	Unused Secondary		704,473		575,897
25	Unused T1SFCO		2,015,074		1,659,452
26	Unused Augmentation		19,164		15,782
27					
28	Value of Unused	$	60,807,887	$	50,145,405
29	Value of System Augmentation not Purchased	$	30,562,264	$	36,821,478
30					
31	Net Credit/(Cost)	$	30,245,623	$	13,323,927
32					
33	$/MWh value of Unused RHWM	**$**	**29.91**		

Table 3.1.3

Rate Design Step
Slice Return of Network Losses Adjustment
Test Period October 2017 - September 2019

	B	C	D
4		**2018**	**2019**
5	Non Slice Loads (MWh)	45,075,185	45,778,106
6	Loss Percent Assumption	1.90%	1.90%
7	Implied Non Slice Losses	856,429	869,784
8	Average Slice&Non-Slice Tier 1 Rate	36.86	36.86
9	Implied Cost/Credit ($1000)	31,568	32,060

Table 3.1.4

Rate Design Step
Balancing Augmentation Adjustment for Change to the Equivalent Tier 1 System Firm Critical Output
Test Period October 2017 - September 2019

	A	B	C	E	F	G
4				**2018**	**2019**	
5		**Table 3.1**				
6			Regulated	6,259	6,255	
7			Independent	348	348	
8		**Table 3.2**				
9			Ashland Solar Project	0	0	
10			Columbia Generating Station	1,100	937	
11			Condon Wind Project	12	12	
12			Dworshak/Clearwater Small Hydropower	3	3	
13			Elwha Hydro	-	-	
14			Foote Creek 1	4	4	
15			Foote Creek 2	-	-	
16			Foote Creek 4	4	4	
17			Fourmile Hill Geothermal	-	-	
18			Georgia-Pacific Paper (Wauna)	-	-	
19			Glines Canyon Hydro	-	-	
20			Klondike I	6	6	
21			Stateline Wind Project	21	21	
22		**Table 3.3**				
23			Canadian Entitlement	136	137	
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	4	4	
35		**Table 3.4**				
36			USBR Pump Load	180	180	
37			Canadian Entitlement	468	462	
38			Non-Treaty Storage	9	9	
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	46	46	
48			PacifiCorp	4	4	
49			PacifiCorp (So Idaho)	-	-	
50			Upper Baker	1	1	
51			Dittmer Station Service	9	9	
52						
53			Federal Power Deliveries			
54			Preference	6,845	6,906	
55			Tier 2	101	117	
56			Net Preference	6,744	6,789	
57			Industrial	61	88	
58			New Resource	0	0	
59			Intraregional Transfer	58	58	
60			FBS Obligation	659	653	
61			Seasonal or Capacity Exchange	31	11	
62			Conservation Augmentation	-	-	
63			Transmission Losses Before Slice Return	231	233	
64			Slice Return of Losses	30	30	
65			Transmission Losses After Slice Return	201	203	
66						
67		**Annual T1SFCO**		6,978	6,816	
68		**RHWM Process T1SFCO (annual)**		6,958	6,801	
69		**Difference**		20	15	
70		**Augmentation Price (Secondary in the case Augmentation is zero)**		$ 19.35	$ 26.99	
71		**Hours**		8,760	8,760	
72		**Credit/Cost to Balancing Augmentation**		$ 3,382,425	$ 3,588,621	

Table 3.1.5

Rate Design Step
Calculation of Load Shaping and Demand Revenuest
Test Period October 2017 - September 2019

	B	E	F	G	H	I	J	K	L
5	**2018**	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-17	292,202	$ 10.45	$ 3,053,507	(219,678)	162,196	$ 26.74	$ 22.49	$ (2,226,399)
7	Nov-17	282,267	$ 10.65	$ 3,006,140	(319,419)	116,794	$ 27.27	$ 24.74	$ (5,821,070)
8	Dec-17	531,530	$ 11.83	$ 6,288,000	53,349	405,696	$ 30.28	$ 26.60	$ 12,406,934
9	Jan-18	604,527	$ 11.45	$ 6,921,836	517,406	568,822	$ 29.30	$ 23.94	$ 28,777,587
10	Feb-18	333,545	$ 11.15	$ 3,719,032	500,980	517,528	$ 28.54	$ 23.94	$ 26,687,592
11	Mar-18	552,965	$ 9.28	$ 5,131,518	159,411	276,454	$ 23.75	$ 20.80	$ 9,536,245
12	Apr-18	366,859	$ 7.68	$ 2,817,477	(174,402)	180,048	$ 19.67	$ 17.54	$ (272,436)
13	May-18	330,783	$ 6.49	$ 2,146,780	(1,268,779)	(473,841)	$ 16.63	$ 11.25	$ (26,430,507)
14	Jun-18	352,389	$ 6.92	$ 2,438,533	(673,655)	(141,924)	$ 17.71	$ 9.31	$ (13,251,740)
15	Jul-18	367,251	$ 9.63	$ 3,536,630	(134,893)	332,348	$ 24.66	$ 19.05	$ 3,004,775
16	Aug-18	515,719	$ 10.98	$ 5,662,599	(346,552)	121,744	$ 28.11	$ 22.61	$ (6,988,953)
17	Sep-18	333,770	$ 10.91	$ 3,641,434	(235,269)	179,953	$ 27.94	$ 22.19	$ (2,580,269)
18	**Total**			**$ 48,363,485**		$ 104,317			**$ 22,841,757**
19									
20	**2019**	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-18	339,994	$ 10.45	$ 3,552,935	(154,380)	119,350	$ 26.74	$ 22.49	$ (1,443,938)
22	Nov-18	287,552	$ 10.65	$ 3,062,430	(296,242)	118,915	$ 27.27	$ 24.74	$ (5,136,571)
23	Dec-18	536,731	$ 11.83	$ 6,349,526	83,613	410,694	$ 30.28	$ 26.60	$ 13,456,238
24	Jan-19	612,246	$ 11.45	$ 7,010,215	553,738	574,969	$ 29.30	$ 23.94	$ 29,989,282
25	Feb-19	354,529	$ 11.15	$ 3,953,003	537,043	521,707	$ 28.54	$ 23.94	$ 27,816,851
26	Mar-19	453,338	$ 9.28	$ 4,206,975	148,613	324,474	$ 23.75	$ 20.80	$ 10,278,633
27	Apr-19	416,067	$ 7.68	$ 3,195,396	(94,667)	132,768	$ 19.67	$ 17.54	$ 466,637
28	May-19	303,650	$ 6.49	$ 1,970,688	(1,244,928)	(482,863)	$ 16.63	$ 11.25	$ (26,135,363)
29	Jun-19	297,652	$ 6.92	$ 2,059,749	(687,824)	(109,820)	$ 17.71	$ 9.31	$ (13,203,792)
30	Jul-19	414,213	$ 9.63	$ 3,988,871	(55,742)	280,657	$ 24.66	$ 19.05	$ 3,971,917
31	Aug-19	474,529	$ 10.98	$ 5,210,333	(313,298)	111,817	$ 28.11	$ 22.61	$ (6,278,616)
32	Sep-19	310,800	$ 10.91	$ 3,390,829	(202,969)	172,611	$ 27.94	$ 22.19	$ (1,840,712)
33	**Total**			**$ 47,950,949**		$ 448,234			**$ 31,940,568**

Rate Design Step
Calculation of PF Preference Rates under Tiered Rate Methodology
Test Period October 2017 - September 2019

	B	C		D		E	
5	**Costs ($000)**		**2018**		**2019**		**Rate Period**
6	**Composite**	$	2,824,880	$	2,668,029	$	5,492,909
7	**Non-Slice**	$	86,333	$	147,259	$	233,591
8	**Slice**	$	-	$	-	$	-
9	**Tier 2**	$	38,265	$	43,545	$	81,811
13							
14	**Revenues from Rate Pools to Composite Cost Pool**		**2018**		**2019**		**Rate Period**
15	DSI Revenue Credit	**$**	**(23,140)**	**$**	**(33,392)**	**$**	**(56,531)**
16	Exchange Revenues	**$**	**-**	**$**	**-**	**$**	**-**
17	New Resource Revenues	**$**	**(0.68)**	**$**	**(0.70)**	**$**	**(1)**
18	FPS Revenues	$	(15,959)	$	(15,959)	$	(31,917)
19	Non-Federal RSS Revenues	$	(1,323)	$	(1,322)	$	(2,645)
20	Other Credits	$	(238,626)	$	(230,069)	$	(468,695)
21	Tiered Rate Elements					$	-
22	Unused RHWM Credit Reallocation	$	(30,246)	$	(13,324)	$	(43,570)
23	Balancing Augmentation Adjustment Reallocation	$	1,364	$	(8,511)	$	(7,147)
24	Composite Augmentation RSS Revenue Debit/(Credit)	$	(1,619)	$	(1,619)	$	(3,238)
25	Composite Tier 2 RSS Revenue Debit/(Credit)	$	(139)	$	(161)	$	(300)
26	Composite Tier 2 Rate Design Adjustment Debit/(Credit)	$	(1,076)	$	(1,273)	$	(2,349)
27	Transmission Losses Adjustment Reallocation	$	(31,568)	$	(32,060)	$	(63,628)
28	Total	$	(342,332)	$	(337,690)	$	(680,022)
29							
30	**Rate Discount Costs Applied to Composite Pool**		**2018**		**2019**		**Rate Period**
31	Irigation Rate Discout Costs	$	22,128	$	22,128	$	44,255
32	Low Density Discount Costs	$	41,010	$	41,971	$	82,980
33	Total	$	63,137	$	64,098	$	127,236
34							
35			**2018**		**2019**		**Rate Period**
36	**Composite**	$	2,545,685	$	2,394,437	$	4,940,123

Rate Design Step
Calculation of PF Preference Rates under Tiered Rate Methodology
Test Period October 2017 - September 2019

	B	C		D		E	
5	**Costs ($000)**		**2018**		**2019**	**Rate Period**	
6	**Composite**	$	2,824,880	$	2,668,029	$	5,492,909
7	**Non-Slice**	$	86,333	$	147,259	$	233,591
8	**Slice**	$	-	$	-	$	-
9	**Tier 2**	$	38,265	$	43,545	$	81,811
37							
38	**Non-Slice Revenues, Credits, and Costs**		**2018**		**2019**	**Rate Period**	
39	Secondary Revenue	$	(378,878)	$	(343,895)	$	(722,772)
40	Unused RHWM Credit Reallocation	$	30,246	$	13,324	$	43,570
41	Product Conversion Adjustment Revenues	$	(2,033)	$	(2,033)	$	(4,066)
42	Other Long Term Contract Revenues	$	(565)	$	(129)	$	(694)
43	Non-federal RSC Revenues	$	113	$	113	$	226
44	NR Revenues from ESS services	$	-	$	-	$	-
45	Load Shaping Revenue	$	(22,842)	$	(31,941)	$	(54,782)
46	Balancing Augmentation Adjustment Reallocation	$	(1,364)	$	8,511	$	7,147
47	Demand Revenue	$	(48,363)	$	(47,951)	$	(96,314)
48	Non-Slice Augmentation RSC Revenue Debit/(Credit)	$	(726)	$	(726)	$	(1,452)
49	Non-Slice Tier 2 RSC Revenue Debit/(Credit)	$	-	$	-	$	-
50	Non-Slice Tier 2 Rate Design Debit/(Credit)	$	-	$	-	$	-
51	Transmission Losses Adjustment Reallocation	$	31,568	$	32,060	$	63,628
52	Total	$	(392,844)	$	(372,667)	$	(765,510)
53							
54			**2018**		**2019**	**Rate Period**	
55	**Non-Slice**	$	(306,511)	$	(225,408)	$	(531,919)

Rate Design Step
Calculation of PF Preference Rates under Tiered Rate Methodology
Test Period October 2017 - September 2019

	B	C		D		E	
5	**Costs ($000)**		**2018**		**2019**	**Rate Period**	
6	**Composite......**	$	2,824,880	$	2,668,029	$	5,492,909
7	**Non-Slice......**	$	86,333	$	147,259	$	233,591
8	**Slice......**	$	-	$	-	$	-
9	**Tier 2......**	$	38,265	$	43,545	$	81,811
56							
57	**TRM Costs after Adjustments**		**2018**		**2019**	**Rate Period**	
58	**Composite......**	$	2,545,685	$	2,394,437	$	4,940,123
59	**Non-Slice......**	$	(306,511)	$	(225,408)	$	(531,919)
60	**Slice......**	$	-	$	-	$	-
61	**Tier 2......**	$	38,265	$	43,545	$	81,811
62	**Total Costs**	$	2,277,440	$	2,212,575	$	4,490,014
63							
64	**Billing Determinants**		**2018**		**2019**	**Rate Period**	
65	**TOCA......**		96.6562		97.2464		96.9513
66	**Non-slice TOCA......**		73.9204		74.5106		74.2155
67	**Slice Percentage......**		22.7358		22.7358		22.7358
68							
69	**Annual TRM Rates ($000/percent)**		**2018**		**2019**	**Rate Period**	
70	**Composite......**	$	26,338	$	24,622	$	25,477
71	**Non-Slice......**	$	(4,146)	$	(3,025)	$	(3,584)
72	**Slice......**	$	-	$	-	$	-
73							
74	**Monthly TRM Rates ($/percent)**		**2018**		**2019**	**Rate Period**	
75	**Composite......**		2,194,793		2,051,865		2,123,112
76	**Non-Slice......**		(345,542)		(252,098)		(298,634)
77	**Slice......**		-		-		-
78							
79	**Tier 2 Rates ($/MWh)**		**2018**		**2019**	**Rate Period**	
80	**Tier 2 Short Term......**	$	27.20	$	24.97	$	26.09
81	**Tier 2 Load Growth......**	$	47.68	$	45.42	$	46.55
82	**Tier 2 Vintage 2014......**	$	51.40	$	53.02	$	52.21
83	**Tier 2 Vintage 2016......**	$	46.50	$	48.02	$	47.26

Table 3.1.7.1

Rate Design Step
Table Showing Net REP Rate Calculation Yields Identical Rates as Gross REP Calculations
Test period October 2017 - September 2019
($ 000, $/MWh)

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
11			2018	2019		PF p	IP	NR	FPS				PF p	IP	NR
12	GENERATION ENERGY														
13													120,464	1,299	0.01752
14	Federal Base System														
15	Hydro		883,506	768,148		1,651,654	0.0	0.0	0				13.71	0.00	0.00
16	Fish & Wildlife		368,604	357,414		726,018	0.0	0.0	0				6.03	0.00	0.00
17	Trojan		1,000	1,000		2,000	0.0	0.0	0				0.02	0.00	0.00
18	WNP #1		60,931	41,272		102,203	0.0	0.0	0				0.85	0.00	0.00
19	WNP #2		454,883	665,946		1,120,828	0.0	0.0	0				9.30	0.00	0.00
20	WNP #3		236,158	32,139		268,297	0.0	0.0	0				2.23	0.00	0.00
21	System Augmentation		0	12,211		12,211	0.0	0.0	0				0.10	0.00	0.00
22	Balancing Power Purchases		60,484	54,409		114,893	0.0	0.0	0				0.95	0.00	0.00
23	Tier 2 Costs		38,265	43,545		81,811	0.0	0.0	0				0.68	0.00	0.00
24	Total Federal Base System		2,103,831	1,976,084		4,079,915	0.0	0.0	0.0				33.87	0.00	0.00
25															
26	New Resources		54,863	56,683		111,545	0.0	0.0	0		PFx Revenue		0.93	0.00	0.00
27	Residential Exchange		2,897,399	2,902,863		637,559	0.0	0.0	0		5,162,703		5.29	0.00	0.00
28	Conservation		167,093	153,145		320,239	0.0	0.0	0				2.66	0.00	0.00
29	BPA Programs & Transmission		302,437	351,927		654,364	0.0	0.0	0		NR Revenue		5.43	0.00	0.00
30	TOTAL COSA ALLOCATIONS		5,525,623	5,440,701		5,803,622	0	0	0		1.4		48.18	0.00	0.00
31															
32															
33	Nonfirm Excess Revenue Credit		(437,427)	(438,258)		(875,686)	0.0	0.0	0.0				-7.27	0.00	0.00
34	LDD/IRD Expense		63,137	64,098		127,236	0.0						1.06	0.00	0.00
35	Other Revenue Credits		(243,649)	(234,874)		(478,524)	0.0	0.0	0.0				-3.97	0.00	0.00
36						0	0.0						0.00	0.00	0.00
37	SP Revenue Surplus/Dfct Adj.		0	0		(68,265)	0	0.0	68,265				-0.57	0.00	0.00
38						(1.4)		1.3832					0.00	0.00	78.95
39	IP Rate Revenue		0	0		(56,532)	56,532						-0.47	43.51	0.00
40															
41	TOTAL RATE DESIGN ADJUSTMENTS		(617,939)	(609,034)		(1,351,773)	56,532	1.4	68,265				-11.22	43.51	78.95
42															
43	Total Generation		4,907,684	4,831,667									**36.96**	**43.51**	**78.95**
44			**PFp Revenue Recovery**			**4,451,849**	56,532	1.4	68,265						

Rate Design Step
Demonstration that TRM PFp Rates Collect the Same Revenue Requirement as the Non-TRM PFp Rate
Test Period October 1, 2017 to September 30, 2019

	C	D	E	F
4				
5				
6	**Proof: TRM PF Revenues = Non-TRM PF Revenues**			
7				
8		2018	2019	
9	Composite Revenue..............................	$ 2,462,544	$ 2,477,578	
10	Non-Slice Revenue...............................	$ (264,902)	$ (267,017)	
11	Slice Revenue...	$ -	$ -	
12	Tier 2..	$ 38,265	$ 43,545	
13	Load Shaping Revenue.........................	$ 22,842	$ 31,941	
14	Demand Revenue.................................	$ 48,363	$ 47,951	
15	Total TRM PF Revenue	$ 2,307,113	$ 2,333,999	
16				
17	Slice Portion of Secondary Revenue......	$ (94,898)	$ (94,364)	
18	Total Net TRM PF Revenue	$ 2,212,215	$ 2,239,635	
19				
20				PF Rate
21	Total TRM PF Revenue Analogous to w/ Slice PF		$ 4,451,850	36.96
22				
23	w/ Slice PF Public Rate Revenue from "Net REP" Table		**$ 4,451,849**	36.96
24		delta	$ (1)	
25				
26				

Rate Design Step
Calculation of Priority Firm Tier 1 Equivalent Rate Components
Test Period October 2017 - September 2019

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18		
15	HLH (mills/kWh)	26.74	27.27	30.28	29.30	28.54	23.75	19.67	16.63	17.71	24.66	28.11	27.94		
16	LLH (mills/kWh)	22.49	24.74	26.60	23.94	23.94	20.80	17.54	11.25	9.31	19.05	22.61	22.19		
17	Demand Rate ($/kW/mo)	10.45	10.65	11.83	11.45	11.15	9.28	7.68	6.49	6.92	9.63	10.98	10.91		
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)	5,526	6,472	7,047	6,804	6,055	6,197	5,428	5,787	5,376	5,690	6,024	5,330		118,552
22	LLH (GWh)	3,449	4,389	4,979	4,714	3,944	4,011	3,447	3,739	3,288	3,729	3,524	3,603		Tier 1 Demand (MW/mo)
23	Demand (MW)	632	570	1,068	1,217	688	1,006	783	634	650	781	990	645		9,665
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)	$ 147,771	$ 176,514	$ 213,374	$ 199,349	$ 172,823	$ 147,187	$ 106,789	$ 96,235	$ 95,205	$ 140,311	$ 169,325	$ 148,948		$ 2,786,929
29	LLH ($000)	$ 77,557	$ 108,581	$ 132,454	$ 112,861	$ 94,421	$ 83,430	$ 60,466	$ 42,059	$ 30,607	$ 71,036	$ 79,682	$ 79,945		Demand Revenue ($000)
30	Demand ($000)	$ 6,606	$ 6,069	$ 12,638	$ 13,932	$ 7,672	$ 9,338	$ 6,013	$ 4,117	$ 4,498	$ 7,526	$ 10,873	$ 7,032		$ 96,314
31															$ 2,883,244
32															Tier 1 Revenue Requirement (RR) ($000)
33															$ 4,369,939
34															Tier 1 RR less Demand Revenue ($000)
35															$ 4,273,624
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)	39.28	39.81	42.82	41.84	41.08	36.29	32.21	29.17	30.25	37.20	40.65	40.48		(12.54)
38	LLH (mills/kWh)	35.03	37.28	39.14	36.48	36.48	33.34	30.08	23.79	21.85	31.59	35.15	34.73		
39	Demand ($/kW/mo)	10.45	10.65	11.83	11.45	11.15	9.28	7.68	6.49	6.92	9.63	10.98	10.91		
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)	$ 217,069	$ 257,653	$ 301,739	$ 284,678	$ 248,736	$ 224,871	$ 174,837	$ 168,819	$ 162,614	$ 211,683	$ 244,883	$ 215,761		$ 4,273,511
45	LLH ($000)	$ 120,802	$ 163,617	$ 194,897	$ 171,978	$ 143,879	$ 133,729	$ 103,695	$ 88,941	$ 71,834	$ 117,797	$ 123,876	$ 125,124		Allocated Cost Demand ($000)
46	Demand ($000)	$ 6,606	$ 6,069	$ 12,638	$ 13,932	$ 7,672	$ 9,338	$ 6,013	$ 4,117	$ 4,498	$ 7,526	$ 10,873	$ 7,032		$ 96,314
47															$ 4,369,826
48	Average Slice&Non-Slice Tier 1 Rate														
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 4,273,511	36.05												
51	Allocated Cost Demand	$ 96,314	0.81												
52	Total Allocated Costs	$ 4,369,826	36.86												
53															
54	Tier 1 Energy (GWh)		118,552												
55	Market Energy Delta (mills/kWh)		(12.54)												

Rate Design Step
Calculation of Priority Firm Public Melded Rate Equivalent Components
Test Period October 2017 - September 2019

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18		
15	HLH (mills/kWh)	26.74	27.27	30.28	29.30	28.54	23.75	19.67	16.63	17.71	24.66	28.11	27.94		
16	LLH (mills/kWh)	22.49	24.74	26.60	23.94	23.94	20.80	17.54	11.25	9.31	19.05	22.61	22.19		
17	Demand Rate ($/kW/mo)	10.45	10.65	11.83	11.45	11.15	9.28	7.68	6.49	6.92	9.63	10.98	10.91		
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)	5,619	6,559	7,134	6,895	6,139	6,289	5,517	5,878	5,465	5,780	6,118	5,414		120,464
22	LLH (GWh)	3,518	4,459	5,055	4,786	4,007	4,081	3,515	3,810	3,356	3,802	3,592	3,676		Tier 1 Demand (MW/mo)
23	Demand (MW)	632	570	1,068	1,217	688	1,006	783	634	650	781	990	645		9,665
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)	$ 150,250	$ 178,896	$ 216,018	$ 202,010	$ 175,216	$ 149,383	$ 108,543	$ 97,746	$ 96,780	$ 142,511	$ 171,976	$ 151,291		$ 2,830,885
29	LLH ($000)	$ 79,126	$ 110,314	$ 134,452	$ 114,575	$ 95,926	$ 84,882	$ 61,658	$ 42,865	$ 31,243	$ 72,431	$ 81,222	$ 81,573		Demand Revenue ($000)
30	Demand ($000)	$ 6,606	$ 6,069	$ 12,638	$ 13,932	$ 7,672	$ 9,338	$ 6,013	$ 4,117	$ 4,498	$ 7,526	$ 10,873	$ 7,032		$ 96,314
31															$ 2,927,200
32															Tier 1&2 Revenue Requirement (RR) ($000)
33															$ 4,451,749
34															T1&2RR less Demand Revenue ($000)
35															$ 4,355,435
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)	39.40	39.93	42.94	41.96	41.20	36.41	32.33	29.29	30.37	37.32	40.77	40.60		(12.66)
38	LLH (mills/kWh)	35.15	37.40	39.26	36.60	36.60	33.46	30.20	23.91	21.97	31.71	35.27	34.85		
39	Demand ($/kW/mo)	10.45	10.65	11.83	11.45	11.15	9.28	7.68	6.49	6.92	9.63	10.98	10.91		
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)	$ 221,385	$ 261,916	$ 306,334	$ 289,305	$ 252,917	$ 228,980	$ 178,373	$ 172,174	$ 165,961	$ 215,695	$ 249,451	$ 219,804		$ 4,355,905
45	LLH ($000)	$ 123,667	$ 166,765	$ 198,443	$ 175,165	$ 146,653	$ 136,545	$ 106,162	$ 91,102	$ 73,728	$ 120,567	$ 126,701	$ 128,113		Allocated Cost Demand ($000)
46	Demand ($000)	$ 6,606	$ 6,069	$ 12,638	$ 13,932	$ 7,672	$ 9,338	$ 6,013	$ 4,117	$ 4,498	$ 7,526	$ 10,873	$ 7,032		$ 96,314
47															$ 4,452,219
48	Average Slice&Non-Slice Tier 1&2 Rate														
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 4,355,905	36.16												
51	Allocated Cost Demand	$ 96,314	0.80												
52	Total Allocated Costs	$ 4,452,219	36.96												
53															
54	Tier 1&2 Energy (GWh)		120,464												
55	PF Melded Equivalent Energy Scalar (mills/kWh)		(12.66)												

Table 3.1.8.3

Rate Design Step
Calculation of Industrial Firm Power Rate Components
Test Period October 2017 - September 2019

	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-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18		
15		HLH (mills/kWh)	39.40	39.93	42.94	41.96	41.20	36.41	32.33	29.29	30.37	37.32	40.77	40.60		
16		LLH (mills/kWh)	35.15	37.40	39.26	36.60	36.60	33.46	30.20	23.91	21.97	31.71	35.27	34.85		
17		Demand Rate ($/kW/mo)	10.45	10.65	11.83	11.45	11.15	9.28	7.68	6.49	6.92	9.63	10.98	10.91		
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)	48	44	44	46	42	73	73	72	70	71	76	67		1,299
22		LLH (GWh)	35	36	38	37	32	57	54	58	56	58	55	59		
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)	$ 1,872	$ 1,761	$ 1,879	$ 1,916	$ 1,738	$ 2,660	$ 2,354	$ 2,119	$ 2,130	$ 2,666	$ 3,086	$ 2,713		$ 45,443
29		LLH ($000)	$ 1,232	$ 1,332	$ 1,509	$ 1,346	$ 1,163	$ 1,909	$ 1,626	$ 1,380	$ 1,220	$ 1,850	$ 1,924	$ 2,059		Demand Rev ($000)
30		Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
31																$ 45,443
32																
33																VOR
34																(0.90)
35																Industrial Margin (mills/kWh)
36		IP Rate	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		0.754
37		HLH (mills/kWh)	48.08	48.61	51.62	50.64	49.88	45.09	41.01	37.97	39.05	46.00	49.45	49.28		Net industrial Margin
38		LLH (mills/kWh)	43.83	46.08	47.94	45.28	45.28	42.14	38.88	32.59	30.65	40.39	43.95	43.53		(0.142)
39		Demand ($/kW/mo)	10.45	10.65	11.83	11.45	11.15	9.28	7.68	6.49	6.92	9.63	10.98	10.91		Settlement Charge
40																**8.825**
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)	$ 2,284	$ 2,144	$ 2,259	$ 2,312	$ 2,104	$ 3,295	$ 2,986	$ 2,747	$ 2,739	$ 3,286	$ 3,743	$ 3,293		$ 56,721
45		LLH ($000)	$ 1,536	$ 1,641	$ 1,842	$ 1,665	$ 1,439	$ 2,404	$ 2,093	$ 1,881	$ 1,702	$ 2,356	$ 2,397	$ 2,572		Allocated Cost Demand ($000)
46		Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
47																$ 56,721
48			Average IP Rate													
49			($000)	(mills/kWh)												
50		Allocated Cost Energy	$ 56,721	43.66												
51		Allocated Cost Demand	$ -	-												
52		Total Allocated Costs	$ 56,721	43.66												
53																
54			IP Energy (GWh)	1,299												
55			Industrial Margin (mills/kWh)	0.75												
56			VOR	(0.90)												
57			Settlement Charge	8.83												

Rate Design Step
Calculation of New Resource Rate Components
Test Period October 2017 - September 2019

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18		
15	HLH (mills/kWh)	26.74	27.27	30.28	29.30	28.54	23.75	19.67	16.63	17.71	24.66	28.11	27.94		
16	LLH (mills/kWh)	22.49	24.74	26.60	23.94	23.94	20.80	17.54	11.25	9.31	19.05	22.61	22.19		
17	Demand Rate ($/kW/mo)	10.45	10.65	11.83	11.45	11.15	9.28	7.68	6.49	6.92	9.63	10.98	10.91		
18															
19															**Totals**
20	NR Determinants	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		NR Energy (GWh)
21	HLH (GWh)	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0009	0.0008		0.0175
22	LLH (GWh)	0.0006	0.0006	0.0007	0.0007	0.0006	0.0006	0.0006	0.0007	0.0006	0.0007	0.0006	0.0007		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)	$ 0.0227	$ 0.0218	$ 0.0242	$ 0.0244	$ 0.0219	$ 0.0201	$ 0.0161	$ 0.0138	$ 0.0145	$ 0.0201	$ 0.0243	$ 0.0215		$ 0.4027
29	LLH ($000)	$ 0.0144	$ 0.0159	$ 0.0183	$ 0.0157	$ 0.0138	$ 0.0133	$ 0.0109	$ 0.0074	$ 0.0058	$ 0.0128	$ 0.0141	$ 0.0149		Demand Revenue ($000)
30	Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
31															$ 0.4027
32															NR Revenue Requirement (RR) ($000)
33															$ 1.3832
34															NR RR less Demand Revenue ($000)
35															$ 1.3832
36	NR Rates	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Market Energy Delta (mills/kWh)
37	HLH (mills/kWh)	82.70	83.23	86.24	85.26	84.50	79.71	75.63	72.59	73.67	80.62	84.07	83.90		(55.96)
38	LLH (mills/kWh)	78.45	80.70	82.56	79.90	79.90	76.76	73.50	67.21	65.27	75.01	78.57	78.15		
39	Demand ($/kW/mo)	10.45	10.65	11.83	11.45	11.15	9.28	7.68	6.49	6.92	9.63	10.98	10.91		
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)	$ 0.0701	$ 0.0666	$ 0.0690	$ 0.0709	$ 0.0649	$ 0.0676	$ 0.0617	$ 0.0604	$ 0.0601	$ 0.0658	$ 0.0726	$ 0.0644		$ 1.3831
45	LLH ($000)	$ 0.0502	$ 0.0518	$ 0.0568	$ 0.0524	$ 0.0460	$ 0.0490	$ 0.0459	$ 0.0441	$ 0.0407	$ 0.0504	$ 0.0490	$ 0.0525		Allocated Cost Demand ($000)
46	Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
47															$ 1.3831
48		Average NR Rate													
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 1.3831	78.94												
51	Allocated Cost Demand	$ -	-												
52	Total Allocated Costs	$ 1.3831	78.94												
53															
54		NR Energy (GWh)	0.0175												
55															

Rate Design Step
Calculation of Priority Firm Tier 1 Equivalent Rate Components
Test Period October 2017 - September 2019

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18		
15	HLH (mills/kWh)	26.74	27.27	30.28	29.30	28.54	23.75	19.67	16.63	17.71	24.66	28.11	27.94		
16	LLH (mills/kWh)	22.49	24.74	26.60	23.94	23.94	20.80	17.54	11.25	9.31	19.05	22.61	22.19		
17	Demand Rate ($/kW/mo)	10.45	10.65	11.83	11.45	11.15	9.28	7.68	6.49	6.92	9.63	10.98	10.91		
18															
19															**Totals**
20	Classic Billing Determinants	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Tier 1 Energy (GWh) [FAT1L]
21	HLH (GWh) [FMDT1L]	4,153	4,804	5,431	5,557	4,798	4,765	4,087	3,822	3,769	4,312	4,443	3,979		90,853
22	LLH (GWh) [FMDT1L]	2,715	3,417	4,021	3,919	3,232	3,192	2,730	2,648	2,460	2,997	2,758	2,845		Tier 1 Demand (MW/mo)
23	Demand (MW)	632	570	1,068	1,217	688	1,006	783	634	650	781	990	645		9,665
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)	$ 111,041	$ 131,030	$ 164,452	$ 162,818	$ 136,952	$ 113,179	$ 80,410	$ 63,549	$ 66,751	$ 106,312	$ 124,871	$ 111,185		$ 2,145,852
29	LLH ($000)	$ 61,050	$ 84,545	$ 106,950	$ 93,817	$ 77,367	$ 66,391	$ 47,891	$ 29,791	$ 22,905	$ 57,097	$ 62,359	$ 63,138		Demand Revenue ($000)
30	Demand ($000)	$ 6,606	$ 6,069	$ 12,638	$ 13,932	$ 7,672	$ 9,338	$ 6,013	$ 4,117	$ 4,498	$ 7,526	$ 10,873	$ 7,032		$ 96,314
31															$ 2,242,167
32															Tier 1 Non-Slice PF Public RR minus Tier 2 Costs
33															**$ 3,400,805**
34															Tier 1 RR less Demand Revenue ($000) [BLFRnD]
35															$ 3,304,490
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)	39.49	40.02	43.03	42.05	41.29	36.50	32.42	29.38	30.46	37.41	40.86	40.69		(12.75)
38	LLH (mills/kWh)	35.24	37.49	39.35	36.69	36.69	33.55	30.29	24.00	22.06	31.80	35.36	34.94		
39	Demand ($/kW/mo)	10.45	10.65	11.83	11.45	11.15	9.28	7.68	6.49	6.92	9.63	10.98	10.91		
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)	$ 163,987	$ 192,270	$ 233,696	$ 233,677	$ 198,117	$ 173,915	$ 132,508	$ 112,282	$ 114,806	$ 161,295	$ 181,526	$ 161,894		$ 3,304,187
45	LLH ($000)	$ 95,661	$ 128,117	$ 158,214	$ 143,782	$ 118,572	$ 107,087	$ 82,703	$ 63,553	$ 54,273	$ 95,312	$ 97,524	$ 99,416		Allocated Cost Demand ($000)
46	Demand ($000)	$ 6,606	$ 6,069	$ 12,638	$ 13,932	$ 7,672	$ 9,338	$ 6,013	$ 4,117	$ 4,498	$ 7,526	$ 10,873	$ 7,032		$ 96,314
47															$ 3,400,502
48	Average Non-Slice Tier 1 Rate														
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 3,304,187	36.37												
51	Allocated Cost Demand	$ 96,314	1.06												
52	Total Allocated Costs	$ 3,400,502	37.43												
53															
54	Tier 1 Energy (GWh) [FAT1L]		90,853												
55	Load Shaping True-up Rate (mills/kWh) [LSTUR]		(12.75)												

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	FY2018	FY2019	FY2020	FY2021	FY2022	FY2023
2	C	RDS	CNTA	Augmentation RSS & RSC Adder	$ 2,345	$ 2,345	$ 2,345	$ 2,345	$ 2,345	$ 2,345
3	C	RDS	CD2RCF	Composite Augmentation RSS Revenue Debit/(Credit)	$ (1,619)	$ (1,619)	$ (1,619)	$ (1,619)	$ (1,619)	$ (1,619)
4	2.0	RDS	2D2RCF	Composite Tier 2 RSS Revenue Debit/(Credit)	$ -	$ -	$ -	$ -	$ -	$ -
5	C	RDS	CD2RCN	Composite Non-Federal RSS Revenue Debit/(Credit)	$ (1,323)	$ (1,322)	$ (1,322)	$ (1,322)	$ (1,322)	$ (1,322)
6	N	RDS	ND2RNF	Non-Slice Augmentation RSC Revenue Debit/(Credit)	$ (726)	$ (726)	$ (726)	$ (726)	$ (726)	$ (726)
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)	$ 113	$ 113	$ 113	$ 113	$ 113	$ 113

Table 3.3
Tier 2 Purchases Made by BPA

	A	B	C	D	E	F	G	H	I	J
1	**Start_Date**	**Maturity_ Date**	**Trade_Date**	**Internal_Portfolio**	**Tran_Status**	**Hours**	**Price**	**Revenue**	**Position**	**Choice**
2	10/1/2017	9/30/2018	12/14/2011	Vintage T2	Validated	8760	$ 49.40	$ (19,906,224.00)	46.00	Seller's Choice
3	10/1/2017	9/30/2018	12/7/2012	Vintage T2	Validated	8760	$ 44.50	$ (8,965,860.00)	23.00	Seller's Choice
4	10/1/2017	9/30/2018	12/20/2011	Load Growth T2	Validated	8760	$ 49.40	$ (2,163,720.00)	5.00	Seller's Choice
5	10/1/2018	9/30/2019	12/7/2012	Vintage T2	Validated	8760	$ 46.05	$ (10,891,746.00)	27.00	Seller's Choice
6	10/1/2018	9/30/2019	12/14/2011	Vintage T2	Validated	8760	$ 51.05	$ (20,571,108.00)	46.00	Seller's Choice
7	10/1/2018	9/30/2019	12/20/2011	Load Growth T2	Validated	8760	$ 51.05	$ (2,235,990.00)	5.00	Seller's Choice
8	10/1/2018	9/30/2019	2/20/2017	ST T2	Validated	8760	$ 23.00	$ (6,850,320.00)	34.00	Seller's Choice
9	10/1/2018	9/30/2019	2/20/2017	Load Growth T2	Validated	8760	$ 23.00	$ (302,220.00)	1.50	Seller's Choice
10	10/1/2018	9/30/2019	2/20/2017	Vintage T2	Validated	8760	$ 23.00	$ (201,480.00)	1.00	Seller's Choice
11	10/1/2018	9/30/2019	2/20/2017	Vintage T2	Validated	8760	$ 23.00	$ (100,740.00)	0.50	Seller's Choice

Table 3.3 (continued)
Tier 2 Purchases Made by BPA

A	B	C	D	E	F	G	H	I	J	K	L
1	**Start_Date**	**Maturity_ Date**	**Trade_Date**	**Product**	**Term**	**Description**	**Reference**	**Buy_Sell**	**RIS**	**Deal_Num**	**Pt_of_Receipt_ Loc**
2	9/30/2018	12/14/2011	Vintage T2	FLAT	Strip	Energy	related to # 245283	Buy	79576	245283	MID-C
3	9/30/2018	12/7/2012	Vintage T2	FLAT	Strip	Energy	Tier 2 Vintage FY18	Buy	79577	314966	MID-C
4	9/30/2018	12/20/2011	Load Growth T2	FLAT	Strip	Energy	related to #245283	Buy	79572	245585	MID-C
5	9/30/2019	12/7/2012	Vintage T2	FLAT	Strip	Energy	Tier 2 Vintage FY19	Buy	79577	314969	MID-C
6	9/30/2019	12/14/2011	Vintage T2	FLAT	Strip	Energy	related to #245582	Buy	79576	245284	MID-C
7	9/30/2019	12/20/2011	Load Growth T2	FLAT	Strip	Energy	related #245284	Buy	79572	245582	MID-C
8	9/30/2019	2/20/2017	ST T2	FLAT	Strip	Energy	related #571583	Buy	79571	571580	MID-C
9	9/30/2019	2/20/2017	Load Growth T2	FLAT	Strip	Energy	related #571585	Buy	79572	571583	MID-C
10	9/30/2019	2/20/2017	Vintage T2	FLAT	Strip	Energy	related #571580	Buy	79576	571585	MID-C
11	9/30/2019	2/20/2017	Vintage T2	FLAT	Strip	Energy	related #571583	Buy	79577	571585	MID-C

Table 3.4
Inputs to TSS Monthly Rate and Charge

	A	B	C	D	E	F
1	**Total TSS Costs FY2018**	**Total TSS Costs FY2019**	**FY2015 Scheduled (MWh)**	**FY2016 Scheduled (MWh)**	**FY2015 Transactions**	**BP16 Imputed Transactions**
2	$ 4,189,396	$ 4,335,208	27,309,297	25,546,455	124,563	105,000
3						
4	**PTKCosts FY2018**	**PTK Costs FY2019**				
5	$ 3,677,592	$ 3,803,096				
6						
7	**PTFR Costs FY2018**	**PTFR Costs FY2019**				
8	$ 511,804	$ 532,112				
9						
10						
11	Note: Total Costs are the sum of all PTK and 19% of PTFR costs for each year of the rate period.					

Table 3.5
Tier 2 Short-Term Rate Costing Table

	A	B	C
1		ST.2.2015_2019	ST.2.2015_2019
2	Hours	8760	8760
3	Fiscal Year	FY2018	FY2019
4	Rate Period	BP-18	
5	Total Forecast Expected Cost	$ 8,953,864	$ 10,895,863
6	Base Power Purchase Cost (Provided by PTL)	$ -	$ 6,850,320
7	Power Purchase Cost	$ -	$ 6,850,320
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 (Provided by PFR & PTM)	$ 405,897	$ 550,883
16	Resource Support Services	$ 46,574	$ 61,754
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	$ 46,574	$ 61,754
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	$ 46,574	$ 61,754
28	Resource Shaping Charge	$ -	$ -
29	Tier 2 Overhead	$ 359,323	$ 489,130
30	Risk Adder	$ -	$ -
31	Carbon Costs Pass Through	$ -	$ -
32	Renewable Energy Credits (MWh)	0	0
33	Quantity Purchased (MWh)	0	297,840
34	Tier 2 Obligation w/o losses (Billing Determinant)	329,148	436,423
35	Tier 2 Obligation w losses	339,223	449,782
36	Energy (Short)/Long (MWh)	-339,223	-151,942
37	Composite Cost Pool Augmentation (MWh) - BP12 Only		
38	Energy Short (MWh)	-339,223	-151,942
39	Energy to be Remarketed (MWh)	0	0
40	Remarketing Available (MWh)	128,579	121,693
41	Total Tier 2 Pool Shortfall (MWh)	-367,263	-163,342
42	Augmentation Price ($/MWh)	$ 27.26	$ 26.99
43	Flat Block RSC ($/MWh)	$ 23.14	$ 22.83
44	Remarketing value ($/MWh)	$ 25.20	$ 23.00
45	Remarketed Purchase (MWh)	118,762	113,200
46	Remarketed Purchase Cost	$ 2,992,650	$ 2,603,597
47	Remaining Shortfall (MWh)	-220,461	-38,742
48	Remaining Shortfall Cost	$ 5,555,316	$ 891,062
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	$ 8,953,864	$ 10,895,863
53	Billing Components		
54	ShortTerm ($/MWh)	$ 27.20	$ 24.97
55	Remarketing Credit	$ -	$ -
56	Remarketing Charge	$ -	$ -
57	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (359,323)	$ (489,130)
58	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
59	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (46,574)	$ (61,754)

Table 3.6
Tier 2 Load Growth Rate Costing Table

	A	B	C
1		LG.1.2012_2028	LG.1.2012_2028
2	Hours	8760	8760
3	Fiscal Year	FY2018	FY2019
4	Rate Period	BP-18	
5	Total Forecast Expected Cost	$ 2,467,892	$ 2,728,247
6	Base Power Purchase Cost (Provided by PTL)	$ 2,163,720	$ 2,538,210
7	Power Purchase Cost	$ 2,163,720	$ 2,538,210
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 (Provided by PFR & PTM)	$ 63,822	$ 75,821
16	Resource Support Services	$ 7,323	$ 8,500
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	$ 7,323	$ 8,500
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	$ 7,323	$ 8,500
28	Resource Shaping Charge	$ -	$ -
29	Tier 2 Overhead	$ 56,499	$ 67,322
30	Risk Adder	$ -	$ -
31	Carbon Costs Pass Through	$ -	$ -
32	Renewable Energy Credits (MWh)	0	0
33	Quantity Purchased (MWh)	43,800	56,940
34	Tier 2 Obligation w/o losses (Billing Determinant)	51,754	60,067
35	Tier 2 Obligation w losses	53,338	61,906
36	Energy (Short)/Long (MWh)	-9,538	-4,966
37	Composite Cost Pool Augmentation (MWh) - BP12 Only		
38	Energy Short (MWh)	-9,538	-4,966
39	Energy to be Remarketed (MWh)	0	0
40	Remarketing Available (MWh)	128,579	121,693
41	Total Tier 2 Pool Shortfall (MWh)	-367,263	-163,342
42	Augmentation Price ($/MWh)	$ 27.26	$ 26.99
43	Flat Block RSC ($/MWh)	$ 23.14	$ 22.83
44	Remarketing value ($/MWh)	$ 25.20	$ 23.00
45	Remarketed Purchase (MWh)	3,339	3,700
46	Remarketed Purchase Cost	$ 84,147	$ 85,094
47	Remaining Shortfall (MWh)	-6,199	-1,266
48	Remaining Shortfall Cost	$ 156,204	$ 29,123
49	Tier 2 Balancing Adjustment Debit/(Credit) - BP12 Only		
50	Remarketing Treatment (Remove From Rate) (Yes or No)	Yes	Yes
51	Additional Remarketing - Vintage Only (MWh)	0	0
52	Total Fixed Costs	$ 2,467,892	$ 2,728,247
53	Billing Components		
54	LoadGrowth ($/MWh)	$ 47.68	$ 45.42
55	Remarketing Credit	$ -	$ -
56	Remarketing Charge	$ -	$ -
57	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (56,499)	$ (67,322)
58	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
59	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (7,323)	$ (8,500)

Table 3.7
Tier 2 VR1-2014 Rate Costing Table

	A	B	C
1		V.1.2014_2018	V.1.2014_2018
2	Hours	8760	8760
3	Fiscal Year	FY2018	FY2019
4	Rate Period	BP-18	
5	Total Forecast Expected Cost	$ 20,713,950	$ 21,363,439
6	Base Power Purchase Cost (Provided by PTL)	$ 19,906,224	$ 20,772,588
7	Power Purchase Cost	$ 19,906,224	$ 20,772,588
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 (Provided by PFR & PTM)	$ 496,920	$ 508,644
16	Resource Support Services	$ 57,019	$ 57,019
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	$ 57,019	$ 57,019
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	$ 57,019	$ 57,019
28	Resource Shaping Charge	$ -	$ -
29	Tier 2 Overhead	$ 439,901	$ 451,625
30	Risk Adder	$ -	$ -
31	Carbon Costs Pass Through	$ -	$ -
32	Renewable Energy Credits (MWh)	0	0
33	Quantity Purchased (MWh)	402,960	411,720
34	Tier 2 Obligation w/o losses (Billing Determinant)	402,960	402,960
35	Tier 2 Obligation w losses	415,294	415,294
36	Energy (Short)/Long (MWh)	-12,334	-3,574
37	Composite Cost Pool Augmentation (MWh) - BP12 Only		
38	Energy Short (MWh)	-12,334	-3,574
39	Energy to be Remarketed (MWh)	0	0
40	Remarketing Available (MWh)	128,579	121,693
41	Total Tier 2 Pool Shortfall (MWh)	-367,263	-163,342
42	Augmentation Price ($/MWh)	$ 27.26	$ 26.99
43	Flat Block RSC ($/MWh)	$ 23.14	$ 22.83
44	Remarketing value ($/MWh)	$ 25.20	$ 23.00
45	Remarketed Purchase (MWh)	4,318	2,663
46	Remarketed Purchase Cost	$ 108,814	$ 61,246
47	Remaining Shortfall (MWh)	-8,016	-911
48	Remaining Shortfall Cost	$ 201,993	$ 20,961
49	Tier 2 Balancing Adjustment Debit/(Credit) - BP12 Only		
50	Remarketing Treatment (Remove From Rate) (Yes or No)	No	No
51	Additional Remarketing (MWh)	41,549	34,952
52	Total Fixed Costs	$ 20,713,950	$ 21,363,439
53	Billing Components		
54	Vintage.1 ($/MWh)	$ 51.40	$ 53.02
55	Remarketing Credit	$ 1,046,979	$ 803,896
56	Remarketing Charge	$ -	$ -
57	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (439,901)	$ (451,625)
58	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
59	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (57,019)	$ (57,019)

Table 3.8
Tier 2 VR2-2016 Rate Costing Table

	A	B	C
1		V.2.2016_2019	V.2.2016_2019
2	Hours	8760	8760
3	Fiscal Year	FY2018	FY2019
4	Rate Period	BP-18	
5	Total Forecast Expected Cost	$ 9,369,723	$ 11,356,810
6	Base Power Purchase Cost (Provided by PTL)	$ 8,965,860	$ 10,992,486
7	Power Purchase Cost	$ 8,965,860	$ 10,992,486
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 (Provided by PFR & PTM)	$ 248,460	$ 298,552
16	Resource Support Services	$ 28,509	$ 33,468
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	$ 28,509	$ 33,468
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	$ 28,509	$ 33,468
28	Resource Shaping Charge	$ -	$ -
29	Tier 2 Overhead	$ 219,950	$ 265,084
30	Risk Adder	$ -	$ -
31	Carbon Costs Pass Through	$ -	$ -
32	Renewable Energy Credits (MWh)	0	0
33	Quantity Purchased (MWh)	201,480	240,900
34	Tier 2 Obligation w/o losses (Billing Determinant)	201,480	236,520
35	Tier 2 Obligation w losses	207,647	243,760
36	Energy (Short)/Long (MWh)	-6,167	-2,860
37	Composite Cost Pool Augmentation (MWh) - BP12 Only		
38	Energy Short (MWh)	-6,167	-2,860
39	Energy to be Remarketed (MWh)	0	0
40	Remarketing Available (MWh)	128,579	121,693
41	Total Tier 2 Pool Shortfall (MWh)	-367,263	-163,342
42	Augmentation Price ($/MWh)	$ 27.26	$ 26.99
43	Flat Block RSC ($/MWh)	$ 23.14	$ 22.83
44	Remarketing value ($/MWh)	$ 25.20	$ 23.00
45	Remarketed Purchase (MWh)	2,159	2,131
46	Remarketed Purchase Cost	$ 54,407	$ 49,002
47	Remaining Shortfall (MWh)	-4,008	-729
48	Remaining Shortfall Cost	$ 100,996	$ 16,770
49	Tier 2 Balancing Adjustment Debit/(Credit) - BP12 Only		
50	Remarketing Treatment (Remove From Rate) (Yes or No)	No	No
51	Additional Remarketing (MWh)	56,887	75,397
52	Total Fixed Costs	$ 9,369,723	$ 11,356,810
53	Billing Components		
54	Vintage.2 (VR1-2016) ($/MWh)	$ 46.50	$ 48.02
55	Remarketing Credit	$ 1,433,476	$ 1,734,131
56	Remarketing Charge	$ -	$ -
57	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (219,950)	$ (265,084)
58	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
59	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (28,509)	$ (33,468)

Table 3.9
Tier 2 Overhead Adder Inputs

	A	B	C	D	E
1		**BP-18**			
2		**FY2018**		**FY2019**	
3	**Line Item**	**FY2018**	**Total Forecast Sales (MWh)**	**FY2019**	**Total Forecast Sales (MWh)**
4	Executive and Administrative Services	$ 4,118,522	78,098,278	$ 4,203,530	78,880,892
5	Generation Project Coordination	$ 6,173,940		$ 6,408,905	
6	Sales & Support	$ 22,885,139		$ 23,485,271	
7	Strategy, Finance & Risk Mgmt.	$ 12,015,710		$ 13,309,816	
8	Agency Services G&A	$ 40,064,542		$ 40,999,734	
9	Total Costs	$ 85,257,853		$ 88,407,256	
10	**Total Cost Divided by Total Sales Averaged for BP-18**		**$ 1.11**		

Table 3.10
Tier 2 Rate Revenues

	A	B	C
1	Hours	8,760	8,760
2	Fiscal Year	FY2018	FY2019
3	Rate Period	BP-18	
4	ShortTerm Rate $/MWh	$ 27.20	$ 24.97
5	LoadGrowth Rate $/MWh	$ 47.68	$ 45.42
6	Vintage.1 (VR1-2014) Rate $/MWh	$ 51.40	$ 53.02
7	Vintage.2 (VR1-2016) Rate $/MWh	$ 46.50	$ 48.02
8			
9	**ShortTerm**		
10	Portfolio Purchased aMW	0.000	34.000
11	Portfolio Purchased MWh	0	297,840
12	Portfolio Obligation /w Losses aMW	38.724	51.345
13	Portfolio Obligation /w Losses MWh	339,223	449,782
14	Portfolio Billing Determinant aMW	37.574	49.820
15	Portfolio Billing Determinant MWh	329,148	436,423
16	RECs MWh	0	0
17	Base Power Purchase Cost	$ -	$ 6,850,320
18	Rate Design Components	$ 405,897	$ 550,883
19	Other Costs	$ -	$ -
20	Rate $/MWh	$ 27.20	$ 24.97
21	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (359,323)	$ (489,130)
22	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
23	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (46,574)	$ (61,754)
24	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -
25	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -
26	Total ShortTerm Rate Revenue	$ 8,952,832	$ 10,897,487
27	Remarketing Credit	$ -	$ -
28	Remarketing Charge	$ -	$ -
29	Forecast Power Purchase Costs	$ 5,555,316	$ 891,062
30			
31	**LoadGrowth**		
32	Portfolio Purchased aMW	5.000	6.500
33	Portfolio Purchased MWh	43,800	56,940
34	Portfolio Obligation /w Losses aMW	6.089	7.067
35	Portfolio Obligation /w Losses MWh	53,338	61,906
36	Portfolio Billing Determinant aMW	5.908	6.857
37	Portfolio Billing Determinant MWh	51,754	60,067
38	RECs MWh	0	0
39	Base Power Purchase Cost	$ 2,163,720	$ 2,538,210
40	Rate Design Components	$ 63,822	$ 75,821
41	Other Costs	$ -	$ -
42	Rate $/MWh	$ 47.68	$ 45.42
43	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (56,499)	$ (67,322)
44	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
45	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (7,323)	$ (8,500)
46	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -
47	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -
48	Total LoadGrowth Rate Revenue	$ 2,467,635	$ 2,728,258
49	Remarketing Credit	$ -	$ -
50	Remarketing Charge	$ -	$ -
51	Forecast Power Purchase Costs	$ 156,204	$ 29,123

Table 3.10 (continued)
Tier 2 Rate Revenues

	A	B	C
1	Hours	8,760	8,760
2	Fiscal Year	FY2018	FY2019
3	Rate Period	BP-18	
4	ShortTerm Rate $/MWh	$ 27.20	$ 24.97
5	LoadGrowth Rate $/MWh	$ 47.68	$ 45.42
6	Vintage.1 (VR1-2014) Rate $/MWh	$ 51.40	$ 53.02
7	Vintage.2 (VR1-2016) Rate $/MWh	$ 46.50	$ 48.02
8			
9	**Vintage.1 (VR1-2014)**		
10	Portfolio Purchased aMW	46.000	47.000
11	Portfolio Purchased MWh	402,960	411,720
12	Portfolio Obligation /w Losses aMW	47.408	47.408
13	Portfolio Obligation /w Losses MWh	415,294	415,294
14	Portfolio Billing Determinant aMW	46.000	46.000
15	Portfolio Billing Determinant MWh	402,960	402,960
16	RECs MWh	0	0
17	Base Power Purchase Cost	$ 19,906,224	$ 20,772,588
18	Rate Design Components	$ 496,920	$ 508,644
19	Other Costs	$ -	$ -
20	Rate $/MWh	$ 51.40	$ 53.02
21	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (439,901)	$ (451,625)
22	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
23	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (57,019)	$ (57,019)
24	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -
25	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -
26	Total Vintage.1 Rate Revenue	$ 20,712,144	$ 21,364,939
27	Remarketing Credit	$ 1,046,979	$ 803,896
28	Remarketing Charge	$ -	$ -
29	Forecast Power Purchase Costs	$ 201,993	$ 20,961
30			
31	**Vintage.2 (VR1-2016)**		
32	Portfolio Purchased aMW	23.000	27.500
33	Portfolio Purchased MWh	201,480	240,900
34	Portfolio Obligation /w Losses aMW	23.704	27.826
35	Portfolio Obligation /w Losses MWh	207,647	243,760
36	Portfolio Billing Determinant aMW	23.000	27.000
37	Portfolio Billing Determinant MWh	201,480	236,520
38	RECs MWh	0	0
39	Base Power Purchase Cost	8,965,860	10,992,486
40	Rate Design Components	248,460	298,552
41	Other Costs	$ -	$ -
42	Rate $/MWh	$ 46.50	$ 48.02
43	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (219,950)	$ (265,084)
44	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
45	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (28,509)	$ (33,468)
46	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -
47	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -
48	Total Vintage.2 Rate Revenue	$ 9,368,820	$ 11,357,690
49	Remarketing Credit	$ 1,433,476	$ 1,734,131
50	Remarketing Charge	$ -	$ -
51	Forecast Power Purchase Costs	$ 100,996	$ 16,770

Table 3.10 (continued) (2)
Tier 2 Rate Revenues

	A	B	C
1	Hours	8,760	8,760
2	Fiscal Year	FY2018	FY2019
3	Rate Period	BP-18	
4	ShortTerm Rate $/MWh	$ 27.20	$ 24.97
5	LoadGrowth Rate $/MWh	$ 47.68	$ 45.42
6	Vintage.1 (VR1-2014) Rate $/MWh	$ 51.40	$ 53.02
7	Vintage.2 (VR1-2016) Rate $/MWh	$ 46.50	$ 48.02
8			
9	**Total Costs**		
10	Total Base Power Purchase Cost	$ 31,035,804	$ 41,153,604
11	Total Rate Design Components	$ 1,215,098	$ 1,433,900
12	Total Other Costs	$ -	$ -
13	Forecast Power Purchase Costs	$ 6,014,509	$ 957,917
14	Total Cost	$ 38,265,411	$ 43,545,421
15			
16	**Total Revenue**		
17	Total Tier 2 Rate Revenue Collection	$ 41,501,431	$ 46,348,375
18	Total Tier 2 Remarketing Charge	$ -	$ -
19	Total Tier 2 Remarketing Credit	$ (2,480,455)	$ (2,538,027)
20	Non-Federal Remarketing Credit	$ (759,563)	$ (260,912)
21	Total Revenue	$ 38,261,413	$ 43,549,436
22	Value of BPA Purchased Remarketing	$ -	$ -
23	Total Tier 2 Revenue and Value of BPA Purchased Remarketing	$ 38,261,413	$ 43,549,436
24			
25	Total Tier 2 Adjustments and Credits*		
26	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (1,075,673)	$ (1,273,161)
27	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
28	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (139,426)	$ (160,740)
29	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -
30	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -
31			
32	*This amount is in addition to any RSS credits that result from the RSS model		

Table 3.11
Total Remarketing Charges and Credits

	A	B	C
1	Rate Period	BP-18	
2	Fiscal Year	FY2018	FY2019
3	ShortTerm Remarket (MWh)	0	0
4	LoadGrowth Remarket (MWh)	0	0
5	Vintage.1 (VR1-2014) Remarket (MWh)	41,549	34,952
6	Vintage.2 (VR1-2016) Remarket (MWh)	56,887	75,397
7	Non-Federal Remarket (MWh)	30,143	11,344
8	Total	128,579	121,693
9			
10	ShortTerm Purchase of Remarket (MWh)	118,762	113,200
11	LoadGrowth Purchase of Remarket (MWh)	3,339	3,700
12	Vintage.1 (VR1-2014) Purchase of Remarket (MWh)	4,318	2,663
13	Vintage.2 (VR1-2016) Purchase of Remarket (MWh)	2,159	2,131
14	BPA Purchase of Remarket (MWh)	0	0
15	Total	128,579	121,693
16			
17	ShortTerm Remarket Credit	$ -	$ -
18	ShortTerm Remarket Charge	$ -	$ -
19	LoadGrowth Remarket Credit	$ -	$ -
20	LoadGrowth Remarket Charge	$ -	$ -
21	Vintage.1 (VR1-2014)Remarket Credit	$ 1,046,979	$ 803,896
22	Vintage.1 (VR1-2014) Remarket Charge	$ -	$ -
23	Vintage.2 (VR1-2016) Remarket Credit	$ 1,433,476	$ 1,734,131
24	Vintage.2 (VR1-2016) Remarket Charge	$ -	$ -
25	Non-Federal Resource Remarketing Credit	$ 759,563	$ 260,912
26			
27	ShortTerm Open Position (MWh)	220,461	38,742
28	LoadGrowth Open Position (MWh)	6,199	1,266
29	Vintage.1 (VR1-2014) Open Position (MWh)	8,016	911
30	Vintage.2 (VR1-2016) Open Position (MWh)	4,008	729
31	BPA Purchase of Remarket (MWh)	0	0
32	Total Open Position (MWh)	238,684	41,649

Table 3.12
Tier 2 Rate Inputs

	A	B	C	D	E	F	G	H	I
1	**Fiscal Year**	**$/MWh TSS Rate**	**Aurora Flat Annual Block Market Forecast ($/MWh)**	**Augmentation Price ($/MWh)**	**Augmentation Amount (MWh)**	**Remarketing Value ($/MWh)**	**Available Non-Federal Resource Remarketing (MWh)**	**Vintage.1 (VR1-2014) Remarketing (MWh)**	**Vintage.2 (VR1-2016) Remarketing (MWh)**
2	FY2018	$ 0.14	$ 23.14	$ 27.26	-	$ 25.20	30,143	41,549	56,887
3	FY2019	$ 0.14	$ 22.83	$ 26.99	452,760	$ 23.00	11,344	34,952	75,397

Table 3.13
RSS and Related Charges for FY2018 and FY 2019

	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 FY2018 Annual aMW**	**Exh. A FY2019 Annual aMW**	**DFS Energy Rate $/MWh**	**DFS Capacity Charge $/mo**	**DFS Capacity $/MWh Equiv.**
1	Benton Rural Electric Association	Unspecified Resource Amounts	TSS TCMS	FY2018&FY2019	N/A	7.579	8.643	$ -	$ -	$ -
2	Big Bend	Unspecified Resource Amounts	TSS TCMS	FY2018&FY2019	N/A	2.000	3.000	$ -	$ -	$ -
3	Kootenai	Unspecified Resource Amounts	TSS TCMS	FY2018&FY2019	N/A	3.000	3.000	$ -	$ -	$ -
4	Tier 1	Klondike 3 (07PB-11860)	DFS TSS TCMS RSC	FY2018&FY2019	14.747	15.967	15.945	$ 2.42	$ 133,943	$ 12.41
5	City of Bonners Ferry	Moyie	GMS	FY2018&FY2019	N/A	1.881	1.881	$ -	$ -	$ -
6	City of Centralia	Yelm Hydro	GMS	FY2018&FY2019	N/A	7.114	7.114	$ -	$ -	$ -
7	City of Centralia	Unspecified Resource Amounts	TSS	FY2018	N/A	1.000	0.000	$ -	$ -	$ -
8	City of Cheney	Unspecified Resource Amounts	TSS TCMS	FY2018&FY2019	N/A	1.000	2.000	$ -	$ -	$ -
9	City of Forest Grove	Priest Rapids	SCS	FY2018&FY2019	N/A	1.455	1.455	$ -	$ -	$ -
10	City of Forest Grove	Wanapum	SCS	FY2018&FY2019	N/A	1.482	1.482	$ -	$ -	$ -
11	The City of McMinnville, a municipal corporatio	Priest Rapids	SCS	FY2018&FY2019	N/A	1.455	1.455	$ -	$ -	$ -
12	The City of McMinnville, a municipal corporatio	Wanapum	SCS	FY2018&FY2019	N/A	1.482	1.482	$ -	$ -	$ -
13	The City of McMinnville, a municipal corporatio	Riverbend Biogas	DFS FOR RSC	FY2018&FY2019	4.051	4.069	4.069	$ 0.15	$ 12,135	$ 4.09
14	City of Milton-Freewater	Priest Rapids	SCS	FY2018&FY2019	N/A	1.455	1.455	$ -	$ -	$ -
15	City of Milton-Freewater	Wanapum	SCS	FY2018&FY2019	N/A	1.482	1.482	$ -	$ -	$ -
16	Public Utility District No. 1 of Clallam County	Packwood	DFS FOR TSS TCMS RSC	FY2018&FY2019	1.233	0.673	0.673	$ 0.92	$ 7,303	$ 8.09
17	Columbia REA	Walla Walla Hydro	DFS FOR RSC	FY2018&FY2019	1.400	1.231	1.231	$ 0.35	$ 4,112	$ 4.01
18	Columbia REA	Unspecified Resource Amounts	TSS TCMS	FY2018&FY2019	N/A	2.000	2.000	$ -	$ -	$ -
19	Flathead Electric Cooperative, Inc.	Flathead LFGTE	DFS FOR RSC	FY2018&FY2019	1.019	1.077	1.077	$ 0.16	$ 3,476	$ 4.66
20	Flathead Electric Cooperative, Inc.	Stoltze Lumber	DFS FOR RSC	FY2018&FY2019	2.372	2.500	2.500	$ 0.11	$ 10,657	$ 6.14
21	Public Utility District No. 1 of Kittitas County	Priest Rapids	SCS	FY2018&FY2019	N/A	0.484	0.485	$ -	$ -	$ -
22	Public Utility District No. 1 of Kittitas County	Wanapum	SCS	FY2018&FY2019	N/A	0.494	0.494	$ -	$ -	$ -
23	Lower Valley Energy, Inc.	Horse Butte	DFS TSS RSC	FY2018&FY2019	2.648	2.573	2.573	$ 2.29	$ 25,159	$ 12.98
24	Public Utility District No. 3 of Mason County	Packwood	SCS TSS TCMS	FY2018&FY2019	N/A	0.656	0.656	$ -	$ -	$ -
25	Public Utility District No. 3 of Mason County	Nine Canyon Wind	DFS TSS TCMS RSC	FY2018&FY2019	0.867	0.809	0.809	$ 2.83	$ 7,821	$ 12.33
26	Public Utility District No. 3 of Mason County	White Creek Wind	DFS TSS TCMS RSC	FY2018&FY2019	1.005	0.920	0.920	$ 2.53	$ 8,937	$ 12.15
27	Mission Valley Power	Kerr	TSS TCMS	FY2018&FY2019	N/A	9.657	9.657	$ -	$ -	$ -
28	PNGC	Lake Creek	SCS	FY2018&FY2019	N/A	1.530	1.530	$ -	$ -	$ -
29	PNGC	Chester Hydro	DFS FOR RSC	FY2018&FY2019	0.599	0.967	0.967	$ 0.34	$ 1,420	$ 3.24
30	PNGC	Island Park	SCS	FY2018&FY2019	N/A	0.992	0.992	$ -	$ -	$ -
31	PNGC	Unspecified Resource Amounts	TSS TCMS	FY2018&FY2019	N/A	73.669	89.669	$ -	$ -	$ -
32	PNGC	Unspecified Resource Amounts	TSS TCMS	FY2018&FY2019	N/A	35.000	35.000	$ -	$ -	$ -
33	Northern Wasco County People's Utility District	Unspecified Resource Amounts	TSS TCMS	FY2018&FY2019	N/A	7.000	11.000	$ -	$ -	$ -
34	Northern Wasco County People's Utility District	McNary Fishway	GMS TSS	FY2018&FY2019	N/A	4.404	4.404	$ -	$ -	$ -
35	United Electric Co-op, Inc.	Unspecified Resource Amounts	TSS TCMS	FY2018&FY2019	N/A	2.000	2.000	$ -	$ -	$ -
36	Vera Water & Power	Unspecified Resource Amounts	TSS TCMS	FY2018&FY2019	N/A	2.000	2.000	$ -	$ -	$ -
37	Klickitat	McNary Fishway	SCS TSS TCMS	FY2018&FY2019	N/A	4.222	4.222	$ -	$ -	$ -
38	Klickitat	Packwood	SCS TSS TCMS	FY2018&FY2019	N/A	0.197	0.197	$ -	$ -	$ -
39	Klickitat	Unspecified Resource Amounts	TSS TCMS	FY2018&FY2019	N/A	7.000	7.000	$ -	$ -	$ -

Table 3.13 Continued
RSS and Related Charges for FY2018 and FY 2019

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
	RSC $/mo	RSC $/MWh Equiv.	FOR Capacity $/mo	FOR Capacity $/MWh Equiv.	TSS $/mo	TSS $/MWh Equiv.	TCMS $/mo	TCMS $/MWh Equiv.	SCS $/mo	SCS $/MWh Equiv.	GMS $/mo	GMS $/MWh Equiv.	Revenue Credit to Composite Cost Pool FY2018	Revenue Credit to Non-Slice Cost Pool FY2018	Revenue Credit to Composite Cost Pool FY2019	Revenue Credit to Non-Slice Cost Pool FY2019	Forecast Total $/MWh Equivalent Rate
1	$ -	$ -	$ -	$ -	$ 846	$ 0.14	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,147	$ -	$ 10,147	$ -	$ 0.14
2	$ -	$ -	$ -	$ -	$ 272	$ 0.15	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,266	$ -	$ 3,266	$ -	$ 0.15
3	$ -	$ -	$ -	$ -	$ 323	$ 0.15	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,879	$ -	$ 3,879	$ -	$ 0.15
4	$ 34,348	$ 3.18	$ -	$ -	$ 994	$ 0.09	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,619,247	$ 725,780	$ 1,619,247	$ 725,780	$ 18.10
5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 809	$ 0.59	$ 9,703	$ -	$ 9,703	$ -	$ 0.59
6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,470	$ 0.67	$ 41,643	$ -	$ 41,643	$ -	$ 0.67
7	$ -	$ -	$ -	$ -	$ 119	$ 0.16	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,426	$ -	$ -	$ -	$ 0.16
8	$ -	$ -	$ -	$ -	$ 170	$ 0.16	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,040	$ -	$ 2,040	$ -	$ 0.16
9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 677	$ 0.64	$ -	$ -	$ 8,123	$ -	$ 8,123	$ -	$ 0.64
10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 685	$ 0.63	$ -	$ -	$ 8,222	$ -	$ 8,222	$ -	$ 0.63
11	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 677	$ 0.64	$ -	$ -	$ 8,123	$ -	$ 8,123	$ -	$ 0.64
12	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 685	$ 0.63	$ -	$ -	$ 8,222	$ -	$ 8,222	$ -	$ 0.63
13	$ (2,280)	$ (0.77)	$ 1,865	$ 0.63	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 168,003	$ (22,037)	$ 168,003	$ (22,037)	$ 4.10
14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 677	$ 0.64	$ -	$ -	$ 8,123	$ -	$ 8,123	$ -	$ 0.64
15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 685	$ 0.63	$ -	$ -	$ 8,222	$ -	$ 8,222	$ -	$ 0.63
16	$ (10,535)	$ (11.67)	$ 235	$ 0.26	$ 85	$ 0.09	$ -	$ -	$ -	$ -	$ -	$ -	$ 91,478	$ (116,402)	$ 91,478	$ (116,402)	$ (2.31)
17	$ (3,082)	$ (3.01)	$ 473	$ 0.46	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 55,022	$ (32,636)	$ 55,022	$ (32,636)	$ 1.81
18	$ -	$ -	$ -	$ -	$ 221	$ 0.15	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,653	$ -	$ 2,653	$ -	$ 0.15
19	$ (3,192)	$ (4.28)	$ 493	$ 0.66	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 47,627	$ (36,871)	$ 47,627	$ (36,871)	$ 1.20
20	$ (3,273)	$ (1.89)	$ 1,014	$ 0.58	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 140,055	$ (36,986)	$ 140,055	$ (36,986)	$ 4.94
21	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 225	$ 0.64	$ -	$ -	$ 2,705	$ -	$ 2,705	$ -	$ 0.64
22	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 228	$ 0.63	$ -	$ -	$ 2,741	$ -	$ 2,741	$ -	$ 0.63
23	$ (1,991)	$ (1.03)	$ -	$ -	$ 280	$ 0.14	$ -	$ -	$ -	$ -	$ -	$ -	$ 305,263	$ 29,415	$ 305,263	$ 29,415	$ 14.38
24	$ -	$ -	$ -	$ -	$ 73	$ 0.15	$ -	$ -	$ 306	$ 0.64	$ -	$ -	$ 4,542	$ -	$ 4,542	$ -	$ 0.79
25	$ (982)	$ (1.55)	$ -	$ -	$ 88	$ 0.14	$ -	$ -	$ -	$ -	$ -	$ -	$ 94,910	$ 9,725	$ 94,910	$ 9,725	$ 13.75
26	$ (887)	$ (1.21)	$ -	$ -	$ 100	$ 0.14	$ -	$ -	$ -	$ -	$ -	$ -	$ 108,439	$ 11,686	$ 108,439	$ 11,686	$ 13.61
27	$ -	$ -	$ -	$ -	$ 994	$ 0.14	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,931	$ -	$ 11,931	$ -	$ 0.14
28	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 648	$ 0.58	$ -	$ -	$ 7,775	$ -	$ 7,775	$ -	$ 0.58
29	$ 6,607	$ 15.08	$ 186	$ 0.42	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 19,268	$ 81,089	$ 19,268	$ 81,089	$ 19.08
30	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 423	$ 0.58	$ -	$ -	$ 5,080	$ -	$ 5,080	$ -	$ 0.58
31	$ -	$ -	$ -	$ -	$ 2,941	$ 0.05	$ -	$ -	$ -	$ -	$ -	$ -	$ 35,294	$ -	$ 35,294	$ -	$ 0.05
32	$ -	$ -	$ -	$ -	$ 986	$ 0.04	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,831	$ -	$ 11,831	$ -	$ 0.04
33	$ -	$ -	$ -	$ -	$ 928	$ 0.14	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,138	$ -	$ 11,138	$ -	$ 0.14
34	$ -	$ -	$ -	$ -	$ 458	$ 0.14	$ -	$ -	$ -	$ -	$ 2,141	$ 0.67	$ 31,191	$ -	$ 31,191	$ -	$ 0.81
35	$ -	$ -	$ -	$ -	$ 221	$ 0.15	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,653	$ -	$ 2,653	$ -	$ 0.15
36	$ -	$ -	$ -	$ -	$ 221	$ 0.15	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,653	$ -	$ 2,653	$ -	$ 0.15
37	$ -	$ -	$ -	$ -	$ 437	$ 0.14	$ -	$ -	$2,053	$ 0.67	$ -	$ -	$ 29,876	$ -	$ 29,876	$ -	$ 0.81
38	$ -	$ -	$ -	$ -	$ 26	$ 0.18	$ -	$ -	$ 92	$ 0.64	$ -	$ -	$ 1,407	$ -	$ 1,407	$ -	$ 0.82
39	$ -	$ -	$ -	$ -	$ 721	$ 0.14	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,651	$ -	$ 8,651	$ -	$ 0.14

Table 3.14
Calculation of Product Conversion Charge

	B	C	D	E	F	G	H
2							
3		**Previous true-up receipts associated with Regional Cooperation Debt actions.**					
4							
5			**FY2014**	**FY2015**	**Total Amount**		
6		Klickitat PUD (Klickitat)	$ (138,407)	$ (97,697)	$ (236,104)		
7		Seattle City Light (Seattle)	$ (2,122,636)	$ (1,498,302)	$ (3,620,938)		
8							
9		Sum Non-Slice TOCA*	74.98778%				
10		Seattle New Non-Slice TOCA	3.62324%				
11		Klickitat New Non-Slice TOCA	0.23625%				
12		Sum New Non-Slice TOCA Switch	3.85949%				
13							
14		Seattle Slice True-up Receipts (FY 2014-2016)	$ (3,620,938)				
15		Klickitat Slice True-up Receipts (FY 2014-2016)	$ (236,104)				
16							
17		Gross up factor [(line9)/ (line 9 - line 12)]**	105.42610%				
18		Seattle Pay Adjusted for Share of Share	$ (3,817,414)				
19		Klickitat Pay Adjusted for Share of Share	$ (248,915)				
20		Monthly Product Switch Charge					
21		Seattle Product Conversion Charge (monthly)	$ (159,059)				
22		Klickitat Product Conversion Charge (monthly)	$ (10,371)				
23							
24		Non-Slice Cost Pool Revenue Credit	$ (4,066,329)				
25		Impact on Non-Slice Rate (%/Non-Slice TOCA/mo)	$ (2,259)				
26							
27		*Includes Seattle and Klickitat's converted loads.					
28		**Gross-up factor to account for monies paid by Seattle and Klickitat are allocated to the Non-Slice cost					
29		pool, and Seattle and Klickitat's new Non-Slice load (formerly Slice) will receive a share of these monies back through the Non-Slice rate.					

SECTION 4: RATE SCHEDULES

This page intentionally left blank.

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 4.1
Tier 1 Demand Rate

	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)	2018		2011	103.31		Oct	26.74	8.90%	$ 10.45
3	Cost of Debt	3.80%	/1	2012	105.21		Nov	27.27	9.07%	$ 10.65
4				2013	106.91		Dec	30.28	10.07%	$ 11.83
5	Inflation Rate	1.53%		2014	108.83		Jan	29.30	9.75%	$ 11.45
6	Insurance Rate	0.25%	/2	2015	110.00		Feb	28.54	9.49%	$ 11.15
7				2016	111.45		Mar	23.75	7.90%	$ 9.28
8	Debt Finance Period (years)	30	/2				Apr	19.67	6.54%	$ 7.68
9	Plant Lifecycle (years)	30	/2		101.53%	5-year Ave.	May	16.63	5.53%	$ 6.49
10							Jun	17.71	5.89%	$ 6.92
11	Plant in service 2018 Vintaged Heat Rate Btu/kWh	8,541	/2	Chained GDP IPD from BEA -- Table 1.1.9. Implicit Price Deflators for Gross Domestic Product (2009 Base year)- Last Revised April 28, 2017			Jul	24.66	8.20%	$ 9.63
12							Aug	28.11	9.35%	$ 10.98
13	Eastside Fixed Fuel $/kW/yr with 10000 Heat Rate 2012$	$ 41.17	/2				Sep	27.94	9.29%	$ 10.91
14	Westside Fixed Fuel $/kW/yr with 10000 Heat Rate 2012$	$ 45.49	/2						**Average $/kW/mo**	**$ 9.79**
15	Eastside Fixed Fuel $/kW/yr with 10000 Heat Rate 2018$	$ 45.09								
16	Westside Fixed Fuel $/kW/yr with 10000 Heat Rate 2018$	$ 49.82								
17	Average of Existing Eastside and Westside with 10000 Heat Rate 2018$	$ 47.46								
18	Average of Existing Eastside and Westside with 8541 Heat Rate 2018$	$ 40.53								
19										
20	All-in Nominal Capital Cost LMS100 $/kW	$ 1,095.21	/3	**End of Fiscal Year**	**Midyear Assessed Value**	**Debt Payment**	**Fixed O&M**	**Insurance**	**Fixed Fuel**	**Cash Expense Each Year**
21	Fixed O&M $/kW/yr 2018$	12.05	/4	2018	$ 1,076.96	$61.81	$ 12.05	$ 2.69	$ 40.53	$ 117.08
22	Fixed Fuel $/kW/yr	$ 40.53		2019	$ 1,040.45	$61.81	$ 12.23	$ 2.60	$ 41.15	$ 117.79
23									**Rate Period Average Expense $/kW/year**	**$ 117.44**
24										
25	/1 Source BPA FY 2017 Third-Party Tax-Exempt Borrowing Rate Forecast 30-year									
26	/2 Source NWPCC 7th Power Plan Appendix H.									
27	/3 Source NWPCC Microfin Model with 100% PUD ownership at 3.80% with plant in service 2018. Version 15.2.1									
28	/4 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-17	27.55	23.25		October	26.74	22.49
4	Nov-17	28.16	25.55		November	27.27	24.74
5	Dec-17	30.76	26.98		December	30.28	26.60
6	Jan-18	29.80	24.32		January	29.30	23.94
7	Feb-18	28.60	23.93		February	28.54	23.94
8	Mar-18	23.94	20.93		March	23.75	20.80
9	Apr-18	19.81	17.55		April	19.67	17.54
10	May-18	16.48	10.85		May	16.63	11.25
11	Jun-18	16.80	8.32		June	17.71	9.31
12	Jul-18	24.96	19.39		July	24.66	19.05
13	Aug-18	27.93	22.59		August	28.11	22.61
14	Sep-18	27.93	22.21		September	27.94	22.19
15	Oct-18	25.93	21.72				
16	Nov-18	26.39	23.94				$/MWh
17	Dec-18	29.80	26.23	FY2018 Aurora Flat Annual Block			23.14
18	Jan-19	28.80	23.57	FY2019 Aurora Flat Annual Block			22.83
19	Feb-19	28.48	23.95				
20	Mar-19	23.56	20.66				
21	Apr-19	19.53	17.53				
22	May-19	16.78	11.66				
23	Jun-19	18.62	10.31				
24	Jul-19	24.35	18.72				
25	Aug-19	28.29	22.64				
26	Sep-19	27.96	22.17				

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_FY2018	LG.1.2012_2028	FY2018	5.908	6.089
3	LG.1.2012_2028_FY2019	LG.1.2012_2028	FY2019	6.857	7.067
4	ST.2.2015_2019_FY2018	ST.2.2015_2019	FY2018	37.574	38.724
5	ST.2.2015_2019_FY2019	ST.2.2015_2019	FY2019	49.820	51.345
6	V.1.2014_2018_FY2018	V.1.2014_2018	FY2018	46.000	47.408
7	V.1.2014_2018_FY2019	V.1.2014_2018	FY2019	46.000	47.408
8	V.2.2016_2019_FY2018	V.2.2016_2019	FY2018	23.000	23.704
9	V.2.2016_2019_FY2019	V.2.2016_2019	FY2019	27.000	27.826
10					
11	*Notes*				
12	(1) Based on a losses factor of 3.06%				

SECTION 5: GENERAL RATE SCHEDULE PROVISIONS

This page intentionally left blank.

Table Descriptions

Table 5.1
Weighted LDD for IRD Eligible Utilities
Table shows the weighted LDD calculation for all IRD eligible utilities using the customers' contract CHWM.

Table 5.2.1
Customers Receiving a VR1-2014 Tier 2 Remarketing Credit
List of customers with remarketed VR1-2014 purchases and their associated credits.

Table 5.2.2
Customers Receiving a VR1-2016 Tier 2 Remarketing Credit
List of customers with remarketed VR1-2016 purchases and their associated credits.

Table 5.3
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	3.50%	1,549.455
10	10046	Central Elec	4,687.388	8,675.756	9,539.100	10,094.599	8,088.614	41,085.457	7.00%	2,875.982
11	10109	Columbia Basin	4,185.302	5,469.756	4,513.543	3,665.441	3,266.293	21,100.335	7.00%	1,477.023
12	10111	Columbia Power	706.641	866.742	1,530.227	1,432.169	691.870	5,227.649	7.00%	365.935
13	10113	Columbia REA	21,258.914	30,832.646	36,368.973	29,431.678	16,763.751	134,655.962	7.00%	9,425.917
14	10173	Fall River	721.884	12,605.402	20,135.316	9,028.407	1,818.987	44,309.996	7.00%	3,101.700
15	10197	Harney	19,540.495	20,142.982	26,028.119	22,023.182	12,164.427	99,899.205	7.00%	6,992.944
16	10209	Inland	10,963.601	14,641.767	12,471.610	11,584.325	10,451.398	60,112.701	7.00%	4,207.889
17	10242	Lost River	3,725.641	9,902.214	10,705.288	8,479.424	4,746.327	37,558.894	7.00%	2,629.123
18	10256	Midstate	7,679.733	8,829.777	11,222.582	9,712.913	4,044.309	41,489.314	6.50%	2,696.805
19	10273	Nespelem	1,216.565	1,778.549	2,517.152	2,274.786	1,734.973	9,522.025	7.00%	666.542
20	10291	OTEC	4,715.415	7,780.401	10,076.149	7,938.224	5,750.412	36,260.601	5.00%	1,813.030
21	10331	Raft River	23,443.131	30,794.718	32,636.209	27,344.114	18,868.686	133,086.858	7.00%	9,316.080
22	10142	East End	1,061.340	1,353.162	1,240.237	1,171.183	943.562	5,769.484	3.00%	173.085
23	10338	Riverside	528.123	986.578	1,167.444	906.478	566.587	4,155.210	4.00%	166.208
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	6.00%	630.340
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	5.50%	12,582.483
28	10442	Wasco	1,883.529	2,101.872	2,215.155	1,766.387	1,766.387	9,733.330	7.00%	681.333
29	10446	Wells	846.538	1,717.671	1,928.492	1,812.765	865.874	7,171.340	6.00%	430.280
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	6.50%	1,195.156
33								**Wt. LDD**	**4.9%**	

Table 5.2.1 VR1-2014
Customers Receiving a VR1-2014 Tier 2 Remarketing Credit

	A	B	C	D	E	F	G	H	I	J	K	L
1		**2018**						**2019**				
2	**Customers Remarketing**	**Remarketing Amount**	**Remarketing Amount**	**Allocation**	**Remarketing Credit**	**Remarketing Credit**		**Remarketing Amount**	**Remarketing Amount**	**Allocation**	**Remarketing Credit**	**Remarketing Credit**
3	**VR1-2014 Purchases**	**aMW**	**MWh**	**Percentage**	**Allocation**	**Monthly**		**aMW**	**MWh**	**Percentage**	**Allocation**	**Monthly**
4	Burley, City of	1.000	8,760	21.08%	$220,742	$18,395		1.000	8,760	25.06%	$201,478	$16,790
5	Ellensburg, City of	1.000	8,760	21.08%	$220,742	$18,395		1.000	8,760	25.06%	$201,478	$16,790
6	Peninsula Light Company, Inc.	1.000	8,760	21.08%	$220,742	$18,395		1.000	8,760	25.06%	$201,478	$16,790
7	Tanner	0.104	911	2.19%	$22,957	$1,913		0.000	0	0.00%	$0	$0
8	Wells Rural Electric Company	1.639	14,358	34.56%	$361,796	$30,150		0.990	8,672	24.81%	$199,463	$16,622
9	Total VR1-2014 Remarketing	4.743	41,549	100.00%	$1,046,979	$87,248		3.990	34,952	100.00%	$803,896	$66,991

Table 5.2.2 VR1-2016
Customers Receiving a VR1-2016 Tier 2 Remarketing Credit

	A	B	C	D	E	F	G	H	I	J	K	L
1		**2018**						**2019**				
2	**Customers Remarketing**	**Remarketing Amount**	**Remarketing Amount**	**Allocation**	**Remarketing Credit**	**Remarketing Credit**		**Remarketing Amount**	**Remarketing Amount**	**Allocation**	**Remarketing Credit**	**Remarketing Credit**
3	**VR1-2016 Purcahses**	**aMW**	**MWh**	**Percentage**	**Allocation**	**Monthly**		**aMW**	**MWh**	**Percentage**	**Allocation**	**Monthly**
4	Burley, City of	1.994	17,467	30.71%	$440,153	$36,679		1.966	17,222	22.84%	$396,108	$33,009
5	Clallam County Public Utility District No. 1	0.826	7,236	12.72%	$182,330	$15,194		1.330	11,651	15.45%	$267,967	$22,331
6	Ellensburg, City of	0.582	5,098	8.96%	$128,470	$10,706		0.520	4,555	6.04%	$104,769	$8,731
7	Inland Power and Light Company	0.000	0	0.00%	$0	$0		0.791	6,929	9.19%	$159,370	$13,281
8	Richland	0.092	806	1.42%	$20,308	$2,114		0.000	0	0.00%	$0	$0
9	Springfield	3.000	26,280	46.20%	$662,215	$55,185		4.000	35,040	46.47%	$805,917	$67,160
10	Total VR1-2016 Remarketing	6.494	56,887	100.00%	$1,433,476	$119,878		8.607	75,397	100.00%	$1,734,131	$144,511

Table 5.3 Non-Federal
Customers Receiving Remarketing Credits for Non-Federal Resources with DFS

	A	B	C	D	E	F
1		**2018**				
2		**Remarketing Amount**	**Remarketing Amount**	**Allocation**	**Remarketing Credit**	**Remarketing Credit**
3	**Customers Remarketing Non-Federal Resources**	**aMW**	**MWh**	**Percentage**	**Allocation**	**Monthly**
4	McMinnville Water and Light	3.441	30,143	100.00%	$759,563	$63,297
5	Total VR1-2016 Remarketing	3.441	30,143	100.00%	$759,563	$63,297
6		**2019**				
7		**Remarketing Amount**	**Remarketing Amount**	**Allocation**	**Remarketing Credit**	**Remarketing Credit**
8	**Customers Remarketing Non-Federal Resources**	**aMW**	**MWh**	**Percentage**	**Allocation**	**Monthly**
9	McMinnville Water and Light	1.295	11,344	100.00%	$260,912	$21,743
10	Total VR1-2016 Remarketing	1.295	11,344	100.00%	$260,912	$21,743

SECTION 6: TRANSFER SERVICE

This page intentionally left blank.

Table Descriptions

Table 6.1
Southeast Idaho Load Service (SILS) Market Purchases
Table shows SILS Monthly Power Purchase Segmented by cost pool and by fiscal year for the duration of the interim service agreement for the five year period commencing July 2016 through June of 2021.

Table 6.2
Southeast Idaho Load Service Five-Year Market Purchases
Table provides additional details on computation of SILS costs that went into Table 6.1.

Table 6.1
Southeast Idaho Load Service Market Purchases - Monthly Power Purchase Segmented by Cost Pool and by Fiscal Year

	A	B	C	D	E	F	G
		Composite Delta		**Non Slice Allocation**		**Total Purchase Cost**	
	Month	**FY 2018**	**FY 2019**	**FY 2018**	**FY 2019**	**FY 2018**	**FY 2019**
1	October	$ 509,648	$ 512,052	$ 3,468,320	$ 3,484,680	$ 3,977,968	$ 3,996,732
2	November	$ 493,421	$ 493,421	$ 3,357,890	$ 3,357,890	$ 3,851,311	$ 3,851,311
3	December	$ 507,244	$ 507,244	$ 3,451,960	$ 3,451,960	$ 3,959,204	$ 3,959,204
4	January	$ 509,648	$ 509,648	$ 3,468,320	$ 3,468,320	$ 3,977,968	$ 3,977,968
5	February	$ 461,568	$ 461,568	$ 3,141,120	$ 3,141,120	$ 3,602,688	$ 3,602,688
6	March	$ 511,451	$ 509,047	$ 3,480,590	$ 3,464,230	$ 3,992,041	$ 3,973,277
7	April	$ 396,660	$ 403,872	$ 2,948,200	$ 3,007,232	$ 3,344,860	$ 3,411,104
8	May	$ 411,084	$ 411,084	$ 3,056,312	$ 3,056,312	$ 3,467,396	$ 3,467,396
9	June	$ 403,872	$ 396,660	$ 3,007,232	$ 2,948,200	$ 3,411,104	$ 3,344,860
10	July	$ 403,872	$ 411,084	$ 2,997,280	$ 3,056,312	$ 3,401,152	$ 3,467,396
11	August	$ 418,296	$ 418,296	$ 3,115,344	$ 3,115,344	$ 3,533,640	$ 3,533,640
12	September	$ 389,448	$ 389,448	$ 2,889,168	$ 2,889,168	$ 3,278,616	$ 3,278,616
13	FY Total (Sum lines 1-12)	$ 5,416,212	$ 5,423,424	$ 38,381,736	$ 38,440,768	$ 43,797,948	$ 43,864,192
14	Total Service Cost		**$ 10,839,636**		**$ 76,822,504**		**$ 87,662,140**

Monthly Cost Breakdown

Table 6.1 displays the total monthly costs resulting from lines 21 (columns D & E), 23 (columns F & G), and 27 (columns B & C) of table 6.2. To do this additional calculations are needed. The average market delta (AMD) established in Step 8 of Table 6.2 is applied to the following formula $((M_H * SM_H) + (M_L * SM_L)) * AMD$. The Monthly heavy and light hours are multiplied by the contracted megawatt hours in the market purchases, and then multiplied by the average market delta resulting in the amounts shown in the table above. For the FY 2018 and 2019 rates, the annual totals for each fiscal year are added to the transfer services budget and thus included in the composite cost pool. Swaping out AMD for WFM (line 21) or WCP (line 23) will get the results in columns D & E and F & G respectivly.

Table 6.2
Southeast Idaho Load Service Five-Year Market Purchases

Steps	Parameter Definitions
Step 1: $((SM_H * S_H) + (SM_L * S_L)) / S_F = SM_F$ Step 1 calculates the combined summer flat weighted average megawatts associated with the five-year market purchases (SM_F). *See* Documentation Table 6.2, line 4. Summer and winter portions of the contract are addressed separately because of the different megawatt amounts associated with each period. This is achieved by taking the summer contracted megawatts multiplied by the associated hours for both heavy and light load, then dividing by the total hours for that period. **Step 2:** $((WM_H * W_H) + (WM_L * W_L)) / W_F = WM_F$ Step 2 calculates the combined winter flat weighted average megawatts associated with the five-year market purchases (WM_F). *See* Documentation Table 6.2, line 12. The calculation process for the winter equation is the same as the summer equation described in line 4. **Step 3:** $SUM (W_F, S_F) = TCH$ Step 3 calculates the sum of all megawatt hours associated with the market purchases (TCH) in line 17. **Step 4:** $((SM_F * S_F) + (WM_F * W_F)) / SUM (W_F, S_F) = TCM$ Once the combined flat weighted average has been calculated for the summer and winter portions of the market purchase, Step 4 calculates flat weighted average megawatts for the entire market purchase (TCM) on line 19. **Step 5:** $((M_1 * RMh_1) + (M_2 * RMh_2)) / TCH = WFM$ Step 5 calculates the weighted average forward market price (WFM) using the ICE forward market curves established at the time each purchase was finalized. To do so, the weighted average market price represented by "M" for each purchase is multiplied by its respective megawatthours (RMH) and then divided by the total megawatthours to yield the WFM, on line 21. **Step 6:** $((R_1 * RMh_1) + (R_2 * RMh_2)) / TCH = WCP$ Step 6 follows the same steps as in steps 1 through 5 but uses each contract's offer price in place of the ICE forward market price to yield the weighted average contract price (WCP), on line 23. **Step 7:** $(TCH * TCM * WCP) = TCC$ Step 7 multiplies the results from steps 3, 4, and 6 to yield the Total Contract Cost (TCC) on line 25. **Step 8:** $(WCP – WFM) = AMD$ Step 8 subtracts the result from Step 6 from the result in Step 5 to yield the Average Market Delta (AMD). The AMD will help determine the total cost to the transfer service customers, on line 27. **Step 9:** $(AMD * TCM) = T$ Step 9 multiplies the Average Market Delta by the TCM to yield the Total Transfer Service Cost (T) on line 29. Monthly values are shown in Table 6.1.	AMD = Average Market Delta M_H = Month heavy hours M_L = Month light hours M_1 = weighted forward market purchase #1 price M_2 = weighted forward market purchase #2 price R_1 = Market purchase #1 offer price R_2 = Market purchase #2 offer price R_A = RFO 1 & 2 weighted average market price RMh_1 = Market purchase #1 contract MW hours RMh_2 = Market purchase #2 contract MW hours S_F = summer flat hours S_H = summer heavy hours S_L = summer light hours SM_F = summer market purchase contract total MW flat SM_H = summer market purchase contract total MW heavy SM_L = summer market purchase contract total MW light T = Transfer service cost TCB = Total Contract Cost TCH = Total Contract Megawatt hours TCM = Total Contract average Megawatts W_F = winter flat hours W_H = winter heavy hours W_L = winter light hours WCP = Weighted average Contract Price WFM = Weighted average Forward Market price WM_F = winter market purchase contract MW flat load WM_H = winter market purchase contract MW heavy load WM_L = winter market purchase contract MW light load

Table 6.2 (continued)
Southeast Idaho Load Service Five-Year Market Purchases

	A	B	C	D
1	**Summer**	**MW**	**MWh**	**MW (SMF)**
2	HLH	125	1,538,000	
3	LLH	50	482,800	
4	Step 1. Flat			92
5				
6	**Summer**	**HLH**	**LLH**	**Flat**
7	Hours	12,304	9656	21,960
8				
9	**Winter**	**MW**	**MWh**	**MW (WMF)**
10	HLH	125	1,532,000	
11	LLH	100	960,800	
12	Step 2. Flat			114
13				
14	**Winter**	**HLH**	**LLH**	**Flat**
15	Hours	12,256	9,608	21,864
16				
17	Step 3. Total Contract Hours (TCH)			43,824
18				
19	Step 4. Total aMW (TCM)			103
20				
21	Step 5. Market (WFM)			$42.59
22				
23	Step 6. RFO (WCP)			$48.61
24				
25	Step 7. Total Contract Cost (TCC)			$219,386,064
26				
27	Step 8. Delta (AMD)			$6.01
28				
29	Step 9. Total Transfer Service Cost (T)			$27,131,407

SECTION 7: SLICE

No Documentation

SECTION 8: AVERAGE SYSTEM COSTS

This page intentionally left blank.

Table Descriptions

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

Table 8.2
IOUs Residential Loads and COUs Forecast Exchange Loads (MWh)
Table lists the monthly two-year average IOU Residential 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 2018**		**FY 2019**	
2	Avista	$	54.67	$	54.67
3	Idaho Power	$	63.09	$	63.09
4	NorthWestern	$	78.46	$	78.46
5	PacifiCorp	$	79.55	$	79.55
6	PGE	$	75.76	$	75.76
7	Puget Sound Energy	$	71.13	$	71.13
8	Clark	$	56.48	$	56.48
9	Snohomish	$	52.66	$	53.99
10					
11	Note: Rate Period ASCs are determined through the ASC review process				

Table 8.2

IOUs FY 2018 - 2019 Residential Loads
(MWh)

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1		**Oct-17**	**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**FY 2018**
2	Avista	235,059	280,401	402,323	448,767	389,685	323,113	285,615	246,792	250,943	295,440	292,870	276,912	**3,727,921**
3	Idaho Power	435,054	406,738	546,939	621,373	540,206	457,486	441,140	461,081	535,363	709,911	693,675	625,158	**6,474,123**
4	NorthWestern	45,442	50,050	65,531	76,141	63,495	57,263	51,200	47,548	49,566	53,945	54,790	49,877	**664,848**
5	PacifiCorp	568,701	646,821	942,865	987,012	790,439	694,242	620,509	598,231	648,469	767,394	747,902	677,969	**8,690,553**
6	PGE	546,339	610,880	863,875	929,728	739,082	677,540	623,901	574,768	604,283	669,078	671,109	643,249	**8,153,832**
7	Puget Sound Energy	763,865	904,657	1,232,152	1,339,430	1,168,987	1,062,152	914,128	780,817	757,239	763,013	773,209	749,716	**11,209,366**
8														
9		**Oct-18**	**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**FY 2019**
10	Avista	235,059	280,401	402,323	448,767	389,685	323,113	285,615	246,792	250,943	295,440	292,870	276,912	**3,727,921**
11	Idaho Power	435,054	406,738	546,939	621,373	540,206	457,486	441,140	461,081	535,363	709,911	693,675	625,158	**6,474,123**
12	NorthWestern	45,442	50,050	65,531	76,141	63,495	57,263	51,200	47,548	49,566	53,945	54,790	49,877	**664,848**
13	PacifiCorp	568,701	646,821	942,865	987,012	790,439	694,242	620,509	598,231	648,469	767,394	747,902	677,969	**8,690,553**
14	PGE	546,339	610,880	863,875	929,728	739,082	677,540	623,901	574,768	604,283	669,078	671,109	643,249	**8,153,832**
15	Puget Sound Energy	763,865	904,657	1,232,152	1,339,430	1,168,987	1,062,152	914,128	780,817	757,239	763,013	773,209	749,716	**11,209,366**
16														
17														
18							COUs FY 2018 - 2019 Forecast Exchange Loads							
19							(MWh)							
20														
21		**Oct-17**	**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**FY 2018**
22	Clark	189,749	250,417	311,350	296,215	240,108	241,851	189,280	170,649	152,508	169,338	170,685	152,787	**2,534,938**
23	Snohomish	265,465	256,266	395,039	445,197	400,782	391,024	365,636	279,551	242,754	232,808	244,564	195,483	**3,714,569**
24														
25		**Oct-18**	**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**FY 2019**
26	Clark	189,643	250,450	311,420	296,461	240,146	241,974	189,199	170,576	152,460	169,363	170,743	152,685	**2,535,119**
27	Snohomish	266,472	257,183	397,106	447,674	402,881	393,033	367,426	280,622	243,514	233,481	229,209	211,970	**3,730,571**
28														
29														

This page intentionally left blank.

SECTION 9: REVENUE FORECAST

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
Composite and Non-Slice Revenue – FY 2018-2019
Table shows calculation of CHWM revenues at proposed rates.

Table 9.4
Load Shaping and Demand Review – FY 2018-2019
Table shows calculation of CHWM revenues at proposed rates.

Table 9.5
Irrigation Rate Discount (IRD) – FY 2018-2019
Table shows calculation of IRD credit at proposed rates.

Table 9.6
Low Density Discount (LDD) – FY 2018-2019
Table shows calculation of LDD credit at proposed rates.

Table 9.7
Tier 2 Revenue – FY 2018-2019
Table shows calculation of CHWM revenues at proposed rates.

Table 9.8
Direct Service Industries (DSI) Revenues – FY 2018-2019
Table shows calculation of DSI revenues at current and proposed rates.

Table 9.9
Inter-Business Line Allocations
The forecasted 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 9.10
Balancing Reserve Capacity Quantity Forecast for FY 2018-2019
The forecasted 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**														
2	**Category**	**201610**	**201611**	**201612**	**201701**	**201702**	**201703**	**201704**	**201705**	**201706**	**201707**	**201708**	**201709**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 200,597	$ 200,597	$ 200,597	$ 200,633	$ 200,578	$ 200,578	$ 200,578	$ 200,578	$ 200,578	$ 200,578	$ 200,578	$ 200,578	$ 2,407,050	6,776
4	Non-Slice Revenue	$ (21,658)	$ (21,658)	$ (21,658)	$ (21,664)	$ (21,655)	$ (21,717)	$ (21,717)	$ (21,717)	$ (21,717)	$ (21,717)	$ (21,717)	$ (21,717)	$ (260,314)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
6	Load Shaping Revenue	$ (3,979)	$ (14,180)	$ 19,465	$ 38,975	$ 24,635	$ 2,395	$ 5,713	$ (32,422)	$ (16,409)	$ (575)	$ (7,146)	$ 2,727	$ 19,201	(34)
7	Demand Revenue	$ 1,353	$ 1,097	$ 6,550	$ 9,341	$ 3,224	$ 5,007	$ 3,236	$ 2,293	$ 2,835	$ 3,470	$ 5,319	$ 4,080	$ 47,805	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,414)	$ (5,102)	$ (5,876)	$ (4,822)	$ (2,933)	$ (22,146)	-
9	Low Density Discount	$ (2,722)	$ (2,465)	$ (3,639)	$ (4,207)	$ (3,566)	$ (2,894)	$ (3,047)	$ (2,399)	$ (2,859)	$ (3,288)	$ (3,178)	$ (3,120)	$ (37,383)	-
10	Tier 2	$ 2,378	$ 2,297	$ 2,378	$ 2,378	$ 2,124	$ 2,279	$ 2,290	$ 2,279	$ 2,290	$ 2,279	$ 2,279	$ 2,290	$ 27,542	70
11	RSS (Non-Federal)	$ 16	$ (37)	$ (56)	$ (28)	$ (92)	$ 140	$ 140	$ 140	$ 140	$ 140	$ 140	$ 140	$ 779	-
12	Load Shaping True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,069)	$ (2,069)	-
13	**PF customers (TRM) sub-total**	**$ 175,985**	**$ 165,651**	**$ 203,637**	**$ 225,428**	**$ 205,248**	**$ 185,788**	**$ 187,193**	**$ 145,338**	**$ 159,757**	**$ 175,010**	**$ 171,453**	**$ 179,976**	**$ 2,180,463**	**6,812**
14	**NR sub-total**	**$ (45)**	**$ (17)**	**$ (45)**	**$ (70)**	**$ (21)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ (198)**	**-**
15	**DSIs sub-total**	**$ 707**	**$ 684**	**$ 714**	**$ 762**	**$ 651**	**$ 1,115**	**$ 1,051**	**$ 600**	**$ 589**	**$ 676**	**$ 727**	**$ 723**	**$ 8,998**	**24**
16	**FPS sub-total**	**$ 443**	**$ 447**	**$ 664**	**$ 706**	**$ 538**	**$ 238**	**$ 217**	**$ 212**	**$ 197**	**$ 85**	**$ 75**	**$ 65**	**$ 3,886**	**8**
17	**Short-term market sales sub-total**	**$ 19,000**	**$ 27,831**	**$ 24,364**	**$ 30,347**	**$ 37,308**	**$ 46,997**	**$ 29,642**	**$ 43,116**	**$ 47,512**	**$ 54,346**	**$ 26,538**	**$ 21,330**	**$ 408,330**	**1,696**
18	**Long Term Contractual Obligations sub-total**	**$ 29**	**$ 7,110**	**$ 7,328**	**$ 7,307**	**$ 6,684**	**$ 3,655**	**$ 3,565**	**$ 61**	**$ 77**	**$ 64**	**$ 72**	**$ 46**	**$ 35,998**	**90**
19	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**114**
20	**Renewable Energy Certificates sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 648**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 648**	**-**
21	Miscellaneous Credits	$ 14	$ 9	$ 31	$ 23	$ 16	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 94	-
22	Slice True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,458)	$ (5,458)	-
23	**Other Sales sub-total**	**$ 14**	**$ 9**	**$ 31**	**$ 23**	**$ 16**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ (5,458)**	**$ (5,364)**	**-**
24	**Gross Sales**	**$196,133**	**$201,714**	**$236,693**	**$264,503**	**$250,423**	**$238,441**	**$221,667**	**$189,327**	**$208,132**	**$230,182**	**$198,863**	**$196,681**	**$2,632,760**	**8,744**
25	GTA Delivery charge	$ 256	$ 268	$ 447	$ 385	$ 322	$ 385	$ 330	$ 345	$ 365	$ 410	$ 375	$ 315	$ 4,203	-
26	Energy Efficiency Revenues	$ (37)	$ (73)	$ 12	$ 617	$ (392)	$ 1,113	$ 1,113	$ 1,113	$ 1,113	$ 1,113	$ 1,113	$ 1,113	$ 7,917	-
27	Irrigation Pumping Power	$ 49	$ 115	$ 149	$ 231	$ 229	$ 140	$ 53	$ 11	$ 6	$ 6	$ 6	$ 7	$ 1,003	15
28	Reserve Energy	$ 914	$ 914	$ 914	$ 914	$ 914	$ 914	$ 914	$ 914	$ 914	$ 914	$ 914	$ 914	$ 10,963	162
29	Downstream Benefits	$ 544	$ 544	$ 544	$ 544	$ 544	$ 547	$ 547	$ 547	$ 547	$ 547	$ 547	$ 547	$ 6,551	-
30	Upper Baker Revenues	$ -	$ 102	$ 102	$ 102	$ 103	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 409	1
31	**Miscellaneous Revenue**	**$1,726**	**$1,870**	**$2,169**	**$2,792**	**$1,720**	**$3,099**	**$2,956**	**$2,930**	**$2,944**	**$2,989**	**$2,954**	**$2,896**	**$31,045**	**178**
32	Balancing Reserve Capacity for Regulating Reserve	$ 4,236	$ 4,236	$ 4,236	$ 4,236	$ 4,236	$ 4,236	$ 4,236	$ 4,236	$ 4,236	$ 4,236	$ 4,236	$ 4,236	$ 50,835	-
33	Balancing Reserve Capacity for VERBS wind, VERBS solar and DERBS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
34	Expected Balancing Reserve Capacity Sales in Spring Months from FCRPS Above Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ -	$ -	$ 4,000	-
35	Capacity Unavailable from FCRPS	$ (68)	$ -	$ -	$ -	$ -	$ (2,161)	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,229)	-
36	Operating Reserve - Spinning	$ 1,696	$ 1,815	$ 2,231	$ 2,292	$ 1,974	$ 2,217	$ 2,078	$ 2,177	$ 2,308	$ 2,187	$ 1,955	$ 1,731	$ 24,661	-
37	Operating Reserve - Supplemental	$ 1,555	$ 1,664	$ 2,045	$ 2,101	$ 1,809	$ 2,032	$ 1,905	$ 1,996	$ 2,116	$ 2,005	$ 1,792	$ 1,587	$ 22,606	-
38	Synchronous Condensing	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 1,610	-
39	Generation Dropping	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 415	-
40	Redispatch	$ 10	$ 18	$ 13	$ 5	$ 22	$ 22	$ 22	$ 22	$ 22	$ 22	$ 22	$ 22	$ 222	-
41	Segmentation of COE/Reclamation Network and Delivery Facilities	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 7,367	-
42	Station Service	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 2,479	9
43	Energy Imbalance	$ (37)	$ 83	$ 137	$ 186	$ 7	$ 149	$ 147	$ 83	$ 78		$ (131)	$ (100)	$ 661	-
44	Generation Imbalance	$ 332	$ 180	$ -	$ -	$ 183	$ 739	$ 790	$ 891	$ 300	$ 629	$ 826	$ 574	$ 5,444	-
45	Operating Reserve - Energy	$ 68	$ 22	$ 117	$ 171	$ 35	$ 8	$ 16	$ 12	$ 10	$ 37	$ 28	$ 24	$ 548	-
46	**Generation Inputs / Inter-business line**	**$ 8,781**	**$ 9,008**	**$ 9,769**	**$ 9,980**	**$ 9,255**	**$ 8,232**	**$ 11,184**	**$ 11,407**	**$ 11,059**	**$ 11,165**	**$ 9,718**	**$ 9,063**	**$ 118,622**	**9**
47	4(h)(10)(c)	$ 6,600	$ 7,348	$ 5,904	$ 4,432	$ 1,510	$ 5,954	$ 4,038	$ 5,680	$ 5,680	$ 5,680	$ 5,296	$ 7,343	$ 65,466	-
48	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
49	**Treasury Credits**	**$ 6,983**	**$ 7,731**	**$ 6,288**	**$ 4,815**	**$ 1,893**	**$ 6,337**	**$ 4,421**	**$ 6,064**	**$ 6,064**	**$ 6,064**	**$ 5,680**	**$ 7,727**	**$ 70,066**	**-**
50	**Augmentation Power Purchase sub-total**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
51	**Balancing Power Purchase sub-total**	$ (485)	$ 3,957	$ 11,308	$ 22,491	$ 8,114	$ 4,702	$ 6,371	$ 3,119	$ 3,076	$ 3,173	$ 6,379	$ 3,125	$ 75,332	181
52	**Other Power Purchase sub-total**	**$ 2,257**	**$ 2,188**	**$ 2,258**	**$ 2,258**	**$ 2,039**	**$ 2,255**	**$ 2,185**	**$ 2,258**	**$ 2,185**	**$ 2,258**	**$ 2,258**	**$ 2,185**	**$ 26,582**	**67**
53	**Power Purchases**	**$ 1,772**	**$ 6,145**	**$ 13,566**	**$ 24,749**	**$ 10,154**	**$ 6,957**	**$ 8,556**	**$ 5,377**	**$ 5,261**	**$ 5,430**	**$ 8,637**	**$ 5,310**	**$ 101,914**	**248**

Table 9.1 - 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**														
2	**Category**	**201710**	**201711**	**201712**	**201801**	**201802**	**201803**	**201804**	**201805**	**201806**	**201807**	**201808**	**201809**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 199,379	$ 199,379	$ 199,379	$ 199,379	$ 199,379	$ 199,379	$ 199,379	$ 199,379	$ 199,379	$ 199,379	$ 199,379	$ 199,379	$ 2,392,551	6,713
4	Non-Slice Revenue	$ (22,668)	$ (22,668)	$ (22,668)	$ (22,668)	$ (22,668)	$ (22,668)	$ (22,668)	$ (22,668)	$ (22,668)	$ (22,668)	$ (22,668)	$ (22,668)	$ (272,014)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
6	Load Shaping Revenue	$ (2,268)	$ (6,263)	$ 11,628	$ 29,770	$ 27,627	$ 10,147	$ (460)	$ (36,346)	$ (18,023)	$ 3,472	$ (7,529)	$ (2,845)	$ 8,909	12
7	Demand Revenue	$ 2,928	$ 2,899	$ 5,586	$ 6,523	$ 3,556	$ 5,049	$ 3,214	$ 2,630	$ 2,935	$ 3,625	$ 5,621	$ 3,812	$ 48,377	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,414)	$ (5,102)	$ (5,876)	$ (4,822)	$ (2,933)	$ (22,146)	-
9	Low Density Discount	$ (2,996)	$ (2,786)	$ (3,386)	$ (3,752)	$ (3,614)	$ (3,221)	$ (3,166)	$ (2,492)	$ (3,121)	$ (3,698)	$ (3,493)	$ (3,181)	$ (38,904)	-
10	Tier 2	$ 3,194	$ 3,194	$ 3,194	$ 3,194	$ 3,194	$ 3,194	$ 3,194	$ 3,194	$ 3,194	$ 3,194	$ 3,194	$ 3,194	$ 38,323	112
11	RSS (Non-Federal)	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 1,248	-
12	Load Shaping True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
13	**PF customers (TRM) sub-total**	**$ 177,673**	**$ 173,859**	**$ 193,838**	**$ 212,550**	**$ 207,577**	**$ 191,984**	**$ 179,597**	**$ 140,387**	**$ 156,698**	**$ 177,532**	**$ 169,787**	**$ 174,861**	**$ 2,156,343**	**6,837**
14	**NR sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
15	**DSIs sub-total**	**$ 730**	**$ 711**	**$ 740**	**$ 755**	**$ 667**	**$ 2,635**	**$ 2,502**	**$ 2,383**	**$ 2,328**	**$ 2,684**	**$ 2,891**	**$ 2,863**	**$ 21,890**	**88**
16	**FPS sub-total**	**$ 285**	**$ 340**	**$ 375**	**$ 375**	**$ 300**	**$ 300**	**$ 300**	**$ 300**	**$ 340**	**$ 360**	**$ 350**	**$ 295**	**$ 3,920**	**-**
17	**Short-term market sales sub-total**	**$ 13,621**	**$ 14,744**	**$ 20,690**	**$ 34,100**	**$ 29,229**	**$ 29,954**	**$ 37,014**	**$ 51,251**	**$ 55,759**	**$ 50,139**	**$ 27,997**	**$ 14,379**	**$ 378,878**	**2,125**
18	**Long Term Contractual Obligations sub-total**	**$ 38**	**$ 3,220**	**$ 3,316**	**$ 3,325**	**$ 2,992**	**$ 1,676**	**$ 1,637**	**$ 61**	**$ 77**	**$ 64**	**$ 72**	**$ 46**	**$ 16,524**	**46**
19	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**468**
20	**Renewable Energy Certificates sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
21	Miscellaneous Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
22	Slice True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
23	**Other Sales sub-total**	**$ 169**	**$ 169**	**$ 169**	**$ 169**	**$ 169**	**$ 169**	**$ 169**	**$ 169**	**$ 169**	**$ 169**	**$ 169**	**$ 169**	**$ 2,033**	**-**
24	**Gross Sales**	**$192,516**	**$193,043**	**$219,128**	**$251,275**	**$240,935**	**$226,719**	**$221,220**	**$194,551**	**$215,372**	**$230,949**	**$201,266**	**$192,613**	**$2,579,588**	**9,565**
25	GTA Delivery charge	$ 225	$ 305	$ 325	$ 295	$ 270	$ 270	$ 245	$ 240	$ 290	$ 295	$ 280	$ 240	$ 3,280	-
26	Energy Efficiency Revenues	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 8,000	-
27	Irrigation Pumping Power	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 1,254	15
28	Reserve Energy	$ 753	$ 753	$ 753	$ 753	$ 753	$ 753	$ 753	$ 753	$ 753	$ 753	$ 753	$ 753	$ 9,037	159
29	Downstream Benefits	$ 545	$ 545	$ 545	$ 545	$ 545	$ 545	$ 545	$ 545	$ 545	$ 545	$ 545	$ 545	$ 6,539	-
30	Upper Baker Revenues	$ -	$ 98	$ 101	$ 98	$ 97	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 395	1
31	**Miscellaneous Revenue**	**$2,294**	**$2,472**	**$2,495**	**$2,462**	**$2,436**	**$2,339**	**$2,314**	**$2,309**	**$2,359**	**$2,364**	**$2,349**	**$2,309**	**$28,504**	**175**
32	Balancing Reserve Capacity for Regulating Reserve	$ 594	$ 575	$ 594	$ 584	$ 528	$ 584	$ 565	$ 584	$ 566	$ 585	$ 585	$ 566	$ 6,912	-
33	Balancing Reserve Capacity for VERBS wind, VERBS solar and DERBS	$ 4,271	$ 4,133	$ 4,271	$ 3,711	$ 3,352	$ 3,711	$ 3,591	$ 3,711	$ 3,374	$ 3,487	$ 3,487	$ 3,375	$ 44,475	-
34	Expected Balancing Reserve Capacity Sales in Spring Months from FCRPS Above Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
35	Capacity Unavailable from FCRPS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
36	Operating Reserve - Spinning	$ 1,829	$ 1,989	$ 2,266	$ 2,261	$ 1,890	$ 2,142	$ 1,859	$ 2,074	$ 2,133	$ 2,002	$ 1,940	$ 1,767	$ 24,151	-
37	Operating Reserve - Supplemental	$ 1,510	$ 1,642	$ 1,871	$ 1,867	$ 1,561	$ 1,768	$ 1,535	$ 1,712	$ 1,761	$ 1,653	$ 1,602	$ 1,459	$ 19,942	-
38	Synchronous Condensing	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 1,273	-
39	Generation Dropping	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 589	-
40	Redispatch	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 225	-
41	Segmentation of COE/Reclamation Network and Delivery Facilities	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 8,867	-
42	Station Service	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 1,996	9
43	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
44	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
45	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	**Generation Inputs / Inter-business line**	**$ 9,283**	**$ 9,417**	**$ 10,081**	**$ 9,502**	**$ 8,410**	**$ 9,285**	**$ 8,629**	**$ 9,160**	**$ 8,913**	**$ 8,808**	**$ 8,694**	**$ 8,246**	**$ 108,430**	**9**
47	4(h)(10)(c)	$ 9,672	$ 7,590	$ 9,315	$ 10,087	$ 8,482	$ 7,448	$ 6,850	$ 6,476	$ 6,999	$ 6,413	$ 6,118	$ 7,722	$ 93,172	-
48	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
49	**Treasury Credits**	**$ 10,055**	**$ 7,974**	**$ 9,698**	**$ 10,471**	**$ 8,865**	**$ 7,831**	**$ 7,233**	**$ 6,859**	**$ 7,382**	**$ 6,797**	**$ 6,502**	**$ 8,106**	**$ 97,772**	**-**
50	**Augmentation Power Purchase sub-total**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
51	**Balancing Power Purchase sub-total**	$ 7,206	$ 5,501	$ 8,272	$ 6,651	$ 5,429	$ 3,763	$ 3,170	$ 3,075	$ 3,026	$ 3,147	$ 4,680	$ 6,565	$ 60,484	233
52	**Other Power Purchase sub-total**	**$ 3,088**	**$ 3,088**	**$ 3,088**	**$ 3,088**	**$ 3,088**	**$ 3,088**	**$ 3,088**	**$ 3,088**	**$ 3,088**	**$ 3,088**	**$ 3,088**	**$ 3,088**	**$ 37,050**	**116**
53	**Power Purchases**	**$ 10,293**	**$ 8,588**	**$ 11,360**	**$ 9,738**	**$ 8,517**	**$ 6,850**	**$ 6,257**	**$ 6,163**	**$ 6,114**	**$ 6,234**	**$ 7,767**	**$ 9,653**	**$ 97,534**	**349**

Table 9.1 - 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**														
2	**Category**	**201810**	**201811**	**201812**	**201901**	**201902**	**201903**	**201904**	**201905**	**201906**	**201907**	**201908**	**201909**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 200,597	$ 200,597	$ 200,597	$ 200,597	$ 200,597	$ 200,597	$ 200,597	$ 200,597	$ 200,597	$ 200,597	$ 200,597	$ 200,597	$ 2,407,159	6,713
4	Non-Slice Revenue	$ (22,849)	$ (22,849)	$ (22,849)	$ (22,849)	$ (22,849)	$ (22,849)	$ (22,849)	$ (22,849)	$ (22,849)	$ (22,849)	$ (22,849)	$ (22,849)	$ (274,186)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
6	Load Shaping Revenue	$ (1,466)	$ (5,550)	$ 12,637	$ 31,015	$ 28,799	$ 10,933	$ 487	$ (35,977)	$ (17,802)	$ 4,528	$ (6,763)	$ (2,008)	$ 18,831	51
7	Demand Revenue	$ 3,407	$ 2,953	$ 5,641	$ 6,606	$ 3,779	$ 4,139	$ 3,645	$ 2,414	$ 2,479	$ 4,088	$ 5,172	$ 3,549	$ 47,874	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,414)	$ (5,102)	$ (5,876)	$ (4,822)	$ (2,933)	$ (22,146)	-
9	Low Density Discount	$ (3,098)	$ (2,854)	$ (3,459)	$ (3,837)	$ (3,709)	$ (3,263)	$ (3,268)	$ (2,560)	$ (3,163)	$ (3,829)	$ (3,572)	$ (3,258)	$ (39,871)	-
10	Tier 2	$ 3,912	$ 3,912	$ 3,912	$ 3,912	$ 3,912	$ 3,912	$ 3,912	$ 3,912	$ 3,912	$ 3,912	$ 3,912	$ 3,912	$ 46,941	130
11	RSS (Non-Federal)	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 1,247	-
12	Load Shaping True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
13	**PF customers (TRM) sub-total**	$ 180,605	$ 176,312	$ 196,582	$ 215,547	$ 210,633	$ 193,572	$ 182,627	$ 142,226	$ 158,176	$ 180,675	$ 171,778	$ 177,114	$ 2,185,847	6,893
14	**NR sub-total**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
15	**DSIs sub-total**	$ 2,794	$ 2,741	$ 2,855	$ 2,902	$ 2,593	$ 2,635	$ 2,502	$ 2,383	$ 2,328	$ 2,684	$ 2,891	$ 2,863	$ 32,172	88
16	**FPS sub-total**	$ 285	$ 340	$ 375	$ 375	$ 300	$ 300	$ 300	$ 300	$ 340	$ 360	$ 350	$ 295	$ 3,920	-
17	**Short-term market sales sub-total**	$ 9,783	$ 12,918	$ 17,286	$ 28,818	$ 25,847	$ 29,543	$ 35,345	$ 45,547	$ 53,088	$ 47,016	$ 25,869	$ 12,834	$ 343,895	1,945
18	**Long Term Contractual Obligations sub-total**	$ 38	$ 3,220	$ 3,316	$ 3,325	$ 2,987	$ 1,627	$ 1,575	$ -	$ -	$ -	$ -	$ -	$ 16,088	47
19	**Canadian Entitlement Return**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	462
20	**Renewable Energy Certificates sub-total**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
21	Miscellaneous Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
22	Slice True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
23	**Other Sales sub-total**	$ 169	$ 169	$ 169	$ 169	$ 169	$ 169	$ 169	$ 169	$ 169	$ 169	$ 169	$ 169	$ 2,033	-
24	**Gross Sales**	$193,675	$195,701	$220,583	$251,137	$242,530	$227,846	$222,520	$190,625	$214,101	$230,905	$201,058	$193,275	$2,583,955	9,436
25	GTA Delivery charge	$ 225	$ 305	$ 325	$ 295	$ 270	$ 270	$ 245	$ 240	$ 290	$ 295	$ 280	$ 240	$ 3,280	-
26	Energy Efficiency Revenues	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 8,000	-
27	Irrigation Pumping Power	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 1,254	16
28	Reserve Energy	$ 753	$ 753	$ 753	$ 753	$ 753	$ 753	$ 753	$ 753	$ 753	$ 753	$ 753	$ 753	$ 9,037	161
29	Downstream Benefits	$ 545	$ 545	$ 545	$ 545	$ 545	$ 545	$ 545	$ 545	$ 545	$ 545	$ 545	$ 545	$ 6,539	-
30	Upper Baker Revenues	$ -	$ 97	$ 100	$ 100	$ 102	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 400	1
31	**Miscellaneous Revenue**	$2,294	$2,472	$2,494	$2,464	$2,441	$2,339	$2,314	$2,309	$2,359	$2,364	$2,349	$2,309	$28,509	177
32	Balancing Reserve Capacity for Regulating Reserve	$ 620	$ 600	$ 620	$ 619	$ 559	$ 619	$ 599	$ 619	$ 599	$ 619	$ 620	$ 597	$ 7,294	-
33	Balancing Reserve Capacity for VERBS wind, VERBS solar and DERBS	$ 3,396	$ 3,288	$ 3,397	$ 3,404	$ 3,074	$ 3,404	$ 3,294	$ 3,404	$ 3,294	$ 3,404	$ 3,020	$ 3,110	$ 39,489	-
34	Expected Balancing Reserve Capacity Sales in Spring Months from FCRPS Above Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
35	Capacity Unavailable from FCRPS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
36	Operating Reserve - Spinning	$ 1,623	$ 1,808	$ 2,089	$ 2,163	$ 1,848	$ 2,092	$ 1,836	$ 2,020	$ 2,071	$ 1,907	$ 1,798	$ 1,632	$ 22,888	-
37	Operating Reserve - Supplemental	$ 1,340	$ 1,493	$ 1,725	$ 1,786	$ 1,526	$ 1,728	$ 1,516	$ 1,668	$ 1,710	$ 1,575	$ 1,485	$ 1,348	$ 18,899	-
38	Synchronous Condensing	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 1,273	-
39	Generation Dropping	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 589	-
40	Redispatch	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 225	-
41	Segmentation of COE/Reclamation Network and Delivery Facilities	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 8,867	-
42	Station Service	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 1,996	9
43	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
44	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
45	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	**Generation Inputs / Inter-business line**	$ 8,058	$ 8,267	$ 8,911	$ 9,052	$ 8,086	$ 8,922	$ 8,324	$ 8,790	$ 8,754	$ 8,585	$ 8,003	$ 7,767	$ 101,519	9
47	4(h)(10)(c)	$ 9,314	$ 7,476	$ 9,096	$ 9,829	$ 8,451	$ 7,207	$ 6,738	$ 6,371	$ 6,956	$ 6,296	$ 6,107	$ 7,684	$ 91,526	-
48	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
49	**Treasury Credits**	$ 9,697	$ 7,859	$ 9,479	$ 10,213	$ 8,834	$ 7,591	$ 7,121	$ 6,754	$ 7,340	$ 6,679	$ 6,491	$ 8,067	$ 96,126	-
50	**Augmentation Power Purchase sub-total**	$ 1,018	$ 1,018	$ 1,018	$ 1,018	$ 1,018	$ 1,018	$ 1,018	$ 1,018	$ 1,018	$ 1,018	$ 1,018	$ 1,018	$ 12,222	45
51	**Balancing Power Purchase sub-total**	$ 5,285	$ 4,668	$ 7,725	$ 6,525	$ 5,457	$ 3,667	$ 3,047	$ 3,075	$ 2,967	$ 3,136	$ 3,806	$ 5,051	$ 54,409	203
52	**Other Power Purchase sub-total**	$ 3,509	$ 3,509	$ 3,509	$ 3,509	$ 3,509	$ 3,509	$ 3,509	$ 3,509	$ 3,509	$ 3,509	$ 3,509	$ 3,509	$ 42,112	134
53	**Power Purchases**	$ 9,813	$ 9,196	$ 12,252	$ 11,053	$ 9,984	$ 8,195	$ 7,575	$ 7,603	$ 7,495	$ 7,664	$ 8,333	$ 9,579	$ 108,742	381

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**														
2	**Category**	**201610**	**201611**	**201612**	**201701**	**201702**	**201703**	**201704**	**201705**	**201706**	**201707**	**201708**	**201709**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 200,597	$ 200,597	$ 200,597	$ 200,633	$ 200,578	$ 200,578	$ 200,578	$ 200,578	$ 200,578	$ 200,578	$ 200,578	$ 200,578	$ 2,407,050	6,776
4	Non-Slice Revenue	$ (21,658)	$ (21,658)	$ (21,658)	$ (21,664)	$ (21,655)	$ (21,717)	$ (21,717)	$ (21,717)	$ (21,717)	$ (21,717)	$ (21,717)	$ (21,717)	$ (260,314)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
6	Load Shaping Revenue	$ (3,979)	$ (14,180)	$ 19,465	$ 38,975	$ 24,635	$ 2,395	$ 5,713	$ (32,422)	$ (16,409)	$ (575)	$ (7,146)	$ 2,727	$ 19,201	(34)
7	Demand Revenue	$ 1,353	$ 1,097	$ 6,550	$ 9,341	$ 3,224	$ 5,007	$ 3,236	$ 2,293	$ 2,835	$ 3,470	$ 5,319	$ 4,080	$ 47,805	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,414)	$ (5,102)	$ (5,876)	$ (4,822)	$ (2,933)	$ (22,146)	-
9	Low Density Discount	$ (2,722)	$ (2,465)	$ (3,639)	$ (4,207)	$ (3,566)	$ (2,894)	$ (3,047)	$ (2,399)	$ (2,859)	$ (3,288)	$ (3,178)	$ (3,120)	$ (37,383)	-
10	Tier 2	$ 2,378	$ 2,297	$ 2,378	$ 2,378	$ 2,124	$ 2,279	$ 2,290	$ 2,279	$ 2,290	$ 2,279	$ 2,279	$ 2,290	$ 27,542	70
11	RSS (Non-Federal)	$ 16	$ (37)	$ (56)	$ (28)	$ (92)	$ 140	$ 140	$ 140	$ 140	$ 140	$ 140	$ 140	$ 779	-
12	Load Shaping True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,069)	$ (2,069)	-
13	**PF customers (TRM) sub-total**	**$ 175,985**	**$ 165,651**	**$ 203,637**	**$ 225,428**	**$ 205,248**	**$ 185,788**	**$ 187,193**	**$ 145,338**	**$ 159,757**	**$ 175,010**	**$ 171,453**	**$ 179,976**	**$ 2,180,463**	**6,812**
14	**NR sub-total**	**$ (45)**	**$ (17)**	**$ (45)**	**$ (70)**	**$ (21)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ (198)**	**-**
15	**DSIs sub-total**	**$ 707**	**$ 684**	**$ 714**	**$ 762**	**$ 651**	**$ 1,115**	**$ 1,051**	**$ 600**	**$ 589**	**$ 676**	**$ 727**	**$ 723**	**$ 8,998**	**24**
16	**FPS sub-total**	**$ 443**	**$ 447**	**$ 664**	**$ 706**	**$ 538**	**$ 238**	**$ 217**	**$ 212**	**$ 197**	**$ 85**	**$ 75**	**$ 65**	**$ 3,886**	**8**
17	**Short-term market sales sub-total**	**$ 19,000**	**$ 27,831**	**$ 24,364**	**$ 30,347**	**$ 37,308**	**$ 46,997**	**$ 29,642**	**$ 43,116**	**$ 47,512**	**$ 54,346**	**$ 26,538**	**$ 21,330**	**$ 408,330**	**1,696**
18	**Long Term Contractual Obligations sub-total**	**$ 29**	**$ 7,110**	**$ 7,328**	**$ 7,307**	**$ 6,684**	**$ 3,655**	**$ 3,565**	**$ 61**	**$ 77**	**$ 64**	**$ 72**	**$ 46**	**$ 35,998**	**90**
19	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**114**
20	**Renewable Energy Certificates sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 648**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 648**	**-**
21	Miscellaneous Credits	$ 14	$ 9	$ 31	$ 23	$ 16	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 94	-
22	Slice True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (5,458)	$ (5,458)	-
23	**Other Sales sub-total**	**$ 14**	**$ 9**	**$ 31**	**$ 23**	**$ 16**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ (5,458)**	**$ (5,364)**	**-**
24	**Gross Sales**	**$196,133**	**$201,714**	**$236,693**	**$264,503**	**$250,423**	**$238,441**	**$221,667**	**$189,327**	**$208,132**	**$230,182**	**$198,863**	**$196,681**	**$2,632,760**	**8,744**
25	GTA Delivery charge	$ 256	$ 268	$ 447	$ 385	$ 322	$ 385	$ 330	$ 345	$ 365	$ 410	$ 375	$ 315	$ 4,203	-
26	Energy Efficiency Revenues	$ (37)	$ (73)	$ 12	$ 617	$ (392)	$ 1,113	$ 1,113	$ 1,113	$ 1,113	$ 1,113	$ 1,113	$ 1,113	$ 7,917	-
27	Irrigation Pumping Power	$ 49	$ 115	$ 149	$ 231	$ 229	$ 140	$ 53	$ 11	$ 6	$ 6	$ 6	$ 7	$ 1,003	15
28	Reserve Energy	$ 914	$ 914	$ 914	$ 914	$ 914	$ 914	$ 914	$ 914	$ 914	$ 914	$ 914	$ 914	$ 10,963	162
29	Downstream Benefits	$ 544	$ 544	$ 544	$ 544	$ 544	$ 547	$ 547	$ 547	$ 547	$ 547	$ 547	$ 547	$ 6,551	-
30	Upper Baker Revenues	$ -	$ 102	$ 102	$ 102	$ 103	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 409	1
31	**Miscellaneous Revenue**	**$1,726**	**$1,870**	**$2,169**	**$2,792**	**$1,720**	**$3,099**	**$2,956**	**$2,930**	**$2,944**	**$2,989**	**$2,954**	**$2,896**	**$31,045**	**178**
32	Balancing Reserve Capacity for Regulating Reserve	$ 4,236	$ 4,236	$ 4,236	$ 4,236	$ 4,236	$ 4,236	$ 4,236	$ 4,236	$ 4,236	$ 4,236	$ 4,236	$ 4,236	$ 50,835	-
33	Balancing Reserve Capacity for VERBS wind, VERBS solar and DERBS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
34	Expected Balancing Reserve Capacity Sales in Spring Months from FCRPS Above Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,000	$ 1,000	$ 1,000	$ 1,000	$ -	$ -	$ 4,000	-
35	Capacity Unavailable from FCRPS	$ (68)	$ -	$ -	$ -	$ -	$ (2,161)	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,229)	-
36	Operating Reserve - Spinning	$ 1,696	$ 1,815	$ 2,231	$ 2,292	$ 1,974	$ 2,217	$ 2,078	$ 2,177	$ 2,308	$ 2,187	$ 1,955	$ 1,731	$ 24,661	-
37	Operating Reserve - Supplemental	$ 1,555	$ 1,664	$ 2,045	$ 2,101	$ 1,809	$ 2,032	$ 1,905	$ 1,996	$ 2,116	$ 2,005	$ 1,792	$ 1,587	$ 22,606	-
38	Synchronous Condensing	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 1,610	-
39	Generation Dropping	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 415	-
40	Redispatch	$ 10	$ 18	$ 13	$ 5	$ 22	$ 22	$ 22	$ 22	$ 22	$ 22	$ 22	$ 22	$ 222	-
41	Segmentation of COE/Reclamation Network and Delivery Facilities	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 7,367	-
42	Station Service	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 2,479	9
43	Energy Imbalance	$ (37)	$ 83	$ 137	$ 186	$ 7	$ 149	$ 147	$ 83	$ 78		$ (131)	$ (100)	$ 661	-
44	Generation Imbalance	$ 332	$ 180	$ -	$ -	$ 183	$ 739	$ 790	$ 891	$ 300	$ 629	$ 826	$ 574	$ 5,444	-
45	Operating Reserve - Energy	$ 68	$ 22	$ 117	$ 171	$ 35	$ 8	$ 16	$ 12	$ 10	$ 37	$ 28	$ 24	$ 548	-
46	**Generation Inputs / Inter-business line**	**$ 8,781**	**$ 9,008**	**$ 9,769**	**$ 9,980**	**$ 9,255**	**$ 8,232**	**$ 11,184**	**$ 11,407**	**$ 11,059**	**$ 11,165**	**$ 9,718**	**$ 9,063**	**$ 118,622**	**9**
47	4(h)(10)(c)	$ 6,600	$ 7,348	$ 5,904	$ 4,432	$ 1,510	$ 5,954	$ 4,038	$ 5,680	$ 5,680	$ 5,680	$ 5,296	$ 7,343	$ 65,466	-
48	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
49	**Treasury Credits**	**$ 6,983**	**$ 7,731**	**$ 6,288**	**$ 4,815**	**$ 1,893**	**$ 6,337**	**$ 4,421**	**$ 6,064**	**$ 6,064**	**$ 6,064**	**$ 5,680**	**$ 7,727**	**$ 70,066**	**-**
50	**Augmentation Power Purchase sub-total**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
51	**Balancing Power Purchase sub-total**	$ (485)	$ 3,957	$ 11,308	$ 22,491	$ 8,114	$ 4,702	$ 6,371	$ 3,119	$ 3,076	$ 3,173	$ 6,379	$ 3,125	$ 75,332	181
52	**Other Power Purchase sub-total**	**$ 2,257**	**$ 2,188**	**$ 2,258**	**$ 2,258**	**$ 2,039**	**$ 2,255**	**$ 2,185**	**$ 2,258**	**$ 2,185**	**$ 2,258**	**$ 2,258**	**$ 2,185**	**$ 26,582**	**67**
53	**Power Purchases**	**$ 1,772**	**$ 6,145**	**$ 13,566**	**$ 24,749**	**$ 10,154**	**$ 6,957**	**$ 8,556**	**$ 5,377**	**$ 5,261**	**$ 5,430**	**$ 8,637**	**$ 5,310**	**$ 101,914**	**248**

Table 9.2 - 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**														
2	**Category**	**201710**	**201711**	**201712**	**201801**	**201802**	**201803**	**201804**	**201805**	**201806**	**201807**	**201808**	**201809**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 205,212	$ 205,212	$ 205,212	$ 205,212	$ 205,212	$ 205,212	$ 205,212	$ 205,212	$ 205,212	$ 205,212	$ 205,212	$ 205,212	$ 2,462,544	6,713
4	Non-Slice Revenue	$ (22,075)	$ (22,075)	$ (22,075)	$ (22,075)	$ (22,075)	$ (22,075)	$ (22,075)	$ (22,075)	$ (22,075)	$ (22,075)	$ (22,075)	$ (22,075)	$ (264,902)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
6	Load Shaping Revenue	$ (2,226)	$ (5,821)	$ 12,407	$ 28,778	$ 26,688	$ 9,536	$ (272)	$ (26,431)	$ (13,252)	$ 3,005	$ (6,989)	$ (2,580)	$ 22,842	12
7	Demand Revenue	$ 3,054	$ 3,006	$ 6,288	$ 6,922	$ 3,719	$ 5,132	$ 2,817	$ 2,147	$ 2,439	$ 3,537	$ 5,663	$ 3,641	$ 48,364	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,411)	$ (5,098)	$ (5,871)	$ (4,818)	$ (2,931)	$ (22,128)	-
9	Low Density Discount	$ (3,177)	$ (2,976)	$ (3,603)	$ (3,926)	$ (3,777)	$ (3,394)	$ (3,310)	$ (2,800)	$ (3,253)	$ (3,806)	$ (3,649)	$ (3,338)	$ (41,010)	-
10	Tier 2	$ 3,188	$ 3,188	$ 3,188	$ 3,188	$ 3,188	$ 3,188	$ 3,188	$ 3,188	$ 3,188	$ 3,188	$ 3,188	$ 3,188	$ 38,261	112
11	RSS (Non-Federal)	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 1,210	-
12	Load Shaping True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
13	**PF customers (TRM) sub-total**	**$ 184,076**	**$ 180,635**	**$ 201,518**	**$ 218,199**	**$ 213,056**	**$ 197,700**	**$ 185,661**	**$ 155,931**	**$ 167,262**	**$ 183,291**	**$ 176,633**	**$ 181,218**	**$ 2,245,182**	**6,837**
14	**NR sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
15	**DSIs sub-total**	**$ 791**	**$ 780**	**$ 844**	**$ 821**	**$ 725**	**$ 2,849**	**$ 2,539**	**$ 2,314**	**$ 2,221**	**$ 2,821**	**$ 3,070**	**$ 2,932**	**$ 22,708**	**88**
16	**FPS sub-total**	**$ 285**	**$ 340**	**$ 375**	**$ 375**	**$ 300**	**$ 300**	**$ 300**	**$ 300**	**$ 340**	**$ 360**	**$ 350**	**$ 295**	**$ 3,920**	**-**
17	**Short-term market sales sub-total**	**$ 13,621**	**$ 14,744**	**$ 20,690**	**$ 34,100**	**$ 29,229**	**$ 29,954**	**$ 37,014**	**$ 51,251**	**$ 55,759**	**$ 50,139**	**$ 27,997**	**$ 14,379**	**$ 378,878**	**2,125**
18	**Long Term Contractual Obligations sub-total**	**$ 38**	**$ 3,220**	**$ 3,316**	**$ 3,325**	**$ 2,992**	**$ 1,676**	**$ 1,637**	**$ 61**	**$ 77**	**$ 64**	**$ 72**	**$ 46**	**$ 16,524**	**46**
19	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**468**
20	**Renewable Energy Certificates sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
21	Miscellaneous Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
22	Slice True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
23	**Other Sales sub-total**	**$ 169**	**$ 169**	**$ 169**	**$ 169**	**$ 169**	**$ 169**	**$ 169**	**$ 169**	**$ 169**	**$ 169**	**$ 169**	**$ 169**	**$ 2,033**	**-**
24	**Gross Sales**	**$198,981**	**$199,888**	**$226,913**	**$256,990**	**$246,472**	**$232,649**	**$227,322**	**$210,027**	**$225,828**	**$236,845**	**$208,291**	**$199,040**	**$2,669,245**	**9,565**
25	GTA Delivery charge	$ 225	$ 305	$ 325	$ 295	$ 270	$ 270	$ 245	$ 240	$ 290	$ 295	$ 280	$ 240	$ 3,280	-
26	Energy Efficiency Revenues	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 8,000	-
27	Irrigation Pumping Power	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 1,254	15
28	Reserve Energy	$ 753	$ 753	$ 753	$ 753	$ 753	$ 753	$ 753	$ 753	$ 753	$ 753	$ 753	$ 753	$ 9,037	158
29	Downstream Benefits	$ 545	$ 545	$ 545	$ 545	$ 545	$ 545	$ 545	$ 545	$ 545	$ 545	$ 545	$ 545	$ 6,539	-
30	Upper Baker Revenues	$ -	$ 98	$ 101	$ 98	$ 97	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 395	1
31	**Miscellaneous Revenue**	**$2,294**	**$2,472**	**$2,495**	**$2,462**	**$2,436**	**$2,339**	**$2,314**	**$2,309**	**$2,359**	**$2,364**	**$2,349**	**$2,309**	**$28,504**	**175**
32	Balancing Reserve Capacity for Regulating Reserve	$ 594	$ 575	$ 594	$ 584	$ 528	$ 584	$ 565	$ 584	$ 566	$ 585	$ 585	$ 566	$ 6,912	-
33	Balancing Reserve Capacity for VERBS wind, VERBS solar and DERBS	$ 4,271	$ 4,133	$ 4,271	$ 3,711	$ 3,352	$ 3,711	$ 3,591	$ 3,711	$ 3,374	$ 3,487	$ 3,487	$ 3,375	$ 44,475	-
34	Expected Balancing Reserve Capacity Sales in Spring Months from FCRPS Above Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
35	Capacity Unavailable from FCRPS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
36	Operating Reserve - Spinning	$ 1,829	$ 1,989	$ 2,266	$ 2,261	$ 1,890	$ 2,142	$ 1,859	$ 2,074	$ 2,133	$ 2,002	$ 1,940	$ 1,767	$ 24,151	-
37	Operating Reserve - Supplemental	$ 1,510	$ 1,642	$ 1,871	$ 1,867	$ 1,561	$ 1,768	$ 1,535	$ 1,712	$ 1,761	$ 1,653	$ 1,602	$ 1,459	$ 19,942	-
38	Synchronous Condensing	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 1,273	-
39	Generation Dropping	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 589	-
40	Redispatch	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 225	-
41	Segmentation of COE/Reclamation Network and Delivery Facilities	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 8,867	-
42	Station Service	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 1,996	9
43	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
44	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
45	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	**Generation Inputs / Inter-business line**	**$ 9,283**	**$ 9,417**	**$ 10,081**	**$ 9,502**	**$ 8,410**	**$ 9,285**	**$ 8,629**	**$ 9,160**	**$ 8,913**	**$ 8,808**	**$ 8,694**	**$ 8,246**	**$ 108,430**	**9**
47	4(h)(10)(c)	$ 9,672	$ 7,590	$ 9,315	$ 10,087	$ 8,482	$ 7,448	$ 6,850	$ 6,476	$ 6,999	$ 6,413	$ 6,118	$ 7,722	$ 93,172	-
48	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
49	**Treasury Credits**	**$ 10,055**	**$ 7,974**	**$ 9,698**	**$ 10,471**	**$ 8,865**	**$ 7,831**	**$ 7,233**	**$ 6,859**	**$ 7,382**	**$ 6,797**	**$ 6,502**	**$ 8,106**	**$ 97,772**	**-**
50	**Augmentation Power Purchase sub-total**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
51	**Balancing Power Purchase sub-total**	$ 7,206	$ 5,501	$ 8,272	$ 6,651	$ 5,429	$ 3,763	$ 3,170	$ 3,075	$ 3,026	$ 3,147	$ 4,680	$ 6,565	$ 60,484	233
52	**Other Power Purchase sub-total**	**$ 3,088**	**$ 3,088**	**$ 3,088**	**$ 3,088**	**$ 3,088**	**$ 3,088**	**$ 3,088**	**$ 3,088**	**$ 3,088**	**$ 3,088**	**$ 3,088**	**$ 3,088**	**$ 37,050**	**116**
53	**Power Purchases**	**$ 10,293**	**$ 8,588**	**$ 11,360**	**$ 9,738**	**$ 8,517**	**$ 6,850**	**$ 6,257**	**$ 6,163**	**$ 6,114**	**$ 6,234**	**$ 7,767**	**$ 9,653**	**$ 105,796**	**349**

Table 9.2 - 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**														
2	**Category**	**201810**	**201811**	**201812**	**201901**	**201902**	**201903**	**201904**	**201905**	**201906**	**201907**	**201908**	**201909**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 206,465	$ 206,465	$ 206,465	$ 206,465	$ 206,465	$ 206,465	$ 206,465	$ 206,465	$ 206,465	$ 206,465	$ 206,465	$ 206,465	$ 2,477,578	6,713
4	Non-Slice Revenue	$ (22,251)	$ (22,251)	$ (22,251)	$ (22,251)	$ (22,251)	$ (22,251)	$ (22,251)	$ (22,251)	$ (22,251)	$ (22,251)	$ (22,251)	$ (22,251)	$ (267,017)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
6	Load Shaping Revenue	$ (1,444)	$ (5,137)	$ 13,456	$ 29,989	$ 27,817	$ 10,279	$ 467	$ (26,135)	$ (13,204)	$ 3,972	$ (6,279)	$ (1,841)	$ 31,941	51
7	Demand Revenue	$ 3,553	$ 3,062	$ 6,350	$ 7,010	$ 3,953	$ 4,207	$ 3,195	$ 1,971	$ 2,060	$ 3,989	$ 5,210	$ 3,391	$ 47,951	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,411)	$ (5,098)	$ (5,871)	$ (4,818)	$ (2,931)	$ (22,128)	-
9	Low Density Discount	$ (3,282)	$ (3,044)	$ (3,679)	$ (4,014)	$ (3,872)	$ (3,436)	$ (3,403)	$ (2,867)	$ (3,299)	$ (3,934)	$ (3,728)	$ (3,413)	$ (41,971)	-
10	Tier 2	$ 3,629	$ 3,629	$ 3,629	$ 3,629	$ 3,629	$ 3,629	$ 3,629	$ 3,629	$ 3,629	$ 3,629	$ 3,629	$ 3,629	$ 43,549	130
11	RSS (Non-Federal)	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 101	$ 1,209	-
12	Load Shaping True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
13	**PF customers (TRM) sub-total**	**$ 186,771**	**$ 182,825**	**$ 204,070**	**$ 220,929**	**$ 215,841**	**$ 198,993**	**$ 188,202**	**$ 157,501**	**$ 168,403**	**$ 186,100**	**$ 178,330**	**$ 183,149**	**$ 2,271,113**	**6,893**
14	**NR sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
15	**DSIs sub-total**	**$ 3,029**	**$ 3,005**	**$ 3,257**	**$ 3,156**	**$ 2,818**	**$ 2,849**	**$ 2,539**	**$ 2,314**	**$ 2,221**	**$ 2,821**	**$ 3,070**	**$ 2,932**	**$ 34,013**	**88**
16	**FPS sub-total**	**$ 285**	**$ 340**	**$ 375**	**$ 375**	**$ 300**	**$ 300**	**$ 300**	**$ 300**	**$ 340**	**$ 360**	**$ 350**	**$ 295**	**$ 3,920**	**-**
17	**Short-term market sales sub-total**	**$ 9,783**	**$ 12,918**	**$ 17,286**	**$ 28,818**	**$ 25,847**	**$ 29,543**	**$ 35,345**	**$ 45,547**	**$ 53,088**	**$ 47,016**	**$ 25,869**	**$ 12,834**	**$ 343,895**	**1,945**
18	**Long Term Contractual Obligations sub-total**	**$ 38**	**$ 3,220**	**$ 3,316**	**$ 3,325**	**$ 2,987**	**$ 1,627**	**$ 1,575**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 16,088**	**47**
19	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**462**
20	**Renewable Energy Certificates sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
21	Miscellaneous Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
22	Slice True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
23	**Other Sales sub-total**	**$ 169**	**$ 169**	**$ 169**	**$ 169**	**$ 169**	**$ 169**	**$ 169**	**$ 169**	**$ 169**	**$ 169**	**$ 169**	**$ 169**	**$ 2,033**	**-**
24	**Gross Sales**	**$200,075**	**$202,477**	**$228,474**	**$256,773**	**$247,963**	**$233,482**	**$228,132**	**$205,831**	**$224,220**	**$236,467**	**$207,788**	**$199,380**	**$2,671,062**	**9,436**
25	GTA Delivery charge	$ 225	$ 305	$ 325	$ 295	$ 270	$ 270	$ 245	$ 240	$ 290	$ 295	$ 280	$ 240	$ 3,280	-
26	Energy Efficiency Revenues	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 667	$ 8,000	-
27	Irrigation Pumping Power	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 104	$ 1,254	15
28	Reserve Energy	$ 753	$ 753	$ 753	$ 753	$ 753	$ 753	$ 753	$ 753	$ 753	$ 753	$ 753	$ 753	$ 9,037	160
29	Downstream Benefits	$ 545	$ 545	$ 545	$ 545	$ 545	$ 545	$ 545	$ 545	$ 545	$ 545	$ 545	$ 545	$ 6,539	-
30	Upper Baker Revenues	$ -	$ 97	$ 100	$ 100	$ 102	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 400	1
31	**Miscellaneous Revenue**	**$2,294**	**$2,472**	**$2,494**	**$2,464**	**$2,441**	**$2,339**	**$2,314**	**$2,309**	**$2,359**	**$2,364**	**$2,349**	**$2,309**	**$28,509**	**177**
32	Balancing Reserve Capacity for Regulating Reserve	$ 620	$ 600	$ 620	$ 619	$ 559	$ 619	$ 599	$ 619	$ 599	$ 619	$ 620	$ 597	$ 7,294	-
33	Balancing Reserve Capacity for VERBS wind, VERBS solar and DERBS	$ 3,396	$ 3,288	$ 3,397	$ 3,404	$ 3,074	$ 3,404	$ 3,294	$ 3,404	$ 3,294	$ 3,404	$ 3,020	$ 3,110	$ 39,489	-
34	Expected Balancing Reserve Capacity Sales in Spring Months from FCRPS Above Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
35	Capacity Unavailable from FCRPS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
36	Operating Reserve - Spinning	$ 1,623	$ 1,808	$ 2,089	$ 2,163	$ 1,848	$ 2,092	$ 1,836	$ 2,020	$ 2,071	$ 1,907	$ 1,798	$ 1,632	$ 22,888	-
37	Operating Reserve - Supplemental	$ 1,340	$ 1,493	$ 1,725	$ 1,786	$ 1,526	$ 1,728	$ 1,516	$ 1,668	$ 1,710	$ 1,575	$ 1,485	$ 1,348	$ 18,899	-
38	Synchronous Condensing	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 106	$ 1,273	-
39	Generation Dropping	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 49	$ 589	-
40	Redispatch	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 225	-
41	Segmentation of COE/Reclamation Network and Delivery Facilities	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 739	$ 8,867	-
42	Station Service	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 166	$ 1,996	9
43	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
44	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
45	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	**Generation Inputs / Inter-business line**	**$ 8,058**	**$ 8,267**	**$ 8,911**	**$ 9,052**	**$ 8,086**	**$ 8,922**	**$ 8,324**	**$ 8,790**	**$ 8,754**	**$ 8,585**	**$ 8,003**	**$ 7,767**	**$ 101,519**	**9**
47	4(h)(10)(c)	$ 9,314	$ 7,476	$ 9,096	$ 9,829	$ 8,451	$ 7,207	$ 6,738	$ 6,371	$ 6,956	$ 6,296	$ 6,107	$ 7,684	$ 91,526	-
48	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
49	**Treasury Credits**	**$ 9,697**	**$ 7,859**	**$ 9,479**	**$ 10,213**	**$ 8,834**	**$ 7,591**	**$ 7,121**	**$ 6,754**	**$ 7,340**	**$ 6,679**	**$ 6,491**	**$ 8,067**	**$ 96,126**	**-**
50	**Augmentation Power Purchase sub-total**	$ 1,018	$ 1,018	$ 1,018	$ 1,018	$ 1,018	$ 1,018	$ 1,018	$ 1,018	$ 1,018	$ 1,018	$ 1,018	$ 1,018	$ 12,222	45
51	**Balancing Power Purchase sub-total**	$ 5,285	$ 4,668	$ 7,725	$ 6,525	$ 5,457	$ 3,667	$ 3,047	$ 3,075	$ 2,967	$ 3,136	$ 3,806	$ 5,051	$ 54,409	203
52	**Other Power Purchase sub-total**	**$ 3,509**	**$ 3,509**	**$ 3,509**	**$ 3,509**	**$ 3,509**	**$ 3,509**	**$ 3,509**	**$ 3,509**	**$ 3,509**	**$ 3,509**	**$ 3,509**	**$ 3,509**	**$ 42,112**	**134**
53	**Power Purchases**	**$ 9,813**	**$ 9,196**	**$ 12,252**	**$ 11,053**	**$ 9,984**	**$ 8,195**	**$ 7,575**	**$ 7,603**	**$ 7,495**	**$ 7,664**	**$ 8,333**	**$ 9,579**	**$ 116,920**	**381**

Table 9.3 – Composite and Non-slice revenue – FY 2018-2019

	A		B	C		D	E		F	G
1	**Table 9.3 – Composite and Non-slice revenue – FY 2018-2019**									
2	Table shows calculation of CHWM revenues at proposed rates.									
3										
4	**Billing Determinants**		**FY 2018**			**FY 2019**			**Rate Period**	
5	**TOCA...**		96.656240	A)		97.246350	A)		96.95130	
6	**Non-slice TOCA...**		73.920440	B)		74.510550	B)		74.21550	
7	**Slice Percentage..**		22.735800			22.735800			22.73580	
8										
9	**Annual TRM Rates ($000)**		**FY 2018**			**FY 2019**			**Rate Period**	
10	**Composite..**	$	26,338		$	24,622		$	25,477	C)
11	**Non-Slice...**	$	(4,146)		$	(3,025)		$	(3,584)	D)
12	**Slice...**	$	-		$	-		$	-	
13										
14	**Yearly Revenues (Yearly TOCA * Rate Period rate)**		**FY 2018**			**FY 2019**				
15	**Composite (A * C)..**	$	2,462,544	E)	$	2,477,578	E)			
16	**Non-Slice (B * D)...**	$	(264,902)	E)	$	(267,017)	E)			
17	**Slice...**	$	-		$	-				
18										
19	**Monthly Revenues (Yearly Revenues / 12)**		**FY 2018**			**FY 2019**				
20	**Composite (E / 12)..**	$	205,212		$	206,465				
21	**Non-Slice (E / 12)...**	$	(22,075)		$	(22,251)				
22	**Slice...**	$	-		$	-				
23										
24	*Ties to Table 4.2, Revenue at Proposed Rates, lines 3-4*									
25										

Table 9.4 – Load Shaping and Demand revenue – FY 2018-2019

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**Table 9.4 – Load Shaping and Demand revenue – FY 2018-2019**														
2	Table shows calculation of CHWM revenues at proposed rates.														
3															
4															
5	**FY 2018**		**Oct-17**	**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Total**
6	Load Shaping HLH (MWh)	A)	(219,678)	(319,419)	53,349	517,406	500,980	159,411	(174,402)	(1,268,779)	(673,655)	(134,893)	(346,552)	(235,269)	
7	Load Shaping LLH (MWh)	B)	162,196	116,794	405,696	568,822	517,528	276,454	180,048	(473,841)	(141,924)	332,348	121,744	179,953	
8	Load Shaping HLH Rate ($/MWh)	C)	$ 26.74	$ 27.27	$ 30.28	$ 29.30	$ 28.54	$ 23.75	$ 19.67	$ 16.63	$ 17.71	$ 24.66	$ 28.11	$ 27.94	
9	Load Shaping LLH Rate ($/MWh)	D)	$ 22.49	$ 24.74	$ 26.60	$ 23.94	$ 23.94	$ 20.80	$ 17.54	$ 11.25	$ 9.31	$ 19.05	$ 22.61	$ 22.19	
10	Load Shaping Revenue (A * C) + (B * D)		$ (2,226,399)	$ (5,821,070)	$ 12,406,934	$ 28,777,587	$ 26,687,592	$ 9,536,245	$ (272,436)	$ (26,430,507)	$ (13,251,740)	$ 3,004,775	$ (6,988,953)	$ (2,580,269)	$ 22,841,757
11															
12	Demand (kW)	E)	292,202	282,267	531,530	604,527	333,545	552,965	366,859	330,783	352,389	367,271	515,719	333,770	
13	Demand Rate ($/kW-mo.)	F)	$ 10.45	$ 10.65	$ 11.83	$ 11.45	$ 11.15	$ 9.28	$ 7.68	$ 6.49	$ 6.92	$ 9.63	$ 10.98	$ 10.91	
14	Demand Revenue (E * F)		$ 3,053,507	$ 3,006,140	$ 6,288,000	$ 6,921,836	$ 3,719,032	$ 5,131,518	$ 2,817,477	$ 2,146,780	$ 2,438,533	$ 3,536,822	$ 5,662,599	$ 3,641,434	$ 48,363,678
15															
16															
17															
18															
19	**FY 2019**		**Oct-18**	**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Total**
20	Load Shaping HLH (MWh)	A)	(154,380)	(296,242)	83,613	553,738	537,043	148,613	(94,667)	(1,244,928)	(687,824)	(55,742)	(313,298)	(202,969)	
21	Load Shaping LLH (MWh)	B)	119,350	118,915	410,694	574,969	521,707	324,474	132,768	(482,863)	(109,820)	280,657	111,817	172,611	
22	Load Shaping HLH Rate ($/MWh)	C)	$ 26.74	$ 27.27	$ 30.28	$ 29.30	$ 28.54	$ 23.75	$ 19.67	$ 16.63	$ 17.71	$ 24.66	$ 28.11	$ 27.94	
23	Load Shaping LLH Rate ($/MWh)	D)	$ 22.49	$ 24.74	$ 26.60	$ 23.94	$ 23.94	$ 20.80	$ 17.54	$ 11.25	$ 9.31	$ 19.05	$ 22.61	$ 22.19	
24	Load Shaping Revenue (A * C) + (B * D)		$ (1,443,938)	$ (5,136,571)	$ 13,456,238	$ 29,989,282	$ 27,816,851	$ 10,278,633	$ 466,637	$ (26,135,363)	$ (13,203,792)	$ 3,971,917	$ (6,278,616)	$ (1,840,712)	$ 31,940,568
25															
26	Demand (kW)	E)	339,994	287,552	536,731	612,246	354,529	453,338	416,067	303,650	297,652	414,233	474,529	310,800	
27	Demand Rate ($/kW-mo.)	F)	$ 10.45	$ 10.65	$ 11.83	$ 11.45	$ 11.15	$ 9.28	$ 7.68	$ 6.49	$ 6.92	$ 9.63	$ 10.98	$ 10.91	
28	Demand Revenue (E * F)		$ 3,552,935	$ 3,062,430	$ 6,349,526	$ 7,010,215	$ 3,953,003	$ 4,206,975	$ 3,195,396	$ 1,970,688	$ 2,059,749	$ 3,989,064	$ 5,210,333	$ 3,390,829	$ 47,951,141
29															
30	*Ties to Table 4.2, Revenue at Proposed Rates, lines 6-7*														

Table 9.5 – Irrigation Rate Discount (IRD) – FY 2018-2019

	A	B	C	D	E	F	G	H
1	**Table 9.5 – Irrigation Rate Discount (IRD) – FY 2018-2019**							
2	Table shows calculation of IRD credit at proposed rates.							
3								
4	**Irrigation Rate Discount**							
5	**IRD Percentage**	37.06%						
6	**Total Irrigation Load (MWh)**	1,881,605						
7	**RT1SC**	6,945						
8	**Annual NonSlice Dollar Amount**	$ 2,245,007						
9	**Average Hours in Rate Period**	8760						
10	**Implied Discount ($/MWh)**	**11.76**	A)					
11								
12								
13								
14	**FY 2018**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**		**TOTAL**
15	IRD Monthly Loads (MWh)	290,041	433,464	499,210	409,669	249,220	B)	
16	IRD credit ($) (A * B)	$ (3,410,884)	$ (5,097,532)	$ (5,870,715)	$ (4,817,708)	$ (2,930,830)		**$ (22,127,669)**
17								
18								
19	**FY2019**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**		**TOTAL**
20	IRD Monthly Loads (MWh)	290,041	433,464	499,210	409,669	249,220	B)	
21	IRD credit ($) (A * B)	$ (3,410,884)	$ (5,097,532)	$ (5,870,715)	$ (4,817,708)	$ (2,930,830)		**$ (22,127,669)**
22								
23								
24	*Ties to Table 4.2, Revenue at Proposed Rates, line 8*							

Table 9.6 – Low Density Discount (LDD) – FY 2018-2019

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**Table 9.6 – Low Density Discount (LDD) – FY 2018-2019**														
2	Table shows calculation of LDD credit at proposed rates.														
3															
4	Low Density Discount														
5	Customer Charge LDD	**FY 2018**	**FY 2019**												
6	TOCA LDD Offset %...	1.71%	1.72%	**A)**											
7															
8	TRM Costs after Adjustments														
9	Composite...	$ 2,462,544	$ 2,477,578												
10	Non-Slice..	$ (264,902)	$ (267,017)												
11	Slice...	$ -	$ -												
12		$ 2,197,642	$ 2,210,562	**B)**											
13															
14	LDD discount - Composite portion (A * B)................................	$ 37,501	$ 38,019	**C)**											
15	LDD discount (Demand/Load Shaping portion)...........................	$ 3,509	$ 3,951	**D) below**											
16	**Total LDD discount (C + D)..**	**$ 41,010**	**$ 41,971**												
17															
18	**Demand and Load Shaping Discount Detail**														
19	**FY 2018**	**Oct-17**	**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**		
20	Demand BD (kW)	17,126	18,741	29,677	31,889	19,038	29,262	23,183	20,743	24,426	24,283	30,753	19,348		
21	Load Shaping BD HLH (MWh)	(5,766)	(11,647)	(1,033)	7,456	8,113	(1,738)	(2,466)	(22,607)	(3,888)	7,898	1,071	(2,539)		
22	Load Shaping BD LLH (MWh)	1,214	(1,244)	5,940	9,084	8,680	1,875	3,150	(7,403)	2,975	13,223	6,911	3,287		
23	Demand Rate	$ 10.45	$ 10.65	$ 11.83	$ 11.45	$ 11.15	$ 9.28	$ 7.68	$ 6.49	$ 6.92	$ 9.63	$ 10.98	$ 10.91		
24	Load Shaping Rate (HLH)	$ 26.74	$ 27.27	$ 30.28	$ 29.30	$ 28.54	$ 23.75	$ 19.67	$ 16.63	$ 17.71	$ 24.66	$ 28.11	$ 27.94		
25	Load Shaping Rate (LLH)	$ 22.49	$ 24.74	$ 26.60	$ 23.94	$ 23.94	$ 20.80	$ 17.54	$ 11.25	$ 9.31	$ 19.05	$ 22.61	$ 22.19		
26	LDD credit (Demand/Load Shaping portion)	$ 52,093	$ (148,788)	$ 477,793	$ 801,077	$ 651,634	$ 269,260	$ 184,788	$ (324,621)	$ 127,870	$ 680,518	$ 524,025	$ 213,083	$ 3,508,731	
27														$ 3,508.73	**D)**
28	**FY 2019**	**Oct-18**	**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**		
29	Demand BD (kW)	22,831	21,424	32,376	34,679	22,872	28,675	29,100	23,569	23,316	31,144	32,819	21,554		
30	Load Shaping BD HLH (MWh)	(4,446)	(10,801)	47	8,826	9,433	(708)	(396)	(21,139)	(2,639)	10,459	2,986	(771)		
31	Load Shaping BD LLH (MWh)	(274)	(2,328)	4,746	7,923	7,501	889	1,088	(9,116)	1,743	10,891	5,086	1,408		
32	Demand Rate	$ 10.45	$ 10.65	$ 11.83	$ 11.45	$ 11.15	$ 9.28	$ 7.68	$ 6.49	$ 6.92	$ 9.63	$ 10.98	$ 10.91		
33	Load Shaping Rate (HLH)	$ 26.74	$ 27.27	$ 30.28	$ 29.30	$ 28.54	$ 23.75	$ 19.67	$ 16.63	$ 17.71	$ 24.66	$ 28.11	$ 27.94		
34	Load Shaping Rate (LLH)	$ 22.49	$ 24.74	$ 26.60	$ 23.94	$ 23.94	$ 20.80	$ 17.54	$ 11.25	$ 9.31	$ 19.05	$ 22.61	$ 22.19		
35	LDD credit(Demand/Load Shaping portion)	$ 113,540	$ (123,978)	$ 510,668	$ 845,358	$ 703,834	$ 267,771	$ 234,792	$ (301,145)	$ 130,840	$ 765,314	$ 559,307	$ 244,876	$ 3,951,178	
36														$ 3,951.18	**D)**
37	**LDD credit is negative revenue*														
38	*Ties to Table 4.2, Revenue at Proposed Rates, line 9*														

Table 9.7 Tier 2 Revenue

	A	B	C
1	**Table 9.7 Tier 2 Revenue**		
2	**Fiscal Year**		
3	**Rate Period**	**FY2018**	**FY2019**
4	**Short-Term Tier 2 Costs**		
5	Base Power Purchase Cost	$ -	$ 6,850,320
6	Rate Design Components	$ 405,897	$ 550,883
7	Other Costs	$ -	$ -
8	Rate $/MWh	**$ 27.20**	**$ 24.97**
9	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (359,323)	$ (489,130)
10	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
11	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (46,574)	$ (61,754)
12	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -
13	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -
14	Total ShortTerm Rate Revenue	$ 8,952,832	$ 10,897,487
15	Remarketing Credit	$ -	$ -
16	Remarketing Charge	$ -	$ -
17	Forecast Power Purchase Costs	$ 5,555,316	$ 891,062
18			
19	**Load Growth Tier 2 Costs**		
20	Base Power Purchase Cost	$ 2,163,720	$ 2,538,210
21	Rate Design Components	$ 63,822	$ 75,821
22	Other Costs	$ -	$ -
23	Rate $/MWh	**$ 47.68**	**$ 45.42**
24	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (56,499)	$ (67,322)
25	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
26	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (7,323)	$ (8,500)
27	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -
28	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -
29	Total LoadGrowth Rate Revenue	$ 2,467,635	$ 2,728,258
30	Remarketing Credit	$ -	$ -
31	Remarketing Charge	$ -	$ -
32	Forecast Power Purchase Costs	$ 156,204	$ 29,123
33			
34	**Vintage 1 Tier 2 Costs**		
35	Base Power Purchase Cost	$ 19,906,224	$ 20,772,588
36	Rate Design Components	$ 496,920	$ 508,644
37	Other Costs	$ -	$ -
38	Rate $/MWh	**$ 51.40**	**$ 53.02**
39	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (439,901)	$ (451,625)
40	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
41	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (57,019)	$ (57,019)
42	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -
43	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -
44	Total Vintage.1 Rate Revenue	$ 20,712,144	$ 21,364,939
45	Remarketing Credit	$ 1,046,979	$ 803,896
46	Remarketing Charge	$ -	$ -
47	Forecast Power Purchase Costs	$ 201,993	$ 20,961
48			
49	**Vintage 2 Tier 2 Costs**		
50	Base Power Purchase Cost	$ 8,965,860	$ 10,992,486
51	Rate Design Components	$ 248,460	$ 298,552
52	Other Costs	$ -	$ -
53	Rate $/MWh	**$ 46.50**	**$ 48.02**
54	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (219,950)	$ (265,084)
55	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
56	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (28,509)	$ (33,468)
57	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -
58	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -
59	Total Vintage.2 Rate Revenue	$ 9,368,820	$ 11,357,690
60	Remarketing Credit	$ 1,433,476	$ 1,734,131
61	Remarketing Charge	$ -	$ -
62	Forecast Power Purchase Costs	$ 100,996	$ 16,770
63			
64			
65	Total Tier 2 Revenue Collection Before Remarking Charge/Credit	$ 41,501,431	$ 46,348,375
66	Total Tier 2 Remarketing Charge	$ -	$ -
67	Total Tier 2 Remarketing Credit	$ (2,480,455)	$ (2,538,027)
68	Non-Federal Remarketing Credit	$ (759,563)	$ (260,912)
69	Value of BPA Purchased Remarketing	$ -	$ -
70	**Total Tier 2 Revenue Collection**	**$ 38,261,413**	**$ 43,549,436**
71			
72	*Ties to Table 4.2, Revenue at Proposed Rates, line 10*		

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**Table 9.8 – Direct Service Industries (DSI) revenues – FY 2017-2019**														
2	Table shows calculation of DSI revenues at current and proposed rates.														
3															
4	**FY 2017**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Total**
5	HLH rate (per MWh)	A)	44.43	45.13	45.79	46.59	46.22	41.95	40.93	38.67	39.72	44	46.87	48.32	
6	LLH rate (per MWh)	B)oihl	40.32	41.05	41.39	41.6	41.25	38.64	37.61	34.1	33.68	38.15	40.98	42.27	
7	Demand rate (kw/Mo)	C)	10.02	10.27	10.51	10.79	10.66	9.13	8.76	7.95	8.33	9.87	10.90	11.42	
8															
9	HLH consumption (MWh)	D)	8,906	8,728	9,071	8,896	8,424	15,984	14,800	9,152	9,152	8,800	9,504	8,800	120,217
10	LLH consumption (MWh)	E)	7,594	7,056	7,216	7,642	6,336	11,507	11,840	7,216	6,688	7,568	6,864	7,040	94,567
11	Demand (kW)	F)	545.00	-	-	2,741.00									3,286
12															
13	HLH revenues (A * D)	G)	395,694	393,895	415,361	414,465	389,357	670,529	605,764	353,908	363,517	387,200	445,452	425,216	5,260,358
14	LLH revenues (B * E)	H)	306,190	289,649	298,670	317,907	261,360	444,630	445,302	246,066	225,252	288,719	281,287	297,581	3,702,613
15	Demand revenues (C * F)	I)	5,461	-	-	29,575	-	-	-	-	-	-	-	-	35,036
16	TOTAL forecast revenues (G + H + I)	J)	$ 707,345	$ 683,543	$ 714,031	$ 761,947	$ 650,717	$ 1,115,159	$ 1,051,066	$ 599,973	$ 588,769	$ 675,919	$ 726,739	$ 722,797	$ 8,998,007
17															
18	**FY 2018 - current rates**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Total**
19	HLH rate (per MWh)	A)	44.43	45.13	45.79	46.59	46.22	41.95	40.93	38.67	39.72	44.00	46.87	48.32	
20	LLH rate (per MWh)	B)	40.32	41.05	41.39	41.60	41.25	38.64	37.61	34.10	33.68	38.15	40.98	42.27	
21	Demand rate (kw/Mo)	C)	10.02	10.27	10.51	10.79	10.66	9.13	8.76	7.95	8.33	9.87	10.90	11.42	
22															
23	HLH consumption (MWh)	D)	9,789	9,090	9,025	9,306	8,581	36,534	36,405	36,175	35,073	35,719	37,847	33,411	296,955
24	LLH consumption (MWh)	E)	7,307	7,336	7,894	7,729	6,561	28,524	26,917	28,851	27,768	29,167	27,272	29,540	234,867
25	Demand (kW)	F)													
26															
27	HLH revenues (A * D)	G)	434,940	410,222	413,254	433,582	396,602	1,532,604	1,490,040	1,398,894	1,393,110	1,571,650	1,773,868	1,614,410	12,863,175
28	LLH revenues (B * E)	H)	294,626	301,155	326,713	321,534	270,629	1,102,158	1,012,358	983,833	935,222	1,112,734	1,117,626	1,248,671	9,027,258
29	Demand revenues (C * F)	I)	-	-	-	-	-	-	-	-	-	-	-	-	-
30	TOTAL revenues (G + H + I)		$ 729,566	$ 711,377	$ 739,967	$ 755,115	$ 667,230	$ 2,634,763	$ 2,502,398	$ 2,382,727	$ 2,328,332	$ 2,684,383	$ 2,891,493	$ 2,863,081	$ 21,890,433
31															
32	**FY 2019 - current rates**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Total**
33	HLH rate (per MWh)	A)	44.43	45.13	45.79	46.59	46.22	41.95	40.93	38.67	39.72	44.00	46.87	48.32	
34	LLH rate (per MWh)	B)	40.32	41.05	41.39	41.60	41.25	38.64	37.61	34.10	33.68	38.15	40.98	42.27	
35	Demand rate (kw/Mo)	C)	10.02	10.27	10.51	10.79	10.66	9.13	8.76	7.95	8.33	9.87	10.90	11.42	
36															
37	HLH consumption (MWh)	D)	37,721	35,017	34,740	36,356	33,593	36,534	36,405	36,175	35,073	35,719	37,847	33,411	428,590
38	LLH consumption (MWh)	E)	27,736	28,274	30,539	29,039	25,229	28,524	26,917	28,851	27,768	29,167	27,272	29,540	338,857
39	Demand (kW)	F)													
40															
41	HLH revenues (A * D)	G)	1,675,934	1,580,314	1,590,726	1,693,847	1,552,662	1,532,604	1,490,040	1,398,894	1,393,110	1,571,650	1,773,868	1,614,410	18,868,061
42	LLH revenues (B * E)	H)	1,118,305	1,160,654	1,264,006	1,208,025	1,040,679	1,102,158	1,012,358	983,833	935,222	1,112,734	1,117,626	1,248,671	13,304,270
43	Demand revenues (C * F)	I)	-	-	-	-	-	-	-	-	-	-	-	-	-
44	TOTAL revenues (G + H + I)		$ 2,794,240	$ 2,740,968	$ 2,854,732	$ 2,901,872	$ 2,593,341	$ 2,634,763	$ 2,502,398	$ 2,382,727	$ 2,328,332	$ 2,684,383	$ 2,891,493	$ 2,863,081	$ 32,172,330
45															
46	**FY 2018 - proposed rates**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Total**
47	HLH rate (per MWh)	A)	48.08	48.61	51.62	50.64	49.88	45.09	41.01	37.97	39.05	46.00	49.45	49.28	
48	LLH rate (per MWh)	B)	43.83	46.08	47.94	45.28	45.28	42.14	38.88	32.59	30.65	40.39	43.95	43.53	
49	Demand rate (kw/Mo)	C)	10.45	10.65	11.83	11.45	11.15	9.28	7.68	6.49	6.92	9.63	10.98	10.91	
50															
51	HLH consumption (MWh)	D)	9,789	9,090	9,025	9,306	8,581	36,534	36,405	36,175	35,073	35,719	37,847	33,411	296,955
52	LLH consumption (MWh)	E)	7,307	7,336	7,894	7,729	6,561	28,524	26,917	28,851	27,768	29,167	27,272	29,540	234,867
53	Demand (kW)		-	-	-	-	-	-	-	-	-	-	-	-	
54															
55	HLH revenues (A * D)	G)	470,671	441,854	465,870	471,272	428,007	1,647,321	1,492,952	1,373,572	1,369,611	1,643,088	1,871,512	1,646,485	13,322,215
56	LLH revenues (B * E)	H)	320,274	338,057	378,416	349,977	297,068	1,201,991	1,046,543	940,267	851,086	1,178,068	1,198,625	1,285,892	9,386,264
57	Demand revenues (C * F)	I)	-	-	-	-	-	-	-	-	-	-	-	-	-
58	TOTAL revenues (G + H + I)		$ 790,945	$ 779,911	$ 844,286	$ 821,249	$ 725,076	$ 2,849,313	$ 2,539,495	$ 2,313,839	$ 2,220,696	$ 2,821,157	$ 3,070,136	$ 2,932,377	$ 22,708,479
59															
60	**FY 2019 - proposed rates**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Total**
61	HLH rate (per MWh)	A)	48.08	48.61	51.62	50.64	49.88	45.09	41.01	37.97	39.05	46.00	49.45	49.28	
62	LLH rate (per MWh)	B)	43.83	46.08	47.94	45.28	45.28	42.14	38.88	32.59	30.65	40.39	43.95	43.53	
63	Demand rate (kw/Mo)	C)	10.45	10.65	11.83	11.45	11.15	9.28	7.68	6.49	6.92	9.63	10.98	10.91	
64															
65	HLH consumption (MWh)	D)	37,721	35,017	34,740	36,356	33,593	36,534	36,405	36,175	35,073	35,719	37,847	33,411	428,590
66	LLH consumption (MWh)	E)	27,736	28,274	30,539	29,039	25,229	28,524	26,917	28,851	27,768	29,167	27,272	29,540	338,857
67	Demand (kW)		-	-	-	-	-	-	-	-	-	-	-	-	
68															
69	HLH revenues (A * D)	G)	1,813,615	1,702,173	1,793,258	1,841,091	1,675,612	1,647,321	1,492,952	1,373,572	1,369,611	1,643,088	1,871,512	1,646,485	19,870,291
70	LLH revenues (B * E)	H)	1,215,658	1,302,873	1,464,036	1,314,888	1,142,350	1,201,991	1,046,543	940,267	851,086	1,178,068	1,198,625	1,285,892	14,142,276
71	Demand revenues (C * F)	I)	-	-	-	-	-	-	-	-	-	-	-	-	-
72	TOTAL revenues (G + H + I)		$ 3,029,273	$ 3,005,046	$ 3,257,294	$ 3,155,979	$ 2,817,962	$ 2,849,313	$ 2,539,495	$ 2,313,839	$ 2,220,696	$ 2,821,157	$ 3,070,136	$ 2,932,377	$ 34,012,567
73															
74															$ 28,360,523
75	*Ties to Table 4.1, Revenue at Current Rates, and 4.2, Revenue at Proposed Rates, line 14*														

Table 9.9-Inter-Business Line Allocations

Inter-Business Line Allocations			
	A	B	C
	Generation Inputs	**Annual Average for FY 2018-2019 Forecast Quantity (MW)**	**Annual Average for FY 2018-2019 Revenue Forecast**
1	Regulating Reserve	63.8	$ 7,102,535
2	Balancing Reserve Capacity for VERBS wind, VERBS solar and DERBS	377.1	$ 41,980,658
3	Operating Reserve - Spinning	227.2	$ 23,519,642
4	Operating Reserve - Supplemental	227.2	$ 19,420,618
5	Operating Reserve Total	454.4	$ 42,940,260
6	Synchronous Condensing		$ 1,272,635
7	Generation Dropping		$ 589,232
8	Redispatch		$ 225,000
9	Segmentation of COE/Reclamation Network and Delivery Facilities		$ 8,867,000
10	Station Service		$ 1,996,009
11	Generation Inputs Total		$ 104,973,328

Table 9.10
Balancing Reserve Capacity Quantity Forecast for FY 2018-2019

Balancing Reserve Capacity Quantity Forecast for FY 2018-2019

	A	B	C	D	E	F	G	H	I	J
	Month	Installed Capacity (MW)			Total Balancing Reserve Capacity (MW)		Load Following and Imbalance Balancing Reserve Capacity (MW)		Load Regulation, VERBS, and DERBS Balancing Reserve Capacity (MW)	
		WIND	SOLAR	DERBS	*inc*	*dec*	*inc*	*dec*	*inc*	*dec*
1	Oct-17	4784.0	5.0	3975.3	710.0	-873.1	195.6	-229.6	514.4	-643.6
2	Nov-17	4784.0	5.0	3975.3	710.0	-873.1	195.6	-229.6	514.4	-643.6
3	Dec-17	4784.0	5.0	3975.3	710.0	-873.1	195.6	-229.6	514.4	-643.6
4	Jan-18	4067.0	5.0	3975.3	645.9	-788.8	191.5	-227.1	454.3	-561.7
5	Feb-18	4067.0	5.0	3975.3	645.9	-788.8	191.5	-227.1	454.3	-561.7
6	Mar-18	4067.0	5.0	3975.3	645.9	-788.8	191.5	-227.1	454.3	-561.7
7	Apr-18	4067.0	5.0	3975.3	645.9	-788.8	191.5	-227.1	454.3	-561.7
8	May-18	4067.0	5.0	3975.3	645.9	-788.8	191.5	-227.1	454.3	-561.7
9	Jun-18	2767.0	5.0	3975.3	620.5	-744.5	189.9	-221.2	430.6	-523.3
10	Jul-18	2787.0	5.0	3975.3	620.4	-744.7	189.7	-221.1	430.7	-523.6
11	Aug-18	2787.0	5.0	3975.3	620.4	-744.7	189.7	-221.1	430.7	-523.6
12	Sep-18	2787.0	5.0	3975.3	620.4	-744.7	189.7	-221.1	430.7	-523.6
13	Oct-18	2787.0	5.0	2339.3	618.2	-745.0	193.4	-226.4	424.8	-518.7
14	Nov-18	2787.0	8.2	2339.3	618.4	-744.9	193.5	-226.4	424.9	-518.5
15	Dec-18	2787.0	8.2	2339.3	618.4	-744.9	193.5	-226.4	424.9	-518.5
16	Jan-19	2787.0	26.2	2339.3	618.8	-744.6	193.3	-226.0	425.5	-518.6
17	Feb-19	2787.0	26.2	2339.3	618.8	-744.6	193.3	-226.0	425.5	-518.6
18	Mar-19	2787.0	26.2	2339.3	618.8	-744.6	193.3	-226.0	425.5	-518.6
19	Apr-19	2787.0	26.2	2339.3	618.8	-744.6	193.3	-226.0	425.5	-518.6
20	May-19	2787.0	26.2	2339.3	618.8	-744.6	193.3	-226.0	425.5	-518.6
21	Jun-19	2787.0	26.2	2339.3	618.8	-744.6	193.3	-226.0	425.5	-518.6
22	Jul-19	2787.0	26.2	2339.3	618.8	-744.6	193.3	-226.0	425.5	-518.6
23	Aug-19	2287.0	26.2	2339.3	578.9	-695.3	193.9	-230.5	385.0	-464.8
24	Sep-19	2481.4	26.2	2339.3	601.6	-729.2	196.3	-235.1	405.3	-494.1
25	Annual Average	3268.9	13.2	3157.3	633.7	-767.2	192.8	-226.5	440.9	-540.8

This page intentionally left blank.

BONNEVILLE POWER ADMINISTRATION
DOE/BP-4802 • July 2017