BP-16 Initial Rate Proposal

Power Rates Study Documentation

BP-16-E-BPA-01A

December 2014

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2016 POWER RATES STUDY DOCUMENTATION
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COMMONLY USED ACRONYMS AND SHORT FORMS

AAC	Anticipated Accumulation of Cash
ACNR	Accumulated Calibrated Net Revenue
AER step	Actual Energy Regulation study
AGC	Automatic Generation Control
ALF	Agency Load Forecast (computer model)
aMW	average megawatt(s)
AMNR	Accumulated Modified Net Revenues
ANR	Accumulated Net Revenues
AOP	Assured Operating Plan
ASC	Average System Cost
BAA	Balancing Authority Area
BiOp	Biological Opinion
BPA	Bonneville Power Administration
BPA-P	Bonneville Power Administration – Power
BPA-T	Bonneville Power Administration – Transmission
Btu	British thermal unit
CDD	cooling degree day(s)
CDQ	Contract Demand Quantity
CGS	Columbia Generating Station
CHWM	Contract High Water Mark
CNR	Calibrated Net Revenue
COE, Corps, or USACE	U.S. Army Corps of Engineers
Commission	Federal Energy Regulatory Commission
Corps, COE, or USACE	U.S. Army Corps of Engineers
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council or NPCC	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)
DDC	Dividend Distribution Clause
dec	decrease, decrement, or decremental
DERBS	Dispatchable Energy Resource Balancing Service
DFS	Diurnal Flattening Service
DOE	Department of Energy
DOP	Detailed Operating Plan
DSI	direct-service industrial customer or direct-service industry
DSO	Dispatcher Standing Order
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.
EPP	Environmentally Preferred Power

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
FHFO	Funds Held for Others
FORS	Forced Outage Reserve Service
FPS	Firm Power and Surplus Products and Services (rate)
FY	fiscal year (October through September)
G&A	general & administrative
GARD	Generation and Reserves Dispatch (computer model)
GEP	Green Energy Premium
GMS	Generation Management Service
GRSPs	General Rate Schedule Provisions
GTA	General Transfer Agreement
GWh	gigawatthour
HDD	heating degree day(s)
HLH	Heavy Load Hour(s)
HOSS	Hourly Operating and Scheduling Simulator (computer model)
HYDSIM	Hydrosystem Simulator (computer model)
ICE	Intercontinental Exchange
inc	increase, increment, or incremental
IOU	investor-owned utility
IP	Industrial Firm Power (rate)
IPR	Integrated Program Review
IRD	Irrigation Rate Discount
IRM	Irrigation Rate Mitigation
IRMP	Irrigation Rate Mitigation Product
JOE	Joint Operating Entity
kcfs	thousand cubic feet per second
kW	kilowatt (1000 watts)
kWh	kilowatthour
LPP	Large Project Program
LDD	Low Density Discount
LLH	Light Load Hour(s)
LPTAC	Large Project Targeted Adjustment Charge
LRA	Load Reduction Agreement
Maf	million acre-feet
Mid-C	Mid-Columbia
MMBtu	million British thermal units
MNR	Modified Net Revenues
MRNR	Minimum Required Net Revenue
MW	megawatt (1 million watts)
MWh	megawatthour

NCP	Non-Coincidental Peak
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NFB	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NORM	Non-Operating Risk Model (computer model)
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPCC or Council	Pacific Northwest Electric Power and Conservation Planning Council
NPV	net present value
NR	New Resource Firm Power (rate)
NRFS	New Resource Flattening Service
NT	Network Transmission
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.
OMB	Office of Management and Budget
OPER step	operational study
OY	operating year (August through July)
PF	Priority Firm Power (rate)
PFp	Priority Firm Public (rate)
PFx	Priority Firm Exchange (rate)
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
POM	Point of Metering
POR	Point of Receipt
Project Act	Bonneville Project Act
PRS	Power Rates Study
PS	BPA Power Services
PSW	Pacific Southwest
PTP	Point to Point Transmission (rate)
PUD	public or people's utility district
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
RD	Regional Dialogue
REC	Renewable Energy Certificate
Reclamation or USBR	U.S. Bureau of Reclamation

REP	Residential Exchange Program
RevSim	Revenue Simulation Model (component of RiskMod)
RFA	Revenue Forecast Application (database)
RHWM	Rate Period High Water Mark
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model (component of RiskMod)
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RR	Resource Replacement (rate)
RRS	Resource Remarketing Service
RSS	Resource Support Services
RT1SC	RHWM Tier 1 System Capability
RTO	Regional Transmission Operator
SCADA	Supervisory Control and Data Acquisition
SCS	Secondary Crediting Service
Slice	Slice of the System (product)
T1SFCO	Tier 1 System Firm Critical Output
TCMS	Transmission Curtailment Management Service
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	BPA Transmission Services
TSS	Transmission Scheduling Service
UAI	Unauthorized Increase
ULS	Unanticipated Load Service
USACE, Corps, or COE	U.S. Army Corps of Engineers
USBR or Reclamation	U.S. Bureau of Reclamation
USFWS	U.S. Fish and Wildlife Service
VERBS	Variable Energy Resources Balancing Service (rate)
VOR	Value of Reserves
VR1-2014	First Vintage rate of the BP-14 rate period
WECC	Western Electricity Coordinating Council (formerly WSCC)
WIT	Wind Integration Team
WSPP	Western Systems Power Pool

DOCUMENTATION FOR THE
2016 POWER RATES STUDY

INTRODUCTION

The Documentation for the Power Rates Study (PRS) shows the details of the calculation of the proposed Power Rates.

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

Section 2: Ratesetting Methodology and Process contains ratemaking tables that are the output of the Rate Analysis Model (RAM2016). The RAM2016 is a group of computer applications that perform most of the computations that determine BPA's proposed power rates. The output tables of RAM2016 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 section II.C.

Section 3: Rate Design documents the calculations of the Demand rate and Load Shaping rates, including the results of the Tier 2 and Resource Support Service (RSS) modules of RAM. The Tier 2 module results include the Tier 2 rates, billing determinants, and rate design adjustments associated with Tier 2. The results of the RSS module include the rate design revenue credits and adjustments associated with RSS and Resource Shaping Charge, the RSS rates and charges, the Resources Shaping charge, the Transmission Scheduling Service charge, and the Grandfathered Generation Management Service charge. This section also includes a table that shows the steps to produce the Slice Billing Adjustments by customer, calculations for WECC and Peak assessment charges, as well as information on the five-year market purchases for Southeast Idaho transfer load service.

Section 4: The Revenue Forecast documents revenue forecasts at both current and proposed rates for the rate period, FY 2016-2017, and at current rates for the period immediately preceding the two-year rate period, FY 2015.

Section 5: Rate Schedules *No documentation*

Section 6: General Rate Schedule Provisions *No documentation*

Section 7: Slice *No documentation*

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

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SECTION 1: INTRODUCTION AND BACKGROUND

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RATE PROCESS MODELING

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

POWER LOADS AND RESOURCES STUDY (BP-16-E-BPA-03):

Federal System Load Obligation Forecast

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

BPA also has contract obligations other than those served under BPA's firm requirements PSC obligations. These "other contract obligations" include contract sales to utilities and marketers and power commitments under the Columbia River Treaty. All these 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 regulated hydro projects for FY 2016-2017.

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 completes BPA's loads and resources picture by comparing Federal system load obligations to Federal system resources. Federal system load obligations include BPA's firm requirements PSC obligations and other Federal contract obligations. Federal system resources include BPA's regulated and independent hydro resources under 1937 water conditions, contract purchases, and other non-hydro generating projects. The result of the Federal system resources less loads yields BPA's estimated Federal system monthly firm energy surplus or deficit, in average megawatts. Should the results indicate an energy deficit in the ratemaking process, augmentation purchases must be made to ensure an annual energy load-resource balance. The surplus/deficit calculation is performed for each year of the rate test 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 Risk and Market Price Study.

POWER REVENUE REQUIREMENT STUDY (BP-16-E-BPA-02):

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

POWER RISK AND MARKET PRICE FORECAST STUDY (BP-16-E-BPA-04):

Secondary Energy Revenue Forecast

RevSim is used to forecast secondary 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 are forecast loads, non-hydro resources, and hydro generation. RevSim uses results from two hydro-regulation 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 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. The Rate Analysis Model and the Power Services Revenue Forecast both use the surplus energy revenues and balancing and augmentation power purchase expenses resulting from the Secondary Energy Revenue Forecast calculated in RevSim. RevSim computes the 4(h)(10)(C) credits BPA is allowed to credit against its annual U.S. Treasury payment. 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, Pisces computer software costs, 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 applying the same AURORAxmp prices used for the calculation of secondary energy revenues to 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.

Risk Analysis

RevSim in conjunction with AURORAxmp and Non-Operating Risk Model (NORM) are used to quantify BPA's net revenue risk. RevSim estimates net revenue variability associated with various operating risks (load, resource, and natural gas price and 4(h)(10)(C) credit variations). NORM estimates the non-operating risks that are associated with uncertainties in the cost projections in the revenue requirement as well as a selection of revenue uncertainties not captured in RevSim and AURORAxmp. NORM also contains Accrual to Cash adjustments, which translates net revenue into cash flow. The results from RevSim and NORM are inputs into the ToolKit, which calculates the probability of making all scheduled Treasury payments on time and in full.

Risk Mitigation

The ToolKit Model is used to determine Treasury Payment Probability (TPP, the probability of making all planned Treasury payments during the rate period) given the net revenue risks quantified in RevSim and 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 on the level of year-end reserves available for risk that are attributable to Power Services.

Market Price

The electric energy price results from the Power Risk and Market Price Study are used as price inputs in the Generation Inputs Study to value the energy in synchronous condensing, generation dropping, and station service. The market price run is used in the Power Rates Study for:

(a) the prices for surplus sales and balancing purchases in RAM2016,
(b) the Load Shaping rate,
(c) the Load Shaping True-up rate,
(d) the Resource Shaping rate,
(e) Resource Support Services rates,
(f) shaping the Demand rate,
(g) the PF Tier 2 Balancing Credit,
(h) the PF Unused RHWM Credit,
(i) Tier 1 PF Equivalent Rates,
(j) Melded PF Equivalent Rates,
(k) the Balancing Augmentation Credit, and
(l) NR rate design.

It is used in the Power Risk and Market Price Study for the risk analysis.

The tool used to calculate electric energy prices is a model of the Western Electricity Coordinating Council (WECC) power system called AURORAxmp. AURORAxmp is an economic fundamentals-based software application that models wholesale electric energy transactions in a competitive pricing system. AURORAxmp uses a demand forecast and supply cost information using WECC data to find an hourly market clearing price, or equivalently, the marginal cost of electric energy. To determine price in a given hour, AURORAxmp models the dispatch of electric generating resources in a least-cost order to meet the load (demand) forecast. The price in the given hour is equal to the variable cost of the marginal resource.

POWER RATES STUDY (BP-16-E-BPA-01):

Rate Analysis Model (RAM2016)

RAM2016, 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 RAM2016 performs these rate adjustments. The amount of PF Public rate protection and the levels of the IP and NR rate are set assuming a 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 TRM specifies a cost allocation methodology to PF Preference costs allocated in the COSA and Rate Directives steps. RAM2016 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 either the Tier 1 Composite, Non-Slice, Slice, or Tier 2 costs pools, and demonstrating by "proof" that cost allocations under the TRM and COSA/Rate Directives are equivalent in terms of aggregate costs recovered from PF Preference, PF Exchange, IP, and NR. To provide a crosswalk between the differences between COSA allocations and TRM allocations, the mapping for each is shown in RAM2016 using unique database keys.
Three rate designs are developed: (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; and (3) a constant annual energy rate for each PFp Tier 2 rate and the PFx rates. RAM2016 designs rates for each rate pool. For the PFp Melded rate, the PFx rate, the IP rate, and the NR rate, the rate design can be applied without further processing.

Resource Support Services Module of RAM

The Resource Support Services (RSS) module of RAM, a spreadsheet-based model, calculates the charges and rates applied to resources receiving Resource Support Services 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 will also calculate 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, 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 RAM

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

Revenue and Purchased Power Expense Forecast

The Revenue Forecast, section 4 of the Power Rates Study, presents BPA's expected level of revenue and purchased power expense for FY 2015-2017. FY 2015 revenues are forecast to estimate the level of reserves at the beginning of the rate period. Selected purchased power expenses, which 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, such as output from RiskMod, to obtain short-term marketing revenues, balancing purchased power expenses, augmentation purchased power expenses, and 4(h)(10)(C) credits.

FY 2016-2017 Average System Cost (ASC) Forecasts

ASCs are used in determining the forecast of REP benefits that exchanging utilities are entitled to during the rate period. For purposes of the Initial Proposal, BPA is using the Initial Report of draft ASCs published by BPA on December 10, 2014.

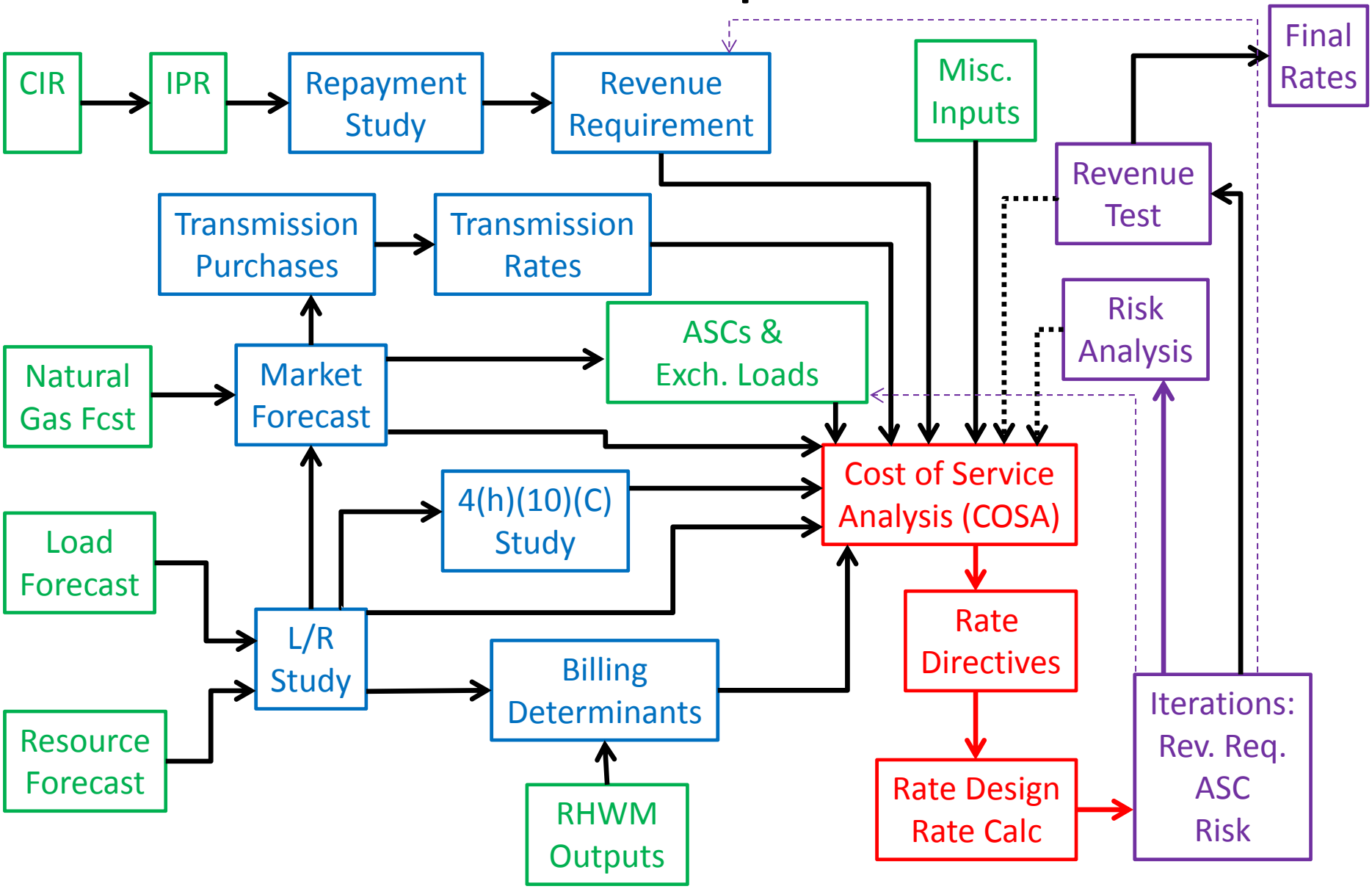
POWER GENERATION INPUTS STUDY (BP-16-E-BPA-05):

Generation and Reserves Dispatch (GARD) Model

The variable costs associated with providing a quantity of reserves are assessed in the Generation and Reserves Dispatch (GARD) Model using inputs from the HYDSIM model, actual system data, and a pre-processing spreadsheet. The purpose of the GARD model is to calculate the variable costs incurred as a result of operating the Federal Columbia River Power System (FCRPS) with the necessary reserves to maintain reliability and deploying those reserves to maintain load-resource balance within the BPA Balancing Authority Area. The GARD model analyzes variable costs in two general categories. The first category is the "stand ready" costs, those costs associated with making a project capable of providing reserves. The next other is the "deployment costs," those costs incurred when the system uses its reserve capability to actually deliver in response to a reserve need. The GARD model produces the following costs associated

with standing ready: 1) energy shift, 2) efficiency change, 3) cycling losses, and 4) spill losses. GARD also calculates the following costs associated with deploying reserves: 1) response losses, 2) deployment cycling losses, and 3) deployment spill losses. After the GARD model is run, the megawatthour values for each month and HLH and LLH period of the 80 water year set are passed to RiskMod.

Power Rate Development Process



SECTION 2: RATESETTING METHODOLOGY AND PROCESS

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Table 2.1.1

Rate Data Input
Disaggregated Loads
Test Period October 2015 - September 2017
(MWh)

	A	B	C	E	F
4				2016	2017
5	Preference			60,969,194	61,134,344
6		Block		222,929	222,320
7		Slice Block		15,580,690	15,876,651
8		Slice (non-block)		16,443,593	16,145,034
9		Load Following		28,122,816	28,125,923
10		Tier 2 (Block)		599,165	764,415
11	Industrial			2,773,146	2,765,569
12		Smelter		2,635,200	2,628,000
13		Other Industrial		137,946	137,569
14	New Resource			9	9
15	Firm Power and Services			7,034,894	6,923,788
16		Intraregional Transfer		871,506	871,281
17			WNP3	788,611	788,612
18			Dittmer Station Service	82,895	82,668
27		FBS Obligation		5,868,317	5,779,713
28			Canadian Entitlement	4,140,141	4,098,372
29			USBR Pump Load	1,570,359	1,569,800
30			Hungry Horse	46,275	0
31			Upper Baker	11,228	11,228
32			Non-Treaty Storage	100,314	100,314
33			Libby Coordination	0	0
38		Seasonal or Capacity Exchange		295,072	272,795
39			Riverside Capacity	19,620	0
40			Riverside Seasonal	0	0
41			Pasadena Capacity	0	0
42			Pasadena Seasonal	0	0
43			PG&E	229,711	227,760
44			Intertie Losses	7,480	6,833
45			PacifiCorp	38,260	38,202
49	Presale of Secondary			0	0
50	Irrigation Mitigation			0	0
51	Conservation				

Table 2.1.2.1

Rate Data Input
Disaggregated Resources
Test Period October 2015 - September 2017
(MWh)

	A	B	C	E	F
5				2016	2017
6	Hydro			59,737,790	60,247,542
7		Regulated		55,430,946	55,952,678
8		Independent		3,099,425	3,095,775
9			Cowlitz Falls	232,671	232,343
10			Idaho Falls	124,397	123,900
11			PreAct	2,742,357	2,739,532
19		Hydro Other		1,207,419	1,199,089
20			Canadian Entitlement	1,207,419	1,199,089
21			Libby Coordination	0	0
22			Other	0	0
30	Non Hydro			9,960,379	8,445,289
31		Water		23,102	23,039
32			Dworshak/Clearwater Small Hydropower	23,102	23,039
33			Elwha Hydro	0	0
34			Glines Canyon Hydro	0	0
42		Thermal		9,442,800	8,023,843
43			Columbia Generating Station	9,442,800	8,023,843
53		Wind		398,922	398,379
54			Foote Creek 1	34,886	34,833
55			Foote Creek 2	0	0
56			Foote Creek 4	38,260	38,202
57			Stateline Wind Project	181,383	181,201
58			Condon Wind Project	84,682	84,511
59			Klondike I	59,711	59,633
64		Renewable		95,555	27
65			Georgia-Pacific Paper (Wauna)	95,528	0
66			Fourmile Hill Geothermal	0	0
67			Ashland Solar Project	27	27
68			White Bluffs Solar	0	0

Table 2.1.2.2

Rate Data Input
Disaggregated Resources
Test Period October 2015 - September 2017
(MWh)

	A	B	C	E	F
5				2016	2017
75	Contracts			726,055	577,109
76		Imports		382,982	312,951
77			Riverside Exchange Energy	64,341	0
78			Pasadena Exchange Energy	0	0
79			BC Hydro Power Purchase	8,784	8,760
80			Slice Return of Losses	309,858	304,191
87		Seasonal or Capacity Exchange		343,073	264,158
88			Riverside Capacity	19,980	0
89			Riverside Seasonal	58,560	0
90			Pasadena Capacity	0	0
91			Pasadena Seasonal	0	0
92			PG&E	226,273	225,956
93			PacifiCorp	38,260	38,202
98		Tier2		0	0
99			Short Term	0	0
100			Load Growth	0	0
101			Vintage 1	0	0
102			Vintage 2	0	0
103			Vintage 3	0	0
109	Augmentation and Balancing			1,205,376	2,171,165
110		System Augmentation		1,078,559	2,044,512
111		Balancing		0	0
112		Tier 1 Resources		126,817	126,654
113			Klondike III	124,614	124,451
114			Rocky Brook	2,203	2,203
115					
116	Transmission Losses			(2,127,399)	(2,121,801)

Table 2.1.3

Rate Data Input
Exchange ASCs, Loads, and Gross Costs
Test Period October 2015 - September 2017

	B	D	E
7	**Exchange ASCs ($/MWh)**	**2016**	**2017**
8			
9	Avista Corporation	$ 53.53	$ 53.53
10	Idaho Power Company	$ 59.54	$ 59.54
11	NorthWestern Energy, LLC	$ 79.66	$ 79.66
12	PacifiCorp	$ 76.93	$ 76.93
13	Portland General Electric Company	$ 78.28	$ 78.28
14	Puget Sound Energy, Inc.	$ 70.03	$ 70.03
15	Clark Public Utilities	$ 54.34	$ 54.34
17	Snohomish County PUD No 1	$ -	$ -
18			
19	**Exchange Loads (GWh)**	**2016**	**2017**
20			
21	Avista Corporation	3,935	3,935
22	Idaho Power Company	6,779	6,779
23	NorthWestern Energy, LLC	686	686
24	PacifiCorp	9,107	9,107
25	Portland General Electric Company	8,666	8,666
26	Puget Sound Energy, Inc.	11,726	11,726
27	Clark Public Utilities	2,394	2,377
29	Snohomish County PUD No 1	0	0
30		43,294	43,277
31			
32	**Exchange Resource Cost ($000)**	**2016**	**2017**
33			
34	Avista Corporation	$ 210,664	$ 210,664
35	Idaho Power Company	$ 403,602	$ 403,602
36	NorthWestern Energy, LLC	$ 54,660	$ 54,660
37	PacifiCorp	$ 700,593	$ 700,593
38	Portland General Electric Company	$ 678,354	$ 678,354
39	Puget Sound Energy, Inc.	$ 821,204	$ 821,204
40	Clark Public Utilities	$ 130,102	$ 129,193
42	Snohomish County PUD No 1	$ -	$ -
43		$ 2,999,179	$ 2,998,270

Table 2.2.1.1

Energy Allocation Factor
Power Sales and Resources
Test Period October 2015 - September 2017
(aMW)

	B	C	E	F
4			**2016**	**2017**
5	**Sales**			
6	Public			
7		Load Following	3,202	3,211
8		Tier 2 (block)	68.211	87.262
9		Block Service	25	25
10		Slice (output energy)	1,872	1,843
11		Slice (block)	1,774	1,812
12		Undistributted Conservation	0	0
13	Exports			
14		BC Hydro (Cdn Entitlement)	471	468
15		Non-Treaty Storage	11	11
16		Libby Coordination	0	0
17		Pasadena Capacity	0.0	0
18		Pasadena Seasonal	0.0	0
19		Riverside Capacity	2	0
20		Riverside Seasonal	0	0
21		PacifiCorp	4	4
22		PG&E	26	26
23		Intertie Losses	1	1
24	Intra-regional Transfers			
25		Avista (WNP#3 Settle.)	90	90
26		Dittmer/Substration Sale	9	9
27	Other Loads			
28		USBR Pump Load	179	179
29		Hungry Horse	5	0
30		Upper Baker	1	1
31		Direct Service Industries	316	316
32		New Resource	0.0	0
33	Total Firm Obligations		**8,058**	**8,085**
34				
35	**Resources**			
36	Hydro			
37		Regulated	6,310	6,387
38		Independent		
39		Cowlitz Falls	26	27
40		Idaho Falls	14	14
41		PreAct	312	313
42		Non-Fed CER (Canada)	137	137
43		Libby Coordination	0	0
44	Other Hydro Resources			
45				

Table 2.2.1.2

Energy Allocation Factor
Power Sales and Resources
Test Period October 2015 - September 2017
(aMW)

	B	C	E	F
4			**2016**	**2017**
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	10	10
53		Klondike I	7	7
54		Georgia-Pacific Paper (Wauna)	11	0
55		Klondike III	14	14
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	7	0
62		Pasadena Exchange Energy	0	0
63		BC Hydro Power Purchase	1	1
64		Riverside Capacity	2	0
65		Riverside Seasonal	7	0
66		Pasadena Capacity	0	0
67		Pasadena Seasonal	0	0
68		Slice Losses Return	35	35
69	Regional Transfers (In)			
70		PG&E	26	26
71		PacifiCorp	4	4
72	Large Thermal		1,075	916
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		70	90
80	Federal Trans. Losses		(242)	(242)
81	Total Net Resources		**7,860**	**7,770**
82				
83	Total Firm Surplus/Deficit		**(198)**	**(315)**

Table 2.2.2.1

Energy Allocation Factor
Aggregated Loads and Resources
Test Period October 2015 - September 2017
(aMW)

	B	C	D	E
4			**2016**	**2017**
7	**Loads**			
8	Priority Firm - 7(b) Loads			
9		Block	26	26
10		Slice (block)	1,828	1,868
11		Load Following	3,300	3,309
12		Slice (output energy)	1,929	1,899
13		Tier 2	70.30	89.93
14		Undistributted Conservation	0	0
15		5(c) Exchange	5,080	5,091
16	Industrial Firm - 7(c) Loads			
17		Direct Service Industries	325	325
18	New Resources - 7(f) Loads			
19		NR	0.001	0.001
20	Surplus Firm - SP Loads			
21		Avista (WNP#3 Settle.)	93	93
22		Dittmer/Substation Sale	10	10
23	Total Loads		**12,661**	**12,712**
24				
25	**Resources**			
26	Federal Base System			
27		Hydro	6,760	6,837
28		Other Resources		
29		Small Thermal & Misc.		
30		Combustion Turbines		
31		Renewables	0	0
32		Cogeneration		
33		Imports	17	1
34		Regional Transfers (In)	30	30
35		Large Thermal	1,075	916
36		Non-Utility Generation	0	0
37		Slice Loss Return	35	35
38		Augmentation Purchases	202.09	320.45
39		Tier 2 Purchases	70	90

Table 2.2.2.2

Energy Allocation Factor
Aggregated Loads and Resources
Test Period October 2015 - September 2017
(aMW)

	B	C	D	E
4			**2016**	**2017**
40	less: FBS Obligations			
41		BC Hydro (Cdn Entitlement)	(486)	(482)
42		Non-Treaty Storage	(12)	(12)
43		Libby Coordination	0	0
44		Hungry Horse	(5)	0
45		Upper Baker	(1)	(1)
46		USBR Pump Load	(184)	(185)
47	less: FBS Uses			
48		Pasadena	0	0
49		Riverside	(2)	0
50		PacifiCorp	(4)	(4)
51		PG&E	(27)	(27)
52		Intertie Losses	(1)	(1)
53	Exchange Resources			
54		5(c) Exchange	5,080	5,091
55	New Resources			
56		Cowlitz Falls	26	27
57		Idaho Falls	14	14
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	10	10
63		Klondike I	7	7
64		Klondike III	14	14
65		Georgia-Pacific Paper (Wauna)	11	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		**12,661**	**12,712**

Table 2.2.3.1

Energy Allocation Factor
Calculation of Energy Allocation Factors
Test Period October 2015 - September 2017

	B	C	D
4		**2016**	**2017**
5			
6	**Loads (after adjustments)**		
7	Public	7,153	7,192
8	Exchange	5,080	5,091
9	DSI	325	325
10	NR	0.001	0.001
11	FPS	102	103
12			
13	Load Pools -- Program Case		
14	Priority Firm - 7(b) Loads	12,233	12,284
15	Industrial Firm - 7(c) Loads	325	325
16	New Resources - 7(f) Loads	0.001	0.001
17	Surplus Firm - SP Loads	102	103
18	Total Firm Loads	12,661	12,712
19	Secondary	2,365	2,220
20	Surplus Firm - SP Loads (for rate protection)	102	103
21			
22	**Resources (after adjustments)**		
23	Federal Base System	7,467	7,517
24	Exchange Resources	5,080	5,091
25	New Resources	114	103
26	Total Firm Resources	12,661	12,712
27			
28	Allocators -- Program Case		
29	Federal Base System		
30	Priority Firm - 7(b) Loads	7,467	7,517
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	4,766	4,767
36	Industrial Firm - 7(c) Loads	239	247
37	New Resources - 7(f) Loads	0.0008	0.0008
38	Surplus Firm - SP Loads	75	78
39	New Resources		
40	Priority Firm - 7(b) Loads	0	0
41	Industrial Firm - 7(c) Loads	87	79
42	New Resources - 7(f) Loads	0	0
43	Surplus Firm - SP Loads	27	25

Table 2.2.3.2

Energy Allocation Factor
Calculation of Energy Allocation Factors
Test Period October 2015 - September 2017

	B	C	D
4		**2016**	**2017**
44			
45	**Allocation Factors -- Program Case with Exchange**		
46	Federal Base System + NR		
47	Priority Firm - 7(b) Loads	0.9850	0.9865
48	Industrial Firm - 7(c) Loads	0.0114	0.0103
49	New Resources - 7(f) Loads	0.0000	0.0000
50	Surplus Firm - SP Loads	0.0036	0.0032
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	0.9383	0.9362
58	Industrial Firm - 7(c) Loads	0.0470	0.0485
59	New Resources - 7(f) Loads	0.0000	0.0000
60	Surplus Firm - SP Loads	0.0148	0.0153
61	New Resources		
62	Priority Firm - 7(b) Loads	0.0000	0.0000
63	Industrial Firm - 7(c) Loads	0.7609	0.7604
64	New Resources - 7(f) Loads	0.0000	0.0000
65	Surplus Firm - SP Loads	0.2391	0.2396
66	Conservation & General		
67	Priority Firm - 7(b) Loads	0.9662	0.9663
68	Industrial Firm - 7(c) Loads	0.0257	0.0256
69	New Resources - 7(f) Loads	0.0000	0.0000
70	Surplus Firm - SP Loads	0.0081	0.0081
81	Surplus Deficit		
82	Priority Firm - 7(b) Loads	0.9741	0.9742
83	Industrial Firm - 7(c) Loads	0.0259	0.0258
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	0.6453	0.6579
91	Industrial Firm - 7(c) Loads	0.0413	0.0420
92	New Resources - 7(f) Loads	0.0000	0.0000
93	Secondary Sales	0.3134	0.3001

Table 2.3.1.1

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2015 - September 2017
($ 000)

	B	D	E
4		**2016**	**2017**
5	**Power System Generation Resources**		
6	**Operating Generation**		
7	Columbia Generating Station (WNP-2)	262,948	322,473
8	Bureau of Reclamation	156,818	158,121
9	Corps of Engineers	243,885	250,981
10	Billing Credits Generation	5,300	5,300
11	Cowlitz Falls O&M	4,300	4,548
12	Idaho Falls Bulb Turbine	5,015	5,095
13	Bureau O&M - Elwha	-	-
14	Clearwater Hatchery Generation	1,100	1,115
15	New Resources Integration Wheeling	975	975
16	Wauna	5,612	-
17	Other New Resources	-	-
18			
19	**Operating Generation Settlement Payment**		
20	Operating Generation Settlement Payment (Colville)	21,863	22,234
21			
22	**Non-Operating Generation**		
23	Trojan Decomissioning	800	800
24	WNP-1&3 Decomissioning	800	1,063
25			
26	**Contracted and Augmentation Power Purchases**		
27	Augmentation Power Purchases	55,974	95,400
28	Balancing Purchases	20,668	14,655
29	PNCA Headwater Benefits	3,000	3,000
30	Tier 1 Augmentation Resources (Klondike III)	10,025	12,658
31	Hedging/Mitigation	8,711	38,438
32	Other Committed Purchase (excl. Hedging)	225	225
33	Bookout Adj to Contracted Power Purchases	-	-
34			
35	**Exchanges and Settlements**		
36	Residential Exchange (IOU)	214,100	214,100
37	Residential Exchange (COU)	4,241	4,211
38	Residential Exchange (Refund)	76,538	76,538
39	Residential Exchange Program Support	920	635
40	Residential Exchange Interest Accrual	-	-
41			
42	**Renewable and Conservation Generation**		
43	Renewables R&D	1,819	1,823
44	Renewable Generation	30,962	28,983
45	Green Energy Premium (contra-expense)	-	-
46	Generation Conservation R&D	4,214	4,223
47	DR & Smart Grid	1,245	1,245
48	Conservation Acquisition	14,632	14,642
49	Low Income Energy Efficiency	5,336	5,422
50	Reimbursable Energy Efficiency Development	15,000	7,000
51	Legacy Conservation	605	605
52	Market Transformation	12,531	12,691

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2015 - September 2017
($ 000)

	B	D	E
4		**2016**	**2017**
53			
54	**Transmission Acquisition and Ancillary Services**		
55	Trans & Ancillary Svcs	74,242	71,452
56	Trans & Ancillary Svcs (sys oblig)	36,001	35,249
57	Third Party GTA Wheeling	62,140	71,689
58	Power 3rd Party Trans & Ancillary Svcs	2,381	2,428
59	Trans Acq Generation Integration	14,596	14,535
60	Power Telemetering/Equipment Replacement	-	-
61			
62	**Power Non-Generation Operations**		
63	Efficiencies Program	-	-
64	Systems Operations R&D	-	-
65	Information Technology	5,805	5,910
66	Generation Project Coordination	7,735	7,845
67	Slice costs Charged to Slice Customers	-	-
68	Slice Implementation	1,101	1,131
69			
70	**PS Scheduling**		
71	Operations Scheduling	10,307	10,496
72	Scheduling R&D	-	-
73	Operations Planning	7,100	7,255
74			
75	**PS Marketing and Business Support**		
76	Sales and Support	22,525	24,765
77	Strategy, Finance & Risk Mgmt	21,718	21,631
78	Executive and Administrative Svcs	4,317	4,392
79	Conservation Support	9,456	9,731
80			
81	**Fish and Wildlife/USF&W/Planning Council/Env Req.**		
82	Fish and Wildlife	267,000	274,000
83	USF&W Lower Snake Hatcheries	32,303	32,949
84	Planning Council	11,236	11,446
85	Environmental Requirements	-	-
86			
87	**BPA Internal Support**		
88	Additional Post-Retirement Contribution	19,143	19,478
89	Agency Svs for Power for Rev Req schedule	45,250	46,119
90	Agency Svs for Energy Efficiency for Rev Req schedule	11,020	11,256

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2015 - September 2017
($ 000)

	B	D	E
4		**2016**	**2017**
91			
92	**Bad Debt Expense/Other**		
93	Bad Debt Expense (composite)	-	-
94	Bad Debt Expense (non-slice)	-	-
95	Other Income, Expenses, Adjustments (composite)	(27,855)	(54,318)
96	Other Income, Expenses, Adjustments (non-slice)	-	-
97			
98	**Non-Federal Debt Service**		
99	**Energy Northwest Debt Service**		
100	CGS Debt Service	100,888	128,148
101	WNP-1 Debt Service	252,395	195,524
102	WNP-3 Debt Service	222,207	252,493
103	EN Retired Debt	-	-
104			
105	**Non-Energy Northwest Debt Service**		
106	Conservation (CARES) Debt Service	-	-
107	Cowlitz Falls (Lewis County) Debt Service	7,300	7,303
108	Northern Wasco Debt Service	1,931	1,935
109			
110	**Depreciation and Amortization**		
111	**Depreciation**		
112	Depreciation - BPA	21,941	21,493
113	Depreciation - Corps	94,783	98,980
114	Depreciation - Bureau	28,551	29,507
115			
116	**Amortization**		
117	Amortization - Legacy Conservation	-	-
118	Amortization - Conservation Acquisitions	44,269	52,286
119	Amortization - Conservation Billing Credit	-	-
120	Amortization - CRFM	8,549	8,549
121	Amortization - Fish & Widlife	35,305	37,989
122			
123	**Interest Expense**		
124	**Net Interest**		
125	Interest On Appropriated Funds	206,826	204,298
126	Capitalization Adjustment	(45,937)	(45,937)
127	Interest On Treasury Bonds	62,679	81,199
128	Non Federal Interest (Prepay)	13,273	12,469
129	Non Federal Interest (Billing Credit)	-	-
130	Capitalized Bond Premium	-	-
131	AFUDC	(6,160)	(4,749)
132	Interest Earned on BPA Fund for Power (composite)	(9,068)	(16,221)
133	Prepay Offset Credit	-	-
134	Interest Earned on BPA Fund for Power (non-slice)	(56)	(359)

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2015 - September 2017
($ 000)

	B	D	E
4		**2016**	**2017**
135			
136	**Net Interest into Cost Pools**		
137	Power Net Interest - Hydro Allocation	182,480	187,541
138	Power Net Interest - Fish & Wildlife Allocation	16,631	17,737
139	Power Net Interest - Conservation Allocation	20,234	23,719
140	Power Net Interest - BPA Programs Allocation	2,212	1,703
141			
142	**Net Interest into Cost Pools 7b2**		
143	Power Net Interest Hydro 7b2 Allocation	182,480	187,541
144	Power Net Interest Fish & Wildlife 7b2 Allocation	16,631	17,737
145	Power Net Interest BPA Programs 7b2 Allocation	22,446	25,422
146			
147	**Net Revenue**		
148	**Minimum Required Net Revenue**		
149	Repayment of Treasury Borrowings	10,500	35,150
150	Payment of Irrigation Assistance	60,954	51,391
151	Depreciation (MRNR - Reverse sign)	(145,275)	(149,980)
152	Amortization (MRNR - Reverse sign)	(88,123)	(98,824)
153	Capitalization Adjustment (MRNR - Reverse Sign)	45,937	45,937
154	Capitalized Bond Premium (Reverse Sign)	-	-
155	Repayment of Federal Appropriations	95,156	94,671
156	PGE WNP #3 Settlement	3,524	3,524
157	Accrual Revenues (MRNR Adjustment - Reverse Sign)	-	-
158	Prepay Revenue Credits (MRNR - Reverse Sign)	30,600	30,600
159	Non Federal Interest (Prepay) (MRNR - Reverse Sign)	(13,273)	(12,469)
160	Conservation Billing Credits (MRNR Adjustment - Reverse Sign)	-	-
161	Revenue Financing Requirement	-	-
162	Depreciation Exceeds Cash Expense	-	-
163			
164	**Minimum Net Revenue into Cost Pools**		
165	Power MNetRev - Hydro Allocation	0	0
166	Power MNetRev - Fish & Wildlife Allocation	-	-
167	Power MNetRev - Conservation Allocation	-	-
168	Power MNetRev - BPA Programs Allocation	-	-
169			
170	**Minimum Net Revenue into Cost Pools 7b2**		
171	Power MNetRev - Hydro 7b2 Allocation	0	0
172	Power MNetRev - Fish & Wildlife 7b2 Allocation	-	-
173	Power MNetRev - PBA Programs 7b2 Allocation	-	-
174			
175	**Planned Net Revenues for Risk into Cost Pools**		
176	Power PNetRev - Hydro Allocation	-	-
177	Power PNetRev - Fish & Wildlife Allocation	-	-
178	Power PNetRev - Conservation Allocation	-	-
179	Power PNetRev - BPA Programs Allocation	-	-
180			
181	**Planned Net Revenues for Risk into Cost Pools 7b2**		
182	Power PNetRev - Hydro 7b2 Allocation	-	-
183	Power PNetRev - Fish & Wildlife 7b2 Allocation	-	-
184	Power PNetRev - BPA Programs 7b2 Allocation	-	-

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2015 - September 2017
($ 000)

	B	D	E
4		**2016**	**2017**
185			
186	**Internally Computed Line Items**		
187	Augmentation Power Purchases	55,974	95,400
188	Balancing Purchases	29,379	53,093
189	Secondary Energy Credit	(337,762)	(377,178)
190	Low Density Discount Costs	38,938	39,639
191	Irrigation Rate Mitigation Costs	20,942	20,942
192	**Charges/Credits to Tiered Rate Pools**		
193	Firm Surplus and Secondary Credit (from unused RHWM)	(4,290)	(2,037)
194	Balancing Augmentation	(433)	(8,726)
195	Transmission Loss Adjustment	(29,183)	(29,383)
196	Demand Revenue	45,051	44,938
197	Load Shaping Revenue	15,638	24,033
198	**Tier 2 and RSS Charges/Credits to Tiered Rate Pools**		
199	Augmentation RSS & RSC Adder	2,480	2,480
200	Tier 2 Purchase Costs	20,310	21,610
201	Tier 2 Rate Design Adjustments (Cost)	891	1,006
202	Tier 2 Other Costs	-	-
203			
204	**Revenue Credits / Rate Design Adjustments**		
205	Downstream Benefits and Pumping Power	(17,176)	(17,176)
206	Generation Inputs for Ancillary and Other Services Revenue	(115,750)	(115,750)
207	4(h)(10)(c)	(95,077)	(92,112)
208	Colville and Spokane Settlements	(4,600)	(4,600)
209	Green Tags (FBS resources)	-	-
210	Green Tags (New resources)	(1,151)	(648)
211	Energy Efficiency Revenues	(15,000)	(7,000)
212	Large Project Revenues	-	-
213	Miscellaneous Credits (incl. GTA)	(5,750)	(5,800)
214	Pre-sub/Hungry Horse	(1,957)	(1,458)
215	Other Locational/Seasonal Exchange	(565)	(565)
216	Upper Baker	(457)	(466)
217	WNP3 Settlement	(37,924)	(37,924)
218	Other Long-Term Contracts	-	-
219	Network Wind Integration & Shaping	-	-
220	Slice Billing Adjustment	(3,877)	-
221	NR Revenues from ESS energy and capacity charges	-	-
222	**Tier 2**		
223	Composite Augmentation RSS Revenue Debit/(Credit)	(1,633)	(1,633)
224	Composite Tier 2 RSS Revenue Debit/(Credit)	(86)	(94)
225	Composite Tier 2 Rate Design Adjustment Debit/(Credit)	(805)	(912)
226	Composite Non-Federal RSS Revenue Debit/(Credit)	(1,248)	(1,353)
227	Non-Slice Augmentation RSC Revenue Debit/(Credit)	(847)	(847)
228	Non-Slice Tier 2 RSC Revenue Debit/(Credit)	-	-
229	Non-Slice Tier 2 Rate Design Debit/(Credit)	-	-
230	Non-Slice Non-Federal RSC Revenue Debit/(Credit)	(83)	(81)

Table 2.3.2

Cost of Service Analysis
Cost Pool Aggregation
Test Period October 2015 - September 2017
($ 000)

	B	D	E
3		**2016**	**2017**
4			
5	**Federal Base System**	**2,049,220**	**2,204,870**
6	Hydro	772,232	791,863
7	Operating Expense	589,752	604,322
8	Net Interest	182,480	187,541
9	PNRR	-	-
10	MRNR	0	0
11	BPA Fish and Wildlife Program	330,172	341,172
12	Operating Expense	313,541	323,435
13	Net Interest	16,631	17,737
14	PNRR	-	-
15	MRNR	-	-
16	Trojan	800	800
17	WNP #1	253,195	196,587
18	WNP #2	363,836	450,621
19	WNP #3	222,207	252,493
20	System Augmentation	55,974	95,400
21	Balancing	29,604	53,318
22	Tier 2 Costs	21,201	22,616
23			
24	**New Resources**	**69,040**	**64,436**
25	Idaho Falls	5,015	5,095
26	Tier 1 Aug (Klondike III)	10,025	12,658
27	Cowlitz Falls	11,600	11,851
28	Other NR	42,400	34,831
29			
30	**Residential Exchange**	**3,000,099**	**2,998,904**
31			
32	**Conservation**	**143,842**	**148,120**
33	Operating Expense	123,608	124,401
34	Net Interest	20,234	23,719
35	PNRR	-	-
36	MRNR	-	-
37			
38	**BPA Programs**	**141,299**	**117,901**
39	Operating Expense	139,087	116,198
40	Net Interest	2,212	1,703
41	PNRR	-	-
42	MRNR	-	-
43			
44			
45	**Transmission**	**189,359**	**195,354**
46	TBL Transmission/Ancillary Services	124,838	121,236
47	3Rd Party Trans/Ancillary Services	2,381	2,428
48	General Transfer Agreements	62,140	71,689
49			
50	**Total PBL Revenue Requirement**	**5,592,859**	**5,729,585**
51			
52	**Transmission Revenue Requirement**	**811,131**	**863,467**
53	Operating Expense	602,570	644,203
54	Net Interest	130,625	145,757
55	PNRR	-	-
56	MRNR	77,936	73,507

Table 2.3.3.1

Cost of Service Analysis
Computation of Low Density and Irrigation Rate Discount Costs
Test Period October 2015 - September 2017
($ 000)

	B	D	E	F	G	H
18	**Program Totals**	**2016**	**2017**			
19	**Low Density Discount Expenses**	**$ 38,938**	**$ 39,639**			
20	**Irrigation Rate Discount**	**$ 20,942**	**$ 20,942**			
21						
22						
23	**TRM Costs after Adjustments**	**2016**	**2017**			
24	**Composite**	$ 2,433,645	$ 2,440,056			
25	**Non-Slice**	$ (271,711)	$ (272,692)			
26	**Slice**	$ -	$ -			
27	**Tier 2**	$ 21,201	$ 22,616			
28	**Total Costs**	$ 2,183,135	$ 2,189,981			
29						
30	**Low Density Discount**					
31	**Customer Charge LDD**	**2016**	**2017**			
32	**TOCA LDD Offest %**	1.66%	1.68%			
33	**LDD Customer Charge ($000)**	$ 35,905	$ 36,364			
34						
35	**Irrigation Rate Discount**					
36	**IRD Percentage**	37.06%				
37	**Total Irrigation Load (MWh)**	1,881,605				
38	**RT1SC**	6,983				
39	**Irrigation Load Weighted LDD**	4.90%				
40						
41		**2016**	**2017**			
42	**Hours**	8784	8760			
43	**IRD TOCA**	3.06753%	3.07593%			
44	**Composite Revenue**	$ 75,825,773	$ 76,033,411			
45	**Non-Slice Revenue**	$ (11,602,804)	$ (11,634,577)			
46	**Load Shaping Revenue**	$ (4,893,325)	$ (4,870,008)			
47	**Total after LDD**	$ 56,422,491	$ 56,611,914			
48						
49	**Irrigation Rate Discount**	**11.13**				
50						
51						

Table 2.3.3.2

Cost of Service Analysis
Computation of Low Density and Irrigation Rate Discount Costs
Test Period October 2015 - September 2017
($ 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-15	23,013	(5,531)	$ 9.47	$ 31.59	$ 43,209
54	Oct-15	-	(433)	$ 9.47	$ 27.35	$ (11,848)
55	Nov-15	14,925	(10,412)	$ 10.01	$ 33.39	$ (198,225)
56	Nov-15	-	(951)	$ 10.01	$ 28.87	$ (27,454)
57	Dec-15	31,988	1,597	$ 10.58	$ 35.30	$ 394,808
58	Dec-15	-	5,930	$ 10.58	$ 30.13	$ 178,690
59	Jan-16	26,747	6,800	$ 10.58	$ 35.31	$ 523,108
60	Jan-16	-	10,020	$ 10.58	$ 29.28	$ 293,432
61	Feb-16	21,348	5,326	$ 10.51	$ 35.09	$ 411,277
62	Feb-16	-	6,983	$ 10.51	$ 29.28	$ 204,491
63	Mar-16	24,874	(3,806)	$ 8.61	$ 28.71	$ 104,886
64	Mar-16	-	(306)	$ 8.61	$ 24.67	$ (7,557)
65	Apr-16	25,938	1,612	$ 8.12	$ 27.09	$ 254,270
66	Apr-16	-	3,273	$ 8.12	$ 23.47	$ 76,809
67	May-16	19,207	(25,388)	$ 7.12	$ 23.75	$ (466,259)
68	May-16	-	(6,948)	$ 7.12	$ 15.93	$ (110,696)
69	Jun-16	24,231	(7,109)	$ 7.11	$ 23.72	$ 3,683
70	Jun-16	-	(1,183)	$ 7.11	$ 10.60	$ (12,536)
71	Jul-16	22,880	2,293	$ 9.21	$ 30.73	$ 281,197
72	Jul-16	-	10,363	$ 9.21	$ 23.55	$ 244,058
73	Aug-16	29,013	(977)	$ 10.20	$ 34.04	$ 262,668
74	Aug-16	-	6,337	$ 10.20	$ 27.94	$ 177,063
75	Sep-16	22,727	1,896	$ 10.56	$ 35.24	$ 306,817
76	Sep-16	-	3,673	$ 10.56	$ 29.03	$ 106,603
77	**Total**					**$ 3,032,494**

Table 2.3.3.3

Cost of Service Analysis
Computation of Low Density and Irrigation Rate Discount Costs
Test Period October 2015 - September 2017
($ 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-16	23,992	(6,037)	$ 9.47	$ 31.59	$ 36,531
80	Oct-16	-	(126)	$ 9.47	$ 27.35	$ (3,448)
81	Nov-16	21,011	(10,148)	$ 10.01	$ 33.39	$ (128,505)
82	Nov-16	-	(1,446)	$ 10.01	$ 28.87	$ (41,745)
83	Dec-16	35,554	1,480	$ 10.58	$ 35.30	$ 428,398
84	Dec-16	-	5,969	$ 10.58	$ 30.13	$ 179,861
85	Jan-17	29,929	6,613	$ 10.58	$ 35.31	$ 550,183
86	Jan-17	-	10,196	$ 10.58	$ 29.28	$ 298,596
87	Feb-17	20,189	6,798	$ 10.51	$ 35.09	$ 450,727
88	Feb-17	-	7,776	$ 10.51	$ 29.28	$ 227,705
89	Mar-17	27,588	(3,873)	$ 8.61	$ 28.71	$ 126,340
90	Mar-17	-	(469)	$ 8.61	$ 24.67	$ (11,582)
91	Apr-17	25,473	1,116	$ 8.12	$ 27.09	$ 237,064
92	Apr-17	-	3,621	$ 8.12	$ 23.47	$ 84,966
93	May-17	24,522	(25,487)	$ 7.12	$ 23.75	$ (430,766)
94	May-17	-	(7,408)	$ 7.12	$ 15.93	$ (118,037)
95	Jun-17	26,301	(7,308)	$ 7.11	$ 23.72	$ 13,698
96	Jun-17	-	(1,298)	$ 7.11	$ 10.60	$ (13,762)
97	Jul-17	24,030	2,092	$ 9.21	$ 30.73	$ 285,588
98	Jul-17	-	10,445	$ 9.21	$ 23.55	$ 245,983
99	Aug-17	30,032	(1,027)	$ 10.20	$ 34.04	$ 271,351
100	Aug-17	-	6,187	$ 10.20	$ 27.94	$ 172,881
101	Sep-17	23,117	1,820	$ 10.56	$ 35.24	$ 308,237
102	Sep-17	-	3,607	$ 10.56	$ 29.03	$ 104,694
103	**Total**					**$ 3,274,958**

Table 2.3.4.1

Cost of Service Analysis
Allocation of Costs
Test Period October 2015 - September 2017
($ 000)

	B	C	D
4	**Costs ($000)**	**2016**	**2017**
5	**FBS.....**	$ 2,049,220	$ 2,204,870
6	**New Resources.....**	$ 69,040	$ 64,436
7	**Residential Exchange.....**	$ 3,000,099	$ 2,998,904
8	**Conservation.....**	$ 143,842	$ 148,120
9	**BPAPrograms.....**	$ 141,299	$ 117,901
10	**Transmission.....**	$ 189,359	$ 195,354
11	**Irrigation/Low Density Discounts.....**	$ 59,880	$ 60,582
12	Total.....	$ 5,652,739	$ 5,790,167
13			
14	**Cost Allocation**		
15			
16	**FBS.....**	$ 2,049,220	$ 2,204,870
17			
18	**Federal Base System Allocators.....**	**2016**	**2017**
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.....**	**2016**	**2017**
26	Priority Firm - 7(b) Loads.....	$ 2,049,220	$ 2,204,870
27	Industrial Firm - 7(c) Loads.....	$ -	$ -
28	New Resources - 7(f) Loads.....	$ -	$ -
29	Surplus Firm - SP Loads.....	$ -	$ -
30	Total.....	$ 2,049,220	$ 2,204,870
31			
32			
33	**Irrigation/Low Density Discounts.....**	$ 59,880	$ 60,582
34			
35	**Irrigation/LDD Allocators.....**	**2016**	**2017**
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.....**	**2016**	**2017**
43	Priority Firm - 7(b) Loads.....	$ 59,880	$ 60,582
44	Industrial Firm - 7(c) Loads.....	$ -	$ -
45	New Resources - 7(f) Loads.....	$ -	$ -
46	Surplus Firm - SP Loads.....	$ -	$ -
47	Total.....	$ 59,880	$ 60,582

Table 2.3.4.2

Cost of Service Analysis
Allocation of Costs
Test Period October 2015 - September 2017
($ 000)

	B	C	D
4	**Costs ($000)**	**2016**	**2017**
5	**FBS.....**	$ 2,049,220	$ 2,204,870
6	**New Resources.....**	$ 69,040	$ 64,436
7	**Residential Exchange.....**	$ 3,000,099	$ 2,998,904
8	**Conservation.....**	$ 143,842	$ 148,120
9	**BPAPrograms.....**	$ 141,299	$ 117,901
10	**Transmission.....**	$ 189,359	$ 195,354
11	**Irrigation/Low Density Discounts.....**	$ 59,880	$ 60,582
12	Total.....	$ 5,652,739	$ 5,790,167
13			
14	**Cost Allocation (continued)**		
15			
16	**New Resources.....**	$ 69,040	$ 64,436
17			
18	**New Resources Allocators**	**2016**	**2017**
19	Priority Firm - 7(b) Loads.....	0.0000	0.0000
20	Industrial Firm - 7(c) Loads.....	0.7609	0.7604
21	New Resources - 7(f) Loads.....	0.00000241	0.00000241
22	Surplus Firm - SP Loads.....	0.2391	0.2396
23	Total.....	1.0000	1.0000
24			
25	**New Resources Cost Allocation.....**	**2016**	**2017**
26	Priority Firm - 7(b) Loads.....	$ -	$ -
27	Industrial Firm - 7(c) Loads.....	$ 52,531	$ 48,999
28	New Resources - 7(f) Loads.....	$ 0.1664	$ 0.1552
29	Surplus Firm - SP Loads.....	$ 16,509	$ 15,436
30	Total.....	$ 69,040	$ 64,436
31			
32			
33	**Residential Exchange.....**	$ 3,000,099	$ 2,998,904
34	Costs Functionalized to Transmission.....	$ (201,315)	$ (201,237)
35	Costs Functionalized to Generation.....	$ 2,798,784	$ 2,797,667
36			
37	**Residential Exchange Allocators**	**2016**	**2017**
38	Priority Firm - 7(b) Loads.....	0.9383	0.9362
39	Industrial Firm - 7(c) Loads.....	0.0470	0.0485
40	New Resources - 7(f) Loads.....	0.00000015	0.00000015
41	Surplus Firm - SP Loads.....	0.0148	0.0153
42	Total.....	1.0000	1.0000
43			
44	**Residential Exchange Cost Allocation**	**2016**	**2017**
45	Priority Firm - 7(b) Loads.....	$ 2,625,985	$ 2,619,286
46	Industrial Firm - 7(c) Loads.....	$ 131,479	$ 135,646
47	New Resources - 7(f) Loads.....	$ 0.416	$ 0.430
48	Surplus Firm - SP Loads.....	$ 41,319	$ 42,735
49	Total.....	$ 2,798,784	$ 2,797,667

Table 2.3.4.3

Cost of Service Analysis
Allocation of Costs
Test Period October 2015 - September 2017
($ 000)

	B	C	D
4	**Costs ($000)**	**2016**	**2017**
5	**FBS.....**	$ 2,049,220	$ 2,204,870
6	**New Resources.....**	$ 69,040	$ 64,436
7	**Residential Exchange.....**	$ 3,000,099	$ 2,998,904
8	**Conservation.....**	$ 143,842	$ 148,120
9	**BPAPrograms.....**	$ 141,299	$ 117,901
10	**Transmission.....**	$ 189,359	$ 195,354
11	**Irrigation/Low Density Discounts...**	$ 59,880	$ 60,582
12	Total.....	$ 5,652,739	$ 5,790,167
13			
14	**Cost Allocation (continued)**		
15			
16	**Conservation.....**	$ 143,842	$ 148,120
17			
18	**BPAPrograms.....**	$ 141,299	$ 117,901
19			
20	**Transmission.....**	$ 189,359	$ 195,354
21			
22			
23	**Conservation & General Allocators**	**2016**	**2017**
24	Priority Firm - 7(b) Loads.....	0.9662	0.9663
25	Industrial Firm - 7(c) Loads.....	0.0257	0.0256
26	New Resources - 7(f) Loads.....	0.0000	0.0000
27	Surplus Firm - SP Loads.....	0.0081	0.0081
28	Total.....	1.0000	1.0000
29			
30	**Conservation Cost Allocation.....**	**2016**	**2017**
31	Priority Firm - 7(b) Loads.....	$ 138,984	$ 143,135
32	Industrial Firm - 7(c) Loads.....	$ 3,697	$ 3,791
33	New Resources - 7(f) Loads.....	$ 0	$ 0
34	Surplus Firm - SP Loads.....	$ 1,162	$ 1,194
35	Total.....	$ 143,842	$ 148,120
36			
37	**BPA Programs Cost Allocation.....**	**2016**	**2017**
38	Priority Firm - 7(b) Loads.....	$ 136,526	$ 113,932
39	Industrial Firm - 7(c) Loads.....	$ 3,631	$ 3,018
40	New Resources - 7(f) Loads.....	$ 0	$ 0
41	Surplus Firm - SP Loads.....	$ 1,141	$ 951
42	Total.....	$ 141,299	$ 117,901
43			
44	**Transmission Cost Allocation.....**	**2016**	**2017**
45	Priority Firm - 7(b) Loads.....	$ 182,963	$ 188,778
46	Industrial Firm - 7(c) Loads.....	$ 4,866	$ 5,000
47	New Resources - 7(f) Loads.....	$ 0	$ 0
48	Surplus Firm - SP Loads.....	$ 1,529	$ 1,575
49	Total.....	$ 189,359	$ 195,354

Table 2.3.5

Cost of Service Analysis
Allocation of Costs Summary
Test Period October 2015 - September 2017
($ 000)

	B	C	D
4	**Costs ($000)**	**2016**	**2017**
5	**FBS.....**	$ 2,049,220	$ 2,204,870
6	**New Resources.....**	$ 69,040	$ 64,436
7	**Residential Exchange.....**	$ 3,000,099	$ 2,998,904
8	**Conservation.....**	$ 143,842	$ 148,120
9	**BPAPrograms.....**	$ 141,299	$ 117,901
10	**Transmission.....**	$ 189,359	$ 195,354
11	**Irrigation/Low Density Discounts.....**	$ 59,880	$ 60,582
12	Total.....	$ 5,652,739	$ 5,790,167
13			
14	**Cost Allocation (continued)**		
15			
16			
17	**Initial Cost Allocation (Costs /$1000)**	**2016**	**2017**
18	Priority Firm - 7(b) Loads.....	$ 5,193,559	$ 5,330,582
19	Industrial Firm - 7(c) Loads.....	$ 196,204	$ 196,455
20	New Resources - 7(f) Loads.....	$ 0.62	$ 0.62
21	Surplus Firm - SP Loads.....	$ 61,660	$ 61,892
22	Total Costs Functionalized to Power.....	$ 5,451,424	$ 5,588,929
23			
24			
25			
26	REP Cost Functionalized to Transmissio	$ 201,315	$ 201,237
27			
28	Total COSA Revenue Requirement	$ 5,652,739	$ 5,790,167

Cost of Service Analysis
General Revenue Credits
Test Period October 2015 - September 2017
($ 000)

	B	C	D
5	**General Revenue Credits ($000))**	**2016**	**2017**
6			
7	**FBS**	**$ (117,744)**	**$ (114,895)**
8	Hydro and Renewable	$ (21,776)	$ (21,776)
9	Downstream Benefits and Pumping Power	$ (17,176)	$ (17,176)
10	Colville and Spokane Settlements	$ (4,600)	$ (4,600)
11	Green Tags (FBS resources)	$ -	$ -
12	Fish and Wildlife	$ (95,077)	$ (92,112)
13	4(h)(10)(c)	$ (95,077)	$ (92,112)
14	Tier 2 Adjustment	$ (891)	$ (1,006)
15	**Contract Obligations**	**$ (2,979)**	**$ (2,489)**
16	Pre-sub/Hungry Horse	$ (1,957)	$ (1,458)
17	Other Locational/Seasonal Exchange	$ (565)	$ (565)
18	Upper Baker	$ (457)	$ (466)
19	**New Resources**	**$ (1,151)**	**$ (648)**
20	Green Tags (New resources)	$ (1,151)	$ (648)
21	**Conservation**	**$ (15,000)**	**$ (7,000)**
22	Energy Efficiency Revenues	$ (15,000)	$ (7,000)
23	Large Project Revenues	$ -	$ -
24	**BPAPrograms**	**$ -**	**$ -**
25	**Transmission**	**$ (5,750)**	**$ (5,800)**
26	Miscellaneous Credits (incl. GTA)	$ (5,750)	$ (5,800)
27			
28	**Other Revenue Credits ($ 000))**	**2016**	**2017**
29	Secondary Revenue	**$ (458,674)**	**$ (505,859)**
30	Incl. Slice	$ (458,674)	$ (505,859)
31	Generation Inputs for Ancillary and Other Services Revenue	**$ (115,750)**	**$ (115,750)**
32	Composite Non-Federal RSS Revenue Debit/(Credit)	**$ (1,248)**	**$ (1,353)**
33	Non-Slice Non-Federal RSC Revenue Debit/(Credit)	**$ (83)**	**$ (81)**
34	NR Revenues from ESS energy and capacity charges	**$ -**	**$ -**
35	**Contract Revenue from Other Long-term Sales**	**$ (41,801)**	**$ (37,924)**
36	WNP3 Settlement	$ (37,924)	$ (37,924)
37	Slice Billing Adjustment	$ (3,877)	$ -
38	Other Long-Term Contracts	$ -	$ -
39			
40	**Total Revenue Credits**	$ (760,179)	$ (791,799)

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2015 - September 2017
($ 000)

	B	C	D
4	**Allocation of Revenue Requirement**	**2016**	**2017**
5	Priority Firm - 7(b) Loads	$ 5,193,559	$ 5,330,582
6	Industrial Firm - 7(c) Loads	$ 196,204	$ 196,455
7	New Resources - 7(f) Loads	$ 1	$ 1
8	Surplus Firm - SP Loads	$ 61,660	$ 61,892
9	Total	$ 5,451,424	$ 5,588,929
10			
11	**General Revenue Credits ($000))**	**2016**	**2017**
12			
13	**FBS**	**$ (120,723)**	**$ (117,384)**
14	Hydro and Renewable	$ (21,776)	$ (21,776)
15	Downstream Benefits and Pumping Power	$ (17,176)	$ (17,176)
16	Colville and Spokane Settlements	$ (4,600)	$ (4,600)
17	Green Tags (FBS resources)	$ -	$ -
18	Fish and Wildlife	$ (95,077)	$ (92,112)
19	4(h)(10)(c)	$ (95,077)	$ (92,112)
20	Tier 2 Adjustment	$ (891)	$ (1,006)
21	Contract Obligations	$ (2,979)	$ (2,489)
22	Pre-sub/Hungry Horse	$ (1,957)	$ (1,458)
23	Other Locational/Seasonal Exchange	$ (565)	$ (565)
24	Upper Baker	$ (457)	$ (466)
25			
26	**Federal Base System Allocators**	**2016**	**2017**
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**	**2016**	**2017**
34	Priority Firm - 7(b) Loads	$ (120,723)	$ (117,384)
35	Industrial Firm - 7(c) Loads	$ -	$ -
36	New Resources - 7(f) Loads	$ -	$ -
37	Surplus Firm - SP Loads	$ -	$ -
38	Total	$ (120,723)	$ (117,384)
39			
40	**Allocation of Revenue Requirement**	**2016**	**2017**
41	Priority Firm - 7(b) Loads	$ 5,072,836	$ 5,213,198
42	Industrial Firm - 7(c) Loads	$ 196,204	$ 196,455
43	New Resources - 7(f) Loads	$ 1	$ 1
44	Surplus Firm - SP Loads	$ 61,660	$ 61,892
45	Total	$ 5,330,702	$ 5,471,545

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2015 - September 2017
($ 000)

	B	C	D
40	**Allocation of Revenue Requirement**	**2016**	**2017**
41	Priority Firm - 7(b) Loads.....	$ 5,072,836	$ 5,213,198
42	Industrial Firm - 7(c) Loads.....	$ 196,204	$ 196,455
43	New Resources - 7(f) Loads.....	$ 1	$ 1
44	Surplus Firm - SP Loads.....	$ 61,660	$ 61,892
45	Total.....	$ 5,330,702	$ 5,471,545
46			
47			
48	**General Revenue Credits (/$1000))**	**2016**	**2017**
49			
50	**Transmission.....**	**$ (5,750)**	**$ (5,800)**
51	Miscellaneous Credits (incl. GTA).....	$ (5,750)	$ (5,800)
52			
53	**Conservation & General Cost Allocators**	**2016**	**2017**
54	Priority Firm - 7(b) Loads.....	0.9662	0.9663
55	Industrial Firm - 7(c) Loads.....	0.0257	0.0256
56	New Resources - 7(f) Loads.....	0.0000	0.0000
57	Surplus Firm - SP Loads.....	0.0081	0.0081
58	Total.....	1.0000	1.0000
59			
60	**FBS Contract Obligation Revenue Allocation**	**2016**	**2017**
61	Priority Firm - 7(b) Loads.....	$ (5,556)	$ (5,605)
62	Industrial Firm - 7(c) Loads.....	$ (148)	$ (148)
63	New Resources - 7(f) Loads.....	$ (0)	$ (0)
64	Surplus Firm - SP Loads.....	$ (46)	$ (47)
65	Total.....	$ (5,750)	$ (5,800)
66			
67	**Allocation of Revenue Requirement**	**2016**	**2017**
68	Priority Firm - 7(b) Loads.....	$ 5,067,281	$ 5,207,594
69	Industrial Firm - 7(c) Loads.....	$ 196,057	$ 196,306
70	New Resources - 7(f) Loads.....	$ 1	$ 1
71	Surplus Firm - SP Loads.....	$ 61,614	$ 61,845
72	Total.....	$ 5,324,952	$ 5,465,745

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2015 - September 2017
($ 000)

	B	C	D
4	**Allocation of Revenue Requirement**	**2016**	**2017**
5	Priority Firm - 7(b) Loads.....	$ 5,067,281	$ 5,207,594
6	Industrial Firm - 7(c) Loads.....	$ 196,057	$ 196,306
7	New Resources - 7(f) Loads.....	$ 1	$ 1
8	Surplus Firm - SP Loads.....	$ 61,614	$ 61,845
9	Total.....	$ 5,324,952	$ 5,465,745
10			
11			
12	**General Revenue Credits ($000))**	**2016**	**2017**
13			
14	**New Resources.....**	**$ (1,151)**	**$ (648)**
15	Green Tags (New resources).....	$ (1,151)	$ (648)
16			
17			
18	**New Resources Cost Allocators**	**2016**	**2017**
19	Priority Firm - 7(b) Loads.....	0.0000	0.0000
20	Industrial Firm - 7(c) Loads.....	0.7609	0.7604
21	New Resources - 7(f) Loads.....	0.000002	0.000002
22	Surplus Firm - SP Loads.....	0.2391	0.2396
23	Total.....	1.0000	1.0000
24			
25	**New Resources Allocation**	**2016**	**2017**
26	Priority Firm - 7(b) Loads.....	$ -	$ -
27	Industrial Firm - 7(c) Loads.....	$ (875)	$ (493)
28	New Resources - 7(f) Loads.....	$ (0.003)	$ (0.002)
29	Surplus Firm - SP Loads.....	$ (275)	$ (155)
30	Total.....	$ (1,151)	$ (648)
31			
32	**Allocation of Revenue Requirement**	**2016**	**2017**
33	Priority Firm - 7(b) Loads.....	$ 5,067,281	$ 5,207,594
34	Industrial Firm - 7(c) Loads.....	$ 195,181	$ 195,813
35	New Resources - 7(f) Loads.....	$ 0.618	$ 0.620
36	Surplus Firm - SP Loads.....	$ 61,339	$ 61,689
37	Total.....	$ 5,323,801	$ 5,465,097
38			

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2015 - September 2017
($ 000)

	B	C	D
32	**Allocation of Revenue Requirement**	**2016**	**2017**
33	Priority Firm - 7(b) Loads.....	$ 5,067,281	$ 5,207,594
34	Industrial Firm - 7(c) Loads.....	$ 195,181	$ 195,813
35	New Resources - 7(f) Loads.....	$ 0.618	$ 0.620
36	Surplus Firm - SP Loads.....	$ 61,339	$ 61,689
37	Total.....	$ 5,323,801	$ 5,465,097
39			
40	**General Revenue Credits (/$1000))**	**2016**	**2017**
41			
42	**Conservation.....**	**$ (15,000)**	**$ (7,000)**
43	Energy Efficiency Revenues.....	$ (15,000)	$ (7,000)
44	Large Project Revenues.....	$ -	$ -
45			
46	**Conservation & General Cost Allocators**	**2016**	**2017**
47	Priority Firm - 7(b) Loads.....	0.9662	0.9663
48	Industrial Firm - 7(c) Loads.....	0.0257	0.0256
49	New Resources - 7(f) Loads.....	0.0000001	0.0000001
50	Surplus Firm - SP Loads.....	0.0081	0.0081
51	Total.....	1.0000	1.0000
52			
53	**Conservation Allocation**	**2016**	**2017**
54	Priority Firm - 7(b) Loads.....	$ (14,493)	$ (6,764)
55	Industrial Firm - 7(c) Loads.....	$ (385)	$ (179)
56	New Resources - 7(f) Loads.....	$ (0.001)	$ (0.001)
57	Surplus Firm - SP Loads.....	$ (121)	$ (56)
58	Total.....	$ (15,000)	$ (7,000)
59			
60	**Allocation of Revenue Requirement**	**2016**	**2017**
61	Priority Firm - 7(b) Loads.....	$ 5,052,787	$ 5,200,829
62	Industrial Firm - 7(c) Loads.....	$ 194,796	$ 195,634
63	New Resources - 7(f) Loads.....	$ 0.617	$ 0.620
64	Surplus Firm - SP Loads.....	$ 61,218	$ 61,633
65	Total.....	$ 5,308,801	$ 5,458,097

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2015 - September 2017
($ 000)

	B	C	D
4	**Allocation of Revenue Requirement**	**2016**	**2017**
5	Priority Firm - 7(b) Loads	$ 5,052,787	$ 5,200,829
6	Industrial Firm - 7(c) Loads	$ 194,796	$ 195,634
7	New Resources - 7(f) Loads	$ 0.6170	$ 0.6197
8	Surplus Firm - SP Loads	$ 61,218	$ 61,633
9	Total	$ 5,308,801	$ 5,458,097
10			
11	**General Revenue Credits (/$1000))**	**2016**	**2017**
12			
13	**Generation Inputs**	**$ (115,750)**	**$ (115,750)**
14			
15	**NR Revenues from ESS energy and capacity charges**	**$ -**	**$ -**
16			
17	**Credit Due to Idaho Deemer Account**	**$ -**	**$ -**
19			
20	**Conservation & General Cost Allocators**	**2016**	**2017**
21	Priority Firm - 7(b) Loads	0.9662	0.9663
22	Industrial Firm - 7(c) Loads	0.0257	0.0256
23	New Resources - 7(f) Loads	0.0000001	0.0000001
24	Surplus Firm - SP Loads	0.0081	0.0081
25	Total	1.0000	1.0000
26			
27	**Gen Inputs & Wind Integration Credit Allocation**	**2016**	**2017**
28	Priority Firm - 7(b) Loads	$ (111,840)	$ (111,854)
29	Industrial Firm - 7(c) Loads	$ (2,975)	$ (2,963)
30	New Resources - 7(f) Loads	$ (0)	$ (0)
31	Surplus Firm - SP Loads	$ (935)	$ (933)
32	Total	$ (115,750)	$ (115,750)
33			
34	**Allocation of Revenue Requirement**	**2016**	**2017**
35	Priority Firm - 7(b) Loads	$ 4,940,947	$ 5,088,975
36	Industrial Firm - 7(c) Loads	$ 191,821	$ 192,672
37	New Resources - 7(f) Loads	$ 0.6076	$ 0.6103
38	Surplus Firm - SP Loads	$ 60,283	$ 60,700
39	Total	$ 5,193,051	$ 5,342,347
40			

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2015 - September 2017
($ 000)

	B	C	D
34	**Allocation of Revenue Requirement**	**2016**	**2017**
35	Priority Firm - 7(b) Loads	$ 4,940,947	$ 5,088,975
36	Industrial Firm - 7(c) Loads	$ 191,821	$ 192,672
37	New Resources - 7(f) Loads	$ 0.6076	$ 0.6103
38	Surplus Firm - SP Loads	$ 60,283	$ 60,700
39	Total	$ 5,193,051	$ 5,342,347
41			
42	**Other Revenue Credits**	**2016**	**2017**
43	Composite Non-Federal RSS Revenue Debit/(Credit)	$ (1,248)	$ (1,353)
44	Non-Slice Non-Federal RSC Revenue Debit/(Credit)	$ (83)	$ (81)
45			
46			
47	**Conservation & General Cost Allocators**	**2016**	**2017**
48	Priority Firm - 7(b) Loads	0.9662	0.9663
49	Industrial Firm - 7(c) Loads	0.0257	0.0256
50	New Resources - 7(f) Loads	0.0000001	0.0000001
51	Surplus Firm - SP Loads	0.0081	0.0081
52	Total	1.0000	1.0000
53			
54	**Non-Federal RSS Revenues**	**2016**	**2017**
55	Priority Firm - 7(b) Loads	$ (1,286)	$ (1,386)
56	Industrial Firm - 7(c) Loads	$ (34)	$ (37)
57	New Resources - 7(f) Loads	$ (0.0001)	$ (0.0001)
58	Surplus Firm - SP Loads	$ (11)	$ (12)
59	Total	$ (1,330)	$ (1,434)
60			
61	**Allocation of Revenue Requirement**	**2016**	**2017**
62	Priority Firm - 7(b) Loads	$ 4,939,661	$ 5,087,589
63	Industrial Firm - 7(c) Loads	$ 191,787	$ 192,635
64	New Resources - 7(f) Loads	$ 0.6075	$ 0.6102
65	Surplus Firm - SP Loads	$ 60,272	$ 60,688
66	Total	$ 5,191,721	$ 5,340,913

Cost of Service Analysis
Calculation and Allocation of Secondary Revenue Credit
Test Period October 2015 - September 2017
(aMW, $ 000)

	C	D	E
4	**General Revenue Credits ($000))**	**2016**	**2017**
9			
10	BPA Secondary Sales Post-Slice (aMW)	1758.5	1731.8
11			
12	Slice Percentage	26.6187%	26.6187%
13			
14	BPA Secondary Sales Pre-Slice, aMW (row 1 * (1-row 3))	2364.9	2219.7
15			
16	aMW to GWh Multiplier	8.784	8.760
17			
18	BPA Secondary Sales Pre-Slice GWh (row 5 * row 7)	20773.5	19444.2
19			
20	Secondary Sales Price	$ 21.87	$ 24.86
21	Adhoc Addition to Secondary (includes other commited sales)	-	-
22	BPA Secondary Sales Pre-Slice $000 (includes other commited sales)	$ 458,674.11	$ 505,858.91
23			
24	BPA Secondary Sales Allocated to 7b3 Rate Protection	$ -	$ -
25			
26	**BPA Secondary Sales Available as Revenue Credit (row 13 - row 15)**	**$ 458,674**	**$ 505,859**
27			
28	Slice Portion of Secondary	$ 120,912	$ 128,681
29			
30	**Federal Base System + NR Cost Allocators**	**2016**	**2017**
31	Priority Firm - 7(b) Loads	0.9850	0.9865
32	Industrial Firm - 7(c) Loads	0.0114	0.0103
33	New Resources - 7(f) Loads	0.0000	0.0000
34	Surplus Firm - SP Loads	0.0036	0.0032
35	Total	1.0000	1.0000
36			
37			
38	**Allocation of Secondary Revenues Credit**	**2016**	**2017**
39	Priority Firm - 7(b) Loads	$ (451,776)	$ (499,006)
40	Industrial Firm - 7(c) Loads	$ (5,248)	$ (5,211)
41	New Resources - 7(f) Loads	$ (0.0166)	$ (0.0165)
42	Surplus Firm - SP Loads	$ (1,649)	$ (1,642)
43	Total	$ (458,674)	$ (505,859)
44			
45	**Allocation of Revenue Requirement**	**2016**	**2017**
46	Priority Firm - 7(b) Loads	$ 4,487,885	$ 4,588,584
47	Industrial Firm - 7(c) Loads	$ 186,538	$ 187,424
48	New Resources - 7(f) Loads	$ 0.5909	$ 0.5937
49	Surplus Firm - SP Loads	$ 58,623	$ 59,046
50	Total	$ 4,733,047	$ 4,835,054

Cost of Servise Analysis
Calculation and Allocation of FPS Revenue Deficiency Delta
Test Period October 2015 - September 2017
($ 000)

	B	C	D
5	**Allocation of Revenue Requirement**	2016	2017
6	Priority Firm - 7(b) Loads	$ 4,487,885	$ 4,588,584
7	Industrial Firm - 7(c) Loads	$ 186,538	$ 187,424
8	New Resources - 7(f) Loads	$ 0.5909	$ 0.5937
9	Surplus Firm - SP Loads	$ 58,623	$ 59,046
10	Total	$ 4,733,047	$ 4,835,054
11			
12	**Contract Revenue from Other Long-term Sales**	**$ (41,801)**	**$ (37,924)**
13	WNP3 Settlement	$ (37,924)	$ (37,924)
14	Slice Billing Adjustment	$ (3,877)	$ -
15	Other Long-Term Contracts	$ -	$ -
16			
17	**Calculation of FPS Revenue Deficiency**	2016	2017
18	Surplus Firm - SP Loads	$ 58,623	$ 59,046
19			
20	**Deficiency**	**$ 16,822**	**$ 21,123**
21			
22			
23			
24	**Surplus Deficit Cost Allocators**	2016	2017
25	Priority Firm - 7(b) Loads	0.9741	0.9742
26	Industrial Firm - 7(c) Loads	0.0259	0.0258
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**	2016	2017
32	Priority Firm - 7(b) Loads	$ 16,386	$ 20,577
33	Industrial Firm - 7(c) Loads	$ 436	$ 545
34	New Resources - 7(f) Loads	$ 0.0014	$ 0.0017
35	Surplus Firm - SP Loads	$ (16,822)	$ (21,123)
36	Total	$ -	$ -
37			
38			
39	**Initial Allocation of Net Revenue Requirement**	2016	2017
40	Priority Firm - 7(b) Loads	$ 4,504,271	$ 4,609,161
41	Industrial Firm - 7(c) Loads	$ 186,974	$ 187,969
42	New Resources - 7(f) Loads	$ 0.5922	$ 0.5954
43	Surplus Firm - SP Loads	$ 41,801	$ 37,924
44	Total	$ 4,733,047	$ 4,835,054

Cost of Service Analysis
Calculation of Initial Allocation Power Rates
Test Period October 2015 - September 2017
($ 000, aMW, $/MWh)

	B	C	D
5	**Initial Allocation of Net Revenue Requirement ($000)**	**2016**	**2017**
6	Unbifurcated Priority Firm - 7(b) Loads.....	$ 4,504,271	$ 4,609,161
7	Industrial Firm - 7(c) Loads.....	$ 186,974	$ 187,969
8	New Resources - 7(f) Loads.....	$ 0.5922	$ 0.5954
9	Surplus Firm - SP Loads.....	$ 41,801	$ 37,924
10	Total.....	$ 4,733,047	$ 4,835,054
11			
12			
13	**Energy Billing Determinants (aMW)**	**2016**	**2017**
14			
15	Unbifurcated Priority Firm - 7(b) Loads.....	11,870	11,919
16	Industrial Firm - 7(c) Loads.....	316	316
17	New Resources - 7(f) Loads.....	0.001	0.001
18			
19			
20	**Average Power Rates ($/MWh)**	**2016**	**2017**
21			
22	Unbifurcated Priority Firm - 7(b) Loads.....	43.20	44.14
23	Industrial Firm - 7(c) Loads.....	67.42	67.97
24	New Resources - 7(f) Loads.....	67.42	67.97

Rate Directive Step
Calculation of DSI VOR and Net Industrial Margin
Test Period October 2015 - September 2017

	B	C	D	E	F	G	H	I
5								
6	Operating Reserves - Supplemental							
8			Embedded Cost $/kW/Mo			$ 7.62		
9								
10	1) Assumed DSI sale					316	aMW	
11	Assumed Wheel Turning Load					6	aMW	
12	Interruptible Load					310		
13	percent of DSI sale that is interruptible					10%		
14	MWs of interruptible load					31	MW	
15								
16	Total value of Operating Reserves per year					$ 2,833,051	per year	
17	Value converted to $/MWh on total load					$ 1.022	$/MWh	
18								
19					industrial margin	0.733		
20								
21					**net industrial margin**	**$ (0.289)**		

Rate Directive Step
Calculation of Annual Energy Rate Scalars for First IP-PF Link Calculation
Test Period October 2015 - September 2017

	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)		31.59	33.39	35.30	35.31	35.09	28.71	27.09	23.75	23.72	30.73	34.04	35.24				
8	LLH (mills/kWh)		27.35	28.87	30.13	29.28	29.28	24.67	23.47	15.93	10.60	23.55	27.94	29.03				
9	Demand Rate ($/kW/mo)		9.47	10.01	10.58	10.58	10.51	8.61	8.12	7.12	7.11	9.21	10.20	10.56				
10																		
11																		
12	**Unbifurcated PF+NR Load**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			**2016**	
13	**2016**	HLH	4852	5466	6134	5813	5264	5409	4649	5209	4992	5097	5347	4606			Energy (GWH)	104263
14		LLH	3023	3893	4235	4202	3439	3467	2989	3476	3052	3394	3155	3100			Allocated Cost	**$ 4,573,686**
15		Demand	625	344	1007	824	618	864	760	511	624	559	805	641			Rate Scalar	**14.22**
16	Revenue at marginal Rates		$ 241,887	$ 298,331	$ 354,815	$ 337,024	$ 291,912	$ 248,244	$ 202,265	$ 182,737	$ 155,174	$ 241,682	$ 278,395	$ 259,053		**$ 3,091,519**		
17			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			**2017**	
18	**2017**	HLH	4834	5609	6180	5814	5206	5459	4687	4998	4841	5103	5381	4635			Energy (GWH)	104411
19		LLH	3098	3804	4246	4250	3419	3463	3117	3646	2924	3398	3172	3124			Allocated Cost	**$ 4,677,394**
20		Demand	542	449	1009	831	500	875	655	642	631	567	822	652			Rate Scalar	**15.13**
21	Revenue at marginal Rates		$ 242,576	$ 301,593	$ 356,776	$ 338,574	$ 288,075	$ 249,710	$ 205,443	$ 181,361	$ 150,286	$ 242,056	$ 280,209	$ 260,881		**$ 3,097,540**		
43																		
50																		
51		**IP Load**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			**2016**	
52	**2016**	HLH	137	127	126	132	127	132	133	132	127	131	137	122			Energy (GWH)	2773
53		LLH	98	101	109	103	93	102	95	102	100	104	98	106			Allocated Cost	**$ 117,559**
54		Demand	0	0	0	0	0	0	0	0	0	0	0	0			Rate Scalar	**13.93**
55	Revenue at marginal Rates		$ 7,006	$ 7,145	$ 7,728	$ 7,676	$ 7,172	$ 6,322	$ 5,815	$ 4,777	$ 4,075	$ 6,472	$ 7,398	$ 7,353		**$ 78,937**		
56			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**			**2017**	
57	**2017**	HLH	137	127	126	132	123	132	133	132	127	131	137	122			Energy (GWH)	2766
58		LLH	98	101	109	103	89	102	95	102	100	104	98	106			Allocated Cost	**$ 119,736**
59		Demand	0	0	0	0	0	0	0	0	0	0	0	0			Rate Scalar	**14.84**
60	Revenue at marginal Rates		$ 7,006	$ 7,145	$ 7,728	$ 7,676	$ 6,925	$ 6,322	$ 5,815	$ 4,777	$ 4,075	$ 6,472	$ 7,398	$ 7,353		**$ 78,690**		

Table 2.4.3

Rate Directive Step
Calculation of Monthly Energy Rate Scalars for First IP-PF Link Calculation
Test Period October 2015 - September 2017
($/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)		31.59	33.39	35.30	35.31	35.09	28.71	27.09	23.75	23.72	30.73	34.04	35.24				
7	LLH (mills/kWh)		27.35	28.87	30.13	29.28	29.28	24.67	23.47	15.93	10.60	23.55	27.94	29.03				
8	Demand Rate ($/kW/mo)		9.47	10.01	10.58	10.58	10.51	8.61	8.12	7.12	7.11	9.21	10.20	10.56				
9																		
10																		
11	**Unbifurcated PF/NR**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
12	**2016**	HLH	45.81	47.60	49.52	49.53	49.31	42.93	41.30	37.97	37.93	44.94	48.26	49.45				**2016**
13		LLH	41.57	43.09	44.35	43.50	43.50	38.89	37.69	30.15	24.82	37.77	42.16	43.25				**14.22**
14		Demand	9.47	10.01	10.58	10.58	10.51	8.61	8.12	7.12	7.11	9.21	10.20	10.56				**Scalar**
15			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
16	**2017**	HLH	46.72	48.52	50.43	50.45	50.22	43.84	42.22	38.88	38.85	45.86	49.17	50.37				**2017**
17		LLH	42.48	44.00	45.26	44.41	44.41	39.80	38.60	31.06	25.73	38.68	43.07	44.16				**15.13**
18		Demand	9.47	10.01	10.58	10.58	10.51	8.61	8.12	7.12	7.11	9.21	10.20	10.56				**Scalar**
36																		
42																		
43		**IP**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
44	**2016**	HLH	45.52	47.31	49.23	49.24	49.02	42.64	41.02	37.68	37.64	44.66	47.97	49.16				**2016**
45		LLH	41.28	42.80	44.06	43.21	43.21	38.60	37.40	29.86	24.53	37.48	41.87	42.96				**13.93**
46		Demand	9.47	10.01	10.58	10.58	10.51	8.61	8.12	7.12	7.11	9.21	10.20	10.56				**Scalar**
47			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
48	**2017**	HLH	46.43	48.23	50.14	50.16	49.93	43.55	41.93	38.59	38.56	45.57	48.88	50.08				**2017**
49		LLH	42.19	43.71	44.97	44.12	44.12	39.51	38.31	30.77	25.44	38.39	42.78	43.87				**14.84**
50		Demand	9.47	10.01	10.58	10.58	10.51	8.61	8.12	7.12	7.11	9.21	10.20	10.56				**Scalar**

Table 2.4.4

Rate Directive Step
Calculation of First IP-PF Link Delta
Test Period October 2015 - September 2017
($ 000)

	B	C	D	E	F	G	H
4						**FY 2016**	**FY 2017**
5							
6	1	IP Allocated Costs				186,974	187,969
7	2	IP Revenues @ Net Margin				(800)	(798)
8	3	adjustment				1,578	1,710
9	4	IP Marginal Cost Rate Revenues				78,937	78,690
10	5	PF/NR Marginal Cost Rate Revenues				3,091,519	3,097,540
11	6	PF/NR Allocated Energy Costs				4,504,272	4,609,162
12	7	Numerator: 1-2-3-((4/5)*6)				71,187	69,966
13	8						
14	9	PF Allocation Factor for Delta				0.999999916	0.999999916
15	10	NR Allocation Factor for Delta				0.000000084	0.000000084
16	11	Total Allocation Factors for Delta				1.000000000	1.000000000
17	12	Denominator: 1.0 + ((9/11)*(4/5))				1.0255	1.0254
18	13						
19	14	DELTA: (7/12)				**69,415**	**68,232**
20							
21						-0.289	-0.289
22							

Rate Directive Step
Reallocation of First IP-PF Link Delta and Recalculation of Rates
Test Period October 2015 - September 2017
($ 000, aMW, $/MWh)

	B	C	D
5	**Initial Allocation of Net Revenue Requirement)**	**2016**	**2017**
6	Unbifurcated Priority Firm - 7(b) Loads.....	$ 4,504,271	$ 4,609,161
7	Industrial Firm - 7(c) Loads.....	$ 186,974	$ 187,969
8	New Resources - 7(f) Loads.....	$ 0.5922	$ 0.5954
9	Surplus Firm - SP Loads.....	$ 41,801	$ 37,924
10	Total.....	$ 4,733,047	$ 4,835,054
11			
12			
13	**First IP-PF Link Delta**	**$ 69,415**	**$ 68,232**
14			
15			
16	**7(c)(2) Delta Cost Allocators**	**2016**	**2017**
17	Unbifurcated Priority Firm - 7(b) Loads.....	0.999999916	0.999999916
18	Industrial Firm - 7(c) Loads.....	-1.000000000	-1.000000000
19	New Resources - 7(f) Loads.....	0.000000084	0.000000084
20			
21	**7(c)(2) Delta Cost Allocation**	**2016**	**2017**
22	Unbifurcated Priority Firm - 7(b) Loads.....	$ 69,415	$ 68,232
23	Industrial Firm - 7(c) Loads.....	$ (69,415)	$ (68,232)
24	New Resources - 7(f) Loads.....	$ 0.006	$ 0.006
25	Total.....	$ 0	$ (0)
26			
27	**Cost Allocation After 7c2 Delta ($ 000)**	**2016**	**2017**
28	Unbifurcated Priority Firm - 7(b) Loads.....	$ 4,573,686	$ 4,677,393
29	Industrial Firm - 7(c) Loads.....	$ 117,559	$ 119,736
30	New Resources - 7(f) Loads.....	$ 0.598	$ 0.601
31	Surplus Firm - SP Loads.....	$ 41,801	$ 37,924
32	Total.....	$ 4,733,047	$ 4,835,054
33			
34	**Energy Billing Determinants (aMW)**	**2016**	**2017**
35	Unbifurcated Priority Firm - 7(b) Loads.....	11,870	11,919
36	Industrial Firm - 7(c) Loads.....	315.7042448	315.7042526
37	New Resources - 7(f) Loads.....	0.001	0.001
38			
39			
40	**Average Power Rates ($/MWh)**	**2016**	**2017**
41			
42	Unbifurcated Priority Firm - 7(b) Loads.....	43.87	44.80
43	Industrial Firm - 7(c) Loads.....	42.39	43.30
44	New Resources - 7(f) Loads.....	68.09	68.62
45			
46			
47	Base PF Exchange Rate w/o Transmission Adder.....	**44.33**	

Rate Directive Step
Calculation of IP Floor Calculation
Test Period October 2015 - September 2017

	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]		3,167	4,451	3,220	2,319	7,618	5,539
18	2	IP-83 Rates		4.62	2.21	14.70	12.20	7.34	
19	3	Revenue		14,630	9,837	47,337	28,286	55,917	156,007
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]		28.17					
36	20	Floor Rate (mills/kWh)[8]		21.04					
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 2015 - September 2017

Industrial Firm Power Floor Rate Test

		A	B	C
		Total Energy	**TOTALS**	**Average Rate**
1	IP Billing Determinants	5,539		
2	Floor Rate (mills/kWh)	21.04		
3	Value of Reserves Credit (mills/kWh)			
4	Revenue at Floor Rate Less VOR Credit	116,529	116,529	21.04
5	IP Revenue Under Proposed Rates		237,296	42.84
6	Difference[1]		0	

Note 1 - Difference is Line 4 - Line 5. If difference is negative, Floor Rate does not trigger and difference is set to zero.

Rate Directive Step
Calculation of IOU and COU Base PF Exchange Rates
Test Period October 2015 - September 2017

	B	C	D	E	F
9		**Cost Allocation After 7c2 Delta**	**2016**	**2017**	Total
10		Unbifurcated Priority Firm - 7(b) Loads.....	$ 4,573,686	$ 4,677,393	$ 9,251,079
11					
12		Exchange Unbifurcated Costs to 7(b) Loads.....	$ 1,899,156	$ 1,938,708	$ 3,837,864
13					
14					
15					
16					
17		**Energy Billing Determinants (aMW)**	**2016**	**2017**	
18		Unbifurcated Priority Firm - 7(b) Loads.....	4,929	4,940	
19					
20					
21		**Average Power Rates**	**2016**	**2017**	
22					
23		Unbifurcated Priority Firm - 7(b) Loads.....	43.87	44.80	
24					
25					
26			(GWh)		
27		Two Year PF Public Load T1	120740		
28		Two Year PF Public Load T2	1364		
29		Two Year IOU PF Exchange Load	81799		
30		Two Year COU PF Exchange Load	4772		
31		Total Two-Year Unbifurcated PF Load	208674		
32					
33					
34		T 2 Costs	$ 43,817		
35		T 1 Costs	$ 9,207,262		
36		Total	$ 9,251,079		
37					
45		Total PF Costs Minus PF T2 Costs	$ 9,207,262		
46		Total PF Load Minus PF T2 Load	207,310		
47		COU Base PF w/o Transmission	44.41		
48		Exchange Transmission Adder	4.65		
49		**COU Base PFx**	**49.06**		
50					
51					
52		Two Year COU PF Exchange Load	4772		
53		Two Year Base PF Public Exchange T2 Revenue	$ 211,926		
54					
55		Total Exchange Costs minus COU Exchange Costs	$ 3,625,938		
56		Total IOU Exchange Loads	81,799		
57		IOU Base PF w/o Transmission	44.33		
58		Exchange Transmission Adder	4.65		
59		**IOU Base PFx**	**48.98**		
60					

Table 2.4.9

Rate Directive Step
Calculation of IOU REP Benefits in Rates
Test Period October 2015 - September 2017

	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	$214,100	
19	Refund Amount*	$76,538	
20	REP Recovery Amount	$290,638	
21			
26			
27			
28		**2016**	**2017**
29		($000)	($000)
30	IOU Unconstrained Benefits	$ 865,926	$ 865,926
31	REP Recovery Amount	**$ 290,638**	**$ 290,638**
32	Rate Protection Delta	$ 575,288	$ 575,288
33			
34	**Refund of Initial EOFY2011 Lookback Completed by end of FY 2019*		

Table 2.4.10

Rate Directive Step
Calculation of REP Base Exchange Benefits
Test Period October 2015 - September 2017

	B	C	D	E	F	G	H	I	J	K	L
5	**IOU Base PFx**	**48.98**									
6	**COU Base PFx**	**49.06**		**ASCs**			**Exchange Loads**			**Unconstrained Benefits**	
7										(load * (ASC - Base PFx)	
8				**2016**	**2017**		**2016**	**2017**		**2016**	**2017**
9											
10											
11	Avista Corporation	1		53.53	53.53		3,935	3,935		$ 17,916	$ 17,916
12	Idaho Power Company	1		59.54	59.54		6,779	6,779		$ 71,599	$ 71,599
13	NorthWestern Energy,	1		79.66	79.66		686	686		$ 21,053	$ 21,053
14	PacifiCorp	1		76.93	76.93		9,107	9,107		$ 254,560	$ 254,560
15	Portland General Elect	1		78.28	78.28		8,666	8,666		$ 253,927	$ 253,927
16	Puget Sound Energy, I	1		70.03	70.03		11,726	11,726		$ 246,871	$ 246,871
17	Clark Public Utilities	1		54.34	54.34		2,394	2,377		$ 12,635	$ 12,546
18	Franklin	0		0.00	0.00		0	0		$ -	$ -
19	Snohomish County PU	0		48.55	48.86		0	0		$ -	$ -
31	Total									**$ 878,560**	**$ 878,472**
32											
33									IOU	**$ 865,926**	**$ 865,926**

Rate Directive Step
Calculation of Utility Specific PF Exchange Rates and REP Benefits
Test Period October 2015 - September 2017

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
4	**Initial Allocations**				**FY 2016**	**FY 2017**	**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	53.53	48.98	3,935	3,935	3,935	$ 17,916			$ 11,903	$ 1,584	3.43	52.40	$ 4,430
9	Idaho Power Company	1	59.54	48.98	6,779	6,779	6,779	$ 71,599			$ 47,568	$ 6,329	7.95	56.93	$ 17,703
10	NorthWestern Energy, LLC	1	79.66	48.98	686	686	686	$ 21,053			$ 13,987	$ 1,861	23.10	72.07	$ 5,205
11	PacifiCorp	1	76.93	48.98	9,107	9,107	9,107	$ 254,560			$ 169,120	$ 22,500	21.04	70.02	$ 62,940
12	Portland General Electric Company	1	78.28	48.98	8,666	8,666	8,666	$ 253,927			$ 168,700	$ 22,444	22.06	71.03	$ 62,783
13	Puget Sound	1	70.03	48.98	11,726	11,726	11,726	$ 246,871			$ 164,011	$ 21,820	15.85	64.82	$ 61,039
14	Clark Public Utilities	1	54.34	49.06	2,394	2,377	2,386	$ 12,590			$ 8,365		3.51	52.57	$ 4,226
15	Franklin	0	0	0.00	0	0	0	$ -			$ -		0.00	0.00	$ -
16	Snohomish County PUD No 1	0	0	0.00	0	0	0	$ -			$ -		0.00	0.00	$ -
17	Total							$ 878,516	$214,100	$76,538	$ 583,653	$76,538			$ 218,326
18															
19	rounding to 5 places = $44						IOU Σ(g)	$ 865,926	$214,100	$290,638	$ 575,288	IOU Σ(j)		IOU REP	$ 214,100
20							COU Σ(g)	$ 12,590		$4,226	$ 8,365	COU Σ(j)		COU REP	$ 4,226
21															
22	**IOU Reallocations**														
23			**Interim**				**Final**	**Final**	**Final**		**Final**			**FY 2016**	**FY 2017**
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		$ 4,430	$ 2,005	$ 191	$ 2,616	$ 15,300	3.89	52.86524		$ 2,616		Avista	$ 2,616	$ 2,616
28	Idaho Power Company		$ 17,703	$ 8,851	$ -	$ 8,851	$ 62,748	9.26	58.23422		$ 8,851		Idaho Power	$ 8,851	$ 8,851
29	NorthWestern Energy, LLC		$ 5,205	$ (383)	$ 637	$ 6,226	$ 14,828	21.61	70.58679		$ 6,226		NorthWestern	$ 6,226	$ 6,226
30	PacifiCorp		$ 62,940	$ 8,443	$ 2,717	$ 57,214	$ 197,346	21.67	70.64751		$ 57,214		PacifiCorp	$ 57,214	$ 57,214
31	Portland General Electric Company		$ 62,783	$ -	$ 7,794	$ 70,577	$ 183,350	21.16	70.13562		$ 70,577		Portland	$ 70,577	$ 70,577
32	Puget Sound		$ 61,039	$ -	$ 7,577	$ 68,616	$ 178,255	15.20	64.17864		$ 68,616		Puget Sound	$ 68,616	$ 68,616
33	Total		$ 214,100	$ 18,916	$ 18,916	$ 214,100	$ 651,826				$ 214,100		IOU REP	$ 214,100	$ 214,100
34															
35													Clark	$ 4,241	$ 4,211
36													Franklin	$ -	$ -
37	**IOU Reallocation Adjustments**												Snohomish	$ -	$ -
38			Avista Corporatio	o Power Comp	Western Energy	PacifiCorp	eneral Electric	Puget Sound	Total				COU REP	$ 4,241	$ 4,211
39			$ 2,005	$ 8,851	$ (383)	$ 8,443	$ -	$ -					Total REP	$ 218,341	$ 218,311
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			$ 200	$ (9)				$ 191				Refund Amt	$ 76,538	$ 76,538
42	Idaho Power Company								$ -				REP Cost	$ 294,878	$ 294,849
43	NorthWestern Energy, LLC		$ 81	$ 216		$ 341	$ -	$ -	$ 637						
44	PacifiCorp			$ 2,843	$ (126)				$ 2,717						
45	Portland General Electric Company		$ 976	$ 2,836	$ (126)	$ 4,108			$ 7,794						
46	Puget Sound		$ 948	$ 2,757	$ (122)	$ 3,994	$ -		$ 7,577						
47			$ 2,005	$ 8,851	$ (383)	$ 8,443	$ -	$ -	$ 18,916						

Rate Directive Step
IOU Reallocation Balances
Test Period October 2015 - September 2017

	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	$ 3,001,474	$ 1,128,281	$ 3,001,474	$ 1,072,086	$ 35,307,537
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	$ 3,001,474	$ 1,014,204	$ 3,001,474	$ 954,586	$ 31,273,379
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	$ 3,001,474	$ 893,179	$ 3,001,474	$ 829,930	$ 26,993,541
53	NorthWestern Energy, LLC	$ -	$ -	$ -	$ -	$ -
54	PacifiCorp	$ -	$ 249,591	$ -	$ 257,078	$ 8,826,357
55	Portland General Electric Company	$ -	$ -	$ -	$ -	$ -
56						
57						

Table 2.4.13

Rate Directive Step
Calculation and Allocation of the Increase in PF Exchange Revenue Requirement Due to REP Settlement
Test Period October 2015 - September 2017

	B	C	D
4	**Cost Allocation After 7c2 Delta**	**2016**	**2017**
5	Priority Firm Public - 7(b) Loads	$ 2,674,530	$ 2,738,685
6	Priority Firm Exchange - 7(b) Loads	$ 1,899,156	$ 1,938,708
7	Industrial Firm - 7(c) Loads	$ 117,559	$ 119,736
8	New Resources - 7(f) Loads	$ 0.598	$ 0.601
9	Surplus Firm - SP Loads	$ 41,801	$ 37,924
10	Total	$ 4,733,047	$ 4,835,054
11			
12			
13	**Calc Rate Protection to PFx Rate**	**2016**	**2017**
14	Unconstrained Benefits	$ 878,560	$ 878,472
15	REP Recovery Amount plus COU Benefits	$ (294,878)	$ (294,849)
16	delta	$ 583,682	$ 583,623
17			
18			
19	**Allocation Factors**	**2016**	**2017**
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**	**2016**	**2017**
27	Priority Firm Public - 7(b) Loads	$ (583,682)	$ (583,623)
28	Priority Firm Exchange - 7(b) Loads	$ 583,682	$ 583,623
29	Industrial Firm - 7(c) Loads	$ -	$ -
30	New Resources - 7(f) Loads	$ -	$ -
31	Total	$ -	$ -
32			
33			
34	**Cost Allocation After Rate Protection to PFx**	**2016**	**2017**
35	Priority Firm Public - 7(b) Loads	$ 2,090,848	$ 2,155,062
36	Priority Firm Exchange - 7(b) Loads	$ 2,482,838	$ 2,522,332
37	Industrial Firm - 7(c) Loads	$ 117,559	$ 119,736
38	New Resources - 7(f) Loads	$ 0.598	$ 0.601
39	Surplus Firm - SP Loads	$ 41,801	$ 37,924
40	Total	$ 4,733,047	$ 4,835,054
41			
42			
43	**Energy Billing Determinants (aMW)**	**2016**	**2017**
44	Priority Firm Public - 7(b) Loads	6,941	6,979
45	Priority Firm Exchange - 7(b) Loads	4,929	4,940
46	Industrial Firm - 7(c) Loads	316	316
47	New Resources - 7(f) Loads	0.001	0.001
48			
50			
51	**Average Power Rates**	**2016**	**2017**
52	Priority Firm Public - 7(b) Loads	34.29	35.25
53	Priority Firm Exchange - 7(b) Loads	62.00	62.93
54	Industrial Firm - 7(c) Loads	42.39	43.30
55	New Resources - 7(f) Loads	68.09	68.62

Table 2.4.14

Rate Directive Step
Calculation of PF, IP and NR Rate Contribution to Net REP Benefit Costs
Test Period October 2015 - September 2017

	B	C	D
25		**2016**	**2017**
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	$ 8.19	$ 8.19
30	IP Load	2,773	2,766
31	NR Load	0	0
32	REP Surharge Revenue from IP Rate	$ 22,701	$ 22,636
33	REP Surharge Revenue from NR Rate	$ 0	$ 0
34			
35	Amount of REP Recovery remaining after IP/NR REP Surchar	$ 272,177	$ 272,212
36	Remaining REP Recovery in PF, IP and NR Rates ($/MWh)	$ 4.27	$ 4.26
37			
38	Before Reallocation		
39	IP REP Recovery Amount in Rates	$ 34,542	$ 34,418
40	NR REP Recovery Amount in Rates	$ 0	$ 0
41			
42	After Reallocation		
43	IP REP Recovery Amount in Rates	$ 21,713	$ 21,657
44	NR REP Recovery Amount in Rates	$ 0	$ 0
45			
46			
47	Reallocation that Should be in Rates	**2016**	**2017**
48	Priority Firm Public - 7(b) Loads.....	$ 260,336	$ 260,431
49	Industrial Firm - 7(c) Loads.....	$ 34,542	$ 34,418
50	New Resources - 7(f) Loads.....	$ 0.109	$ 0.109
51		$ 294,878	$ 294,849
52			
53	Adjustment Necessary to Achieve Reallocation	**2016**	**2017**
54	Priority Firm Public - 7(b) Loads.....	$ (21,713)	$ (21,657)
55	Industrial Firm - 7(c) Loads.....	$ 21,713	$ 21,657
56	New Resources - 7(f) Loads.....	$ 0.069	$ 0.069
57		$ (0)	$ (0)
58			
59		**2016**	**2017**
60	PF Contribution to Net REP Benefits $/MWh.....	4.27	4.26
61	IP Contribution to Net REP Benefits $/MWh.....	12.46	12.45
62	NR Contribution to Net REP Benefits $/MWh.....	12.46	12.45

Table 2.4.15

Rate Directive Step
Reallocation of Rate Protection Provided by the IP and NR Rates
Test Period October 2015 - September 2017

	B	C	D
4	**Cost Allocation After Rate Protection Provided by PFx**	**2016**	**2017**
5	Priority Firm Public - 7(b) Loads	$ 2,090,848	$ 2,155,062
6	Priority Firm Exchange - 7(b) Loads	$ 2,482,838	$ 2,522,332
7	Industrial Firm - 7(c) Loads	$ 117,559	$ 119,736
8	New Resources - 7(f) Loads	$ 0.598	$ 0.601
9	Surplus Firm - SP Loads	$ 41,801	$ 37,924
10	Total	$ 4,733,047	$ 4,835,054
11			
12			
13			
14	**Allocation of Rate Protection Provided by IP and NR**	**2016**	**2017**
15	Priority Firm Public - 7(b) Loads	$ (21,713)	$ (21,657)
16			
17	Industrial Firm - 7(c) Loads	$ 21,713	$ 21,657
18	New Resources - 7(f) Loads	$ 0.069	$ 0.069
19	Total	$ (0)	$ (0)
20			
21			
22	**Cost Allocation After Rate Protection Provided by IP and NR**	**2016**	**2017**
23	Priority Firm Public - 7(b) Loads	$ 2,069,135	$ 2,133,405
24	Priority Firm Exchange - 7(b) Loads	$ 2,482,838	$ 2,522,332
25	Industrial Firm - 7(c) Loads	$ 139,273	$ 141,393
26	New Resources - 7(f) Loads	$ 0.667	$ 0.670
27	Surplus Firm - SP Loads	$ 41,801	$ 37,924
28	Total	$ 4,733,047	$ 4,835,054
29			
30			
31	**Energy Billing Determinants (aMW)**	**2016**	**2017**
32	Priority Firm Public - 7(b) Loads	6,941	6,979
33	Priority Firm Exchange - 7(b) Loads	4,929	4,940
34	Industrial Firm - 7(c) Loads	316	316
35	New Resources - 7(f) Loads	0.001	0.001
36			
38			
39	**Average Power Rates After Rate Protection Reallocations**	**2016**	**2017**
40	Priority Firm Public - 7(b) Loads	33.94	34.90
41	Priority Firm Exchange - 7(b) Loads	62.00	62.93
42	Industrial Firm - 7(c) Loads	50.22	51.13
43	New Resources - 7(f) Loads	75.92	76.45

Table 2.4.16

Rate Directive Step
Calculation of Annual Energy Rate Scalars for Second IP-PF Link Calculation
Test Period October 2015 - September 2017

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
5																			
6	**Load Shaping Rate**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**					
7	HLH (mills/kWh)		31.59	33.39	35.30	35.31	35.09	28.71	27.09	23.75	23.72	30.73	34.04	35.24					
8	LLH (mills/kWh)		27.35	28.87	30.13	29.28	29.28	24.67	23.47	15.93	10.60	23.55	27.94	29.03					
9	Demand Rate ($/kW/mo)		9.47	10.01	10.58	10.58	10.51	8.61	8.12	7.12	7.11	9.21	10.20	10.56					
10																			
11		**PF+NR Load**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				**2016**	
12	**2016**	HLH	2837	3196	3587	3399	3078	3163	2718	3046	2919	2980	3127	2693				Energy (GWH)	60969
13		LLH	1768	2277	2477	2457	2011	2027	1748	2032	1784	1984	1845	1813				Allocated Cost	$ 2,094,530
14		Demand	366	201	589	482	361	505	445	299	365	327	471	375				Rate Scalar	**4.70**
15	Revenue at marginal Rates		$ 141,447	$ 174,453	$ 207,483	$ 197,079	$ 170,700	$ 145,164	$ 118,278	$ 106,858	$ 90,740	$ 141,327	$ 162,796	$ 151,485			$ 1,807,811		
16			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				**2017**	
17	**2017**	HLH	2830	3284	3619	3404	3048	3197	2744	2926	2835	2988	3151	2714				Energy (GWH)	61134
18		LLH	1814	2228	2486	2489	2002	2028	1825	2135	1712	1990	1858	1829				Allocated Cost	$ 2,158,665
19		Demand	317	263	591	487	293	512	383	376	369	332	481	382				Rate Scalar	**5.64**
20	Revenue at marginal Rates		$ 142,032	$ 176,587	$ 208,898	$ 198,240	$ 168,672	$ 146,209	$ 120,290	$ 106,190	$ 87,995	$ 141,727	$ 164,067	$ 152,750			$ 1,813,657		
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**				**2016**	
26	**2016**	HLH	137	127	126	132	127	132	133	132	127	131	137	122				Energy (GWH)	2773
27		LLH	98	101	109	103	93	102	95	102	100	104	98	106				Allocated Cost	$ 113,878
28		Demand	0	0	0	0	0	0	0	0	0	0	0	0				Rate Scalar	**12.60**
29	Revenue at marginal Rates		$ 7,006	$ 7,145	$ 7,728	$ 7,676	$ 7,172	$ 6,322	$ 5,815	$ 4,777	$ 4,075	$ 6,472	$ 7,398	$ 7,353			$ 78,937		
30			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				**2017**	
31	**2017**	HLH	137	127	126	132	123	132	133	132	127	131	137	122				Energy (GWH)	2766
32		LLH	98	101	109	103	89	102	95	102	100	104	98	106				Allocated Cost	$ 116,134
33		Demand	0	0	0	0	0	0	0	0	0	0	0	0				Rate Scalar	**13.54**
34	Revenue at marginal Rates		$ 7,006	$ 7,145	$ 7,728	$ 7,676	$ 6,925	$ 6,322	$ 5,815	$ 4,777	$ 4,075	$ 6,472	$ 7,398	$ 7,353			$ 78,690		
35																			

Table 2.4.17

Rate Directive Step
Calculation of Monthly Energy Rate Scalars for Second IP-PF Link Rate Calculation
Test Period October 2015 - Septmentber 2017

	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)		31.59	33.39	35.30	35.31	35.09	28.71	27.09	23.75	23.72	30.73	34.04	35.24				
7	LLH (mills/kWh)		27.35	28.87	30.13	29.28	29.28	24.67	23.47	15.93	10.60	23.55	27.94	29.03				
8	Demand Rate ($/kW/mo)		9.47	10.01	10.58	10.58	10.51	8.61	8.12	7.12	7.11	9.21	10.20	10.56				
9																		
10																		
11	**Unbifurcated PF /NR**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
12	**2016**	HLH	36.29	38.09	40.00	40.02	39.79	33.41	31.79	28.45	28.42	35.43	38.74	39.94				**2016**
13		LLH	32.05	33.57	34.83	33.98	33.98	29.37	28.17	20.63	15.30	28.25	32.64	33.73				**4.70**
14		Demand	9.47	10.01	10.58	10.58	10.51	8.61	8.12	7.12	7.11	9.21	10.20	10.56				**Scalar**
15			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
16	**2017**	HLH	37.23	39.03	40.95	40.96	40.73	34.35	32.73	29.40	29.36	36.37	39.68	40.88				**2017**
17		LLH	32.99	34.51	35.77	34.92	34.92	30.31	29.11	21.57	16.24	29.19	33.58	34.67				**5.64**
18		Demand	9.47	10.01	10.58	10.58	10.51	8.61	8.12	7.12	7.11	9.21	10.20	10.56				**Scalar**
19																		
20																		
21		**IP**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
22	**2016**	HLH	44.19	45.99	47.90	47.91	47.69	41.31	39.69	36.35	36.32	43.33	46.64	47.84				**2010**
23		LLH	39.95	41.47	42.73	41.88	41.88	37.27	36.07	28.53	23.20	36.15	40.54	41.63				**12.60**
24		Demand	9.47	10.01	10.58	10.58	10.51	8.61	8.12	7.12	7.11	9.21	10.20	10.56				**Scalar**
25			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				
26	**2017**	HLH	45.13	46.93	48.84	48.85	48.63	42.25	40.63	37.29	37.25	44.27	47.58	48.78				**2011**
27		LLH	40.89	42.41	43.67	42.82	42.82	38.21	37.01	29.47	24.14	37.09	41.48	42.57				**13.54**
28		Demand	9.47	10.01	10.58	10.58	10.51	8.61	8.12	7.12	7.11	9.21	10.20	10.56				**Scalar**

Table 2.4.18

Rate Directive Step
Calculation of Second IP-PF Link Delta
Test Period October 2015 - September 2017

	B	C	D	E	F	G	H
4						**FY 2016**	**FY 2017**
5							
6	1	IP Allocated Costs				117,559	119,736
7	2	IP Revenues @ Net Margin				(800)	(798)
8	3	adjustment				1,509	1,616
9	4	IP Marginal Cost Rate Revenues				78,937	78,690
10	5	PF/NR Marginal Cost Rate Revenues				1,807,811	1,813,657
11	6	PF Allocated Energy Costs				2,069,135	2,133,405
12	7	Numerator: 1-2-3-((4/5)*6)				26,503	26,355
13	8						
14	9	PF Allocation Factor for Delta				0.999999916	0.999999916
15	10	NR Allocation Factor for Delta				0.000000084	0.000000084
16	11	Total Allocation Factors for Delta				1.000000000	1.000000000
17	12	Denominator: 1.0 + ((9/11)*(4/5))				1.0437	1.0434
18	13						
19	14	DELTA: (7/12)				**25,394**	**25,259**
20							
21						-0.289	-0.289
22							

Table 2.4.19

Rate Directive Step
Reallocation of IP-PF Link Delta and Recalculation of Rates
Test Period October 2015 - September 2017

	B	C	D	E
4	**Cost Allocation After Rate Protection Provided by IP and NR**	**2016**	**2017**	
5	Priority Firm Public - 7(b) Loads	$ 2,069,135	$ 2,133,405	
6	Priority Firm Exchange - 7(b) Loads	$ 2,482,838	$ 2,522,332	
7	Industrial Firm - 7(c) Loads	$ 139,273	$ 141,393	
8	New Resources - 7(f) Loads	$ 0.667	$ 0.670	
9	Surplus Firm - SP Loads	$ 41,801	$ 37,924	
10	Total	$ 4,733,047	$ 4,835,054	
11				
12				
13	IP-PF Link Delta	$ 25,394	$ 25,259	
14				
15		**2016**	**2017**	
16	Priority Firm Public - 7(b) Loads	0.99999986	0.99999986	
17	Industrial Firm - 7(c) Loads	(1.00000000)	(1.00000000)	
18	New Resources - 7(f) Loads	0.00000014	0.00000014	
19				
20				
21	**Allocation of Second IP-PF Link Delta**	**2016**	**2017**	
22	Priority Firm Public - 7(b) Loads	$ 25,394	$ 25,259	
23	Priority Firm Exchange - 7(b) Loads	$ -	$ -	
24	Industrial Firm - 7(c) Loads	$ (25,394)	$ (25,259)	
25	New Resources - 7(f) Loads	$ 0.004	$ 0.004	
26	Total	$ 0	$ (0)	
27				
28				
29	**Cost Allocation After Second IP-PF Link**	**2016**	**2017**	
30	Priority Firm Public - 7(b) Loads	$ 2,094,529	$ 2,158,664	
31	Priority Firm Exchange - 7(b) Loads	$ 2,482,838	$ 2,522,332	
32	Industrial Firm - 7(c) Loads	$ 113,878	$ 116,134	
33	New Resources - 7(f) Loads	$ 0.671	$ 0.673	
34	Surplus Firm - SP Loads	$ 41,801	$ 37,924	
35	Total	$ 4,733,047	$ 4,835,054	
36				
37				
38	**Energy Billing Determinants (aMW)**	**2016**	**2017**	
39	Priority Firm Public - 7(b) Loads	6,941	6,979	
40	Priority Firm Exchange - 7(b) Loads	4,929	4,940	
41	Industrial Firm - 7(c) Loads	316	316	
42	New Resources - 7(f) Loads	0.001	0.001	
43				
45				
46	**Average Power Rates After Second IP-PF Link**	**2016**	**2017**	Average
47	Priority Firm Public - 7(b) Loads	34.35	35.31	**34.83**
48	Priority Firm Exchange - 7(b) Loads	62.00	62.93	**62.47**
49	Industrial Firm - 7(c) Loads	41.06	41.99	**41.53**
50	New Resources - 7(f) Loads	76.34	76.86	**76.60**

Rate Design Step
REP Benefit Reconciliation
Test Period October 2015 to September 2017

	B	D	E	F	G	H	I	J	K	L
4		**2016**	**2017**	**Avg**				**2016**	**2017**	**Avg**
5	Resource Costs	2,999,179	2,998,270	2,998,725			PFx Alloc Cost	(2,482,838)	(2,522,332)	
6	PFx Revenues	(2,684,153)	(2,723,569)	(2,703,861)			Exch Tmn Cost	(201,315)	(201,237)	
7	REP Benefits	315,026	274,701	294,863				(2,684,153)	(2,723,569)	(2,703,861)
8										
9	**REP Benefits**						**PFx Revenues**			
10	Avista Corporation	2,616	2,616				Avista Corporation	208,048	208,048	
11	Idaho Power Company	8,851	8,851				Idaho Power Company	394,751	394,751	
12	NorthWestern Energy, LLC	6,226	6,226				NorthWestern Energy, LLC	48,435	48,435	
13	PacifiCorp	57,214	57,214				PacifiCorp	643,379	643,379	
14	Portland General Electric Company	70,577	70,577				Portland General Electric Compai	607,777	607,777	
15	Puget Sound Energy, Inc.	68,616	68,616				Puget Sound Energy, Inc.	752,588	752,588	
16	IOU REP	214,100	214,100	214,100			IOU REP	2,654,977	2,654,977	2,654,977
17										
18	Clark Public Utilities	4,241	4,211				Clark Public Utilities	125,862	124,982	
19	Franklin	-	-				Franklin	-	-	
20	Snohomish County PUD No 1	-	-				Snohomish County PUD No 1	-	-	
21	COU REP	4,241	4,211	4,226			COU REP	125,862	124,982	125,422
22										
23	Refund Amounts	76,538	76,538				Refund Amounts	(76,538)	(76,538)	
24	Total REP	294,878	294,849	294,863			Total REP	2,704,301	2,703,421	2,703,861
25				0				20,148	(20,148)	(0)
26										
27	**For Slice True-Up**									100.00%
28	IOU REP	214,100	214,100							
29	COU REP	4,241	4,211							
30	Refund Amounts	76,538	76,538							
31	Total REP	294,878	294,849							

Table 2.5.1

Rate Design Step
Cost Aggregation under Tiered Rate Methodology
Test Period October 2015 to September 2017

	A	B	C	D	E	F	G	H
4						AggregationKey	**2016**	**2017**
5		**Composite**						
6			Federal Base System					
7				Hydro				
8					Operating Expense	CFHYOP	589,752	604,322
9					Interest	IFHYIT	182,480	187,541
10					MRNR	MFHYMR	0	0
11				Fish & Wildlife				
12					Operating Expense	CFFWOP	313,541	323,435
13					Interest	IFFWIT	16,631	17,737
14					MRNR	MFFWMR	-	-
15				Trojan		CFTR	800	800
16				WNP #1		CFW1	253,195	196,587
17				Columbia Generating Station		CFCG	363,836	450,621
18				WNP #3		CFW3	222,207	252,493
19				Augmentation		Internal	55,974	95,400
20			Residentail Exchange Program					
21				REP Net Cost		Internal	294,878	294,849
22				Program Support		CRSP	920	635
23				Settlement Interest Accrual		CRST	-	-
24			NewResources					
25				Cowlitz		CNCZ	11,600	11,851
26				Idaho		CNID	5,015	5,095
27				Tier 1 Aug (Klondike III)		CNTA	12,505	15,138
28				Other		CNOT	42,400	34,831
29			Conservation					
30				Operating Expense		CCOP	123,608	124,401
31				Interest		ICIT	20,234	23,719
32				MRNR		MCMR	-	-
33			BPAPrograms					
34				Operating Expense		CBOP	139,087	116,198
35				Interest		IBIT	2,212	1,703
36				MRNR		MBMR	-	-
38			Transmission					
39				Transmission and Ancillary Services		CTTA	50,597	49,784
40				General Transfer Agreements		CTGA	62,140	71,689
41			Nonslice Interest and MRNR Allocated to Cost Pools					
42				Interest on BPA fund Credit to Nonslice		Internal	56	359
43				Accrual Revenue (MRNR Adjustment)		Internal	-	-
44			**Total**			Internal	**2,763,666**	**2,879,187**

Rate Design Step
Cost Aggregation under Tiered Rate Methodology
Test Period October 2015 to September 2017

	A	B	C	D	E	F	G	H
4						AggregationKey	**2016**	**2017**
45		**Non-Slice**						
46			FBS					
47					Balancing Purchases from Risk Mod	Internal	20,668	14,655
48					Balancing in Revenue Requirement	NFBL	8,936	38,663
49					PNRR			
50					Hydro	NFHYPR	-	-
51					Fish & Wildlife	NFFWPR	-	-
52			Conservation					
53					PNRR	NCPR	-	-
54			BPAPrograms					
55					Hedging Mitigation	NBHM	-	-
56					Bad Debt	NBOP	-	-
57					PNRR	NBPR	-	-
58			Transmission					
59					Transmission and Ancillary Services	NTTA	74,242	71,452
60					Third-party T&A	NT3A	2,381	2,428
61			Nonslice Interest and MRNR					
62					BPA Fund	NIBF	(56)	(359)
63					Non-Slice MRNR Adjustment	NMAJ	-	-
64			**Total**			Internal	**106,171**	**126,840**
65		**Slice**						
66			BPAPrograms					
67					Other Slice Costs	SBSW	-	-
68			**Total**			Internal	-	-
69		**Tier 2**						
70			FBS					
71					Tier 2 Purchase Costs	2FT2PC	20,310	21,610
72					Tier 2 Rate Design Adjustments	2FT2RD	891	1,006
73					Tier 2 Other Costs	2FT2OT	-	-
74			**Total**			Internal	**21,201**	**22,616**

Rate Design Step
Cost Aggregation under Tiered Rate Methodology
Test Period October 2015 to September 2017

	A	B	C	D	E	F	G	H
4						AggregationKey	**2016**	**2017**
75			**Rate Direct/Design Adjustments**					
76				Credits Allocated Against Cost Pools				
77					FBS (excluding T2 Adjustment)		(116,853)	(113,888)
78					Contract Obligations		(2,414)	(1,924)
79					New Resources		(1,151)	(648)
80					Conservation		(15,000)	(7,000)
81					BPAPrograms		-	-
82					Transmission		(5,750)	(5,800)
83								
84				Secondary Energy Credit (includes pre-sale)		Internal	(458,674)	(505,859)
85				Generation Inputs Credit		CDGI	(115,750)	(115,750)
86				NR Revenues from ESS services		NDNR	-	-
87				Composite revenues associated with firm surplus sales		CDFC	(37,924)	(37,924)
88				Non-slice revenues associated with firm surplus sales		NDFC	(4,442)	(565)
89								
90				Low Density Discount		Internal	38,938	39,639
91				Irrigation Rate Mitigation Costs		Internal	20,942	20,942
92								
93				Composite Augmentation RSS Revenue Debit/(Credit)		CD2RCF	(1,633)	(1,633)
94				Composite Tier 2 RSS Revenue Debit/(Credit)		2D2RCF	(86)	(94)
95				Composite Tier 2 Rate Design Adjustment Debit/(Credit)		2D2DC	(805)	(912)
96				Composite Non-Federal RSS Revenue Debit/(Credit)		CD2RCN	(1,248)	(1,353)
97				Non-Slice Augmentation RSC Revenue Debit/(Credit)		ND2RNF	(847)	(847)
98				Non-Slice Tier 2 RSC Revenue Debit/(Credit)		2D2RNF	-	-
99				Non-Slice Tier 2 Rate Design Debit/(Credit)		2D2DN	-	-
100				Non-Slice Non-Federal RSC Revenue Debit/(Credit)		ND2RNN	(83)	(81)
101								
102				Firm Surplus and Secondary Credit (from unused RHWM)		Internal	(4,290)	(2,037)
103				Demand Revenue		Internal	45,051	44,938
104				Load Shaping Revenue		Internal	15,638	24,033
105								

Table 2.5.2

Rate Design Step
Unused RHWM (net) Credit Computation
Test Period October 2015 to September 2017

	B	C	D
4		**2016**	**2017**
5	Secondary (aMW)	2,365	2,220
6	T1SFCO (aMW)	6,924	6,924
7	RHWM Augmentation (aMW)	59	59
8	RP Augmentation (aMW)	-	-
9	System Augmentation (aMW)	202	320
10	Augmentation Base (aMW)	261	380
11	IP and NR Loads contributing to avoided cost	325	325
12			
13	Value of Secondary	$ 21.87	$ 24.86
14	Value of T1SFCO ($/MWh)	$ 28.62	$ 28.62
15	Value of Augmentation	$ 31.53	$ 33.98
16			
17	Secondary (MWh)	20,773,533	19,444,198
18	T1SFCO (MWh)	60,820,223	60,654,047
19	RHWM Augmentation (MWh)	519,196	517,777
20	Augmentation Base (MWh)	2,294,354	3,324,919
21	IP and NR Loads (MWh)	2,858,039	2,850,230
22			
23	Unused RHWM (MWh)	948,884	787,630
24			
25	Unused Secondary	321,354	250,358
26	Unused T1SFCO	940,852	780,963
27	Unused Augmentation	8,032	6,667
28			
29	Value of Unused	$ 34,209,811	$ 28,804,269
30	Value of System Augmentation not Purchased	$ 29,919,839	$ 26,767,335
31			
32	Net Credit/(Cost)	$ 4,289,972	$ 2,036,934
33			
34	$/MWh value of Unused RHWM	**$ 36.29**	

Table 2.5.3

Rate Design Step
Slice Return of Network Losses Adjustment
Test Period October 2015 - September 2017

	B	C	D
4		**2016**	**2017**
5	Non Slice Loads (MWh)	44,060,147	44,361,881
6	Loss Percent Assumption	1.90%	1.90%
7	Implied Non Slice Losses	837,143	842,876
8	Average Slice&Non-Slice Tier 1 Rate	34.86	34.86
9	Implied Cost/Credit ($1000)	29,183	29,383

Table 2.5.4

Rate Design Step
Balancing Augmentation Adjustment for Change to the Equivalent Tier 1 System Firm Critical Output
Test Period October 2015 - September 2017

	A	B	C	E	F	G
4				**2016**	**2017**	
5		**Table 3.1**				
6			Regulated	6,310	6,387	
7			Independent	353	353	
8		**Table 3.2**				
9			Ashland Solar Project	0	0	
10			Columbia Generating Station	1,075	916	
11			Condon Wind Project	10	10	
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)	11	-	
19			Glines Canyon Hydro	-	-	
20			Klondike I	7	7	
21			Stateline Wind Project	21	21	
22		**Table 3.3**				
23			Canadian Entitlement	137	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	2	-	
31			Riverside Seasonal	7	-	
32			Riverside Exchange Energy	7	-	
33			Sierra Pacific (Wells)	-	-	
34			PacifiCorp	4	4	
35		**Table 3.4**				
36			USBR Pump Load	179	179	
37			Canadian Entitlement	471	468	
38			Non-Treaty Storage	11	11	
39			Libby Coordination	-	-	
40			Hungry Horse	5	-	
41			Riverside Capacity	2	-	
42			Riverside Seasonal	-	-	
43			Pasadena Capacity	-	-	
44			Pasadena Seasonal	-	-	
45			Sierra Pacific (Wells)	-	-	
46			Intertie Losses	0.1	-	
47			WNP3	90	90	
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	6,941	6,979	
55			Tier 2	68	87	
56			Net Preference	6,873	6,892	
57			Industrial	316	316	
58			New Resource	0	0	
59			Intraregional Transfer	99	99	
60			FBS Obligation	668	660	
61			Seasonal or Capacity Exchange	34	31	
62			Conservation Augmentation	-	-	
63			Transmission Losses Before Slice Return	245	245	
64			Slice Return of Losses	35	35	
65			Transmission Losses After Slice Return	209	210	
66						
67		**Annual T1SFCO**		6,973	6,873	
68		**RHWM Process T1SFCO (annual)**		6,975	6,873	
69		**Difference**		(2)	0	
70		**Augmentation Price (Secondary in the case Augmentation is zero)**		$ 31.53	$ 33.98	
71		**Hours**		8,784	8,760	
72		**Credit/Cost to Balancing Augmentation**		$ (516,663)	$ 136,836	

Table 2.5.5

Rate Design Step
Calculation of Load Shaping and Demand Revenuest
Test Period October 2015 - September 2017

	B	E	F	G	H	I	J	K	L
5	**2016**	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-15	365,533	$ 9.47	$ 3,461,596	(175,476)	69,016	$ 31.59	$ 27.35	$ (3,655,704)
7	Nov-15	201,099	$ 10.01	$ 2,013,005	(363,196)	146,824	$ 33.39	$ 28.87	$ (7,888,332)
8	Dec-15	588,738	$ 10.58	$ 6,228,845	130,836	353,265	$ 35.30	$ 30.13	$ 15,262,367
9	Jan-16	482,040	$ 10.58	$ 5,099,987	401,660	632,522	$ 35.31	$ 29.28	$ 32,702,858
10	Feb-16	361,121	$ 10.51	$ 3,795,381	336,337	403,298	$ 35.09	$ 29.28	$ 23,610,640
11	Mar-16	505,115	$ 8.61	$ 4,349,039	30,511	145,869	$ 28.71	$ 24.67	$ 4,474,555
12	Apr-16	444,661	$ 8.12	$ 3,610,646	105,434	185,516	$ 27.09	$ 23.47	$ 7,210,252
13	May-16	298,767	$ 7.12	$ 2,127,221	(1,250,989)	(333,634)	$ 23.75	$ 15.93	$ (35,025,774)
14	Jun-16	364,733	$ 7.11	$ 2,593,255	(596,685)	(187,763)	$ 23.72	$ 10.60	$ (16,143,668)
15	Jul-16	326,775	$ 9.21	$ 3,009,601	(253,909)	284,836	$ 30.73	$ 23.55	$ (1,094,740)
16	Aug-16	470,983	$ 10.20	$ 4,804,028	(331,090)	119,227	$ 34.04	$ 27.94	$ (7,939,116)
17	Sep-16	374,816	$ 10.56	$ 3,958,056	(13,243)	158,174	$ 35.24	$ 29.03	$ 4,125,118
18	**Total**			**$ 45,050,660**		$ (2,663)			**$ 15,638,457**
19									
20	**2017**	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-16	317,280	$ 9.47	$ 3,004,645	(208,440)	120,050	$ 31.59	$ 27.35	$ (3,301,265)
22	Nov-16	262,996	$ 10.01	$ 2,632,594	(299,170)	102,526	$ 33.39	$ 28.87	$ (7,029,361)
23	Dec-16	590,825	$ 10.58	$ 6,250,925	142,983	364,552	$ 35.30	$ 30.13	$ 16,031,248
24	Jan-17	486,717	$ 10.58	$ 5,149,471	413,290	642,918	$ 35.31	$ 29.28	$ 33,417,889
25	Feb-17	292,980	$ 10.51	$ 3,079,225	402,252	448,594	$ 35.09	$ 29.28	$ 27,249,866
26	Mar-17	512,048	$ 8.61	$ 4,408,734	40,480	153,935	$ 28.71	$ 24.67	$ 4,959,744
27	Apr-17	383,401	$ 8.12	$ 3,113,214	70,258	236,778	$ 27.09	$ 23.47	$ 7,460,476
28	May-17	375,930	$ 7.12	$ 2,676,624	(1,211,646)	(369,305)	$ 23.75	$ 15.93	$ (34,659,632)
29	Jun-17	369,330	$ 7.11	$ 2,625,937	(596,863)	(187,347)	$ 23.72	$ 10.60	$ (16,143,469)
30	Jul-17	331,725	$ 9.21	$ 3,055,190	(250,791)	288,421	$ 30.73	$ 23.55	$ (914,500)
31	Aug-17	481,291	$ 10.20	$ 4,909,168	(325,089)	124,182	$ 34.04	$ 27.94	$ (7,596,389)
32	Sep-17	381,818	$ 10.56	$ 4,031,997	(5,694)	163,929	$ 35.24	$ 29.03	$ 4,558,205
33	**Total**			**$ 44,937,725**		$ 260,801			**$ 24,032,810**

Rate Design Step
Calculation of PF Preference Rates under Tiered Rate Methodology
Test Period October 2015 - September 2017

	B	C	D	E
5	**Costs ($000)**	**2016**	**2017**	**Rate Period**
6	**Composite**	$ 2,763,666	$ 2,879,187	$ 5,642,854
7	**Non-Slice**	$ 106,171	$ 126,840	$ 233,010
8	**Slice**	$ -	$ -	$ -
9	**Tier 2**	$ 21,201	$ 22,616	$ 43,817
13				
14	**Revenues from Rate Pools to Composite Cost Pool**	**2016**	**2017**	**Rate Period**
15	DSI Revenue Credit	**$ (115,169)**	**$ (114,854)**	**$ (230,023)**
16	Exchange Revenues	**$ -**	**$ -**	**$ -**
17	New Resource Revenues	**$ (0.67)**	**$ (0.67)**	**$ (1)**
18	FPS Revenues	$ (37,924)	$ (37,924)	$ (75,848)
19	Non-Federal RSS Revenues	$ (1,248)	$ (1,353)	$ (2,601)
20	Other Credits	$ (256,918)	$ (245,011)	$ (501,928)
21	Tiered Rate Elements			$ -
22	Unused RHWM Credit Reallocation	$ (4,290)	$ (2,037)	$ (6,327)
23	Balancing Augmentation Adjustment Reallocation	$ (433)	$ (8,726)	$ (9,159)
24	Composite Augmentation RSS Revenue Debit/(Credit)	$ (1,633)	$ (1,633)	$ (3,265)
25	Composite Tier 2 RSS Revenue Debit/(Credit)	$ (86)	$ (94)	$ (180)
26	Composite Tier 2 Rate Design Adjustment Debit/(Credit)	$ (805)	$ (912)	$ (1,716)
27	Transmission Losses Adjustment Reallocation	$ (29,183)	$ (29,383)	$ (58,565)
28	Total	$ (447,687)	$ (441,927)	$ (889,615)
29				
30	**Rate Discount Costs Applied to Composite Pool**	**2016**	**2017**	**Rate Period**
31	Irigation Rate Discout Costs	$ 20,942	$ 20,942	$ 41,885
32	Low Density Discount Costs	$ 38,938	$ 39,639	$ 78,577
33	Total	$ 59,880	$ 60,582	$ 120,462
34				
35		**2016**	**2017**	**Rate Period**
36	**Composite**	$ 2,375,859	$ 2,497,842	$ 4,873,701

Rate Design Step
Calculation of PF Preference Rates under Tiered Rate Methodology
Test Period October 2015 - September 2017

	B	C	D	E
5	**Costs ($000)**	**2016**	**2017**	**Rate Period**
6	**Composite.....**	$ 2,763,666	$ 2,879,187	$ 5,642,854
7	**Non-Slice.....**	$ 106,171	$ 126,840	$ 233,010
8	**Slice.....**	$ -	$ -	$ -
9	**Tier 2.....**	$ 21,201	$ 22,616	$ 43,817
37				
38	**Non-Slice Revenues, Credits, and Costs**	**2016**	**2017**	**Rate Period**
39	Secondary Revenue.....	$ (337,762)	$ (377,178)	$ (714,940)
40	Unused RHWM Credit Reallocation.....	$ 4,290	$ 2,037	$ 6,327
41	FPS Revenues not classified as Obligations in TRM.....	$ (4,442)	$ (565)	$ (5,007)
42	Non-federal RSC Revenues.....	$ (83)	$ (81)	$ (164)
43	NR Revenues from ESS services.....	$ -	$ -	$ -
44	Load Shaping Revenue.....	$ (15,638)	$ (24,033)	$ (39,671)
45	Balancing Augmentation Adjustment Reallocation.....	$ 433	$ 8,726	$ 9,159
46	Demand Revenue.....	$ (45,051)	$ (44,938)	$ (89,988)
47	Non-Slice Augmentation RSC Revenue Debit/(Credit).....	$ (847)	$ (847)	$ (1,694)
48	Non-Slice Tier 2 RSC Revenue Debit/(Credit).....	$ -	$ -	$ -
49	Non-Slice Tier 2 Rate Design Debit/(Credit).....	$ -	$ -	$ -
50	Transmission Losses Adjustment Reallocation.....	$ 29,183	$ 29,383	$ 58,565
51	Total.....	$ (369,917)	$ (407,496)	$ (777,413)
52				
53		**2016**	**2017**	**Rate Period**
54	**Non-Slice.....**	$ (263,746)	$ (280,656)	$ (544,402)

Rate Design Step
Calculation of PF Preference Rates under Tiered Rate Methodology
Test Period October 2015 - September 2017

	B	C	D	E
5	**Costs ($000)**	**2016**	**2017**	**Rate Period**
6	**Composite**	$ 2,763,666	$ 2,879,187	$ 5,642,854
7	**Non-Slice**	$ 106,171	$ 126,840	$ 233,010
8	**Slice**	$ -	$ -	$ -
9	**Tier 2**	$ 21,201	$ 22,616	$ 43,817
55				
56	**TRM Costs after Adjustments**	**2016**	**2017**	**Rate Period**
57	**Composite**	$ 2,375,859	$ 2,497,842	$ 4,873,701
58	**Non-Slice**	$ (263,746)	$ (280,656)	$ (544,402)
59	**Slice**	$ -	$ -	$ -
60	**Tier 2**	$ 21,201	$ 22,616	$ 43,817
61	**Total Costs**	$ 2,133,314	$ 2,239,802	$ 4,373,116
62				
63	**Billing Determinants**	**2016**	**2017**	**Rate Period**
64	**TOCA**	98.4531	98.7124	98.5827
65	**Non-slice TOCA**	71.8344	72.0938	71.9641
66	**Slice Percentage**	26.6187	26.6187	26.6187
67				
68	**Annual TRM Rates ($000/percent)**	**2016**	**2017**	**Rate Period**
69	**Composite**	$ 24,132	$ 25,304	$ 24,719
70	**Non-Slice**	$ (3,672)	$ (3,893)	$ (3,782)
71	**Slice**	$ -	$ -	$ -
72				
73	**Monthly TRM Rates ($/percent)**	**2016**	**2017**	**Rate Period**
74	**Composite**	2,010,991	2,108,686	2,059,903
75	**Non-Slice**	(305,966)	(324,411)	(315,205)
76	**Slice**	-	-	-
77				
78	**Tier 2 Rates ($/MWh)**	**2016**	**2017**	**Rate Period**
79	**Tier 2 Short Term**	$ 34.05	$ 36.62	$ 35.34
80	**Tier 2 Load Growth**	$ 45.32	$ 49.73	$ 49.73
81	**Tier 2 Vintage 2014**	$ 44.99	$ 49.34	$ 49.34

Table 2.5.7.1

Rate Design Step
Table Showing Net REP Rate Calculation Yields Identical Rates as Gross REP Calculations
Test period October 2015 - September 2017
($ 000, $/MWh)

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
11			2016	2017		PF p	IP	NR	FPS				PF p	IP	NR
12	GENERATION ENERGY														
13													122,104	5,539	0.017544
14	Federal Base System														
15	Hydro		772,232	791,863		1,564,095	0.0	0.0	0				12.81	0.00	0.00
16	Fish & Wildlife		330,172	341,172		671,344	0.0	0.0	0				5.50	0.00	0.00
17	Trojan		800	800		1,600	0.0	0.0	0				0.01	0.00	0.00
18	WNP #1		253,195	196,587		449,782	0.0	0.0	0				3.68	0.00	0.00
19	WNP #2		363,836	450,621		814,457	0.0	0.0	0				6.67	0.00	0.00
20	WNP #3		222,207	252,493		474,699	0.0	0.0	0				3.89	0.00	0.00
21	System Augmentation		55,974	95,400		151,373	0.0	0.0	0				1.24	0.00	0.00
22	Balancing Power Purchases		29,604	53,318		82,922	0.0	0.0	0				0.68	0.00	0.00
23	Tier 2 Costs		21,201	22,616		43,817	0.0	0.0	0				0.36	0.00	0.00
24	Total Federal Base System		2,049,220	2,204,870		4,254,090	0.0	0.0	0.0				34.84	0.00	0.00
25															
26	New Resources		69,040	64,436		133,476	0.0	0.0	0		PFx Revenue		1.09	0.00	0.00
27	Residential Exchange		2,798,784	2,797,667		591,281	0.0	0.0	0		5,005,170		4.84	0.00	0.00
28	Conservation		143,842	148,120		291,963	0.0	0.0	0				2.39	0.00	0.00
29	BPA Programs & Transmission		330,658	313,254		643,912	0.0	0.0	0		NR Revenue		5.27	0.00	0.00
30	TOTAL COSA ALLOCATIONS		5,391,544	5,528,348		5,914,722	0	0	0		1.3		48.44	0.00	0.00
31															
32															
33	Nonfirm Excess Revenue Credit		(458,674)	(505,859)		(964,533)	0.0	0.0	0.0				-7.90	0.00	0.00
34	LDD/IRD Expense		59,880	60,582		120,462	0.0						0.99	0.00	0.00
35	Other Revenue Credits		(259,704)	(248,016)		(507,720)	0.0	0.0	0.0				-4.16	0.00	0.00
36						0	0.0						0.00	0.00	0.00
37	SP Revenue Surplus/Dfct Adj.		0	0		(79,725)	0	0.0	79,725				-0.65	0.00	0.00
38						(1.3)		1.3439					0.00	0.00	76.60
39	IP Rate Revenue		0	0		(230,017)	230,017						-1.88	41.53	0.00
40															
41	TOTAL RATE DESIGN ADJUSTMENTS		(658,498)	(693,294)		(1,661,534)	230,017	1.3	79,725				-13.61	41.53	76.60
42															
43	Total Generation		4,733,047	4,835,054									**34.83**	**41.53**	**76.60**
44				**PFp Revenue Recovery**		**4,253,187**	230,017	1.3	79,725						

Rate Design Step
Demonstration that TRM PFp Rates Collect the Same Revenue Requirement as the Non-TRM PFp Rate
Test Period October 1, 2015 to September 30, 2017

Proof: TRM PF Revenues = Non-TRM PF Revenues

	2016	2017
Composite Revenue.....	$ 2,433,645	$ 2,440,056
Non-Slice Revenue.....	$ (271,711)	$ (272,692)
Slice Revenue.....	$ -	$ -
Tier 2.....	$ 21,201	$ 22,616
Load Shaping Revenue.....	$ 15,638	$ 24,033
Demand Revenue.....	$ 45,051	$ 44,938
Total TRM PF Revenue	$ 2,243,824	$ 2,258,951
Slice Portion of Secondary Revenue.....	$ (120,912)	$ (128,681)
Total Net TRM PF Revenue	$ 2,122,912	$ 2,130,270

		PF Rate
Total TRM PF Revenue Analogous to w/ Slice PF	$ 4,253,182	34.83
w/ Slice PF Public Rate Revenue from "Net REP" Table	**$ 4,253,187**	34.83
delta	$ 5	

Table 2.5.8.1

Rate Design Step
Calculation of Priority Firm Tier 1 Equivalent Rate Components
Test Period October 2015 - September 2017

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16		
15	HLH (mills/kWh)	31.59	33.39	35.30	35.31	35.09	28.71	27.09	23.75	23.72	30.73	34.04	35.24		
16	LLH (mills/kWh)	27.35	28.87	30.13	29.28	29.28	24.67	23.47	15.93	10.60	23.55	27.94	29.03		
17	Demand Rate ($/kW/mo)	9.47	10.01	10.58	10.58	10.51	8.61	8.12	7.12	7.11	9.21	10.20	10.56		
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)	5,602	6,419	7,141	6,741	6,066	6,292	5,399	5,909	5,689	5,906	6,211	5,345		120,740
22	LLH (GWh)	3,532	4,453	4,912	4,892	3,968	4,007	3,525	4,115	3,449	3,921	3,654	3,592		Tier 1 Demand (MW/mo)
23	Demand (MW)	683	464	1,180	969	654	1,017	828	675	734	659	952	757		9,571
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)	$ 176,963	$ 214,319	$ 252,092	$ 238,071	$ 212,858	$ 180,651	$ 146,263	$ 140,349	$ 134,921	$ 181,490	$ 211,414	$ 188,340		$ 3,492,682
29	LLH ($000)	$ 96,607	$ 128,563	$ 147,989	$ 143,237	$ 116,180	$ 98,844	$ 82,724	$ 65,555	$ 36,560	$ 92,329	$ 102,094	$ 104,269		Demand Revenue ($000)
30	Demand ($000)	$ 6,466	$ 4,646	$ 12,480	$ 10,249	$ 6,875	$ 8,758	$ 6,724	$ 4,804	$ 5,219	$ 6,065	$ 9,713	$ 7,990		$ 89,988
31															$ 3,582,670
32															Tier 1 Revenue Requirement (RR) ($000)
33															**$ 4,209,376**
34															Tier 1 RR less Demand Revenue ($000)
35															$ 4,119,387
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)	36.78	38.58	40.49	40.50	40.28	33.90	32.28	28.94	28.91	35.92	39.23	40.43		(5.19)
38	LLH (mills/kWh)	32.54	34.06	35.32	34.47	34.47	29.86	28.66	21.12	15.79	28.74	33.13	34.22		
39	Demand ($/kW/mo)	9.47	10.01	10.58	10.58	10.51	8.61	8.12	7.12	7.11	9.21	10.20	10.56		
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)	$ 206,037	$ 247,654	$ 289,140	$ 273,029	$ 244,331	$ 213,302	$ 174,295	$ 171,004	$ 164,474	$ 212,154	$ 243,645	$ 216,100		$ 4,119,334
45	LLH ($000)	$ 114,939	$ 151,675	$ 173,480	$ 168,627	$ 136,773	$ 119,638	$ 101,018	$ 86,913	$ 54,460	$ 112,677	$ 121,058	$ 122,910		Allocated Cost Demand ($000)
46	Demand ($000)	$ 6,466	$ 4,646	$ 12,480	$ 10,249	$ 6,875	$ 8,758	$ 6,724	$ 4,804	$ 5,219	$ 6,065	$ 9,713	$ 7,990		$ 89,988
47															$ 4,209,323
48	Average Slice&Non-Slice Tier 1 Rate														
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 4,119,334	34.12												
51	Allocated Cost Demand	$ 89,988	0.75												
52	Total Allocated Costs	$ 4,209,323	34.86												
53															
54	Tier 1 Energy (GWh)		120,740												
55	Market Energy Delta (mills/kWh)		(5.19)												

Table 2.5.8.2

Rate Design Step
Calculation of Priority Firm Public Melded Rate Equivalent Components
Test Period October 2015 - September 2017

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16		
15	HLH (mills/kWh)	31.59	33.39	35.30	35.31	35.09	28.71	27.09	23.75	23.72	30.73	34.04	35.24		
16	LLH (mills/kWh)	27.35	28.87	30.13	29.28	29.28	24.67	23.47	15.93	10.60	23.55	27.94	29.03		
17	Demand Rate ($/kW/mo)	9.47	10.01	10.58	10.58	10.51	8.61	8.12	7.12	7.11	9.21	10.20	10.56		
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)	5,668	6,480	7,206	6,804	6,127	6,359	5,463	5,972	5,754	5,968	6,278	5,407		122,104
22	LLH (GWh)	3,582	4,504	4,963	4,945	4,013	4,055	3,573	4,167	3,496	3,974	3,703	3,642		Tier 1 Demand (MW/mo)
23	Demand (MW)	683	464	1,180	969	654	1,017	828	675	734	659	952	757		9,571
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)	$ 179,041	$ 216,359	$ 254,376	$ 240,267	$ 214,991	$ 182,579	$ 147,977	$ 141,860	$ 136,455	$ 183,401	$ 213,700	$ 190,531		$ 3,531,479
29	LLH ($000)	$ 97,972	$ 130,035	$ 149,525	$ 144,803	$ 117,507	$ 100,036	$ 83,866	$ 66,385	$ 37,061	$ 93,589	$ 103,449	$ 105,713		Demand Revenue ($000)
30	Demand ($000)	$ 6,466	$ 4,646	$ 12,480	$ 10,249	$ 6,875	$ 8,758	$ 6,724	$ 4,804	$ 5,219	$ 6,065	$ 9,713	$ 7,990		$ 89,988
31															$ 3,621,467
32															Tier 1&2 Revenue Requirement (RR) ($000)
33															$ 4,253,193
34															T1&2RR less Demand Revenue ($000)
35															$ 4,163,205
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)	36.76	38.56	40.47	40.48	40.26	33.88	32.26	28.92	28.89	35.90	39.21	40.41		(5.17)
38	LLH (mills/kWh)	32.52	34.04	35.30	34.45	34.45	29.84	28.64	21.10	15.77	28.72	33.11	34.20		
39	Demand ($/kW/mo)	9.47	10.01	10.58	10.58	10.51	8.61	8.12	7.12	7.11	9.21	10.20	10.56		
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)	$ 208,343	$ 249,882	$ 291,614	$ 275,412	$ 246,657	$ 215,452	$ 176,229	$ 172,725	$ 166,229	$ 214,268	$ 246,154	$ 218,506		$ 4,162,766
45	LLH ($000)	$ 116,491	$ 153,322	$ 175,182	$ 170,372	$ 138,255	$ 121,001	$ 102,341	$ 87,930	$ 55,136	$ 114,135	$ 122,591	$ 124,540		Allocated Cost Demand ($000)
46	Demand ($000)	$ 6,466	$ 4,646	$ 12,480	$ 10,249	$ 6,875	$ 8,758	$ 6,724	$ 4,804	$ 5,219	$ 6,065	$ 9,713	$ 7,990		$ 89,988
47															$ 4,252,755
48		Average Slice&Non-Slice Tier 1&2 Rate													
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 4,162,766	34.09												
51	Allocated Cost Demand	$ 89,988	0.74												
52	Total Allocated Costs	$ 4,252,755	34.83												
53															
54	Tier 1&2 Energy (GWh)		122,104												
55	PF Melded Equivalent Energy Scalar (mills/kWh)		(5.17)												

Table 2.5.8.3

Rate Design Step
Calculation of Industrial Firm Power Rate Components
Test Period October 2015 - September 2017

PF Melded Equiv Rate	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16
HLH (mills/kWh)	36.76	38.56	40.47	40.48	40.26	33.88	32.26	28.92	28.89	35.90	39.21	40.41
LLH (mills/kWh)	32.52	34.04	35.30	34.45	34.45	29.84	28.64	21.10	15.77	28.72	33.11	34.20
Demand Rate ($/kW/mo)	9.47	10.01	10.58	10.58	10.51	8.61	8.12	7.12	7.11	9.21	10.20	10.56

IP Billing Determinants	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	**Totals** IP Energy (GWh)
HLH (GWh)	275	254	252	265	250	265	265	265	254	262	274	243	5,539
LLH (GWh)	195	201	218	205	182	204	189	205	201	208	196	212	
Demand (MW)	-	-	-	-	-	-	-	-	-	-	-	-	

Revenue @ PF Melded Rates	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	Energy Rev & Tier1&2 ($000)
HLH ($000)	$ 10,093	$ 9,786	$ 10,187	$ 10,710	$ 10,053	$ 8,967	$ 8,559	$ 7,658	$ 7,336	$ 9,403	$ 10,737	$ 9,821	$ 186,263
LLH ($000)	$ 6,348	$ 6,858	$ 7,697	$ 7,069	$ 6,276	$ 6,102	$ 5,421	$ 4,325	$ 3,165	$ 5,969	$ 6,487	$ 7,236	Demand Rev ($000)
Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
													$ 186,263

IP Rate	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
HLH (mills/kWh)	44.66	46.46	48.37	48.38	48.16	41.78	40.16	36.82	36.79	43.80	47.11	48.31
LLH (mills/kWh)	40.42	41.94	43.20	42.35	42.35	37.74	36.54	29.00	23.67	36.62	41.01	42.10
Demand ($/kW/mo)	9.47	10.01	10.58	10.58	10.51	8.61	8.12	7.12	7.11	9.21	10.20	10.56

VOR
(1.02)
Industrial Margin (mills/kWh)
0.733
Net industrial Margin
(0.289)
Settlement Charge
8.186

Revenues @ Posted IP Rate	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	Allocated Cost Energy ($000)
HLH ($000)	$ 12,262	$ 11,791	$ 12,176	$ 12,800	$ 12,025	$ 11,058	$ 10,655	$ 9,749	$ 9,342	$ 11,472	$ 12,901	$ 11,741	$ 230,019
LLH ($000)	$ 7,890	$ 8,449	$ 9,420	$ 8,690	$ 7,716	$ 7,717	$ 6,917	$ 5,944	$ 4,750	$ 7,611	$ 8,035	$ 8,907	Allocated Cost Demand ($000)
Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
													$ 230,019

	Average IP Rate ($000)	(mills/kWh)
Allocated Cost Energy	$ 230,019	41.53
Allocated Cost Demand	$ -	-
Total Allocated Costs	$ 230,019	41.53
	IP Energy (GWh)	5,539
	Industrial Margin (mills/kWh)	0.73
	VOR	(1.02)
	Settlement Charge	8.19

Table 2.5.8.4

Rate Design Step
Calculation of New Resource Rate Components
Test Period October 2015 - September 2017

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16		
15	HLH (mills/kWh)	31.59	33.39	35.30	35.31	35.09	28.71	27.09	23.75	23.72	30.73	34.04	35.24		
16	LLH (mills/kWh)	27.35	28.87	30.13	29.28	29.28	24.67	23.47	15.93	10.60	23.55	27.94	29.03		
17	Demand Rate ($/kW/mo)	9.47	10.01	10.58	10.58	10.51	8.61	8.12	7.12	7.11	9.21	10.20	10.56		
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	0.0009	0.0008	0.0008	0.0008	0.0008	0.0009	0.0008		0.0175
22	LLH (GWh)	0.0006	0.0007	0.0007	0.0007	0.0006	0.0006	0.0006	0.0007	0.0006	0.0007	0.0006	0.0006		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)	$ 0.0268	$ 0.0262	$ 0.0294	$ 0.0283	$ 0.0275	$ 0.0248	$ 0.0221	$ 0.0194	$ 0.0197	$ 0.0246	$ 0.0294	$ 0.0282		$ 0.4992
29	LLH ($000)	$ 0.0175	$ 0.0190	$ 0.0198	$ 0.0201	$ 0.0171	$ 0.0153	$ 0.0146	$ 0.0107	$ 0.0064	$ 0.0162	$ 0.0174	$ 0.0186		Demand Revenue ($000)
30	Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
31															$ 0.4992
32															NR Revenue Requirement (RR) ($000)
33															$ 1.3439
34															NR RR less Demand Revenue ($000)
35															$ 1.3439
36	NR Rates	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Market Energy Delta (mills/kWh)
37	HLH (mills/kWh)	79.74	81.54	83.45	83.46	83.24	76.86	75.24	71.90	71.87	78.88	82.19	83.39		(48.15)
38	LLH (mills/kWh)	75.50	77.02	78.28	77.43	77.43	72.82	71.62	64.08	58.75	71.70	76.09	77.18		
39	Demand ($/kW/mo)	9.47	10.01	10.58	10.58	10.51	8.61	8.12	7.12	7.11	9.21	10.20	10.56		
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)	$ 0.0676	$ 0.0639	$ 0.0694	$ 0.0668	$ 0.0653	$ 0.0664	$ 0.0614	$ 0.0587	$ 0.0598	$ 0.0631	$ 0.0710	$ 0.0667		$ 1.3439
45	LLH ($000)	$ 0.0483	$ 0.0507	$ 0.0514	$ 0.0533	$ 0.0452	$ 0.0453	$ 0.0447	$ 0.0431	$ 0.0357	$ 0.0493	$ 0.0475	$ 0.0494		Allocated Cost Demand ($000)
46	Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
47															$ 1.3439
48		Average NR Rate													
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 1.3439	76.60												
51	Allocated Cost Demand	$ -	-												
52	Total Allocated Costs	$ 1.3439	76.60												
53															
54	NR Energy (GWh)	0.0175													
55															

Rate Design Step
Calculation of Priority Firm Tier 1 Equivalent Rate Components
Test Period October 2015 - September 2017

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16		
15	HLH (mills/kWh)	31.59	33.39	35.30	35.31	35.09	28.71	27.09	23.75	23.72	30.73	34.04	35.24		
16	LLH (mills/kWh)	27.35	28.87	30.13	29.28	29.28	24.67	23.47	15.93	10.60	23.55	27.94	29.03		
17	Demand Rate ($/kW/mo)	9.47	10.01	10.58	10.58	10.51	8.61	8.12	7.12	7.11	9.21	10.20	10.56		
18															
19															**Totals**
20	Classic Billing Determinants	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Tier 1 Energy (GWh) [FAT1L]
21	HLH (GWh) [FMDT1L]	3,982	4,486	5,242	5,116	4,603	4,625	3,962	3,735	3,805	4,144	4,317	3,864		88,422
22	LLH (GWh) [FMDT1L]	2,676	3,363	3,796	3,956	3,173	3,072	2,735	2,739	2,454	3,061	2,771	2,746		Tier 1 Demand (MW/mo)
23	Demand (MW)	683	464	1,180	969	654	1,017	828	675	734	659	952	757		9,571
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)	$ 125,789	$ 149,765	$ 185,048	$ 180,676	$ 161,526	$ 132,789	$ 107,329	$ 88,711	$ 90,231	$ 127,348	$ 146,940	$ 136,148		$ 2,564,525
29	LLH ($000)	$ 73,198	$ 97,076	$ 114,362	$ 115,829	$ 92,898	$ 75,789	$ 64,188	$ 43,630	$ 26,012	$ 72,086	$ 77,431	$ 79,725		Demand Revenue ($000)
30	Demand ($000)	$ 6,466	$ 4,646	$ 12,480	$ 10,249	$ 6,875	$ 8,758	$ 6,724	$ 4,804	$ 5,219	$ 6,065	$ 9,713	$ 7,990		$ 89,988
31															$ 2,654,513
32															Tier 1 Non-Slice PF Public RR minus Tier 2 Costs
33															**$ 3,143,035**
34															Tier 1 RR less Demand Revenue ($000) [BLFRnD]
35															$ 3,053,047
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)	37.11	38.91	40.82	40.83	40.61	34.23	32.61	29.27	29.24	36.25	39.56	40.76		(5.52)
38	LLH (mills/kWh)	32.87	34.39	35.65	34.80	34.80	30.19	28.99	21.45	16.12	29.07	33.46	34.55		
39	Demand ($/kW/mo)	9.47	10.01	10.58	10.58	10.51	8.61	8.12	7.12	7.11	9.21	10.20	10.56		
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)	$ 147,770	$ 174,539	$ 213,972	$ 208,894	$ 186,928	$ 158,316	$ 129,207	$ 109,319	$ 111,250	$ 150,233	$ 170,766	$ 157,490		$ 3,052,620
45	LLH ($000)	$ 87,971	$ 115,637	$ 135,314	$ 137,665	$ 110,412	$ 92,747	$ 79,285	$ 58,749	$ 39,559	$ 88,982	$ 92,729	$ 94,885		Allocated Cost Demand ($000)
46	Demand ($000)	$ 6,466	$ 4,646	$ 12,480	$ 10,249	$ 6,875	$ 8,758	$ 6,724	$ 4,804	$ 5,219	$ 6,065	$ 9,713	$ 7,990		$ 89,988
47															$ 3,142,609
48		Average Non-Slice Tier 1 Rate													
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 3,052,620	34.52												
51	Allocated Cost Demand	$ 89,988	1.02												
52	Total Allocated Costs	$ 3,142,609	35.54												
53															
54	Tier 1 Energy (GWh) [FAT1L]		88,422												
55	Load Shaping True-up Rate (mills/kWh) [LSTUR]		(5.52)												

Table 2.5.9.1

Rate Design Study
Allocated Cost and Unit Cost Priority Firm Rates
Test Period October 2015 - September 2017

	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	1,564,095	7.495	16.91%		915,215	7.495	648,880	7.495	
19		Fish & Wildlife	671,344	3.217	7.26%		392,830	3.217	278,514	3.217	
20		Trojan	1,600	0.008	0.02%		936	0.008	664	0.008	
21		WNP #1	449,782	2.155	4.86%		263,186	2.155	186,597	2.155	
22		WNP #2	814,457	3.903	8.80%		476,572	3.903	337,886	3.903	
23		WNP #3	474,699	2.275	5.13%		277,766	2.275	196,934	2.275	
24		System Augmentation	151,373	0.725	1.64%		88,575	0.725	62,799	0.725	
25		Balancing Power Purchases	82,922	0.397	0.90%		48,521	0.397	34,401	0.397	
26		Tier 2 Costs	43,817	0.210	0.47%		25,639	0.210	18,178	0.210	
27		Total Federal Base System	4,254,090	20.386	45.98%		2,489,239	20.386	1,764,851	20.386	
28		New Resources									
29		Gross Residential Exchange	5,245,271	25.136	56.70%		3,069,219	25.136	2,176,052	25.136	
30		Conservation	282,119	1.352	3.05%		165,079	1.352	117,040	1.352	
31		BPA Programs	250,458	1.200	2.71%		146,553	1.200	103,905	1.200	
32		Power Transmission	371,742	1.781	4.02%		217,521	1.781	154,221	1.781	
33		TOTAL COSA ALLOCATIONS	10,403,679	49.856	112.46%		6,087,611	49.856	4,316,068	49.856	
34											
35											
36		Nonfirm Excess Revenue Credit	(950,782)	-4.556	-10.28%		(556,341)	-4.556	(394,441)	-4.556	
37		Low Density Discount Expense	120,462	0.577	1.30%		70,487	0.577	49,975	0.577	
38		Other Revenue Credits	(496,891)	-2.381	-5.37%		(290,751)	-2.381	(206,140)	-2.381	
39		Irrigation Rate Mitigation Expense									
40		SP Revenue Surplus/Dfct Adj.	36,964	0.177	0.40%		21,629	0.177	15,335	0.177	
41		7(c)(2) Delta Adjustment	137,647	0.660	1.49%		80,543	0.660	57,104	0.660	
42		7(c)(2) Floor Rate Adjustment									
43		TOTAL RATE DESIGN ADJUSTMENTS	(1,152,600)	-5.523	-12.46%		(674,433)	-5.523	(478,168)	-5.523	
44											
45		Total Generation	9,251,079	**44.3327**	100.00%		5,413,178	**44.33**	3,837,901	**44.33**	
46											
47											
48		REP Settlement Rate Protection Adjustment					(1,210,676)	-9.915	1,167,305	1,167,305	
49		7(b)(2) - 7(c)(2) Industrial Adjustment					50,654	0.415	1	0.000	
50		Total Generation					**4,253,157**	**34.83**	5,005,207	**57.82**	
51											
52		Total Transmission							402,553	4.650	
53									5,407,759	**62.47**	
54											

Rate Design Study
Allocated Cost and Unit Costs for Industrial Firm Power Rate
Test Period October 2015 - September 2017

	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	101,530	18.331	44.14%
28	Gross Residential Exchange	267,125	48.229	116.13%
29	Conservation	7,488	1.352	3.26%
30	BPA Programs	6,649	1.200	2.89%
31	Power Transmission	9,867	1.781	4.29%
32	TOTAL COSA ALLOCATIONS	392,659	70.894	170.70%
33				
34	Nonfirm Excess Revenue Credit	(10,460)	-1.888	-4.55%
35				
36	Other Revenue Credits	(8,238)	-1.487	-3.58%
37				
38	SP Revenue Surplus/Dfct Adj.	981	0.177	0.43%
39	7(c)(2) Delta Adjustment	(137,647)	-24.852	-59.84%
40	7(c)(2) Floor Rate Adjustment			
41	TOTAL RATE DESIGN ADJSTMTS	(155,363)	-28.050	-67.54%
42	Total Generation	237,296	42.843	103.16%
43				
55	Total Allocated & Adjusted Costs	237,296	42.843	103.16%
56				
57	Settlement Adjustments			
58	REP Settlement Rate Protection Adjustment	43,370	7.830	18.85%
59	7(b)(2) - 7(c)(2) Industrial Adjustment	(50,654)	-9.145	-22.02%
60		230,012	**41.53**	100.00%
61				
62	Billing Determinants:			
63	Energy (GwH)	5,539		

Rate Design Study
Allocated Costs and Unit Costs for New Resources Firm Power Rate
Test Period October 2015 - September 2017

	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	0.3216	18.331	23.93%
27	Gross Residential Exchange	0.8461	48.229	62.96%
28	Conservation	0.0237	1.352	1.76%
29	BPA Programs	0.0523	2.982	3.89%
30	TOTAL COSA ALLOCATIONS	1.2438	70.894	92.55%
31				
32	Nonfirm Excess Revenue Credit	(0.0331)	-1.888	-2.47%
33				
34	Other Revenue Credits	(0.0261)	-1.487	-1.94%
35				
36	SP Revenue Surplus/Dfct Adj.	0.0031	0.177	0.23%
37	7(c)(2) Delta Adjustment	0.0116	0.660	0.86%
38	7(c)(2) Floor Rate Adjustment			
39	TOTAL RATE DESIGN ADJSTMTS	(0.0445)	-2.539	-3.31%
40	Total Generation Energy	1.1992	68.355	89.24%
41				
50				
51	Total Allocated & Adjusted Costs	1.1992	68.355	89.24%
52	Settlement Adjustments			
53	REP Settlement Rate Protection Adjustment	0.1374	7.830	10.22%
54	7(b)(2) - 7(c)(2) Industrial Adjustment	0.0073	0.415	0.54%
55				
56	Total With 7(b)(2) Adjustments	1.3439	**76.60**	100.00%
57				
58	Billing Determinant / Energy (GWh)	0.01754		

Table 2.5.9.4

Rate Design Study
Resource Cost Percent Contribution to Load Pools
Test Period October 2015 - September 2017

	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	2,489,239	3,069,219		5,558,458		44.78%	55.22%		100.00%
18	Priority Firm - Exchange	1,764,851	2,176,052		3,940,903		44.78%	55.22%		100.00%
19	Priority Firm Power - Total	4,254,090	5,245,271		9,499,361		44.78%	55.22%		100.00%
20	Industrial Firm Power		267,125	101,530	368,656			72.46%	27.54%	100.00%
21	New Resources Firm		0.846	0	1			72.46%	27.54%	100.00%
22	Firm Power Products and Services		84,054	31,945	115,999			72.46%	27.54%	100.00%
23										
24										
25	**TOTALS**	**4,254,090**	**5,596,451**	**133,476**	**9,984,017**		**42.61%**	**56.05%**	**1.34%**	**100.00%**
26										
27					214,213					
28										
29				Average Cost of Resources	46.61					
30										
31				Average Cost to Serve Load Growth	43.80					

SECTION 3: RATE DESIGN

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Table Descriptions

Table 3.1
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 3.2
Tier 2 Overhead Adder Inputs
Table lists inputs to Tier 2 Overhead Cost Adder.

Table 3.3
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 3.4
Tier 1 Demand Rates
Table shows calculation of the Tier 1 Demand rate.

Table 3.5
Slice Billing Adjustment
This table is used to calculate the Slice Billing Adjustments by customer.

Table 3.6
Tier 2 Rate Revenues
Table summarizes the Tier 2 rate-related revenues and adjustments to Tier 1 cost pools.

Table 3.6(continued)
Tier 2 Rate Revenues
Table summarizes the Tier 2 rate-related revenues and adjustments to Tier 1 cost pools.

Table 3.6(continued 2)
Tier 2 Rate Revenues
Table summarizes the Tier 2 rate-related revenues and adjustments to Tier 1 cost pools.

Table 3.7
Tier 2 Rate Inputs
Table lists prices used for Tier 2 surplus credit or deficit debit.

Table 3.8
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 3.9
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 3.10
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 3.11
Tier 2 VR1-2014 Rate Costing Table
Costing table used to calculate the VR1-2014 rates for each year of the rate period.

Table 3.12
Tier 2 VR1-2016 Rate Costing Table
Costing table used to calculate the VR1-2016 rates for each year of the rate period.

Table 3.13
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 3.13(continued)
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 3.14
Total Remarketing Charges and Credits
Table summarizes the sources of power for meeting different Tier 2 loads including purchases, executed and forecast, and remarketed power from other Tier 2 cost pools, remarketed power from non-Federal resources with DFS.

Table 3.15
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 when delivering Tier 2-priced power to loads.

Table 3.16
Customers Receiving a VR1-2014 Tier 2 Remarketing Credit
List of customers with remarketed VR1-2014 purchases and their associated credits.

Table 3.17
Customers Receiving a VR1-2016 Tier 2 Remarketing Credit
List of customers with remarketed VR1-2016 purchases and their associated credits.

Table 3.18
Customers Receiving a FY16 Load Growth Billing Adjustment
List of Load Growth rate customers and their billing adjustments.

Table 3.19
Customers Receiving a FY17 Load Growth Billing Adjustment
List of Load Growth rate customers and their billing adjustments.

Table 3.20
Weighted LDD for IRD Eligible Utilities
Table shows the weighted LDD calculation for all IRD eligible utilities using the customers' contract CHWM.

Table 3.21
Rates and Charges for RSS and Related Services in FY 2016 and FY 2017
Table summarizes the RSS model forecast results for the purchasers 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 3.21(continued)
Rates and Charges for RSS and Related Services in FY 2016 and FY 2017
Table summarizes the RSS model forecast results for the purchasers 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 3.22
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 3.23
WECC and Peak Dues Charge Calculations
Table shows calculations of the WECC Dues Charge and the Peak Dues Charge.

Table 3.24
Southeast Idaho Load Service Five-Year Market Purchases
Table shows calculations for the Southeast Idaho Load Service five-year market purchases.

Table 3.25
Southeast Idaho Load Service Five-Year Market Purchases – Monthly Transfer Cost by Fiscal Year
Table shows the monthly transfer cost by fiscal year for the Southeast Idaho Load Service five-year market purchases.

Table 3.1
Summary RSS Revenue Credits for Tier 1 Cost Pools

	A	B	C	D	E	F	G	H	I	J
1	TRM	COSA	Aggregation Key	Category	2016	2017	2018	2019	2020	2021
2	C	RDS	CNTA	Augmentation RSS & RSC Adder	2,479.8	2,479.8	2,479.8	2,479.8	2,479.8	2,479.8
3	C	RDS	CD2RCF	Composite Augmentation RSS Revenue Debit/(Credit)	-1,632.7	-1,632.7	-1,632.7	-1,632.7	-1,632.7	-1,632.7
4	2	RDS	2D2RCF	Composite Tier 2 RSS Revenue Debit/(Credit)	0.0	0.0	0.0	0.0	0.0	0.0
5	C	RDS	CD2RCN	Composite Non-Federal RSS Revenue Debit/(Credit)	-1,247.8	-1,353.1	-1,353.1	-1,353.1	-1,353.1	-1,353.1
6	N	RDS	ND2RNF	Non-Slice Augmentation RSC + RSS Revenue Debit/(Credit)	-847.0	-847.0	-847.0	-847.0	-847.0	-847.0
7	2	RDS	2D2RNF	Non-Slice Tier 2 RSC + RSS Revenue Debit/(Credit)	0.0	0.0	0.0	0.0	0.0	0.0
8	N	RDS	ND2RNN	Non-Slice Non-Federal RSC + RSS Revenue Debit/(Credit)	-82.7	-81.2	-81.2	-81.2	-81.2	-81.2

Table 3.2
Tier 2 Overhead Adder Inputs

	A	B	C	D	E
1		BP-16			
2		FY2016		FY2017	
3	Line Item	FY2016	Total Forecast Sales (MWh)	FY2017	Total Forecast Sales (MWh)
4	Executive and Administrative Services	$ 4,316,887	80,219,020	$ 4,392,446	80,054,088
5	Generation Project Coordination	$ 7,735,034		$ 7,844,803	
6	Sales & Support	$ 22,524,914		$ 24,764,931	
7	Strategy, Finance & Risk Mgmt	$ 21,718,064		$ 21,630,824	
8	Agency Services G&A	$ 56,269,851		$ 57,375,865	

Table 3.3

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-15	30.80	26.77		October	31.59	27.35
4	Nov-15	32.68	28.24		November	33.39	28.87
5	Dec-15	34.44	29.28		December	35.30	30.13
6	Jan-16	34.13	27.49		January	35.31	29.28
7	Feb-16	33.38	27.96		February	35.09	29.28
8	Mar-16	27.80	23.86		March	28.71	24.67
9	Apr-16	26.17	22.55		April	27.09	23.47
10	May-16	22.42	14.62		May	23.75	15.93
11	Jun-16	21.81	7.88		June	23.72	10.60
12	Jul-16	29.28	22.50		July	30.73	23.55
13	Aug-16	32.80	27.16		August	34.04	27.94
14	Sep-16	34.38	28.43		September	35.24	29.03
15	Oct-16	32.38	27.94				
16	Nov-16	34.10	29.50				$/MWh
17	Dec-16	36.17	30.98		FY2016 Aurora Flat Annual Block		27.32
18	Jan-17	36.50	31.08		FY2017 Aurora Flat Annual Block		29.59
19	Feb-17	36.80	30.60				
20	Mar-17	29.62	25.48				
21	Apr-17	28.00	24.39				
22	May-17	25.08	17.24				
23	Jun-17	25.62	13.32				
24	Jul-17	32.18	24.59				
25	Aug-17	35.28	28.72				
26	Sep-17	36.10	29.62				

Table 3.4
Tier 1 Demand Rates

	A	B	C	D	E	F	G	H	I	J
1				Calendar Year	Chained GDP IPD		Month	Load Shaping Rate HLH $/MWh	Demand Shaping Factor	Monthly Demand Rate $/kW/mo
2	Start Year of Operation (FY)	2016		2008	99.24		Oct	31.59	8.45%	$ 9.47
3	Cost of Debt	4.52%	/1	2009	100.00		Nov	33.39	8.93%	$ 10.01
4				2010	101.21		Dec	35.30	9.44%	$ 10.58
5	Inflation Rate	1.44%		2011	103.20		Jan	35.31	9.44%	$ 10.58
6	Insurance Rate	0.25%	/2	2012	105.00		Feb	35.09	9.38%	$ 10.51
7				2013	106.59		Mar	28.71	7.68%	$ 8.61
8	Debt Finance Period (years)	30	/2				Apr	27.09	7.24%	$ 8.12
9	Plant Lifecycle (years)	30	/2		101.44%	5-year Ave.	May	23.75	6.35%	$ 7.12
10							Jun	23.72	6.34%	$ 7.11
11	Plant in service 2016 Vintaged Heat Rate Btu/kWh	8,541	/2	Chained GDP IPD from BEA --			Jul	30.73	8.22%	$ 9.21
12				Table 1.1.9. Implicit Price			Aug	34.04	9.10%	$ 10.20
13	Existing Fixed Fuel $/kW/yr with 10000 Heat Rate 2006$	$ 33.70	/2	Deflators for Gross Domestic			Sep	35.24	9.42%	$ 10.56
14	New Fixed Fuel $/kW/yr with 10000 Heat Rate 2006$	$ 46.97	/2	Product (2009 Base year)- Last				Average $/kW/mo		$ 9.34
15	Existing Fixed Fuel $/kW/yr with 10000 Heat Rate 2014$	$ 38.88		Revised June 25, 2014						
16	New Fixed Fuel $/kW/yr with 10000 Heat Rate 2014$	$ 54.19								
17	Average of Existing and New with 10000 Heat Rate 2014$	$ 46.54								
18	Average of Existing and New with 8541 Heat Rate 2014$	$ 39.75								
19										
20	All-in Nominal Capital Cost LMS100 $/kW	$1,011.00	/2	End of Fiscal Year	Midyear Assessed Value	Debt Payment	Fixed O&M	Insurance	Fixed Fuel	Cash Expense Each Year
21	Fixed O&M $/kW/yr 2016$	$ 11.32	/3	2016	$994.15	$62.21	$11.32	$ 2.49	$ 35.78	$111.80
22	Fixed Fuel adjusted for 10% capacity release credit $/kW/yr	$ 35.78		2017	$960.45	$62.21	$11.48	$ 2.40	$ 36.30	$112.39
23						Rate Period Average Expense $/kW/year				$112.10
24	/1 Source BPA FY 2014 Third-Party Tax-Exempt Borrowing Rate Forecast 30-year									
25	/2 Source NWPCC Microfin Model with 100% PUD ownership at 4.52% with plant in service 2016 and PNWE fixed fuel. Version 15.0.1									
26	/3 Source NWPCC Microfin Model assumption of $8/kW/yr in 2006$									

Table 3.5
Slice Billing Adjustment

	A	B	C	D	E	F	G	H	I	J
1			BP-12	FY2012	FY2013		BP-14	FY2014	FY2015	
2		WNP3/PGE Adjustment		$3,524,000.00	$3,524,000.00			$3,524,000.00	$3,524,000.00	
3		Sum of TOCA		0.9605186	0.964213			0.9797477	0.9851395	
4		Adjusted Amount		$3,668,851.39	$3,654,794.12			$3,596,844.37	$3,577,158.36	
5		Total Slice %	0.2685407	985,235.92	981,460.97		0.2662752	957,750.45	952,508.56	
6										
7		SLICE PERCENTAGES		Charge	Charge			Charge	Charge	Total Charge
8	Cust ID	Customer Name	Slice %	Amount	Amount		Slice %	Amount	Amount	Amount
9	10024	BENTON PUD	1.37242%	$ 50,352	50,159		1.37031%	$ 49,288	$ 49,018	$ 198,817
10	10103	CLARK PUD	2.18934%	$ 80,324	80,016		2.18597%	$ 78,626	$ 78,196	$ 317,162
11	10105	CLATSKANIE PUD	0.72773%	$ 26,699	26,597		0.72661%	$ 26,135	$ 25,992	$ 105,423
12	10123	COWLITZ	4.00153%	$ 146,810	146,248		3.99536%	$ 143,707	$ 142,920	$ 579,685
13	10157	EMERALD	0.37102%	$ 13,612	13,560		0.37045%	$ 13,325	$ 13,252	$ 53,749
14	10170	EWEB	1.79926%	$ 66,012	65,759		1.79649%	$ 64,617	$ 64,263	$ 260,651
15	10183	FRANKLIN PUD	0.78152%	$ 28,673	28,563		0.78031%	$ 28,067	$ 27,913	$ 113,216
16	10191	GRAYS HARBOR PUD	0.97145%	$ 35,641	35,504		0.96996%	$ 34,888	$ 34,697	$ 140,730
17	10204	IDAHO FALLS	0.55073%	$ 20,205	20,128		0.54988%	$ 19,778	$ 19,670	$ 79,781
18	10231	KLICKITAT PUD	0.23690%	$ 8,692	8,658		0.23654%	$ 8,508	$ 8,461	$ 34,319
19	10237	LEWIS PUD	0.96364%	$ 35,355	35,219		0.96216%	$ 34,607	$ 34,418	$ 139,599
20	10286	OKANOGAN PUD	0.36217%	$ 13,287	13,237		0.36161%	$ 13,007	$ 12,935	$ 52,466
21	10294	PACIFIC PUD	0.28252%	$ 10,365	10,326		0.28209%	$ 10,146	$ 10,091	$ 40,928
22	10306	PEND OREILLE PUD	0.18549%	$ 6,805	6,779		0.00000%	$ -	$ -	$ 13,584
23	10349	SEATTLE	3.63323%	$ 133,298	132,787		3.62763%	$ 130,480	$ 129,766	$ 526,331
24	10354	SNOHOMISH PUD	5.45427%	$ 200,109	199,342		5.44587%	$ 195,879	$ 194,807	$ 790,137
25	10370	TACOMA	2.97085%	$ 108,996	108,578		2.96628%	$ 106,692	$ 106,109	$ 430,375
26		Subtotal	26.85407%	$ 985,235	981,460		26.62752%	$ 957,750	$ 952,508	$ 3,876,953
27										$ 3,876,953

Table 3.6
Tier 2 Rate Revenues

	A	B	C
1	Hours	8,784	8,760
2	Fiscal Year	FY2016	FY2017
3	Rate Period	BP-16	
4	ShortTerm Rate $/MWh	$ 34.05	$ 36.62
5	LoadGrowth Rate $/MWh	$ 45.32	$ 49.73
6	Vintage.1 Rate $/MWh	$ 44.99	$ 49.34
7	Vintage.2 Rate $/MWh	$ 40.87	$ 43.44
8			
9	**ShortTerm**		
10	Portfolio Purchased aMW	0.000	0.000
11	Portfolio Purchased MWh	0	0
12	Portfolio Obligation /w Losses aMW	9.506	8.986
13	Portfolio Obligation /w Losses MWh	83,503	78,716
14	Portfolio Billing Determinant aMW	9.224	8.719
15	Portfolio Billing Determinant MWh	81,024	76,378
16	RECs MWh	0	0
17	Base Power Purchase Cost	$ -	$ -
18	Rate Design Components	$ 125,847	$ 122,139
19	Other Costs	$ -	$ -
20	Rate $/MWh	$ 34.05	$ 36.62
21	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (113,694)	$ (110,682)
22	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
23	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (12,154)	$ (11,457)
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	$ 2,758,854	$ 2,796,978
27	Remarketing Credit	$ -	$ -
28	Remarketing Charge	$ -	$ -
29	Forecast Power Purchase Costs	$ -	$ -

Table 3.6(continued)
Tier 2 Rate Revenues

	A	B	C
1	Hours	8,784	8,760
2	Fiscal Year	FY2016	FY2017
3	Rate Period	BP-16	
4	ShortTerm Rate $/MWh	$ 34.05	$ 36.62
5	LoadGrowth Rate $/MWh	$ 45.32	$ 49.73
6	Vintage.1 Rate $/MWh	$ 44.99	$ 49.34
7	Vintage.2 Rate $/MWh	$ 40.87	$ 43.44
8			
9	**LoadGrowth**		
10	Portfolio Purchased aMW	5.000	5.000
11	Portfolio Purchased MWh	43,920	43,800
12	Portfolio Obligation /w Losses aMW	1.080	1.152
13	Portfolio Obligation /w Losses MWh	9,487	10,093
14	Portfolio Billing Determinant aMW	1.048	1.118
15	Portfolio Billing Determinant MWh	9,206	9,794
16	RECs MWh	0	0
17	Base Power Purchase Cost	$ 1,865,282	$ 2,045,460
18	Rate Design Components	$ 14,298	$ 15,661
19	Other Costs	$ -	$ -
20	Rate $/MWh	$ 45.32	$ 49.73
21	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (12,917.51)	$ (14,192.33)
22	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
23	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (1,381)	$ (1,469)
24	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -
25	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -
26	Total LoadGrowth Rate Revenue	$ 417,199	$ 487,040
27	Remarketing Credit	$ -	$ -
28	Remarketing Charge	$ 376,693	$ 428,748
29	Forecast Power Purchase Costs	$ -	$ -
30			
31	**Vintage.1**		
32	Portfolio Purchased aMW	46.000	46.000
33	Portfolio Purchased MWh	404,064	402,960
34	Portfolio Obligation /w Losses aMW	47.408	47.408
35	Portfolio Obligation /w Losses MWh	416,428	415,291
36	Portfolio Billing Determinant aMW	46.000	46.000
37	Portfolio Billing Determinant MWh	404,064	402,960
38	RECs MWh	0	0
39	Base Power Purchase Cost	$ 17,160,598	$ 18,818,232
40	Rate Design Components	$ 627,599	$ 644,386
41	Other Costs	$ -	$ -
42	Rate $/MWh	$ 44.99	$ 49.34
43	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (566,989.76)	$ (583,941.87)
44	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
45	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (60,610)	$ (60,444)
46	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -
47	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -
48	Total Vintage.1 Rate Revenue	$ 18,178,839	$ 19,882,046
49	Remarketing Credit	$ 2,468,263	$ 2,460,798
50	Remarketing Charge	$ -	$ -
51	Forecast Power Purchase Costs	$ -	$ -

Table 3.6(continued 2)
Tier 2 Rate Revenues

	A	B	C
1	Hours	8,784	8,760
2	Fiscal Year	FY2016	FY2017
3	Rate Period	BP-16	
4	ShortTerm Rate $/MWh	$ 34.05	$ 36.62
5	LoadGrowth Rate $/MWh	$ 45.32	$ 49.73
6	Vintage.1 Rate $/MWh	$ 44.99	$ 49.34
7	Vintage.2 Rate $/MWh	$ 40.87	$ 43.44
8			
9	**Vintage.2**		
10	Portfolio Purchased aMW	9.000	16.000
11	Portfolio Purchased MWh	79,056	140,160
12	Portfolio Obligation /w Losses aMW	9.275	16.490
13	Portfolio Obligation /w Losses MWh	81,475	144,449
14	Portfolio Billing Determinant aMW	9.000	16.000
15	Portfolio Billing Determinant MWh	79,056	140,160
16	RECs MWh	0	0
17	Base Power Purchase Cost	$ 3,031,798	$ 5,718,528
18	Rate Design Components	$ 122,791	$ 224,134
19	Other Costs	$ -	$ -
20	Rate $/MWh	$ 40.87	$ 43.44
21	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (110,933)	$ (203,110)
22	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
23	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (11,858)	$ (21,024)
24	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -
25	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -
26	Total Vintage.2 Rate Revenue	$ 3,231,019	$ 6,088,550
27	Remarketing Credit	$ 830,879	$ 1,395,151
28	Remarketing Charge	$ -	$ -
29	Forecast Power Purchase Costs	$ -	$ -
30			
31	Total Tier 2 Rate Revenue Collection	$ 24,585,911	$ 29,254,615
32	Total Tier 2 Remarketing Charge	$ 376,693	$ 428,748
33	Total Tier 2 Remarketing Credit	$ (3,299,142)	$ (3,855,948)
34	Non-Federal Remarketing Credit	$ (1,284,532)	$ (746,235)
35	Total	$ 20,378,931	$ 25,081,180
36			
37	Total Tier 2 Adjustments and Credits*		
38	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (804,534)	$ (911,927)
39	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
40	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (86,002)	$ (94,394)
41	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -
42	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -

Table 3.7
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 Remarketing (MWh)	Vintage.2 Remarketing (MWh)
2	FY2016	$ 0.15	$ 27.32	$ 31.53	1,080,432	$ 31.53	40,740	78,283	26,352
3	FY2017	$ 0.15	$ 29.59	$ 33.98	2,041,080	$ 33.98	21,961	72,419	41,058

Table 3.8
Inputs to TSS Monthly Rate and Charge

	A	B	C	D	E	F
1	PTK Costs FY2016	PTK Costs FY2017	FY2013 Scheduled (MWh)	FY2014 Scheduled (MWh)	FY2013 Transactions	FY2014 Transactions
2	$4,030,732	$4,137,580	28,201,197	27,309,297	122,273	124,563

Table 3.9
Tier 2 Short-Term Rate Costing Table

	A	B	C
1		ST.2.2015_2019	ST.2.2015_2019
2	Hours	8784	8760
3	Fiscal Year	FY2016	FY2017
4	Rate Period	BP-16	
5	Total Forecast Expected Cost	$ 2,758,695	$ 2,796,896
6	Base Power Purchase Cost (Provided by PTL)	$ -	$ -
7	Power Purchase Cost	$ -	$ -
8	Transmission	$ -	$ -
9	Third Party PTP		
10	Ancillary Services		
11	Scheduling, System Control, Dispatch Services		
12	Operating Reserves (Spinning and Non-Spinning)		
13	Within Hour Balancing		
14	Other BA Losses		
15	Rate Design Components (Provided by PFR & PTM)	$ 125,847	$ 122,139
16	Resource Support Services	$ 12,154	$ 11,457
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	$ 12,154	$ 11,457
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	$ 12,154	$ 11,457
28	Resource Shaping Charge	$ -	$ -
29	Tier 2 Overhead	$ 113,694	$ 110,682
30	Risk Adder	$ -	$ -
31	Carbon Costs Passthrough	0	0
32	Renewable Energy Credits (MWh)	0	0
33	Quantity Purchased (MWh)	0	0
34	Tier 2 Obligation w/o losses (Billing Determinant)	81,024	76,378
35	Tier 2 Obligation w losses	83,503	78,716
36	Energy (Short)/Long (MWh)	-83,503	-78,716
37	Composite Cost Pool Augmentation (MWh) - BP12 Only		
38	Energy Short (MWh)	-83,503	-78,716
39	Energy to be Remarketed (MWh)	0	0
40	Remarketing Available (MWh)	179,808	169,145
41	Total Tier 2 Pool Shortfall (MWh)	-98,286	-95,335
42	Augmentation Price ($/MWh)	$ 31.53	$ 33.98
43	Flat Block RSC ($/MWh)	$ 27.32	$ 29.59
44	Remarketing value ($/MWh)	$ 31.53	$ 33.98
45	Remarketed Purchase (MWh)	83,503	78,716
46	Remarketed Purchase Cost	$ 2,632,848	$ 2,674,757
47	Remaining Shortfall (MWh)	$ -	$ -
48	Remaining Shortfall Cost	$ -	$ -
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	$ 2,758,695	$ 2,796,896
53	Billing Components		
54	ShortTerm ($/MWh)	$ 34.05	$ 36.62
55	Remarketing Credit	$ -	$ -
56	Remarketing Charge	$ -	$ -
57	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (113,694)	$ (110,682)
58	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
59	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (12,154)	$ (11,457)
60	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit) - BP12 Only		
61	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit) - BP12 Only		

Table 3.10
Tier 2 Load Growth Rate Costing Table

	A	B	C
1		LG.1.2012_2028	LG.1.2012_2028
2	Hours	8,784	8,760
3	Fiscal Year	FY2016	FY2017
4	Rate Period	BP-16	
5	Total Forecast Expected Cost	$ 1,879,581	$ 2,061,121
6	Base Power Purchase Cost (Provided by PTL)	$ 1,865,282	$ 2,045,460
7	Power Purchase Cost	$ 1,865,282	$ 2,045,460
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)	$ 14,298	$ 15,661
16	Resource Support Services	$ 1,381	$ 1,469
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	$ 1,381	$ 1,469
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	$ 1,381	$ 1,469
28	Resource Shaping Charge	$ -	$ -
29	Tier 2 Overhead	$ 12,918	$ 14,192
30	Risk Adder	$ -	$ -
31	Carbon Costs Passthrough	0	0
32	Renewable Energy Credits (MWh)	0	0
33	Quantity Purchased (MWh)	43,920	43,800
34	Tier 2 Obligation w/o losses (Billing Determinant)	9,206	9,794
35	Tier 2 Obligation w losses	9,487	10,093
36	Energy (Short)/Long (MWh)	34,433	33,707
37	Composite Cost Pool Augmentation (MWh) - BP12 Only		
38	Energy Short (MWh)	0	0
39	Energy to be Remarketed (MWh)	34,433	33,707
40	Remarketing Available (MWh)	179,808	169,145
41	Total Tier 2 Pool Shortfall (MWh)	-98,286	-95,335
42	Augmentation Price ($/MWh)	$ 31.53	$ 33.98
43	Flat Block RSC ($/MWh)	$ 27.32	$ 29.59
44	Remarketing value ($/MWh)	$ 31.53	$ 33.98
45	Remarketed Purchase (MWh)	0	0
46	Remarketed Purchase Cost	$ -	$ -
47	Remaining Shortfall (MWh)	0	0
48	Remaining Shortfall Cost	$ -	$ -
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)		
52	Total Fixed Costs	$ 1,879,581	$ 2,061,121
53	Billing Components		
54	LoadGrowth ($/MWh)	$ 45.32	$ 49.73
55	Remarketing Credit	$ -	$ -
56	Remarketing Charge	$ 376,693	$ 428,748
57			
58	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (12,917.51)	$ (14,192.33)
59	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
60	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (1,380.84)	$ (1,469.05)
61	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit) - BP12 Only		
62	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit) - BP12 Only		

Table 3.11
Tier 2 VR1-2014 Rate Costing Table

	A	B	C
1		V.1.2014_2018	V.1.2014_2018
2	Hours	8,784	8,760
3	Fiscal Year	FY2016	FY2017
4	Rate Period	BP-16	
5	Total Forecast Expected Cost	$ 18,178,046	$ 19,881,611
6	Base Power Purchase Cost (Provided by PTL)	$ 17,160,598	$ 18,818,232
7	Power Purchase Cost	$ 17,160,598	$ 18,818,232
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)	$ 627,599	$ 644,386
16	Resource Support Services	$ 60,610	$ 60,444
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	$ 60,610	$ 60,444
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	$ 60,610	$ 60,444
28	Resource Shaping Charge	$ -	$ -
29	Tier 2 Overhead	$ 566,990	$ 583,942
30	Risk Adder	$ -	$ -
31	Carbon Costs Passthrough	0	0
32	Renewable Energy Credits (MWh)	0	0
33	Quantity Purchased (MWh)	404,064	402,960
34	Tier 2 Obligation w/o losses (Billing Determinant)	404,064	402,960
35	Tier 2 Obligation w losses	416,428	415,291
36	Energy (Short)/Long (MWh)	-12,364	-12,331
37	Composite Cost Pool Augmentation (MWh) - BP12 Only		
38	Energy Short (MWh)	-12,364	-12,331
39	Energy to be Remarketed (MWh)	0	0
40	Remarketing Available (MWh)	179,808	169,145
41	Total Tier 2 Pool Shortfall (MWh)	-98,286	-95,335
42	Augmentation Price ($/MWh)	$ 31.53	$ 33.98
43	Flat Block RSC ($/MWh)	$ 27.32	$ 29.59
44	Remarketing value ($/MWh)	$ 31.53	$ 33.98
45	Remarketed Purchase (MWh)	12,364	12,331
46	Remarketed Purchase Cost	$ 389,848	$ 418,993
47	Remaining Shortfall (MWh)	0	0
48	Remaining Shortfall Cost	$ -	$ -
49	Tier 2 Balancing Adjustment Debit/(Credit) - BP12 Only		
50	Remarketing Treatment (Remove From Rate) (Yes or No)	No	No
51	Additional Remarketing (MWh)	78,283	72,419
52	Total Fixed Costs	$ 18,178,046	$ 19,881,611
53	Billing Components		
54	Vintage.1 ($/MWh)	$ 44.99	$ 49.34
55	Remarketing Credit	$ 2,468,263	$ 2,460,798
56	Remarketing Charge	$ -	$ -
57	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (566,990)	$ (583,942)
58	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
59	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (60,610)	$ (60,444)
60	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit) - BP12 Only		
61	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit) - BP12 Only		

Table 3.12
Tier 2 VR1-2016 Rate Costing Table

	A	B	C
1		V.2.2016_2019	V.2.2016_2019
2	Hours	8,784	8,760
3	Fiscal Year	FY2016	FY2017
4	Rate Period	BP-16	
5	Total Forecast Expected Cost	$ 3,230,863	$ 6,088,399
6	Base Power Purchase Cost (Provided by PTL)	$ 3,031,798	$ 5,718,528
7	Power Purchase Cost	$ 3,031,798	$ 5,718,528
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)	$ 122,791	$ 224,134
16	Resource Support Services	$ 11,858	$ 21,024
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	$ 11,858	$ 21,024
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	$ 11,858	$ 21,024
28	Resource Shaping Charge	$ -	$ -
29	Tier 2 Overhead	$ 110,933	$ 203,110
30	Risk Adder	$ -	$ -
31	Carbon Costs Passthrough	0	0
32	Renewable Energy Credits (MWh)	0	0
33	Quantity Purchased (MWh)	79,056	140,160
34	Tier 2 Obligation w/o losses (Billing Determinant)	79,056	140,160
35	Tier 2 Obligation w losses	81,475	144,449
36	Energy (Short)/Long (MWh)	-2,419	-4,289
37	Composite Cost Pool Augmentation (MWh) - BP12 Only		
38	Energy Short (MWh)	-2,419	-4,289
39	Energy to be Remarketed (MWh)	0	0
40	Remarketing Available (MWh)	179,808	169,145
41	Total Tier 2 Pool Shortfall (MWh)	-98,286	-95,335
42	Augmentation Price ($/MWh)	$ 31.53	$ 33.98
43	Flat Block RSC ($/MWh)	$ 27.32	$ 29.59
44	Remarketing value ($/MWh)	$ 31.53	$ 33.98
45	Remarketed Purchase (MWh)	2,419	4,289
46	Remarketed Purchase Cost	$ 76,275	$ 145,737
47	Remaining Shortfall (MWh)	$ -	$ -
48	Remaining Shortfall Cost	$ -	$ -
49	Tier 2 Balancing Adjustment Debit/(Credit) - BP12 Only		
50	Remarketing Treatment (Remove From Rate) (Yes or No)	No	No
51	Additional Remarketing (MWh)	26,352	41,058
52	Total Fixed Costs	$ 3,230,863	$ 6,088,399
53	Billing Components		
54	Vintage.2 ($/MWh)	$ 40.87	$ 43.44
55	Remarketing Credit	$ 830,879	$ 1,395,151
56	Remarketing Charge	$ -	$ -
57	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (110,933)	$ (203,110)
58	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
59	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (11,858)	$ (21,024)
60	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit) - BP12 Only		
61	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit) - BP12 Only		

Table 3.13

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	10/1/2015	9/30/2016	12/14/2011	Vintage T2	Validated	8784	$ 42.47	$ (17,160,598.08)	46.00	Seller's Choice
3	10/1/2015	9/30/2016	12/20/2011	Load Growth T2	Validated	8784	$ 42.47	$ (1,865,282.40)	5.00	Seller's Choice
4	10/1/2016	9/30/2017	12/14/2011	Vintage T2	Validated	8760	$ 46.70	$ (18,818,232.00)	46.00	Seller's Choice
5	10/1/2016	9/30/2017	12/20/2011	Load Growth T2	Validated	8760	$ 46.70	$ (2,045,460.00)	5.00	Seller's Choice
6	10/1/2015	9/30/2016	12/7/2012	Vintage T2	Validated	8784	$ 38.35	$ (3,031,797.60)	9.00	Seller's Choice
7	10/1/2016	9/30/2017	12/7/2012	Vintage T2	Validated	8760	$ 40.80	$ (5,718,528.00)	16.00	Seller's Choice

Table 3.13(continued)

Tier 2 Purchases Made by BPA

	A	B	C	D	E	F	G	H	I
1	product	term	Description	reference	tran_num	buy_sell	RIS	deal_num	pt_of_receipt_loc
2	FLAT	Strip	Energy	related to # 245589	245590	Buy	79576	245281	MID-C
3	FLAT	Strip	Energy	related to # 245281	245589	Buy	79572	245589	MID-C
4	FLAT	Strip	Energy	related to # 245591	415275	Buy	79576	245282	MID-C
5	FLAT	Strip	Energy	related to # 245282	245591	Buy	79572	245591	MID-C
6	FLAT	Strip	Energy	Tier 2 Vintage FY16	314963	Buy	79577	314963	MID-C
7	FLAT	Strip	Energy	Tier 2 Vintage FY17	314976	Buy	79577	314965	MID-C

Table 3.14

Total Remarketing Charges and Credits

	A	B	C
1	Rate Period	BP-16	
2	Fiscal Year	FY2016	FY2017
3	ShortTerm Remarket (MWh)	0	0
4	LoadGrowth Remarket (MWh)	34,433	33,707
5	Vintage.1 Remarket (MWh)	78,283	72,419
6	Vintage.2 Remarket (MWh)	26,352	41,058
7	Non-Federal Remarket (MWh)	40,740	21,961
8		179,808	169,145
9			
10	ShortTerm Purchase of Remarket (MWh)	83,503	78,716
11	LoadGrowth Purchase of Remarket (MWh)	0	0
12	Vintage.1 Purchase of Remarket (MWh)	12,364	12,331
13	Vintage.2 Purchase of Remarket (MWh)	2,419	4,289
14	BPA Purchase of Remarket (MWh)	81,521	73,810
15		179,808	169,145
16			
17	ShortTerm Remarket Credit	$ -	$ -
18	ShortTerm Remarket Charge	$ -	$ -
19	LoadGrowth Remarket Credit	$ -	$ -
20	LoadGrowth Remarket Charge	$ 376,693	$ 428,748
21	Vintage.1 Remarket Credit	$ 2,468,263	$ 2,460,798
22	Vintage.1 Remarket Charge	$ -	$ -
23	Vintage.2 Remarket Credit	$ 830,879	$ 1,395,151
24	Vintage.2 Remarket Charge	$ -	$ -
25	Non-Federal Resource Remarketing Credit	$ 1,284,532	$ 746,235
26			
27	ShortTerm Open Position (MWh)	0	0
28	LoadGrowth Open Position (MWh)	0	0
29	Vintage.1 Open Position (MWh)	0	0
30	Vintage.2 Open Position (MWh)	0	0
31	BPA Purchase of Remarket (MWh)	-81,521	-73,810
32	Total Open Position (MWh)	-81,521	-73,810

Table 3.15
Tier 2 Load Obligations

1	A	B	C	D	E
2	Sorting Key	Rate Pool	Fiscal Year	aMW Quantity w/o Losses	aMW Quantity w/ Losses (1)
3	LG.1.2012_2028_FY2016	LG.1.2012_2028	FY2016	1.048	1.080
4	LG.1.2012_2028_FY2017	LG.1.2012_2028	FY2017	1.118	1.152
5	ST.2.2015_2019_FY2016	ST.2.2015_2019	FY2016	9.224	9.506
6	ST.2.2015_2019_FY2017	ST.2.2015_2019	FY2017	8.719	8.986
7	V.1.2014_2018_FY2016	V.1.2014_2018	FY2016	46.000	47.408
8	V.1.2014_2018_FY2017	V.1.2014_2018	FY2017	46.000	47.408
9	V.2.2016_2019_FY2016	V.2.2016_2019	FY2016	9.000	9.275
10	V.2.2016_2019_FY2017	V.2.2016_2019	FY2017	16.000	16.490
11					
12	*Notes*				
13	(1) Based on a losses factor of 3.06%				

Table 3.16

Customers Receiving a VR1-2014 Tier 2 Remarketing Credit

	A	B	C	D	E	F	G	H	I	J	K	L
1		2016						2017				
2		Remarketing Amount	Remarketing Amount	Allocation	Remarket Credit	Remarket Credit		Remarketing Amount	Remarketing Amount	Allocation	Remarket Credit	Remarket Credit
3	Customers Remarketing VR1-2014 Purchases	aMW	MWH	Percentage	Allocation	Monthly		aMW	MWH	Percentage	Allocation	Monthly
4	Burley, City of	1.000	8,784	11.22%	$276,959	$23,079.96		1.000	8,760	12.10%	$152,871	$12,739.21
5	Ellensburg, City of	0.600	5,270	6.73%	$166,176	$13,847.97		0.321	2,812	3.88%	$49,071	$4,089.29
6	Wells Rural Electric Company	0.000	-	0.00%	$0	$0.00		0.000	-	0.00%	$0	$0.00
7	Peninsula Light Company, Inc.	1.000	8,784	11.22%	$276,959	$23,079.96		1.000	8,760	12.10%	$152,871	$12,739.21
8	Columbia Rural Electric Association, Inc.	1.093	9,601	12.26%	$302,717	$25,226.39		0.579	5,072	7.00%	$88,512	$7,376.00
9	Big Bend Elec Coop	0.893	7,844	10.02%	$247,325	$20,610.40		0.367	3,215	4.44%	$56,103	$4,675.29
10	Springfield Utility Board	0.000	-	0.00%	$0	$0.00		0.000	-	0.00%	$0	$0.00
11	Richland, City of	4.299	37,762	48.24%	$1,190,649	$99,220.74		5.000	43,800	60.48%	$764,353	$63,696.07
12	Tanner Elec Coop	0.027	237	0.30%	$7,478	$623.16		0.000	-	0.00%	$0	$0.00
13	Total	8.912	78,283	100.00%	$2,468,263	$205,689		8.267	72,419	100.00%	1,263,781	105,315

Table 3.17

Customers Receiving a VR1-2016 Tier 2 Remarketing Credit

	A	B	C	D	E	F	G	H	I	J	K	L
1		2016						2017				
2		Remarketing Amount	Remarketing Amount	Allocation	Remarket Credit	Remarket Credit		Remarketing Amount	Remarketing Amount	Allocation	Remarket Credit	Remarket Credit
3	Customers Remarketing VR1-2016 Purchases	aMW	MWH	Percentage	Allocation	Monthly		aMW	MWH	Percentage	Allocation	Monthly
4	Burley, City of	1.000	8,784	33.33%	$276,960	$23,080		1.000	8,760	21.34%	$297,664	$24,805
5	Ellensburg, City of		-	0.00%	$0	$0			-	0.00%	$0	$0
6	Wells Rural Electric Company		-	0.00%	$0	$0			-	0.00%	$0	$0
7	Peninsula Light Company, Inc.		-	0.00%	$0	$0			-	0.00%	$0	$0
8	Columbia Rural Electric Association, Inc.		-	0.00%	$0	$0			-	0.00%	$0	$0
9	Big Bend Elec Coop		-	0.00%	$0	$0			-	0.00%	$0	$0
10	Springfield Utility Board	2.000	17,568	66.67%	$553,919	$46,160		3.000	26,280	64.01%	$892,992	$74,416
11	Richland, City of		-	0.00%	$0	$0		0.687	6,018	14.66%	$204,495	$17,041
12	Tanner Elec Coop		-	0.00%	$0	$0			-	0.00%	$0	$0
13	Total	3	26,352	100.00%	$830,879	$69,240		5	41,058	100.00%	$1,395,151	$116,263

Table 3.18
Customers Receiving a FY16 Load Growth Billing Adjustment

	A	B	C	D	E	E	F	G
1			Tier 2	Load Growth	Remarketed			
2			Purchase	Usage	Amount			
3		Quantity (aMW)	5.00					
4		Quantity (MWh)	43,920	9,487	34,433			
5		Price	$ 42.47	$ 42.47	$ 42.47			
6		Cost	$ 1,865,282	$ 402,927	$ 1,462,355			
7								
8		Remarket Price			$ 32			
9		Remarket Credit			$ 1,085,662			
10		Stranded Cost			$ 376,693			
11								
12						Stranded		Premium on
13	FY 2016	Load Growth Pool Members	AHWML <1 aMW	Allocation Percentage		Cost Allocation	Monthly Allocation	Load Shaping $/MWh
14	10055	Albion, City of	0.008	0.100%		$ 378	$ 31	$ 5.37
15	10059	Alder Mutual	0	0.000%		$ -	$ -	N/A
16	10015	Asotin County PUD #1	0.023	0.288%		$ 1,086	$ 90	$ 5.37
17	10065	Bandon, City of	0	0.000%		$ -	$ -	N/A
18	10025	Benton REA	0	0.000%		$ -	$ -	N/A
19	10061	Blaine, City of	0.737	9.237%		$ 34,794	$ 2,900	$ 5.37
20	10068	Cascade Locks, City of	0	0.000%		$ -	$ -	N/A
21	10082	Chewelah, City of	0	0.000%		$ -	$ -	N/A
22	10109	Columbia Basin Elec Coop	0.614	7.695%		$ 28,987	$ 2,416	$ 5.37
23	10116	Columbia Power Coop	0	0.000%		$ -	$ -	N/A
24	10144	Consolidated Irrigation District #19	0	0.000%		$ -	$ -	N/A
25	10378	Coulee Dam, City of	0.047	0.589%		$ 2,219	$ 185	$ 5.37
26	10070	Declo, City of	0.019	0.238%		$ 897	$ 75	$ 5.37
27	10071	Drain, City of	0.043	0.539%		$ 2,030	$ 169	$ 5.37
28	10142	East End Mutual Electric	0.394	4.938%		$ 18,601	$ 1,550	$ 5.37
29	10156	Eatonville, City of	0	0.000%		$ -	$ -	N/A
30	10172	Elmhurst Mutual P & L	0	0.000%		$ -	$ -	N/A
31	10174	Farmers Elec Coop	0.013	0.163%		$ 614	$ 51	$ 5.37
32	10177	Ferry County PUD #1	0.789	9.888%		$ 37,249	$ 3,104	$ 5.37
33	10190	Grant County PUD #2	0.405	5.076%		$ 19,120	$ 1,593	$ 5.37
34	10197	Harney Elec Coop	0.557	6.981%		$ 26,296	$ 2,191	$ 5.37
35	10597	Hermiston, City of	0	0.000%		$ -	$ -	N/A
36	10202	Hood River Elec Coop	0.713	8.936%		$ 33,661	$ 2,805	$ 5.37
37	10230	Kittitas County PUD #1	0.868	10.879%		$ 40,979	$ 3,415	$ 5.37
38	10256	Lakeview L & P (WA)	0	0.000%		$ -	$ -	N/A
39	10242	Lost River Elec Coop	0.029	0.363%		$ 1,369	$ 114	$ 5.37
40	10246	Mason County PUD #1	0.322	4.036%		$ 15,202	$ 1,267	$ 5.37
41	10260	Midstate Elec Coop	0	0.000%		$ -	$ -	N/A
42	10080	Milton, Town of	0.515	6.454%		$ 24,313	$ 2,026	$ 5.37
43	10111	Minidoka, City of	0	0.000%		$ -	$ -	N/A
44	10273	Modern Elec Coop	0	0.000%		$ -	$ -	N/A
45	10083	Monmouth, City of	0.018	0.226%		$ 850	$ 71	$ 5.37
46	10005	Nespelem Valley Elec Coop	0	0.000%		$ -	$ -	N/A
47	10284	Ohop Mutual Light Company	0	0.000%		$ -	$ -	N/A
48	10288	Orcas P & L	0.097	1.216%		$ 4,579	$ 382	$ 5.37
49	10291	Oregon Trail Coop	0	0.000%		$ -	$ -	N/A
50	10304	Parkland L & W	0	0.000%		$ -	$ -	N/A
51	10086	Plummer, City of	0.054	0.677%		$ 2,549	$ 212	$ 5.37
52	10338	Riverside Elec Coop	0.153	1.918%		$ 7,223	$ 602	$ 5.37
53	10342	Salem Elec Coop	0	0.000%		$ -	$ -	N/A
54	10352	Skamania County PUD #1	0	0.000%		$ -	$ -	N/A
55	10360	Southside Elec Lines	0.567	7.106%		$ 26,768	$ 2,231	$ 5.37
56	10379	Steilacoom, Town of	0.135	1.692%		$ 6,373	$ 531	$ 5.37
57	10095	Sumas, Town of	0.078	0.978%		$ 3,682	$ 307	$ 5.37
58	10097	Troy, City of	0.152	1.905%		$ 7,176	$ 598	$ 5.37
59	10235	U.S. Airforce Base, Fairchild	0	0.000%		$ -	$ -	N/A
60	10406	U.S. DOE Albany Research Center	0.074	0.927%		$ 3,494	$ 291	$ 5.37
61	10326	U.S. Naval Base, Bremerton	0	0.000%		$ -	$ -	N/A
62	10408	U.S. Naval Station, Everett (Jim Creek)	0	0.000%		$ -	$ -	N/A
63	10409	U.S. Naval Submarine Base, Bangor	0.036	0.451%		$ 1,700	$ 142	$ 5.37
64	10482	Umpqua Indian Utility Cooperative	0	0.000%		$ -	$ -	N/A
65	10440	Wahkiakum County PUD #1	0.12	1.504%		$ 5,665	$ 472	$ 5.37
66	10442	Wasco Elec Coop	0	0.000%		$ -	$ -	N/A
67	11680	Weiser, City of	0.399	5.001%		$ 18,837	$ 1,570	$ 5.37
68		Total	7.979	100.00%		$ 376,693	$ 31,391	

Table 3.19
Customers Receiving a FY17 Load Growth Billing Adjustment

	A	B	C	D	E	E	F	G
1			Tier 2	Load Growth	Remarketed			
2			Purchase	Usage	Amount			
3		Quantity (aMW)	5.00					
4		Quantity (MWh)	43,800.00	10,093.37	33,706.6333			
5		Price	$ 47	$ 47	$ 47			
6		Cost	$ 2,045,460	$ 471,360	$ 1,574,100			
7								
8		Remarket Price			33.98			
9		Remarket Credit			1,145,351			
10		Stranded Cost			428,748			
11								
12						Stranded		Premium on
13	FY 201´	Load Growth Pool Members	AHWML <1 aMW	Allocation Percentage		Cost Allocation	Monthly Allocation	Load Shaping
14	10055	Albion, City of	0.011	0.108%		$ 465	$ 39	$ 4.81
15	10005	Alder Mutual	0	0.000%		$ -	$ -	N/A
16	10015	Asotin County PUD #1	0.029	0.286%		$ 1,225	$ 102	$ 4.81
17	10059	Bandon, City of	0.029	0.286%		$ 1,225	$ 102	$ 4.81
18	10025	Benton REA	0	0.000%		$ -	$ -	N/A
19	10061	Blaine, City of	0.867	8.545%		$ 36,638	$ 3,053	$ 4.81
20	10065	Cascade Locks, City of	0	0.000%		$ -	$ -	N/A
21	10068	Chewelah, City of	0	0.000%		$ -	$ -	N/A
22	10109	Columbia Basin Elec Coop	0.656	6.466%		$ 27,721	$ 2,310	$ 4.81
23	10111	Columbia Power Coop	0	0.000%		$ -	$ -	N/A
24	10116	Consolidated Irrigation District #19	0	0.000%		$ -	$ -	N/A
25	10378	Coulee Dam, City of	0.084	0.828%		$ 3,550	$ 296	$ 4.81
26	10070	Declo, City of	0.019	0.187%		$ 803	$ 67	$ 4.81
27	10071	Drain, City of	0.047	0.463%		$ 1,986	$ 166	$ 4.81
28	10142	East End Mutual Electric	0.446	4.396%		$ 18,847	$ 1,571	$ 4.81
29	10144	Eatonville, City of	0.003	0.030%		$ 127	$ 11	$ 4.81
30	10156	Elmhurst Mutual P & L	0.175	1.725%		$ 7,395	$ 616	$ 4.81
31	10174	Farmers Elec Coop	0.016	0.158%		$ 676	$ 56	$ 4.81
32	10177	Ferry County PUD #1	0.919	9.058%		$ 38,835	$ 3,236	$ 4.81
33	10190	Grant County PUD #2	0.474	4.672%		$ 20,030	$ 1,669	$ 4.81
34	10197	Harney Elec Coop	0.632	6.229%		$ 26,707	$ 2,226	$ 4.81
35	10597	Hermiston, City of	0	0.000%		$ -	$ -	N/A
36	10202	Hood River Elec Coop	0.887	8.742%		$ 37,483	$ 3,124	$ 4.81
37	10230	Kittitas County PUD #1	0.958	9.442%		$ 40,483	$ 3,374	$ 4.81
38	10235	Lakeview L & P (WA)	0	0.000%		$ -	$ -	N/A
39	10242	Lost River Elec Coop	0.117	1.153%		$ 4,944	$ 412	$ 4.81
40	10246	Mason County PUD #1	0.356	3.509%		$ 15,044	$ 1,254	$ 4.81
41	10256	Midstate Elec Coop	0	0.000%		$ -	$ -	N/A
42	10080	Milton, Town of	0.579	5.707%		$ 24,467	$ 2,039	$ 4.81
43	10082	Minidoka, City of	0	0.000%		$ -	$ -	N/A
44	10260	Modern Elec Coop	0	0.000%		$ -	$ -	N/A
45	10083	Monmouth, City of	0.063	0.621%		$ 2,662	$ 222	$ 4.81
46	10273	Nespelem Valley Elec Coop	0	0.000%		$ -	$ -	N/A
47	10284	Ohop Mutual Light Company	0	0.000%		$ -	$ -	N/A
48	10288	Orcas P & L	0.162	1.597%		$ 6,846	$ 570	$ 4.81
49	10291	Oregon Trail Coop	0.478	4.711%		$ 20,199	$ 1,683	$ 4.81
50	10304	Parkland L & W	0.009	0.089%		$ 380	$ 32	$ 4.81
51	10086	Plummer, City of	0.097	0.956%		$ 4,099	$ 342	$ 4.81
52	10338	Riverside Elec Coop	0.191	1.883%		$ 8,071	$ 673	$ 4.81
53	10342	Salem Elec Coop	0	0.000%		$ -	$ -	N/A
54	10352	Skamania County PUD #1	0	0.000%		$ -	$ -	N/A
55	10360	Southside Elec Lines	0.662	6.525%		$ 27,975	$ 2,331	$ 4.81
56	10379	Steilacoom, Town of	0.169	1.666%		$ 7,142	$ 595	$ 4.81
57	10095	Sumas, Town of	0.1	0.986%		$ 4,226	$ 352	$ 4.81
58	10097	Troy, City of	0.182	1.794%		$ 7,691	$ 641	$ 4.81
59	10172	U.S. Airforce Base, Fairchild	0	0.000%		$ -	$ -	N/A
60	10406	U.S. DOE Albany Research Center	0.075	0.739%		$ 3,169	$ 264	$ 4.81
61	10326	U.S. Naval Base, Bremerton	0	0.000%		$ -	$ -	N/A
62	10408	U.S. Naval Station, Everett (Jim Cree	0	0.000%		$ -	$ -	N/A
63	10409	U.S. Naval Submarine Base, Bangor	0.051	0.503%		$ 2,155	$ 180	$ 4.81
64	10482	Umpqua Indian Utility Cooperative	0	0.000%		$ -	$ -	N/A
65	10440	Wahkiakum County PUD #1	0.121	1.193%		$ 5,113	$ 426	$ 4.81
66	10442	Wasco Elec Coop	0	0.000%		$ -	$ -	N/A
67	11680	Weiser, City of	0.482	4.751%		$ 20,368	$ 1,697	$ 4.81
68		Total	10.146	100.000%		$428,748	$ 35,729	$ 4.81

Table 3.20
Weighted LDD for IRD Eligible Utilities

	A	B	C	D	E	E	F	G	H	J
1	Monthly Irrigation Rate Mitigation Amounts from Exhibit D of the Regional Dialogue Contracts (in MWh)									
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	6.50%	5,388.556
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	2.50%	144.237
23	10338	Riverside	528.123	986.578	1,167.444	906.478	566.587	4,155.210	3.50%	145.432
24	10360	Southside	2,180.245	5,429.243	5,273.390	4,387.577	2,738.885	20,009.340	4.50%	900.420
25	10343	Salmon River	1,257.157	2,671.504	2,659.622	2,533.409	1,383.969	10,505.661	5.50%	577.811
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	6.00%	13,726.346
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	5.00%	358.567
30	10502	Yakama Power	1,463.062	1,175.985	1,228.497	1,619.426	1,702.727	7,189.697	0.00%	0.000
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 3.21
Rates and Charges for RSS and Related Services in FY 2016 and FY 2017

	A	B	C	D	E	F
1	Purchaser	Resource Name	Services & RSC	Applicable Year(s)	"ResourceInput" Tab Adj. for Schedule Annual aMW	Exh. A FY2016 Annual aMW
2	Benton Rural Electric Association	Unspecified Resource Amounts	TSS TCMS	FY2016&FY2017	N/A	3.447
3	Kootenai	Unspecified Resource Amounts	TSS TCMS	FY2016&FY2017	N/A	1.000
4	Tier 1	Klondike 3	DFS TSS TCMS RSC	FY2016&FY2017	14.736	15.923
5	City of Bonners Ferry	Moyie	GMS	FY2016&FY2017	N/A	1.878
6	City of Centralia	Yelm Hydro	GMS	FY2016&FY2017	N/A	7.109
7	NO WASCO	Unspecified Resource Amounts	TSS TCMS	FY2016&FY2017	N/A	15.000
8	City of Cheney	Unspecified Resource Amounts	TSS TCMS	FY2017	N/A	0.000
9	City of Forest Grove	Priest Rapids	SCS	FY2016&FY2017	N/A	1.454
10	City of Forest Grove	Wanapum	SCS	FY2016&FY2017	N/A	1.481
11	The City of McMinnville, a municipal corporation	Priest Rapids	SCS	FY2016&FY2017	N/A	1.454
12	The City of McMinnville, a municipal corporation	Wanapum	SCS	FY2016&FY2017	N/A	1.481
13	City of Milton-Freewater	Priest Rapids	SCS	FY2016&FY2017	N/A	1.454
14	City of Milton-Freewater	Wanapum	SCS	FY2016&FY2017	N/A	1.481
15	Wells REC	Unspecified Resource Amounts	TSS TCMS	FY2017	N/A	0.000
16	Public Utility District No. 1 of Clallam County	Packwood	DFS FOR TSS TCMS RSC	FY2016&FY2017	1.126	0.673
17	Columbia REA	Walla Walla Hydro	DFS FOR RSC	FY2016&FY2017	1.478	1.231
18	Flathead Electric Cooperative, Inc.	Flathead LFGTE	DFS FOR RSC	FY2016&FY2017	1.054	1.077
19	Flathead Electric Cooperative, Inc.	Stoltze Lumber	DFS FOR RSC	FY2016&FY2017	1.916	2.499
20	Public Utility District No. 1 of Kittitas County	Priest Rapids	SCS	FY2016&FY2017	N/A	0.484
21	Public Utility District No. 1 of Kittitas County	Wanapum	SCS	FY2016&FY2017	N/A	0.494
22	Lower Valley Energy, Inc.	Horse Butte	DFS TSS RSC	FY2017	0.923	0.000
23	Public Utility District No. 3 of Mason County	Packwood	SCS TSS TCMS	FY2016&FY2017	N/A	0.656
24	Public Utility District No. 3 of Mason County	Nine Canyon Wind	DFS TSS TCMS RSC	FY2016&FY2017	0.873	0.809
25	Public Utility District No. 3 of Mason County	White Creek Wind	DFS TSS TCMS RSC	FY2016&FY2017	0.994	0.919
26	Mission Valley Power	Kerr	TSS TCMS	FY2016&FY2017	N/A	9.651
27	PNGC	Lake Creek	SCS	FY2016&FY2017	N/A	1.527
28	PNGC	Chester Hydro	DFS FOR RSC	FY2016&FY2017	0.420	0.966
29	PNGC	Island Park	SCS	FY2016&FY2017	N/A	0.989
30	PNGC	Unspecified Resource Amounts	TSS TCMS	FY2016&FY2017	N/A	21.000
31	Northern Wasco County People's Utility District	McNary Fishway	GMS	FY2016&FY2017	N/A	4.405
32	Peninsula Light Company	Harvest Wind	DFS TSS TCMS RSC	FY2016&FY2017	2.131	2.000
33	McMinnville	Riverbend Biogas	DFS FOR RSC	FY2016&FY2017	4.173	4.069

Table 3.21(continued)

Rates and Charges for RSS and Related Services in FY 2016 and FY 2017

	A	B	C	D	E	F	G	H	I	J	K	L	M	O	P	Q	R	S	T
1	Exh. A FY2017 Annual aMW	DFS Energy Rate $/MWh	DFS Capacity Charge $/mo	DFS Capacity $/MWh Equiv.	RSC $/mo	RSC $/MWh Equiv.	FOR Capacity $/mo	FOR Capacity $/MWh Equiv.	TSS $/mo	TSS $/MWh Equiv.	TCMS $/mo	TCMS $/MWh Equiv.	SCS $/mo	GMS $/mo	GMS $/MWh Equiv.	Revenue Credit to Composite Cost Pool FY2016	Revenue Credit to Non-Slice Cost Pool FY2016	Revenue Credit to Composite Cost Pool FY2017	Revenue Credit to Non-Slice Cost Pool FY2017
2	4.423	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 444	$ 0.15	$ -	$ -	$ -	$ -	$ -	$ 5,327	$ -	$ 5,327	$ -
3	1.000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 122	$ 0.17	$ -	$ -	$ -	$ -	$ -	$ 1,466	$ -	$ 1,466	$ -
4	15.945	$ 2.82	$135,059	$ 12.52	$ 40,126	$ 3.72	$ -	$ -	$ 1,005	$ 0.09	$ -	$ -	$ -	$ -	$ -	$ 1,632,738	$ 847,020	$1,632,738	$ 847,020
5	1.881	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$1,277	$ 0.93	$ 15,322	$ -	$ 15,322	$ -
6	7.114	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$5,304	$ 1.02	$ 63,654	$ -	$ 63,654	$ -
7	22.000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,041	$ 0.15	$ -	$ -	$ -	$ -	$ -	$ 24,486	$ -	$ 24,486	$ -
8	1.000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 122	$ 0.17	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,464	$ -
9	1.454	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,027	$ -	$ -	$ 12,319	$ -	$ 12,319	$ -
10	1.482	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,042	$ -	$ -	$ 12,506	$ -	$ 12,506	$ -
11	1.454	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,027	$ -	$ -	$ 12,319	$ -	$ 12,319	$ -
12	1.482	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,042	$ -	$ -	$ 12,506	$ -	$ 12,506	$ -
13	1.454	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,027	$ -	$ -	$ 12,319	$ -	$ 12,319	$ -
14	1.482	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,042	$ -	$ -	$ 12,506	$ -	$ 12,506	$ -
15	2.000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 232	$ 0.16	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,778	$ -
16	0.673	$ 0.87	$ 6,556	$ 7.97	$(10,179)	$(12.38)	$ 277.00	$ 0.34	$ 86	$ 0.10	$ -	$ -	$ -	$ -	$ -	$ 83,036	$ (113,552)	$ 83,036	$ (113,552)
17	1.231	$ 0.34	$ 5,072	$ 4.70	$ (5,078)	$ (4.71)	$ 690.00	$ 0.64	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 69,149	$ (56,507)	$ 69,149	$ (56,507)
18	1.077	$ 0.15	$ 2,025	$ 2.63	$ (328)	$ (0.43)	$ 622.00	$ 0.81	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 31,768	$ (2,523)	$ 31,768	$ (2,523)
19	2.500	$ 0.29	$ 13,274	$ 9.49	$ (1,410)	$ (1.01)	$ 294.00	$ 0.21	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 162,820	$ (11,976)	$ 162,820	$ (11,976)
20	0.484	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 342	$ -	$ -	$ 4,102	$ -	$ 4,102	$ -
21	0.494	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 347	$ -	$ -	$ 4,165	$ -	$ 4,165	$ -
22	0.832	$ 2.59	$ 8,312	$ 12.34	$ (1,867)	$ (2.77)	$ -	$ -	$ 104	$ 0.15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 100,988	$ (1,462)
23	0.656	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 76	$ 0.16	$ -	$ -	$ 472	$ -	$ -	$ 6,582	$ -	$ 6,582	$ -
24	0.809	$ 3.49	$ 7,742	$ 12.15	$ (1,523)	$ (2.39)	$ -	$ -	$ 93	$ 0.15	$ -	$ -	$ -	$ -	$ -	$ 94,018	$ 8,451	$ 94,018	$ 8,451
25	0.920	$ 3.17	$ 8,718	$ 12.01	$ (1,146)	$ (1.58)	$ -	$ -	$ 105	$ 0.14	$ -	$ -	$ -	$ -	$ -	$ 105,876	$ 13,889	$ 105,876	$ 13,889
26	9.657	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,005	$ 0.14	$ -	$ -	$ -	$ -	$ -	$ 12,030	$ -	$ 12,030	$ -
27	1.530	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,027	$ -	$ -	$ 12,324	$ -	$ 12,324	$ -
28	0.967	$ 0.44	$ 1,726	$ 5.62	$ 9,753	$ 31.77	$ 145.00	$ 0.47	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,452	$ 118,663	$ 22,452	$ 118,663
29	0.992	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 668	$ -	$ -	$ 8,020	$ -	$ 8,020	$ -
30	23.000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,425	$ 0.15	$ -	$ -	$ -	$ -	$ -	$ 29,096	$ -	$ 29,096	$ -
31	4.404	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$3,275	$ 1.02	$ 39,299	$ -	$ 39,299	$ -
32	3.000	$ 3.11	$ 19,257	$ 12.38	$ 8,389	$ 5.39	$ -	$ -	$ 287	$ 0.18	$ -	$ -	$ -	$ -	$ -	$ 234,522	$ 158,658	$ 234,522	$ 158,658
33	4.069	$ 0.20	$ 9,685	$ 3.18	$ (3,310)	$ (1.09)	$2,302.00	$ 0.76	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 143,840	$ (32,444)	$ 143,840	$ (32,444)

Table 3.22

Customers Receiving Remarketing Credits for Non-Federal Resources with DFS.

	A	B	C	D	E	E
1		2016	2016	2016	2016	2016
2		Remarketing amount aMW	Remarketing Amount	Allocation	Remarket Credit	Remarket
3	Customers Remarketing 2016 Non-Federal Resource Purchases		MWH	Percentage	Allocation	Monthly Credit
4	Flathead Electric Cooperative, Inc.	1.700	14,892	36.65%	$470,829	$39,236
5	Peninsula Light Company	1.952	17,082	42.04%	$540,068	$45,006
6	Public Utility District No. 3 of Mason County, Washington: Nine Canyon Resource	0.988	8,655	21.30%	$273,635	$22,803
7	Total	4.638	40,629	100.00%	$1,284,532	$107,044
8						
9						
10		2017	2017	2017	2017	2017
11		Remarketing amount aMW	Remarketing Amount	Allocation	Remarket Credit	Remarket
12	Customers Remarketing 2017 Non-Federal Resource Purchases		MWH	Percentage	Allocation	Monthly Credit
13	Peninsula Light Company	1.947	17,056	77.66%	$1,566	$131
14	Public Utility District No. 3 of Mason County, Washington: White Creek Resource	0.560	4,906	22.34%	$166,690	$13,891
15	Total	2.507	21,961	100.00%	$168,256	$14,021

Table 3.23
WECC and Peak Dues Charge Calculations

	A	B	C	D	E
	Balancing Authority Area (BAA)	NEL as reported by BAA (MWh)	WECC Dues Rate ($0.0424/MWh)	Peak Dues Rate ($0.056/MWh)	
1	Avista				
2	Subtotal (Losses Included)	1,851,401	$78,499	$103,678	
3	Subtotal (Losses Removed)	1,795,859			
4	Idaho Power				
5	Subtotal (Losses Included)	1,864,617	$79,060	$104,419	
6	Subtotal (Losses Removed)	1,797,491			
7	Portland General Electric				
8	Subtotal (Losses Included)	505,247	$21,422	$28,294	
9	Subtotal (Losses Removed)	497,719			
10	Puget Sound Energy				
11	Subtotal (Losses Included)	365,995	$15,518	$20,496	
12	Subtotal (Losses Removed)	356,077			
13	Northwestern				
14	Subtotal (Losses Included)	779,199	$33,038	$43,635	
15	Subtotal (Losses Removed)	748,031			
16	Nevada Energy (Sierra Pacific)				
17	Subtotal (Losses Included)	763,129	$32,357	$42,735	
18	Subtotal (Losses Removed)	732,604			
19	Grant PUD				
20	Subtotal (Losses Included)	44,719	$1,896	$2,504	
21	Subtotal (Losses Removed)	43,154			
22					
23					
24	Total (Sum Lines 1-23)	5,970,934	261,791	$345,761	
25	Total NEL of BAAs that roll ALL WECC & Peak Dues into their rates (MWh)	3,071,682	$266,189	$351,570	2016 RR
26			$270,448	$357,195	2017 RR
27			$268,318	$354,383	RRavg
28	Non-BPA BAA Transfer Service CustomerTotal NEL (Sum Lines 24-25)	9,042,616			
29	Non-BPA BAA Transfer Service Customer WECC Dues Rate* ($/MWh)	$ 0.0297			
30	Non-BPA BAA Transfer Service Customer Peak Dues Rate* ($/MWh)	$ 0.0392			

Table 3.24

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	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	Flat			114
13				
14	Winter	HLH	LLH	Flat
15	Hours	12,256	9,608	21,864
16				
17	Total Contract Hours (TCH)			43,824
18				
19	Total aMW (TCM)			103
20				
21	Market (WFM)			$42.59
22				
23	RFO (WCP)			$48.61
24				
25	Total Contract Cost (TCC)			$219,386,064
26				
27	Delta (AMD)			$6.01
28				
29	Total Transfer Service Cost (T)			$27,131,407

Table 3.25

Southeast Idaho Load Service Five-Year Market Purchases – Monthly Transfer Cost by Fiscal Year

	A	B	C	D	E	F	G
1	Month	FY 2016	FY 2017	FY 2018	FY 2019	FY 2020	FY 2021
2	October		$ 509,736	$ 509,736	$ 512,140	$ 512,140	$ 512,140
3	November		$ 493,506	$ 493,506	$ 493,506	$ 493,506	$ 491,102
4	December		$ 509,736	$ 507,331	$ 507,331	$ 507,331	$ 509,736
5	January		$ 507,331	$ 509,736	$ 509,736	$ 509,736	$ 507,331
6	February		$ 461,647	$ 461,647	$ 461,647	$ 478,478	$ 461,647
7	March		$ 511,539	$ 511,539	$ 509,135	$ 509,135	$ 511,539
8	April		$ 396,728	$ 396,728	$ 403,942	$ 403,942	$ 403,942
9	May		$ 411,155	$ 411,155	$ 411,155	$ 403,942	$ 403,942
10	June		$ 403,942	$ 403,942	$ 396,728	$ 403,942	$ 403,942
11	July	$ 403,942	$ 403,942	$ 403,942	$ 411,155	$ 411,155	
12	August	$ 418,368	$ 418,368	$ 418,368	$ 418,368	$ 411,155	
13	September	$ 396,728	$ 396,728	$ 389,515	$ 389,515	$ 396,728	
14	FY Total (Sum lines 1-12)	$ 1,219,038	$ 5,424,358	$ 5,417,145	$ 5,424,358	$ 5,441,189	$ 4,205,320
15	Total Transfer Service Cost						$ 27,131,407

SECTION 4: REVENUE FORECAST

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Table Descriptions

Table 4.1 Revenue at Current Rates
Table provides breakdown of revenue and power purchases at current rates.

Table 4.2 Revenue at Proposed Rates
Table provides breakdown of revenue and power purchases at proposed rates.

Table 4.3 Composite and Non-Slice Revenue – FY 2016-2017
Table shows calculation of CHWM revenues at proposed rates.

Table 4.4 Load Shaping and Demand Revenue – FY 2016-2017
Table shows calculation of CHWM revenues at proposed rates.

Table 4.5 Irrigation Rate Discount (IRD) – FY 2016-2017
Table shows calculation of IRD credit at proposed rates.

Table 4.6 Low Density Discount (LDD) – FY 2016-2017
Table shows calculation of LDD credit at proposed rates.

Table 4.7 Tier 2 Revenue – FY 2016-2017
Table shows calculation of CHWM revenues at proposed rates.

Table 4.8 Direct Service Industries (DSI) Revenues – FY 2016-2017
Table shows calculation of DSI revenues at current and proposed rates.

Table 4.1 - Revenue at Current Rates

	B C D E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
1	**Table 4.1 - Revenue at Current Rates**													**2015**	
2	**Category**	**201410**	**201411**	**201412**	**201501**	**201502**	**201503**	**201504**	**201505**	**201506**	**201507**	**201508**	**201509**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 191,710	$ 191,710	$ 191,710	$ 191,710	$ 191,710	$ 191,710	$ 191,710	$ 191,710	$ 191,710	$ 191,710	$ 191,710	$ 191,710	$ 2,300,518	5,063
4	Non-Slice Revenue	$ (21,451)	$ (21,451)	$ (21,451)	$ (21,451)	$ (21,451)	$ (21,451)	$ (21,451)	$ (21,451)	$ (21,451)	$ (21,451)	$ (21,451)	$ (21,451)	$ (257,411)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	1,862
6	Load Shaping Revenue	$ 822	$ (4,885)	$ 17,110	$ 17,657	$ 21,664	$ 12,426	$ 20,899	$ (28,621)	$ (16,885)	$ (15,723)	$ (3,424)	$ 1,572	$ 22,610	19
7	Demand Revenue	$ 3,704	$ 1,556	$ 6,847	$ 6,109	$ 3,212	$ 3,817	$ 3,325	$ 1,791	$ 2,364	$ 3,599	$ 3,772	$ 3,290	$ 43,388	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,900)	$ (4,335)	$ (4,992)	$ (4,097)	$ (2,492)	$ (18,816)	-
9	Low Density Discount	$ (2,862)	$ (2,574)	$ (3,274)	$ (3,226)	$ (3,316)	$ (3,033)	$ (3,381)	$ (2,273)	$ (2,555)	$ (2,745)	$ (2,958)	$ (2,903)	$ (35,099)	-
10	Tier 2	$ 2,169	$ 2,156	$ 2,169	$ 2,169	$ 1,959	$ 2,166	$ 2,099	$ 2,169	$ 2,099	$ 2,169	$ 2,169	$ 2,084	$ 25,580	75
11	RSS (Non-Federal)	$ 62	$ 64	$ 63	$ 64	$ 64	$ 64	$ 63	$ 61	$ 61	$ 62	$ 61	$ 61	$ 750	-
12	**PF customers (TRM) sub-total**	**$ 174,155**	**$ 166,576**	**$ 193,174**	**$ 193,032**	**$ 193,842**	**$ 185,699**	**$ 193,264**	**$ 140,486**	**$ 151,009**	**$ 152,629**	**$ 165,783**	**$ 171,871**	**$ 2,081,520**	**7,019**
13	**NR sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
14	**DSIs sub-total**	**$ 9,279**	**$ 9,827**	**$ 10,797**	**$ 10,396**	**$ 9,293**	**$ 8,833**	**$ 7,527**	**$ 6,376**	**$ 6,608**	**$ 8,816**	**$ 9,531**	**$ 9,261**	**$ 106,545**	**312**
15	**FPS sub-total**	**$ 229**	**$ 229**	**$ 229**	**$ 229**	**$ 229**	**$ 229**	**$ 229**	**$ 229**	**$ 229**	**$ 229**	**$ 229**	**$ 229**	**$ 2,749**	**8**
16	**Short-term market sales sub-total**	**$ 15,041**	**$ (292)**	**$ 13,382**	**$ 40,430**	**$ 38,225**	**$ 37,416**	**$ 27,548**	**$ 44,399**	**$ 45,135**	**$ 34,699**	**$ 14,898**	**$ 7,332**	**$ 318,212**	**1,153**
17	**Long Term Contractual Obligations sub-total**	**$ 30**	**$ 27,323**	**$ 754**	**$ 767**	**$ 766**	**$ 429**	**$ 416**	**$ 72**	**$ 46**	**$ 38**	**$ 31**	**$ 21**	**$ 30,692**	**108**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**114**
19	**Renewable Energy Certificates sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,107**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,107**	**-**
20	Miscellaneous Credits	$ (8)	$ (7)	$ (6)	$ (5)	$ (4)	$ (3)	$ (2)	$ (1)	$ -	$ -	$ -	$ -	$ (36)	-
21	Load Shaping True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
22	Slice True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (26,755)	$ (26,755)	-
23	**Other Sales sub-total**	**$ (8)**	**$ (7)**	**$ (6)**	**$ (5)**	**$ (4)**	**$ (3)**	**$ (2)**	**$ (1)**	**$ -**	**$ -**	**$ -**	**$ (26,755)**	**$ (26,791)**	**-**
24	**Gross Sales**	**$198,726**	**$203,656**	**$218,330**	**$244,849**	**$242,351**	**$233,710**	**$228,984**	**$191,560**	**$203,026**	**$196,411**	**$190,472**	**$161,958**	**$2,514,035**	**8,716**
25	GTA Delivery charge	$ 145	$ 165	$ 205	$ 170	$ 205	$ 165	$ 135	$ 140	$ 140	$ 165	$ 150	$ 145	$ 1,930	-
26	Energy Efficiency Revenues	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 13,000	-
27	Irrigation Pumping Power	$ 235	$ 233	$ 140	$ 58	$ 8	$ 3	$ 3	$ 3	$ 4	$ 37	$ 111	$ 155	$ 991	15
28	Reserve Energy	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 8,327	162
29	Downstream Benefits	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 6,700	-
30	Upper Baker Revenues	$ -	$ 110	$ 115	$ 110	$ 111	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 446	1
31	**Miscellaneous Revenues**	**$2,715**	**$2,844**	**$2,796**	**$2,673**	**$2,660**	**$2,503**	**$2,474**	**$2,478**	**$2,480**	**$2,538**	**$2,597**	**$2,636**	**$31,394**	**178**
32	Regulating Reserve	$ 505	$ 505	$ 505	$ 505	$ 505	$ 505	$ 505	$ 505	$ 505	$ 505	$ 505	$ 505	$ 6,058	-
33	Variable Energy Resource Balancing Service Reserve - Wind	$ 4,874	$ 4,874	$ 5,194	$ 5,194	$ 5,194	$ 5,194	$ 5,194	$ 5,194	$ 5,194	$ 5,194	$ 5,194	$ 5,194	$ 61,688	-
34	VERBS for Solar	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 15	-
35	Dispatchable Energy Resource Balancing Service Reserve inc	$ 133	$ 133	$ 133	$ 133	$ 133	$ 133	$ 125	$ 125	$ 125	$ 125	$ 125	$ 125	$ 1,548	-
36	Dispatchable Energy Resource Balancing Service Reserve dec	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 202	-
37	Settlement Annual Budget Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
38	Rounding Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
39	Adjustment for Settlement for Supplying Only 900 MW dec Balancing Reserve Capacity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
40	Expected Balancing Reserve Capacity Sales in Spring from FCRPS Above Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
41	Operating Reserve - Spinning	$ 1,713	$ 1,809	$ 2,093	$ 2,125	$ 1,890	$ 2,227	$ 2,119	$ 2,157	$ 2,322	$ 2,117	$ 1,988	$ 1,673	$ 24,233	-
42	Operating Reserve - Supplemental	$ 1,569	$ 1,657	$ 1,917	$ 1,947	$ 1,732	$ 2,040	$ 1,941	$ 1,977	$ 2,128	$ 1,940	$ 1,821	$ 1,533	$ 22,202	-
43	Synchronous Condensing	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 1,569	-
44	Generation Dropping	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 333	-
45	Energy Imbalance	$ 45	$ 87	$ (85)	$ 55	$ (46)	$ (40)	$ 157	$ 63	$ 200	$ 242	$ 215	$ 64	$ 957	-
46	Generation Imbalance	$ 582	$ 520	$ 313	$ 194	$ 304	$ 117	$ 90	$ 211	$ 406	$ 774	$ 1,034	$ 173	$ 4,718	-
47	Redispatch	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 400	9
48	COE/Reclamation Network/Delivery Facilities Segmentation	$ 625	$ 625	$ 625	$ 625	$ 625	$ 625	$ 625	$ 625	$ 625	$ 625	$ 625	$ 625	$ 7,500	-
49	Station Service	$ 199	$ 199	$ 199	$ 199	$ 199	$ 199	$ 199	$ 199	$ 199	$ 199	$ 199	$ 199	$ 2,385	-
50	Operating Reserve - Energy	$ 115	$ 76	$ 31	$ 76	$ 138	$ 122	$ 101	$ 97	$ 92	$ 37	$ 61	$ 13	$ 959	-
51	**Generation Inputs / Inter-business line**	**$ 10,569**	**$ 10,694**	**$ 11,134**	**$ 11,262**	**$ 10,883**	**$ 11,332**	**$ 11,266**	**$ 11,363**	**$ 12,006**	**$ 11,967**	**$ 11,977**	**$ 10,314**	**$ 134,767**	**9**
52	4(h)(10)(c)	$ 11,819	$ 9,865	$ 8,657	$ 7,280	$ 6,708	$ 7,035	$ 7,010	$ 6,876	$ 7,514	$ 6,432	$ 5,585	$ 8,896	$ 93,677	-
53	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
54	**Treasury Credits**	**$ 12,202**	**$ 10,248**	**$ 9,040**	**$ 7,664**	**$ 7,091**	**$ 7,418**	**$ 7,394**	**$ 7,259**	**$ 7,898**	**$ 6,815**	**$ 5,968**	**$ 9,279**	**$ 98,277**	**-**
55	**Augmentation Power Purchase total**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
56	**Balancing Power Purchase sub-total**	$ 6,731	$ 7,309	$ 5,128	$ 3,995	$ 2,703	$ 1,639	$ 2,620	$ 410	$ 2,073	$ 3,321	$ 6,135	$ 4,448	$ 46,511	282
57	**Other Power Purchase total**	**$ 2,094**	**$ 2,029**	**$ 2,094**	**$ 2,094**	**$ 1,891**	**$ 2,091**	**$ 2,027**	**$ 2,094**	**$ 2,027**	**$ 2,094**	**$ 2,094**	**$ 2,027**	**$ 24,656**	**141**
58	**Power Purchases**	**$ 8,825**	**$ 9,338**	**$ 7,222**	**$ 6,089**	**$ 4,595**	**$ 3,730**	**$ 4,646**	**$ 2,504**	**$ 4,099**	**$ 5,415**	**$ 8,229**	**$ 6,475**	**$ 71,167**	**423**
59															
60															

Table 4.1 - Revenue at Current Rates

	B C D E	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG
1	**Table 4.1 - Revenue at Current Rates**													**2016**	
2	**Category**	**201510**	**201511**	**201512**	**201601**	**201602**	**201603**	**201604**	**201605**	**201606**	**201607**	**201608**	**201609**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 193,072	$ 193,072	$ 193,072	$ 193,072	$ 193,072	$ 193,072	$ 193,072	$ 193,072	$ 193,072	$ 193,072	$ 193,072	$ 193,072	$ 2,316,860	6,894
4	Non-Slice Revenue	$ (21,663)	$ (21,663)	$ (21,663)	$ (21,663)	$ (21,663)	$ (21,663)	$ (21,663)	$ (21,663)	$ (21,663)	$ (21,663)	$ (21,663)	$ (21,663)	$ (259,956)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	1,877
6	Load Shaping Revenue	$ (3,650)	$ (8,324)	$ 16,835	$ 34,582	$ 24,748	$ 4,584	$ 6,449	$ (30,635)	$ (16,298)	$ (763)	$ (8,014)	$ 3,967	$ 23,480	(0)
7	Demand Revenue	$ 3,410	$ 2,112	$ 6,753	$ 5,384	$ 3,936	$ 4,511	$ 3,384	$ 1,852	$ 2,451	$ 2,944	$ 4,724	$ 3,726	$ 45,187	-
8	Irrigation Rate Discount	$ (1,654)	$ (1,654)	$ (1,654)	$ (1,654)	$ (1,654)	$ (1,654)	$ (1,654)	$ (1,654)	$ (1,654)	$ (1,654)	$ (1,654)	$ (1,654)	$ (19,851)	-
9	Low Density Discount	$ (3,090)	$ (3,090)	$ (3,090)	$ (3,090)	$ (3,090)	$ (3,090)	$ (3,090)	$ (3,090)	$ (3,090)	$ (3,090)	$ (3,090)	$ (3,090)	$ (37,078)	-
10	Tier 2	$ 2,014	$ 2,014	$ 2,014	$ 2,014	$ 2,014	$ 2,014	$ 2,014	$ 2,014	$ 2,014	$ 2,014	$ 2,014	$ 2,014	$ 24,164	68
11	RSS (Non-Federal)	$ 111	$ 111	$ 111	$ 111	$ 111	$ 111	$ 111	$ 111	$ 111	$ 111	$ 111	$ 111	$ 1,337	-
12	**PF customers (TRM) sub-total**	**$ 168,550**	**$ 162,577**	**$ 192,377**	**$ 208,756**	**$ 197,474**	**$ 177,884**	**$ 178,622**	**$ 140,007**	**$ 154,942**	**$ 170,971**	**$ 165,500**	**$ 176,483**	**$ 2,094,145**	**8,839**
13	**NR sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
14	**DSIs sub-total**	**$ 9,393**	**$ 9,968**	**$ 10,895**	**$ 10,526**	**$ 9,749**	**$ 8,943**	**$ 7,624**	**$ 6,500**	**$ 6,651**	**$ 8,918**	**$ 9,683**	**$ 9,343**	**$ 108,194**	**317**
15	**FPS sub-total**	**$ 228**	**$ 233**	**$ 253**	**$ 248**	**$ 238**	**$ 233**	**$ 228**	**$ 233**	**$ 238**	**$ 248**	**$ 233**	**$ 228**	**$ 2,842**	**8**
16	**Short-term market sales sub-total**	**$ 9,586**	**$ 14,401**	**$ 9,324**	**$ 33,544**	**$ 26,194**	**$ 31,884**	**$ 36,808**	**$ 55,321**	**$ 46,015**	**$ 45,830**	**$ 22,451**	**$ 6,404**	**$ 337,762**	**1,732**
17	**Long Term Contractual Obligations sub-total**	**$ 38**	**$ 7,610**	**$ 7,828**	**$ 7,837**	**$ 7,138**	**$ 3,908**	**$ 3,810**	**$ 61**	**$ 77**	**$ 64**	**$ 72**	**$ 46**	**$ 38,490**	**89**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**119**
19	**Renewable Energy Certificates sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,151**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,151**	**-**
20	Miscellaneous Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
21	Load Shaping True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
22	Slice True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
23	**Other Sales sub-total**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 3,877**	**-**
24	**Gross Sales**	**$188,119**	**$195,112**	**$221,001**	**$261,235**	**$241,116**	**$224,326**	**$227,416**	**$202,446**	**$208,246**	**$226,355**	**$198,261**	**$192,827**	**$2,586,459**	**11,104**
25	GTA Delivery charge	$ 360	$ 405	$ 510	$ 450	$ 455	$ 410	$ 345	$ 370	$ 390	$ 435	$ 400	$ 335	$ 4,865	-
26	Energy Efficiency Revenues	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 15,000	-
27	Irrigation Pumping Power	$ 134	$ 208	$ 252	$ 331	$ 330	$ 237	$ 155	$ 105	$ 99	$ 100	$ 99	$ 101	$ 2,149	18
28	Reserve Energy	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 8,327	161
29	Downstream Benefits	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 6,700	-
30	Upper Baker Revenues	$ -	$ 103	$ 117	$ 114	$ 117	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 457	1
31	**Miscellaneous Revenues**	**$2,996**	**$3,218**	**$3,381**	**$3,398**	**$3,404**	**$3,149**	**$3,002**	**$2,977**	**$2,992**	**$3,037**	**$3,001**	**$2,938**	**$37,498**	**180**
32	Regulating Reserve	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 6,224	-
33	Variable Energy Resource Balancing Service Reserve - Wind	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 57,250	-
34	VERBS for Solar	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 86	-
35	Dispatchable Energy Resource Balancing Service Reserve inc	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 2,059	-
36	Dispatchable Energy Resource Balancing Service Reserve dec	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 391	-
37	Settlement Annual Budget Adjustment	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (15,200)	-
38	Rounding Adjustment	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 26	-
39	Adjustment for Settlement for Supplying Only 900 MW dec Balancing Reserve Capacity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
40	Expected Balancing Reserve Capacity Sales in Spring from FCRPS Above Planned	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 4,000	-
41	Operating Reserve - Spinning	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 25,470	-
42	Operating Reserve - Supplemental	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 23,348	-
43	Synchronous Condensing	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 1,610	-
44	Generation Dropping	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 415	-
45	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	Redispatch	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 225	9
48	COE/Reclamation Network/Delivery Facilities Segmentation	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 7,367	-
49	Station Service	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 2,479	-
50	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
51	**Generation Inputs / Inter-business line**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 115,750**	**9**
52	4(h)(10)(c)	$ 8,688	$ 6,443	$ 9,961	$ 11,625	$ 9,482	$ 7,674	$ 6,896	$ 6,374	$ 6,932	$ 6,023	$ 5,776	$ 9,204	$ 95,077	-
53	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
54	**Treasury Credits**	**$ 9,071**	**$ 6,826**	**$ 10,345**	**$ 12,009**	**$ 9,866**	**$ 8,058**	**$ 7,279**	**$ 6,758**	**$ 7,315**	**$ 6,406**	**$ 6,159**	**$ 9,587**	**$ 99,677**	**-**
55	**Augmentation Power Purchase total**	$ 4,569	$ 4,569	$ 4,569	$ 4,569	$ 4,569	$ 4,569	$ 4,569	$ 4,569	$ 4,569	$ 4,569	$ 4,569	$ 4,569	$ 54,828	198
56	**Balancing Power Purchase sub-total**	$ 1,976	$ 2,164	$ 4,711	$ 4,487	$ 2,228	$ 176	$ 45	$ 19	$ 19	$ 300	$ 846	$ 3,923	$ 20,893	133
57	**Other Power Purchase total**	**$ 1,693**	**$ 1,693**	**$ 1,693**	**$ 1,693**	**$ 1,693**	**$ 1,693**	**$ 1,693**	**$ 1,693**	**$ 1,693**	**$ 4,578**	**$ 4,683**	**$ 4,527**	**$ 29,022**	**60**
58	**Power Purchases**	**$ 8,237**	**$ 8,425**	**$ 10,972**	**$ 10,749**	**$ 8,490**	**$ 6,437**	**$ 6,307**	**$ 6,280**	**$ 6,280**	**$ 9,448**	**$ 10,098**	**$ 13,020**	**$ 104,743**	**391**
59															
60															

Table 4.1 - Revenue at Current Rates

	B C D E	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT	AU
1	**Table 4.1 - Revenue at Current Rates**													**2017**	
2	**Category**	**201610**	**201611**	**201612**	**201701**	**201702**	**201703**	**201704**	**201705**	**201706**	**201707**	**201708**	**201709**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 193,580	$ 193,580	$ 193,580	$ 193,580	$ 193,580	$ 193,580	$ 193,580	$ 193,580	$ 193,580	$ 193,580	$ 193,580	$ 193,580	$ 2,322,964	6,893
4	Non-Slice Revenue	$ (21,741)	$ (21,741)	$ (21,741)	$ (21,741)	$ (21,741)	$ (21,741)	$ (21,741)	$ (21,741)	$ (21,741)	$ (21,741)	$ (21,741)	$ (21,741)	$ (260,894)	-
5	Slice	$ -	$ 1	$ 2	$ 3	$ 4	$ 5	$ 6	$ 7	$ 8	$ 9	$ 10	$ 11	$ 66	1,843
6	Load Shaping Revenue	$ (3,292)	$ (7,432)	$ 17,682	$ 35,341	$ 28,566	$ 5,087	$ 6,574	$ (30,275)	$ (16,296)	$ (580)	$ (7,676)	$ 4,382	$ 32,080	30
7	Demand Revenue	$ 2,960	$ 2,761	$ 6,777	$ 5,437	$ 3,193	$ 4,573	$ 2,918	$ 2,331	$ 2,482	$ 2,989	$ 4,827	$ 3,795	$ 45,043	-
8	Irrigation Rate Discount	$ (1,654)	$ (1,654)	$ (1,654)	$ (1,654)	$ (1,654)	$ (1,654)	$ (1,654)	$ (1,654)	$ (1,654)	$ (1,654)	$ (1,654)	$ (1,654)	$ (19,851)	-
9	Low Density Discount	$ (3,151)	$ (3,151)	$ (3,151)	$ (3,151)	$ (3,151)	$ (3,151)	$ (3,151)	$ (3,151)	$ (3,151)	$ (3,151)	$ (3,151)	$ (3,151)	$ (37,810)	-
10	Tier 2	$ 2,595	$ 2,595	$ 2,595	$ 2,595	$ 2,595	$ 2,595	$ 2,595	$ 2,595	$ 2,595	$ 2,595	$ 2,595	$ 2,595	$ 31,139	80
11	RSS (Non-Federal)	$ 120	$ 120	$ 120	$ 120	$ 120	$ 120	$ 120	$ 120	$ 120	$ 120	$ 120	$ 120	$ 1,440	-
12	**PF customers (TRM) sub-total**	**$ 169,418**	**$ 165,079**	**$ 194,210**	**$ 210,529**	**$ 201,512**	**$ 179,414**	**$ 179,246**	**$ 141,812**	**$ 155,943**	**$ 172,166**	**$ 166,910**	**$ 177,937**	**$ 2,114,177**	**8,846**
13	**NR sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
14	**DSIs sub-total**	**$ 9,393**	**$ 9,968**	**$ 10,895**	**$ 10,526**	**$ 9,412**	**$ 8,943**	**$ 7,624**	**$ 6,500**	**$ 6,651**	**$ 8,918**	**$ 9,683**	**$ 9,343**	**$ 107,858**	**316**
15	**FPS sub-total**	**$ 187**	**$ 192**	**$ 217**	**$ 207**	**$ 202**	**$ 197**	**$ 187**	**$ 192**	**$ 197**	**$ 207**	**$ 197**	**$ 187**	**$ 2,363**	**9**
16	**Short-term market sales sub-total**	**$ 11,785**	**$ 15,550**	**$ 12,028**	**$ 37,409**	**$ 28,332**	**$ 39,682**	**$ 42,774**	**$ 56,666**	**$ 46,962**	**$ 52,320**	**$ 26,102**	**$ 7,567**	**$ 377,178**	**1,732**
17	**Long Term Contractual Obligations sub-total**	**$ 38**	**$ 7,610**	**$ 7,828**	**$ 7,837**	**$ 7,138**	**$ 3,908**	**$ 3,810**	**$ 61**	**$ 77**	**$ 64**	**$ 72**	**$ 46**	**$ 38,489**	**90**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**118**
19	**Renewable Energy Certificates sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 648**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 648**	**-**
20	Miscellaneous Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
21	Load Shaping True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
22	Slice True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
23	**Other Sales sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
24	**Gross Sales**	**$190,821**	**$198,398**	**$225,177**	**$266,508**	**$246,596**	**$232,792**	**$233,642**	**$205,230**	**$209,828**	**$233,676**	**$202,964**	**$195,080**	**$2,640,712**	**11,110**
25	GTA Delivery charge	$ 360	$ 410	$ 510	$ 460	$ 460	$ 410	$ 350	$ 370	$ 390	$ 440	$ 400	$ 335	$ 4,895	-
26	Energy Efficiency Revenues	$ 583	$ 583	$ 583	$ 583	$ 583	$ 583	$ 583	$ 583	$ 583	$ 583	$ 583	$ 583	$ 7,000	-
27	Irrigation Pumping Power	$ 134	$ 208	$ 252	$ 331	$ 330	$ 237	$ 155	$ 105	$ 99	$ 100	$ 99	$ 101	$ 2,149	18
28	Reserve Energy	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 8,327	162
29	Downstream Benefits	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 6,700	-
30	Upper Baker Revenues	$ -	$ 116	$ 121	$ 116	$ 119	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 466	1
31	**Miscellaneous Revenues**	**$1,970**	**$2,160**	**$2,208**	**$2,283**	**$2,284**	**$2,072**	**$1,990**	**$1,940**	**$1,935**	**$1,935**	**$1,935**	**$1,936**	**$29,537**	**181**
32	Regulating Reserve	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 6,224	-
33	Variable Energy Resource Balancing Service Reserve - Wind	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 57,250	-
34	VERBS for Solar	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 86	-
35	Dispatchable Energy Resource Balancing Service Reserve inc	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 2,059	-
36	Dispatchable Energy Resource Balancing Service Reserve dec	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 391	-
37	Settlement Annual Budget Adjustment	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (15,200)	-
38	Rounding Adjustment	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 26	-
39	Adjustment for Settlement for Supplying Only 900 MW dec Balancing Reserve Capacity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
40	Expected Balancing Reserve Capacity Sales in Spring from FCRPS Above Planned	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 4,000	-
41	Operating Reserve - Spinning	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 25,470	-
42	Operating Reserve - Supplemental	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 23,348	-
43	Synchronous Condensing	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 1,610	-
44	Generation Dropping	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 415	-
45	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	Redispatch	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 225	9
48	COE/Reclamation Network/Delivery Facilities Segmentation	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 7,367	-
49	Station Service	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 2,479	-
50	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
51	**Generation Inputs / Inter-business line**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 115,750**	**9**
52	4(h)(10)(c)	$ 8,480	$ 6,183	$ 9,779	$ 11,593	$ 9,271	$ 7,163	$ 6,549	$ 6,025	$ 6,839	$ 5,698	$ 5,435	$ 9,099	$ 92,112	-
53	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
54	**Treasury Credits**	**$ 8,863**	**$ 6,566**	**$ 10,162**	**$ 11,977**	**$ 9,654**	**$ 7,546**	**$ 6,932**	**$ 6,408**	**$ 7,222**	**$ 6,081**	**$ 5,818**	**$ 9,482**	**$ 96,712**	**-**
55	**Augmentation Power Purchase total**	$ 7,885	$ 7,885	$ 7,885	$ 7,885	$ 7,885	$ 7,885	$ 7,885	$ 7,885	$ 7,885	$ 7,885	$ 7,885	$ 7,885	$ 94,619	318
56	**Balancing Power Purchase sub-total**	$ 1,554	$ 919	$ 3,356	$ 1,870	$ 2,036	$ 110	$ 44	$ 19	$ 19	$ 519	$ 1,254	$ 3,180	$ 14,880	105
57	**Other Power Purchase total**	**$ 5,388**	**$ 5,274**	**$ 5,388**	**$ 5,371**	**$ 5,050**	**$ 5,401**	**$ 4,636**	**$ 4,739**	**$ 4,688**	**$ 4,687**	**$ 4,792**	**$ 4,636**	**$ 60,048**	**67**
58	**Power Purchases**	**$ 14,826**	**$ 14,078**	**$ 16,629**	**$ 15,126**	**$ 14,970**	**$ 13,396**	**$ 12,564**	**$ 12,643**	**$ 12,592**	**$ 13,091**	**$ 13,930**	**$ 15,701**	**$ 169,547**	**490**
59															
60															

Table 4.2 - Revenue at Proposed Rates

	B C D E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
1	**Table 4.2 - Revenue at Proposed Rates**													**2015**	
2	**Category**	**201410**	**201411**	**201412**	**201501**	**201502**	**201503**	**201504**	**201505**	**201506**	**201507**	**201508**	**201509**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 191,710	$ 191,710	$ 191,710	$ 191,710	$ 191,710	$ 191,710	$ 191,710	$ 191,710	$ 191,710	$ 191,710	$ 191,710	$ 191,710	$ 2,300,518	5,063
4	Non-Slice Revenue	$ (21,451)	$ (21,451)	$ (21,451)	$ (21,451)	$ (21,451)	$ (21,451)	$ (21,451)	$ (21,451)	$ (21,451)	$ (21,451)	$ (21,451)	$ (21,451)	$ (257,411)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	1,862
6	Load Shaping Revenue	$ 822	$ (4,885)	$ 17,110	$ 17,657	$ 21,664	$ 12,426	$ 20,899	$ (28,621)	$ (16,885)	$ (15,723)	$ (3,424)	$ 1,572	$ 22,610	19
7	Demand Revenue	$ 3,704	$ 1,556	$ 6,847	$ 6,109	$ 3,212	$ 3,817	$ 3,325	$ 1,791	$ 2,364	$ 3,599	$ 3,772	$ 3,290	$ 43,388	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,900)	$ (4,335)	$ (4,992)	$ (4,097)	$ (2,492)	$ (18,816)	-
9	Low Density Discount	$ (2,862)	$ (2,574)	$ (3,274)	$ (3,226)	$ (3,316)	$ (3,033)	$ (3,381)	$ (2,273)	$ (2,555)	$ (2,745)	$ (2,958)	$ (2,903)	$ (35,099)	-
10	Tier 2	$ 2,169	$ 2,156	$ 2,169	$ 2,169	$ 1,959	$ 2,166	$ 2,099	$ 2,169	$ 2,099	$ 2,169	$ 2,169	$ 2,084	$ 25,580	75
11	RSS (Non-Federal)	$ 62	$ 64	$ 63	$ 64	$ 64	$ 64	$ 63	$ 61	$ 61	$ 62	$ 61	$ 61	$ 750	-
12	**PF customers (CHWM) sub-total**	**$ 174,155**	**$ 166,576**	**$ 193,174**	**$ 193,032**	**$ 193,842**	**$ 185,699**	**$ 193,264**	**$ 140,486**	**$ 151,009**	**$ 152,629**	**$ 165,783**	**$ 171,871**	**$ 2,081,520**	**7,019**
13	**NR sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
14	**DSIs sub-total**	**$ 9,279**	**$ 9,827**	**$ 10,797**	**$ 10,396**	**$ 9,293**	**$ 8,833**	**$ 7,527**	**$ 6,376**	**$ 6,608**	**$ 8,816**	**$ 9,531**	**$ 9,261**	**$ 106,545**	**312**
15	**FPS sub-total**	**$ 229**	**$ 229**	**$ 229**	**$ 229**	**$ 229**	**$ 229**	**$ 229**	**$ 229**	**$ 229**	**$ 229**	**$ 229**	**$ 229**	**$ 2,749**	**8**
16	**Short-term market sales sub-total**	**$ 15,041**	**$ (292)**	**$ 13,382**	**$ 40,430**	**$ 38,225**	**$ 37,416**	**$ 27,548**	**$ 44,399**	**$ 45,135**	**$ 34,699**	**$ 14,898**	**$ 7,332**	**$ 318,212**	**1,153**
17	**Long Term Contractual Obligations sub-total**	**$ 30**	**$ 27,323**	**$ 754**	**$ 767**	**$ 766**	**$ 429**	**$ 416**	**$ 72**	**$ 46**	**$ 38**	**$ 31**	**$ 21**	**$ 30,692**	**108**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**114**
19	**Renewable Energy Certificates sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,107**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,107**	**-**
20	Miscellaneous Credits	$ (8)	$ (7)	$ (6)	$ (5)	$ (4)	$ (3)	$ (2)	$ (1)	$ -	$ -	$ -	$ -	$ (36)	-
21	Load Shaping True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
22	Slice True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (26,755)	$ (26,755)	-
23	**Other Sales sub-total**	**$ (8)**	**$ (7)**	**$ (6)**	**$ (5)**	**$ (4)**	**$ (3)**	**$ (2)**	**$ (1)**	**$ -**	**$ -**	**$ -**	**$ (26,755)**	**$ (26,791)**	**-**
24	**Gross Sales**	**$198,726**	**$203,656**	**$218,330**	**$244,849**	**$242,351**	**$233,710**	**$228,984**	**$191,560**	**$203,026**	**$196,411**	**$190,472**	**$161,958**	**$2,514,035**	**8,716**
25	GTA Delivery charge	$ 145	$ 165	$ 205	$ 170	$ 205	$ 165	$ 135	$ 140	$ 140	$ 165	$ 150	$ 145	$ 1,930	-
26	Energy Efficiency Revenues	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 1,083	$ 13,000	-
27	Irrigation Pumping Power	$ 235	$ 233	$ 140	$ 58	$ 8	$ 3	$ 3	$ 3	$ 4	$ 37	$ 111	$ 155	$ 991	15
28	Reserve Energy	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 8,327	162
29	Downstream Benefits	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 6,700	-
30	Upper Baker Revenues	$ -	$ 110	$ 115	$ 110	$ 111	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 446	1
31	**Miscellaneous Revenues**	**$2,715**	**$2,844**	**$2,796**	**$2,673**	**$2,660**	**$2,503**	**$2,474**	**$2,478**	**$2,480**	**$2,538**	**$2,597**	**$2,636**	**$31,394**	**178**
32	Regulating Reserve	$ 505	$ 505	$ 505	$ 505	$ 505	$ 505	$ 505	$ 505	$ 505	$ 505	$ 505	$ 505	$ 6,058	-
33	Variable Energy Resource Balancing Service Reserve - Wind	$ 4,874	$ 4,874	$ 5,194	$ 5,194	$ 5,194	$ 5,194	$ 5,194	$ 5,194	$ 5,194	$ 5,194	$ 5,194	$ 5,194	$ 61,688	-
34	VERBS for Solar	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 15	-
35	Dispatchable Energy Resource Balancing Service Reserve inc	$ 133	$ 133	$ 133	$ 133	$ 133	$ 133	$ 125	$ 125	$ 125	$ 125	$ 125	$ 125	$ 1,548	-
36	Dispatchable Energy Resource Balancing Service Reserve dec	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 17	$ 202	-
37	Settlement Annual Budget Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
38	Rounding Adjustment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
39	Adjustment for Settlement for Supplying Only 900 MW dec Balancing Reserve Capacity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
40	Expected Balancing Reserve Capacity Sales in Spring from FCRPS Above Planned	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
41	Operating Reserve - Spinning	$ 1,713	$ 1,809	$ 2,093	$ 2,125	$ 1,890	$ 2,227	$ 2,119	$ 2,157	$ 2,322	$ 2,117	$ 1,988	$ 1,673	$ 24,233	-
42	Operating Reserve - Supplemental	$ 1,569	$ 1,657	$ 1,917	$ 1,947	$ 1,732	$ 2,040	$ 1,941	$ 1,977	$ 2,128	$ 1,940	$ 1,821	$ 1,533	$ 22,202	-
43	Synchronous Condensing	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 1,569	-
44	Generation Dropping	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 333	-
45	Energy Imbalance	$ 45	$ 87	$ (85)	$ 55	$ (46)	$ (40)	$ 157	$ 63	$ 200	$ 242	$ 215	$ 64	$ 957	-
46	Generation Imbalance	$ 582	$ 520	$ 313	$ 194	$ 304	$ 117	$ 90	$ 211	$ 406	$ 774	$ 1,034	$ 173	$ 4,718	-
47	Redispatch	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 400	-
48	COE/Reclamation Network/Delivery Facilities Segmentation	$ 625	$ 625	$ 625	$ 625	$ 625	$ 625	$ 625	$ 625	$ 625	$ 625	$ 625	$ 625	$ 7,500	9
49	Station Service	$ 199	$ 199	$ 199	$ 199	$ 199	$ 199	$ 199	$ 199	$ 199	$ 199	$ 199	$ 199	$ 2,385	-
50	Operating Reserve - Energy	$ 115	$ 76	$ 31	$ 76	$ 138	$ 122	$ 101	$ 97	$ 92	$ 37	$ 61	$ 13	$ 959	-
51	**Generation Inputs / Inter-business line**	**$ 10,569**	**$ 10,694**	**$ 11,134**	**$ 11,262**	**$ 10,883**	**$ 11,332**	**$ 11,266**	**$ 11,363**	**$ 12,006**	**$ 11,967**	**$ 11,977**	**$ 10,314**	**$ 134,767**	**9**
52	4(h)(10)(c)	$ 11,819	$ 9,865	$ 8,657	$ 7,280	$ 6,708	$ 7,035	$ 7,010	$ 6,876	$ 7,514	$ 6,432	$ 5,585	$ 8,896	$ 93,677	-
53	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
54	**Treasury Credits**	**$ 12,202**	**$ 10,248**	**$ 9,040**	**$ 7,664**	**$ 7,091**	**$ 7,418**	**$ 7,394**	**$ 7,259**	**$ 7,898**	**$ 6,815**	**$ 5,968**	**$ 9,279**	**$ 98,277**	**-**
55	**Augmentation Power Purchase sub-total**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
56	**Balancing Power Purchase sub-total**	$ 6,731	$ 7,309	$ 5,128	$ 3,995	$ 2,703	$ 1,639	$ 2,620	$ 410	$ 2,073	$ 3,321	$ 6,135	$ 4,448	$ 46,511	282
57	**Other Power Purchase sub-total**	**$ 2,094**	**$ 2,029**	**$ 2,094**	**$ 2,094**	**$ 1,891**	**$ 2,091**	**$ 2,027**	**$ 2,094**	**$ 2,027**	**$ 2,094**	**$ 2,094**	**$ 2,027**	**$ 24,656**	**47**
58	**Power Purchases**	**$ 8,825**	**$ 9,338**	**$ 7,222**	**$ 6,089**	**$ 4,595**	**$ 3,730**	**$ 4,646**	**$ 2,504**	**$ 4,099**	**$ 5,415**	**$ 8,229**	**$ 6,475**	**$ 71,167**	**329**

Table 4.2 - Revenue at Proposed Rates

	B C D E	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG
1	**Table 4.2 - Revenue at Proposed Rates**													**2016**	
2	**Category**	**201510**	**201511**	**201512**	**201601**	**201602**	**201603**	**201604**	**201605**	**201606**	**201607**	**201608**	**201609**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 202,804	$ 202,804	$ 202,804	$ 202,804	$ 202,804	$ 202,804	$ 202,804	$ 202,804	$ 202,804	$ 202,804	$ 202,804	$ 202,804	$ 2,433,645	6,894
4	Non-Slice Revenue	$ (22,643)	$ (22,643)	$ (22,643)	$ (22,643)	$ (22,643)	$ (22,643)	$ (22,643)	$ (22,643)	$ (22,643)	$ (22,643)	$ (22,643)	$ (22,643)	$ (271,711)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	1,877
6	Load Shaping Revenue	$ (3,656)	$ (7,888)	$ 15,262	$ 32,703	$ 23,611	$ 4,475	$ 7,210	$ (35,026)	$ (16,144)	$ (1,095)	$ (7,939)	$ 4,125	$ 15,638	(0)
7	Demand Revenue	$ 3,462	$ 2,013	$ 6,229	$ 5,100	$ 3,795	$ 4,349	$ 3,611	$ 2,127	$ 2,593	$ 3,010	$ 4,804	$ 3,958	$ 45,051	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,228)	$ (4,824)	$ (5,556)	$ (4,560)	$ (2,774)	$ (20,942)	-
9	Low Density Discount	$ (3,023)	$ (2,766)	$ (3,566)	$ (3,809)	$ (3,608)	$ (3,089)	$ (3,323)	$ (2,415)	$ (2,983)	$ (3,517)	$ (3,432)	$ (3,406)	$ (38,938)	-
10	Tier 2	$ 1,767	$ 1,767	$ 1,767	$ 1,767	$ 1,767	$ 1,767	$ 1,767	$ 1,767	$ 1,767	$ 1,767	$ 1,767	$ 1,767	$ 21,201	68
11	RSS (Non-Federal)	$ 111	$ 111	$ 111	$ 111	$ 111	$ 111	$ 111	$ 111	$ 111	$ 111	$ 111	$ 111	$ 1,330	-
12	**PF customers (CHWM) sub-total**	**$ 178,821**	**$ 173,397**	**$ 199,964**	**$ 216,033**	**$ 205,837**	**$ 187,773**	**$ 189,537**	**$ 143,497**	**$ 160,681**	**$ 174,880**	**$ 170,912**	**$ 183,943**	**$ 2,185,275**	**8,839**
13	**NR sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
14	**DSIs sub-total**	**$ 10,076**	**$ 10,120**	**$ 10,798**	**$ 10,745**	**$ 10,044**	**$ 9,387**	**$ 8,786**	**$ 7,847**	**$ 7,046**	**$ 9,542**	**$ 10,468**	**$ 10,324**	**$ 115,183**	**317**
15	**FPS sub-total**	**$ 228**	**$ 233**	**$ 253**	**$ 248**	**$ 238**	**$ 233**	**$ 228**	**$ 233**	**$ 238**	**$ 248**	**$ 233**	**$ 228**	**$ 2,842**	**8**
16	**Short-term market sales sub-total**	**$ 9,586**	**$ 14,401**	**$ 9,324**	**$ 33,544**	**$ 26,194**	**$ 31,884**	**$ 36,808**	**$ 55,321**	**$ 46,015**	**$ 45,830**	**$ 22,451**	**$ 6,404**	**$ 337,762**	**1,732**
17	**Long Term Contractual Obligations sub-total**	**$ 38**	**$ 7,610**	**$ 7,828**	**$ 7,837**	**$ 7,138**	**$ 3,908**	**$ 3,810**	**$ 61**	**$ 77**	**$ 64**	**$ 72**	**$ 46**	**$ 38,490**	**89**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**119**
19	**Renewable Energy Certificates sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,151**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,151**	**-**
20	Miscellaneous Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
21	Load Shaping True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
22	Slice True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
23	**Other Sales sub-total**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 323**	**$ 3,877**	**-**
24	**Gross Sales**	**$199,073**	**$206,084**	**$228,491**	**$268,730**	**$249,774**	**$234,659**	**$239,492**	**$207,282**	**$214,380**	**$230,887**	**$204,459**	**$201,268**	**$2,684,578**	**11,104**
25	GTA Delivery charge	$ 360	$ 405	$ 510	$ 450	$ 455	$ 410	$ 345	$ 370	$ 390	$ 435	$ 400	$ 335	$ 4,865	-
26	Energy Efficiency Revenues	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 1,250	$ 15,000	-
27	Irrigation Pumping Power	$ 134	$ 208	$ 252	$ 331	$ 330	$ 237	$ 155	$ 105	$ 99	$ 100	$ 99	$ 101	$ 2,149	18
28	Reserve Energy	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 8,327	161
29	Downstream Benefits	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 6,700	-
30	Upper Baker Revenues	$ -	$ 103	$ 117	$ 114	$ 117	$ 5	$ -	$ -	$ -	$ -	$ -	$ -	$ 457	1
31	**Miscellaneous Revenues**	**$2,996**	**$3,218**	**$3,381**	**$3,398**	**$3,404**	**$3,154**	**$3,002**	**$2,977**	**$2,992**	**$3,037**	**$3,001**	**$2,938**	**$37,498**	**180**
32	Regulating Reserve	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 6,224	-
33	Variable Energy Resource Balancing Service Reserve - Wind	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 57,250	-
34	VERBS for Solar	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 86	-
35	Dispatchable Energy Resource Balancing Service Reserve inc	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 2,059	-
36	Dispatchable Energy Resource Balancing Service Reserve dec	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 391	-
37	Settlement Annual Budget Adjustment	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (15,200)	-
38	Rounding Adjustment	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 26	-
39	Adjustment for Settlement for Supplying Only 900 MW dec Balancing Reserve Capacity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
40	Expected Balancing Reserve Capacity Sales in Spring from FCRPS Above Planned	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 4,000	-
41	Operating Reserve - Spinning	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 25,470	-
42	Operating Reserve - Supplemental	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 23,348	-
43	Synchronous Condensing	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 1,610	-
44	Generation Dropping	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 415	-
45	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	Redispatch	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 225	-
48	COE/Reclamation Network/Delivery Facilities Segmentation	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 7,367	-
49	Station Service	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 2,479	-
50	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
51	**Generation Inputs / Inter-business line**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 115,750**	**9**
52	4(h)(10)(c)	$ 8,688	$ 6,443	$ 9,961	$ 11,625	$ 9,482	$ 7,674	$ 6,896	$ 6,374	$ 6,932	$ 6,023	$ 5,776	$ 9,204	$ 95,077	-
53	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
54	**Treasury Credits**	**$ 9,071**	**$ 6,826**	**$ 10,345**	**$ 12,009**	**$ 9,866**	**$ 8,058**	**$ 7,279**	**$ 6,758**	**$ 7,315**	**$ 6,406**	**$ 6,159**	**$ 9,587**	**$ 99,677**	**-**
55	**Augmentation Power Purchase sub-total**	$ 4,569	$ 4,569	$ 4,569	$ 4,569	$ 4,569	$ 4,569	$ 4,569	$ 4,569	$ 4,569	$ 4,569	$ 4,569	$ 4,569	$ 54,828	198
56	**Balancing Power Purchase sub-total**	$ 1,957	$ 2,145	$ 4,692	$ 4,468	$ 2,209	$ 157	$ 26	$ -	$ -	$ 282	$ 827	$ 3,904	$ 20,668	133
57	**Other Power Purchase sub-total**	**$ 1,693**	**$ 1,693**	**$ 1,693**	**$ 1,693**	**$ 1,693**	**$ 1,693**	**$ 1,693**	**$ 1,693**	**$ 1,693**	**$ 4,578**	**$ 4,683**	**$ 4,527**	**$ 29,022**	**60**
58	**Power Purchases**	**$ 8,219**	**$ 8,407**	**$ 10,953**	**$ 10,730**	**$ 8,471**	**$ 6,418**	**$ 6,288**	**$ 6,262**	**$ 6,262**	**$ 9,429**	**$ 10,079**	**$ 13,001**	**$ 104,518**	**391**

Table 4.2 - Revenue at Proposed Rates

	B C D E	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT	AU
1	**Table 4.2 - Revenue at Proposed Rates**													**2017**	
2	**Category**	**201610**	**201611**	**201612**	**201701**	**201702**	**201703**	**201704**	**201705**	**201706**	**201707**	**201708**	**201709**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 203,338	$ 203,338	$ 203,338	$ 203,338	$ 203,338	$ 203,338	$ 203,338	$ 203,338	$ 203,338	$ 203,338	$ 203,338	$ 203,338	$ 2,440,056	6,893
4	Non-Slice Revenue	$ (22,724)	$ (22,724)	$ (22,724)	$ (22,724)	$ (22,724)	$ (22,724)	$ (22,724)	$ (22,724)	$ (22,724)	$ (22,724)	$ (22,724)	$ (22,724)	$ (272,692)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	1,843
6	Load Shaping Revenue	$ (3,301)	$ (7,029)	$ 16,031	$ 33,418	$ 27,250	$ 4,960	$ 7,460	$ (34,660)	$ (16,143)	$ (915)	$ (7,596)	$ 4,558	$ 24,033	30
7	Demand Revenue	$ 3,005	$ 2,633	$ 6,251	$ 5,149	$ 3,079	$ 4,409	$ 3,113	$ 2,677	$ 2,626	$ 3,055	$ 4,909	$ 4,032	$ 44,938	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,228)	$ (4,824)	$ (5,556)	$ (4,560)	$ (2,774)	$ (20,942)	-
9	Low Density Discount	$ (3,064)	$ (2,860)	$ (3,639)	$ (3,879)	$ (3,709)	$ (3,145)	$ (3,352)	$ (2,482)	$ (3,030)	$ (3,562)	$ (3,475)	$ (3,443)	$ (39,640)	-
10	Tier 2	$ 1,885	$ 1,885	$ 1,885	$ 1,885	$ 1,885	$ 1,885	$ 1,885	$ 1,885	$ 1,885	$ 1,885	$ 1,885	$ 1,885	$ 22,616	80
11	RSS (Non-Federal)	$ 120	$ 120	$ 120	$ 120	$ 120	$ 120	$ 120	$ 120	$ 120	$ 120	$ 120	$ 120	$ 1,434	-
12	**PF customers (CHWM) sub-total**	**$ 179,258**	**$ 175,361**	**$ 201,261**	**$ 217,306**	**$ 209,238**	**$ 188,841**	**$ 189,839**	**$ 144,925**	**$ 161,246**	**$ 175,640**	**$ 171,896**	**$ 184,991**	**$ 2,199,804**	**8,846**
13	**NR sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
14	**DSIs sub-total**	**$ 10,076**	**$ 10,120**	**$ 10,798**	**$ 10,745**	**$ 9,697**	**$ 9,387**	**$ 8,786**	**$ 7,847**	**$ 7,046**	**$ 9,542**	**$ 10,468**	**$ 10,324**	**$ 114,836**	**316**
15	**FPS sub-total**	**$ 187**	**$ 192**	**$ 217**	**$ 207**	**$ 202**	**$ 197**	**$ 187**	**$ 192**	**$ 197**	**$ 207**	**$ 197**	**$ 187**	**$ 2,363**	**9**
16	**Short-term market sales sub-total**	**$ 11,785**	**$ 15,550**	**$ 12,028**	**$ 37,409**	**$ 28,332**	**$ 39,682**	**$ 42,774**	**$ 56,666**	**$ 46,962**	**$ 52,320**	**$ 26,102**	**$ 7,567**	**$ 377,178**	**1,732**
17	**Long Term Contractual Obligations sub-total**	**$ 38**	**$ 7,610**	**$ 7,828**	**$ 7,837**	**$ 7,138**	**$ 3,908**	**$ 3,810**	**$ 61**	**$ 77**	**$ 64**	**$ 72**	**$ 46**	**$ 38,489**	**90**
18	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**118**
19	**Renewable Energy Certificates sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 648**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 648**	**-**
20	Miscellaneous Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
21	Load Shaping True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
22	Slice True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
23	**Other Sales sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**-**
24	**Gross Sales**	**$201,344**	**$208,832**	**$232,132**	**$273,504**	**$254,607**	**$242,664**	**$245,396**	**$209,691**	**$215,527**	**$237,773**	**$208,734**	**$203,115**	**$2,733,318**	**11,110**
25	GTA Delivery charge	$ 360	$ 410	$ 510	$ 460	$ 460	$ 410	$ 350	$ 370	$ 390	$ 440	$ 400	$ 335	$ 4,895	-
26	Energy Efficiency Revenues	$ 583	$ 583	$ 583	$ 583	$ 583	$ 583	$ 583	$ 583	$ 583	$ 583	$ 583	$ 583	$ 7,000	-
27	Irrigation Pumping Power	$ 134	$ 208	$ 252	$ 331	$ 330	$ 237	$ 155	$ 105	$ 99	$ 100	$ 99	$ 101	$ 2,149	18
28	Reserve Energy	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 694	$ 8,327	162
29	Downstream Benefits	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 558	$ 6,700	-
30	Upper Baker Revenues	$ -	$ 110	$ 121	$ 116	$ 119	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 466	1
31	**Miscellaneous Revenues**	**$2,330**	**$2,564**	**$2,718**	**$2,743**	**$2,744**	**$2,482**	**$2,340**	**$2,310**	**$2,325**	**$2,375**	**$2,335**	**$2,271**	**$29,537**	**181**
32	Regulating Reserve	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 519	$ 6,224	-
33	Variable Energy Resource Balancing Service Reserve - Wind	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 4,771	$ 57,250	-
34	VERBS for Solar	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	$ 86	-
35	Dispatchable Energy Resource Balancing Service Reserve inc	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 172	$ 2,059	-
36	Dispatchable Energy Resource Balancing Service Reserve dec	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 391	-
37	Settlement Annual Budget Adjustment	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (1,267)	$ (15,200)	-
38	Rounding Adjustment	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	$ 26	-
39	Adjustment for Settlement for Supplying Only 900 MW dec Balancing Reserve Capacity	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
40	Expected Balancing Reserve Capacity Sales in Spring from FCRPS Above Planned	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 333	$ 4,000	-
41	Operating Reserve - Spinning	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 2,123	$ 25,470	-
42	Operating Reserve - Supplemental	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 1,946	$ 23,348	-
43	Synchronous Condensing	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 134	$ 1,610	-
44	Generation Dropping	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 35	$ 415	-
45	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	Redispatch	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 19	$ 225	-
48	COE/Reclamation Network/Delivery Facilities Segmentation	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 614	$ 7,367	-
49	Station Service	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 207	$ 2,479	-
50	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
51	**Generation Inputs / Inter-business line**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 9,646**	**$ 115,750**	**9**
52	4(h)(10)(c)	$ 8,480	$ 6,183	$ 9,779	$ 11,593	$ 9,271	$ 7,163	$ 6,549	$ 6,025	$ 6,839	$ 5,698	$ 5,435	$ 9,099	$ 92,112	-
53	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
54	**Treasury Credits**	**$ 8,863**	**$ 6,566**	**$ 10,162**	**$ 11,977**	**$ 9,654**	**$ 7,546**	**$ 6,932**	**$ 6,408**	**$ 7,222**	**$ 6,081**	**$ 5,818**	**$ 9,482**	**$ 96,712**	**-**
55	**Augmentation Power Purchase sub-total**	$ 7,885	$ 7,885	$ 7,885	$ 7,885	$ 7,885	$ 7,885	$ 7,885	$ 7,885	$ 7,885	$ 7,885	$ 7,885	$ 7,885	$ 94,619	318
56	**Balancing Power Purchase sub-total**	$ 1,535	$ 900	$ 3,337	$ 1,852	$ 2,017	$ 92	$ 25	$ -	$ -	$ 501	$ 1,235	$ 3,161	$ 14,655	105
57	**Other Power Purchase sub-total**	**$ 5,388**	**$ 5,274**	**$ 5,388**	**$ 5,371**	**$ 5,050**	**$ 5,401**	**$ 4,636**	**$ 4,739**	**$ 4,688**	**$ 4,687**	**$ 4,792**	**$ 4,636**	**$ 60,048**	**67**
58	**Power Purchases**	**$ 14,808**	**$ 14,059**	**$ 16,610**	**$ 15,108**	**$ 14,952**	**$ 13,377**	**$ 12,546**	**$ 12,624**	**$ 12,573**	**$ 13,072**	**$ 13,912**	**$ 15,682**	**$ 169,322**	**490**

Table 4.3 – Composite and Non-Slice Revenue – FY 2016-2017

	A	B	C	D	E	F	G
1	**Table 4.3 – Composite and Non-slice revenue – FY 2016-2017**						
2	Table shows calculation of CHWM revenues at proposed rates.						
3							
4	**Billing Determinants**	**FY 2016**		**FY 2017**		**Rate Period**	
5	**TOCA.....**	98.453060	A)	98.712430	A)	98.582745	
6	**Non-slice TOCA.....**	71.834410	B)	72.093780	B)	71.964095	
7	**Slice Percentage.....**	26.618650		26.618650		26.618650	
8							
9	**Annual TRM Rates ($000)**	**FY 2016**		**FY 2017**		**Rate Period**	
10	**Composite.....**	$ 24,132		$ 25,304		$ 24,719	C)
11	**Non-Slice.....**	$ (3,672)		$ (3,893)		$ (3,782)	D)
12	**Slice.....**	$ -		$ -		$ -	
13							
14	**Yearly Revenues (Yearly TOCA * Rate Period rate)**	**FY 2016**		**FY 2017**			
15	**Composite (A * C).....**	$ 2,433,645	E)	$ 2,440,056	E)		
16	**Non-Slice (B * D).....**	$ (271,711)	E)	$ (272,692)	E)		
17	**Slice.....**	$ -		$ -			
18							
19	**Monthly Revenues (Yearly Revenues / 12)**	**FY 2016**		**FY 2017**			
20	**Composite (E / 12).....**	$ 202,804		$ 203,338			
21	**Non-Slice (E / 12).....**	$ (22,643)		$ (22,724)			
22	**Slice.....**	$ -		$ -			
23							
24	*Ties to Table 4.2, Revenue at Proposed Rates, lines 3-4*						

Table 4.4 – Load Shaping and Demand Revenue – FY 2016-2017

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**Table 4.4 – Load Shaping and Demand Revenue – FY 2016-2017**														
2	Table shows calculation of CHWM revenues at proposed rates.														
3															
4															
5	**FY 2016**		**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**Total**
6	Load Shaping HLH (MWh)	A)	(175,476)	(363,196)	130,836	401,660	336,337	30,511	105,434	(1,250,989)	(596,685)	(253,909)	(331,090)	(13,243)	
7	Load Shaping LLH (MWh)	B)	69,016	146,824	353,265	632,522	403,298	145,869	185,516	(333,634)	(187,763)	284,836	119,227	158,174	
8	Load Shaping HLH Rate ($/MWh)	C)	$ 31.59	$ 33.39	$ 35.30	$ 35.31	$ 35.09	$ 28.71	$ 27.09	$ 23.75	$ 23.72	$ 30.73	$ 34.04	$ 35.24	
9	Load Shaping LLH Rate ($/MWh)	D)	$ 27.35	$ 28.87	$ 30.13	$ 29.28	$ 29.28	$ 24.67	$ 23.47	$ 15.93	$ 10.60	$ 23.55	$ 27.94	$ 29.03	
10	Load Shaping Revenue (A * C) + (B * D)		$ (3,655,704)	$ (7,888,332)	$ 15,262,367	$ 32,702,858	$ 23,610,640	$ 4,474,555	$ 7,210,252	$ (35,025,774)	$ (16,143,668)	$ (1,094,740)	$ (7,939,116)	$ 4,125,118	$ 15,638,457
11															
12	Demand (kW)	E)	365,533	201,099	588,738	482,040	361,121	505,115	444,661	298,767	364,733	326,775	470,983	374,816	
13	Demand Rate ($/kW-mo.)	F)	$ 9.47	$ 10.01	$ 10.58	$ 10.58	$ 10.51	$ 8.61	$ 8.12	$ 7.12	$ 7.11	$ 9.21	$ 10.20	$ 10.56	
14	Demand Revenue (E * F)		$ 3,461,596	$ 2,013,005	$ 6,228,845	$ 5,099,987	$ 3,795,381	$ 4,349,039	$ 3,610,646	$ 2,127,221	$ 2,593,255	$ 3,009,601	$ 4,804,028	$ 3,958,056	$ 45,050,660
15															
16															
17															
18															
19	**FY 2017**		**Oct-16**	**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Total**
20	Load Shaping HLH (MWh)	A)	(208,440)	(299,170)	142,983	413,290	402,252	40,480	70,258	(1,211,646)	(596,863)	(250,791)	(325,089)	(5,694)	
21	Load Shaping LLH (MWh)	B)	120,050	102,526	364,552	642,918	448,594	153,935	236,778	(369,305)	(187,347)	288,421	124,182	163,929	
22	Load Shaping HLH Rate ($/MWh)	C)	$ 31.59	$ 33.39	$ 35.30	$ 35.31	$ 35.09	$ 28.71	$ 27.09	$ 23.75	$ 23.72	$ 30.73	$ 34.04	$ 35.24	
23	Load Shaping LLH Rate ($/MWh)	D)	$ 27.35	$ 28.87	$ 30.13	$ 29.28	$ 29.28	$ 24.67	$ 23.47	$ 15.93	$ 10.60	$ 23.55	$ 27.94	$ 29.03	
24	Load Shaping Revenue (A * C) + (B * D)		$ (3,301,265)	$ (7,029,361)	$ 16,031,248	$ 33,417,889	$ 27,249,866	$ 4,959,744	$ 7,460,476	$ (34,659,632)	$ (16,143,469)	$ (914,500)	$ (7,596,389)	$ 4,558,205	$ 24,032,810
25															
26	Demand (kW)	E)	317,280	262,996	590,825	486,717	292,980	512,048	383,401	375,930	369,330	331,725	481,291	381,818	
27	Demand Rate ($/kW-mo.)	F)	$ 9.47	$ 10.01	$ 10.58	$ 10.58	$ 10.51	$ 8.61	$ 8.12	$ 7.12	$ 7.11	$ 9.21	$ 10.20	$ 10.56	
28	Demand Revenue (E * F)		$ 3,004,645	$ 2,632,594	$ 6,250,925	$ 5,149,471	$ 3,079,225	$ 4,408,734	$ 3,113,214	$ 2,676,624	$ 2,625,937	$ 3,055,190	$ 4,909,168	$ 4,031,997	$ 44,937,725
29															
30	*Ties to Table 4.2, Revenue at Proposed Rates, lines 6-7*														

Table 4.5 – Irrigation Rate Discount (IRD) – FY 2016-2017

	A	B	C	D	E	F	G	H
1	**Table 4.5 – Irrigation Rate Discount (IRD) – FY 2016-2017**							
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**	6,983						
8	**Annual NonSlice Dollar Amount**	2,186,558						
9	**Average Hours in Rate Period**	8772						
10	**Implied Discount ($/MWh)**	**11.13**	A)					
11								
12								
13								
14	**FY 2016**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**		**TOTAL**
15	IRD Monthly Loads (MWh)	290,041	433,464	499,210	409,669	249,220	B)	
16	IRD credit ($) (A * B)	$ (3,228,158)	$ (4,824,450)	$ (5,556,213)	$ (4,559,617)	$ (2,773,822)		**$ (20,942,259)**
17								
18								
19	**FY2017**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**		**TOTAL**
20	IRD Monthly Loads (MWh)	290,041	433,464	499,210	409,669	249,220	B)	
21	IRD credit ($) (A * B)	$ (3,228,158)	$ (4,824,450)	$ (5,556,213)	$ (4,559,617)	$ (2,773,822)		**$ (20,942,259)**
22								
23								
24	*Ties to Table 4.2, Revenue at Proposed Rates, line 8*							
25								

Table 4.6 – Low Density Discount (LDD) – FY 2016-2017

Table 4.6 – Low Density Discount (LDD) – FY 2016-2017

Table shows calculation of LDD credit at proposed rates.

Low Density Discount

Customer Charge LDD	FY 2016	FY 2017	
TOCA LDD Offset %	1.66%	1.68%	**A)**
TRM Costs after Adjustments			
Composite	$ 2,433,645	$ 2,440,056	
Non-Slice	$ (271,711)	$ (272,692)	
Slice	$ -	$ -	
	$ 2,161,934	$ 2,167,365	**B)**
LDD discount - Composite portion (A * B)	$ 35,905.48	$ 36,364.45	**C)**
LDD discount (Demand/Load Shaping portion)	$ 3,032.49	$ 3,274.96	**D) below**
Total LDD discount (C + D)	**$ 38,937.97**	**$ 39,639.41**	

Demand and Load Shaping Discount Detail

FY 2016	**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**		
Demand BD (kW)	23,013	14,925	31,988	26,747	21,348	24,874	25,938	19,207	24,231	22,880	29,013	22,727		
Load Shaping BD HLH (MWh)	(5,531)	(10,412)	1,597	6,800	5,326	(3,806)	1,612	(25,388)	(7,109)	2,293	(977)	1,896		
Load Shaping BD LLH (MWh)	(433)	(951)	5,930	10,020	6,983	(306)	3,273	(6,948)	(1,183)	10,363	6,337	3,673		
Demand Rate	$ 9.47	$ 10.01	$ 10.58	$ 10.58	$ 10.51	$ 8.61	$ 8.12	$ 7.12	$ 7.11	$ 9.21	$ 10.20	$ 10.56		
Load Shaping Rate (HLH)	$ 31.59	$ 33.39	$ 35.30	$ 35.31	$ 35.09	$ 28.71	$ 27.09	$ 23.75	$ 23.72	$ 30.73	$ 34.04	$ 35.24		
Load Shaping Rate (LLH)	$ 27.35	$ 28.87	$ 30.13	$ 29.28	$ 29.28	$ 24.67	$ 23.47	$ 15.93	$ 10.60	$ 23.55	$ 27.94	$ 29.03		
LDD credit (Demand/Load Shaping portion)	$ 31,362	$ (225,679)	$ 573,498	$ 816,540	$ 615,767	$ 97,330	$ 331,079	$ (576,954)	$ (8,853)	$ 525,255	$ 439,731	$ 413,420	$ 3,032,494	
													$ 3,032.49	**D)**
FY 2017	**Oct-16**	**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**		
Demand BD (kW)	23,992	21,011	35,554	29,929	20,189	27,588	25,473	24,522	26,301	24,030	30,032	23,117		
Load Shaping BD HLH (MWh)	(6,037)	(10,148)	1,480	6,613	6,798	(3,873)	1,116	(25,487)	(7,308)	2,092	(1,027)	1,820		
Load Shaping BD LLH (MWh)	(126)	(1,446)	5,969	10,196	7,776	(469)	3,621	(7,408)	(1,298)	10,445	6,187	3,607		
Demand Rate	$ 9.47	$ 10.01	$ 10.58	$ 10.58	$ 10.51	$ 8.61	$ 8.12	$ 7.12	$ 7.11	$ 9.21	$ 10.20	$ 10.56		
Load Shaping Rate (HLH)	$ 31.59	$ 33.39	$ 35.30	$ 35.31	$ 35.09	$ 28.71	$ 27.09	$ 23.75	$ 23.72	$ 30.73	$ 34.04	$ 35.24		
Load Shaping Rate (LLH)	$ 27.35	$ 28.87	$ 30.13	$ 29.28	$ 29.28	$ 24.67	$ 23.47	$ 15.93	$ 10.60	$ 23.55	$ 27.94	$ 29.03		
LDD credit(Demand/Load Shaping portion)	$ 33,084	$ (170,249)	$ 608,259	$ 848,779	$ 678,432	$ 114,757	$ 322,030	$ (548,803)	$ (65)	$ 531,571	$ 444,232	$ 412,931	$ 3,274,958	
													$ 3,274.96	**D)**

**LDD credit is negative revenue*

Ties to Table 4.2, Revenue at Proposed Rates, line 9

Table 4.7 – Tier 2 Revenue – FY 2016-2017

	A	B	C
1	**Fiscal Year**		
2	**Rate Period**	**FY2016**	**FY2017**
3			
4	Base Power Purchase Cost	$ -	$ -
5	Rate Design Components	$ 125,847	$ 122,139
6	Other Costs	$ -	$ -
7	Rate $/MWh	**$ 34.05**	**$ 36.62**
8	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (113,694)	$ (110,682)
9	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
10	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (12,154)	$ (11,457)
11	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -
12	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -
13	Total ShortTerm Rate Revenue	$ 2,758,854	$ 2,796,978
14	Remarketing Credit	$ -	$ -
15	Remarketing Charge	$ -	$ -
16	Forecast Power Purchase Costs	$ -	$ -
17			
18			
19	Base Power Purchase Cost	$ 1,865,282	$ 2,045,460
20	Rate Design Components	$ 14,298	$ 15,661
21	Other Costs	$ -	$ -
22	Rate $/MWh	**$ 45.32**	**$ 49.73**
23	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (12,918)	$ (14,192)
24	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
25	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (1,381)	$ (1,469)
26	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -
27	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -
28	Total LoadGrowth Rate Revenue	$ 417,199	$ 487,040
29	Remarketing Credit	$ -	$ -
30	Remarketing Charge	$ 376,693	$ 428,748
31	Forecast Power Purchase Costs	$ -	$ -
32			
33	Base Power Purchase Cost	$ 17,160,598	$ 18,818,232
34	Rate Design Components	$ 627,599	$ 644,386
35	Other Costs	$ -	$ -
36	Rate $/MWh	**$ 44.99**	**$ 49.34**
37	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (566,990)	$ (583,942)
38	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
39	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (60,610)	$ (60,444)
40	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -
41	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -
42	Total Vintage.1 Rate Revenue	$ 17,716,327	$ 16,670,881
43	Remarketing Credit	$ 2,468,263	$ 2,460,798
44	Remarketing Charge	$ -	$ -
45	Forecast Power Purchase Costs	$ -	$ -
46			
47	Base Power Purchase Cost	$ -	$ -
48	Rate Design Components	$ 122,791	$ 224,134
49	Other Costs	$ -	$ -
50	Rate $/MWh	**$ 40.87**	**$ 43.44**
51	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (110,933)	$ (203,110)
52	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
53	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (11,858)	$ (21,024)
54	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -
55	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -
56	Total Vintage.2 Rate Revenue	$ 3,231,019	$ 6,088,550
57	Remarketing Credit	$ 830,879	$ 1,395,151
58	Remarketing Charge	$ -	$ -
59	Forecast Power Purchase Costs	$ -	$ -
60			
61			
62	Total Tier 2 Revenue Collection Before Remarking Charge/Credit	$ 24,123,399	$ 26,043,450
63	Total Tier 2 Remarketing Charge	$ 376,693	$ 428,748
64	Total Tier 2 Remarketing Credit	$ (3,299,142)	$ (3,855,948)
65	**Total Tier 2 Revenue Collection**	**$ 21,200,951**	**$ 22,616,249**
66			
67	*Ties to Table 4.2, Revenue at Proposed Rates, line 10*		

Table 4.8 – Direct Service Industries (DSI) Revenues – FY 2015-2017

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**Table 4.8 – Direct Service Industries (DSI) Revenues – FY 2015-2017**														
2	Table shows calculation of DSI revenues at current and proposed rates.														
3															
4	**FY 2015**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Total**
5	HLH rate (per MWh)	A)	41.72	45.69	48.97	47.93	47.02	40.36	35.89	31.13	32.86	40.62	44.09	43.78	
6	LLH rate (per MWh)	B)	37.56	41.4	43.4	40.8	40.73	35.23	30.25	23.21	24.7	34.63	37.22	38.03	
7	Demand rate (kw/Mo)	C)	9.18	9.31	9.97	9.70	9.92	9.60	9.10	8.50	8.72	10.20	10.75	10.53	
8															
9	HLH consumption (MWh)	D)	134,784	119,808	129,792	129,792	119,808	129,792	129,792	124,800	129,792	129,792	129,792	124,800	1,532,544
10	LLH consumption (MWh)	E)	97,344	105,144	102,336	102,336	89,856	102,024	94,848	107,328	94,848	102,336	102,336	99,840	1,200,576
11	Demand (kW)	F)	-	-	-	-	-	-	-	-	-	-	-	-	-
12															
13	HLH revenues (A * D)	G)	5,623,188	5,474,028	6,355,914	6,220,931	5,633,372	5,238,405	4,658,235	3,885,024	4,264,965	5,272,151	5,722,529	5,463,744	63,812,486
14	LLH revenues (B * E)	H)	3,656,241	4,352,962	4,441,382	4,175,309	3,659,835	3,594,306	2,869,152	2,491,083	2,342,746	3,543,896	3,808,946	3,796,915	42,732,771
15	Demand revenues (C * F)	I)	-	-	-	-	-	-	-	-	-	-	-	-	-
16	TOTAL forecast revenues (G + H + I)	J)	$ 9,279,429	$ 9,826,989	$ 10,797,297	$ 10,396,239	$ 9,293,207	$ 8,832,711	$ 7,527,387	$ 6,376,107	$ 6,607,711	$ 8,816,047	$ 9,531,475	$ 9,260,659	$ 106,545,258
17															
18															
19	**FY 2016 - current rates**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Total**
20	HLH rate (per MWh)	A)	41.72	45.69	48.97	47.93	47.02	40.36	35.89	31.13	32.86	40.62	44.09	43.78	
21	LLH rate (per MWh)	B)	37.56	41.40	43.40	40.80	40.73	35.23	30.25	23.21	24.70	34.63	37.22	38.03	
22	Demand rate (kw/Mo)	C)	9.18	9.31	9.97	9.70	9.92	9.60	9.10	8.50	8.72	10.20	10.75	10.53	
23															
24	HLH consumption (MWh)	D)	137,278	126,892	125,860	132,285	127,039	132,331	132,658	132,392	126,961	130,957	136,921	121,519	1,563,093
25	LLH consumption (MWh)	E)	97,603	100,731	109,026	102,599	92,690	102,238	94,646	102,490	100,348	103,925	97,967	105,789	1,210,053
26	Demand (kW)	F)													
27															
28	HLH revenues (A * D)	G)	5,727,238	5,797,699	6,163,354	6,340,409	5,973,357	5,340,884	4,761,090	4,121,378	4,171,952	5,319,468	6,036,837	5,320,107	65,073,775
29	LLH revenues (B * E)	H)	3,665,962	4,170,274	4,731,730	4,186,054	3,775,284	3,601,848	2,863,049	2,378,795	2,478,585	3,598,928	3,646,322	4,023,166	43,119,998
30	Demand revenues (C * F)	I)	-	-	-	-	-	-	-	-	-	-	-	-	-
31	TOTAL revenues (G + H + I)		$ 9,393,201	$ 9,967,974	$ 10,895,084	$ 10,526,464	$ 9,748,641	$ 8,942,732	$ 7,624,139	$ 6,500,173	$ 6,650,537	$ 8,918,396	$ 9,683,159	$ 9,343,273	$ 108,193,772
32															
33	**FY 2017 - current rates**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Total**
34	HLH rate (per MWh)	A)	41.72	45.69	48.97	47.93	47.02	40.36	35.89	31.13	32.86	40.62	44.09	43.78	
35	LLH rate (per MWh)	B)	37.56	41.40	43.40	40.80	40.73	35.23	30.25	23.21	24.70	34.63	37.22	38.03	
36	Demand rate (kw/Mo)	C)	9.18	9.31	9.97	9.70	9.92	9.60	9.10	8.50	8.72	10.20	10.75	10.53	
37															
38	HLH consumption (MWh)	D)	137,279	126,892	125,860	132,285	122,658	132,331	132,659	132,392	126,961	130,957	136,921	121,519	1,558,713
39	LLH consumption (MWh)	E)	97,602	100,732	109,026	102,599	89,494	102,238	94,646	102,491	100,348	103,925	97,967	105,789	1,206,857
40	Demand (kW)	F)													
41															
42	HLH revenues (A * D)	G)	5,727,265	5,797,680	6,163,354	6,340,409	5,767,382	5,340,884	4,761,114	4,121,361	4,171,952	5,319,468	6,036,837	5,320,107	64,867,815
43	LLH revenues (B * E)	H)	3,665,938	4,170,292	4,731,730	4,186,054	3,645,100	3,601,848	2,863,029	2,378,807	2,478,585	3,598,928	3,646,322	4,023,166	42,989,800
44	Demand revenues (C * F)	I)	-	-	-	-	-	-	-	-	-	-	-	-	-
45	TOTAL revenues (G + H + I)		$ 9,393,203	$ 9,967,972	$ 10,895,084	$ 10,526,464	$ 9,412,482	$ 8,942,732	$ 7,624,143	$ 6,500,169	$ 6,650,537	$ 8,918,396	$ 9,683,159	$ 9,343,273	$ 107,857,614
46															
47	**FY 2016 - proposed rates**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Total**
48	HLH rate (per MWh)	A)	44.66	46.46	48.37	48.38	48.16	41.78	40.16	36.82	36.79	43.80	47.11	48.31	
49	LLH rate (per MWh)	B)	40.42	41.94	43.20	42.35	42.35	37.74	36.54	29.00	23.67	36.62	41.01	42.10	
50	Demand rate (kw/Mo)	C)	9.47	10.01	10.58	10.58	10.51	8.61	8.12	7.12	7.11	9.21	10.2	10.56	
51															
52	HLH consumption (MWh)	D)	137,278	126,892	125,860	132,285	127,039	132,331	132,658	132,392	126,961	130,957	136,921	121,519	1,563,093
53	LLH consumption (MWh)	E)	97,603	100,731	109,026	102,599	92,690	102,238	94,646	102,490	100,348	103,925	97,967	105,789	1,210,053
54															
55															
56	HLH revenues (A * D)	G)	6,130,836	5,895,406	6,087,838	6,399,937	6,118,181	5,528,795	5,327,539	4,874,692	4,670,911	5,735,910	6,450,338	5,870,588	69,090,971
57	LLH revenues (B * E)	H)	3,945,106	4,224,669	4,709,925	4,345,083	3,925,443	3,858,465	3,458,374	2,972,212	2,375,227	3,805,739	4,017,616	4,453,729	46,091,589
58	Demand revenues (C * F)	I)	-	-	-	-	-	-	-	-	-	-	-	-	-
59	TOTAL revenues (G + H + I)		$ 10,075,942	$ 10,120,076	$ 10,797,763	$ 10,745,021	$ 10,043,623	$ 9,387,260	$ 8,785,913	$ 7,846,904	$ 7,046,137	$ 9,541,650	$ 10,467,954	$ 10,324,317	$ 115,182,560
60															
61	**FY 2017 - proposed rates**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Total**
62	HLH rate (per MWh)	A)	44.66	46.46	48.37	48.38	48.16	41.78	40.16	36.82	36.79	43.80	47.11	48.31	
63	LLH rate (per MWh)	B)	40.42	41.94	43.20	42.35	42.35	37.74	36.54	29.00	23.67	36.62	41.01	42.10	
64	Demand rate (kw/Mo)	C)	9.47	10.01	10.58	10.58	10.51	8.61	8.12	7.12	7.11	9.21	10.2	10.56	
65															
66	HLH consumption (MWh)	D)	137,279	126,892	125,860	132,285	122,658	132,331	132,659	132,392	126,961	130,957	136,921	121,519	1,558,713
67	LLH consumption (MWh)	E)	97,602	100,732	109,026	102,599	89,494	102,238	94,646	102,491	100,348	103,925	97,967	105,789	1,206,857
68															
69															
70	HLH revenues (A * D)	G)	6,130,865	5,895,386	6,087,838	6,399,937	5,907,213	5,528,795	5,327,566	4,874,672	4,670,911	5,735,910	6,450,338	5,870,588	68,880,019
71	LLH revenues (B * E)	H)	3,945,080	4,224,687	4,709,925	4,345,083	3,790,081	3,858,465	3,458,349	2,972,228	2,375,227	3,805,739	4,017,616	4,453,729	45,956,210
72	Demand revenues (C * F)	I)	-	-	-	-	-	-	-	-	-	-	-	-	-
73	TOTAL revenues (G + H + I)		$ 10,075,945	$ 10,120,074	$ 10,797,763	$ 10,745,021	$ 9,697,293	$ 9,387,260	$ 8,785,915	$ 7,846,900	$ 7,046,137	$ 9,541,650	$ 10,467,954	$ 10,324,317	$ 114,836,229
74															
75															
76	*Ties to Table 4.1, Revenue at Current Rates, and 4.2, Revenue at Proposed Rates, line 14*														

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SECTION 5: RATE SCHEDULES

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SECTION 6: GENERAL RATE SCHEDULE PROVISIONS

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SECTION 7: SLICE

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SECTION 8: AVERAGE SYSTEM COSTS

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Table Descriptions

Table 8.1 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 8.2 Forecast Average System Costs (ASCs)
Table lists the Fiscal Year Forecasted ASCs in $/MWh as determined through the ASC review process.

Table 8.1

IOUs CY 2013 - 2014 Residential Loads
(MWh)

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1		**Oct-14**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**	**FY 2015**
2	Avista	272,139	297,240	429,549	456,283	426,678	374,194	309,565	273,799	243,323	262,256	303,002	287,410	**3,935,437**
3	Idaho Power	446,946	437,379	572,643	643,022	646,777	501,437	425,494	459,557	528,687	663,892	747,534	705,304	**6,778,672**
4	NorthWestern	49,697	52,447	67,650	72,747	66,539	62,909	53,085	48,414	47,926	52,069	55,694	56,992	**686,171**
5	PacifiCorp	607,844	664,581	1,051,997	1,055,914	886,730	755,576	642,733	619,364	666,921	707,545	755,313	692,371	**9,106,889**
6	PGE	598,042	654,444	980,663	988,358	869,970	755,895	658,189	609,488	577,986	640,288	681,445	650,968	**8,665,735**
7	Puget Sound Energy	812,208	988,415	1,317,692	1,383,344	1,269,404	1,157,392	1,009,263	849,358	731,718	748,804	760,883	697,982	**11,726,463**
8														
9		**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**FY 2016**
10	Avista	272,139	297,240	429,549	456,283	426,678	374,194	309,565	273,799	243,323	262,256	303,002	287,410	**3,935,437**
11	Idaho Power	446,946	437,379	572,643	643,022	646,777	501,437	425,494	459,557	528,687	663,892	747,534	705,304	**6,778,672**
12	NorthWestern	49,697	52,447	67,650	72,747	66,539	62,909	53,085	48,414	47,926	52,069	55,694	56,992	**686,171**
13	PacifiCorp	607,844	664,581	1,051,997	1,055,914	886,730	755,576	642,733	619,364	666,921	707,545	755,313	692,371	**9,106,889**
14	PGE	598,042	654,444	980,663	988,358	869,970	755,895	658,189	609,488	577,986	640,288	681,445	650,968	**8,665,735**
15	Puget Sound Energy	812,208	988,415	1,317,692	1,383,344	1,269,404	1,157,392	1,009,263	849,358	731,718	748,804	760,883	697,982	**11,726,463**
16														
17														
18						COUs FY 2016 - 2017 Forecast Exchange Loads								
19														
20		**Oct-15**	**Nov-15**	**Dec-15**	**Jan-16**	**Feb-16**	**Mar-16**	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**	**FY 2016**
21	Clark	174,112	229,882	289,295	280,837	230,235	227,160	178,573	162,901	144,514	163,017	163,564	143,600	**2,387,690**
22	Snohomish	250,909	248,922	400,178	465,901	413,991	422,754	353,632	300,764	266,538	234,584	235,524	213,095	**3,806,792**
23														
24		**Oct-16**	**Nov-16**	**Dec-16**	**Jan-17**	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**FY 2017**
25	Clark	173,579	228,945	287,891	279,587	224,687	226,473	177,885	162,720	144,634	163,464	163,984	143,637	**2,377,487**
26	Snohomish	255,025	253,005	406,743	473,824	421,030	429,943	359,645	305,879	271,071	238,573	239,529	216,719	**3,870,986**

Table 8.2

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

	A	B	C
1		**FY 2016**	**FY 2017**
2	Avista	$ 53.53	$ 53.53
3	Idaho Power	$ 59.54	$ 59.54
4	NorthWestern	$ 79.66	$ 79.66
5	PacifiCorp	$ 76.93	$ 76.93
6	PGE	$ 78.28	$ 78.28
7	Puget Sound Energy	$ 70.03	$ 70.03
8	Clark	$ 54.34	$ 54.34
9	Snohomish	$ 48.55	$ 48.86
10			
11	Note: Forecasted ASCs are determined through the ASC review process		

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