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

BP-14 Initial Rate Proposal

Power Rates Study Documentation

November 2012

BP-14-E-BPA-01A

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2014 POWER RATES STUDY DOCUMENTATION
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COMMONLY USED ACRONYMS AND SHORT FORMS

AAC	Anticipated Accumulation of Cash
AGC	Automatic Generation Control
ALF	Agency Load Forecast (computer model)
aMW	average megawatt(s)
AMNR	Accumulated Modified Net Revenues
ANR	Accumulated Net Revenues
ASC	Average System Cost
BiOp	Biological Opinion
BPA	Bonneville Power Administration
Btu	British thermal unit
CDD	cooling degree day(s)
CDQ	Contract Demand Quantity
CGS	Columbia Generating Station
CHWM	Contract High Water Mark
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
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
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 Products and Services (rate)
FY	fiscal year (October through September)
GARD	Generation and Reserves Dispatch (computer model)
GEP	Green Energy Premium
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	IntercontinentalExchange
inc	increase, increment, or incremental
IOU	investor-owned utility
IP	Industrial Firm Power (rate)
IPR	Integrated Program Review
IRD	Irrigation Rate Discount
JOE	Joint Operating Entity
kW	kilowatt (1000 watts)
kWh	kilowatthour
LDD	Low Density Discount
LLH	Light Load Hour(s)
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)

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
OMB	Office of Management and Budget
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)
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
Transmission System Act	Federal Columbia River Transmission System Act
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
WECC	Western Electricity Coordinating Council (formerly WSCC)
WIT	Wind Integration Team
WSPP	Western Systems Power Pool

DOCUMENTATION FOR THE
2014 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 (RAM2014). The RAM2014 is a group of computer applications that perform most of the computations that determine BPA's proposed power rates. The output tables of RAM2014 include billing determinants, which are based on power sales forecasts, and revenue requirements used in the PRS cost of service analysis (COSA). Other tables show the initial allocation of the revenue requirement over the billing determinants. Next, tables present the rate design steps, the basis for which is 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. Lastly, this section includes several resource examples that provide a greater level of detail on how the Resource Support Service module calculates rates and charges for different resource types.

Section 4: Revenue Forecast documents revenue forecasts at both current and proposed rates for the rate period, FY 2014-2015, and at current rates for the period immediately proceeding the two-year rate period, FY 2013.

Section 5: Rate Schedules *No documentation*

Section 6: General Rate Schedule Provisions *No documenation*

Section 7: Slice *No documenation*

Section 8: Average System Costs documents Residential Exchange Loads and costs, 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-14-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 allocation factors used to apportion costs and 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 under 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 70 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 2014-2015.

The HYDSIM studies incorporate the power and nonpower operating requirements BPA expects to be in effect during the rate period, including those described by the NOAA Fisheries in its Biological Opinion (BiOp), published May 5, 2008; the United States Fish and Wildlife Service (USFWS) BiOp, published December 2000; operations described in the Northwest Power and Conservation Council's Fish and Wildlife Program; and other fish mitigation measures. Each hydro regulation study specifies particular hydroelectric project operations for fish, such as seasonal flow augmentation, minimum flow levels, spill for juvenile fish passage, reservoir drawdown limitations, and turbine operation efficiency requirements. HYDSIM uses hydro plant operating characteristics in combination with the power and non-power requirements to simulate the coordinated operation of the hydro system. For the WP-12 Initial Proposal, the Federal hydro plant operating characteristics were updated to include increased reserve requirements associated with new wind generating plants. These reserve requirements are incorporated into the availability factors in HYDSIM and reduce the powerhouse capacity available for generation. The Federal system hydro generation is used in the Federal system loads and resources balance and is detailed in the Power Loads and Resources Study.

Federal System Loads and Resources Balance

The Federal system loads and resources 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-14-E-BPA-02):

The Power Revenue Requirement Study provides 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-14-E-BPA-04):

Secondary Energy Revenue Forecast

The Risk Analysis Model (RiskMod) is used to forecast the secondary energy revenues, balancing power purchase expenses, and augmentation purchase expenses. RiskMod is comprised of a set of risk simulation models, collectively referred to as RiskSim and RevSim, a model that calculates net revenues. After accounting for all loads and resources (including augmentation purchases), RiskMod 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 forecasted loads, non-hydro resources, and varying hydro generation. RiskMod uses results from two hydroregulation models, Hydro Simulation (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. RiskMod applies HLH and LLH monthly spot market prices supplied by the AURORA$_{xmp®}$ model to the sales and purchase amounts to calculate revenues from surplus energy sales and expenses from balancing power purchases. It also computes augmentation costs based on hydro generation data and AURORA$_{xmp®}$ 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 RiskMod. RiskMod 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 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 AURORA$_{xmp®}$ 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
The Risk Analysis Model (RiskMod) and Non-Operating Risk Model (NORM) are used to quantify BPA's net revenue risk. RiskMod 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. The results from RiskMod 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 TPP (the probability of making all planned Treasury payments during the rate period) given the net revenue risks quantified in RiskMod 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 Power Generation Inputs Study, to compute the variable cost component of generation input capacity. The market price run is used in the Power Rates Study for:

(a) the prices for surplus sales and balancing purchases in RAM2014,
(b) Load Shaping rate,
(c) Load Shaping True-up rate,
(d) Resource Shaping rate,

(e) Resource Support Service rates,
(f) shaping the Demand rate,
(g) PF Tier 2 Balancing Credit,
(h) PF Unused RHWM Credit,
(i) Tier 1 PF Equivalent Rates,
(j) Melded PF Equivalent Rates,
(k) 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 AURORA$_{xmp}$®. AURORA$_{xmp}$ is an economic fundamentals-based software application that models wholesale electric energy transactions in a competitive pricing system. AURORA$_{xmp}$ 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, AURORA$_{xmp}$ 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-14-E-BPA-01):
Rate Analysis Model (RAM2014)
RAM2014, a spreadsheet-based model, has three main steps that perform the calculations necessary to develop BPA's wholesale power rates: Cost of Service Analysis Step (COSA), Rate Directive Step, and Tiered Rates Methodology Step.

1. Cost of Service Analysis Step. This step complies with BPA's rate directives by determining the costs associated with the three resource pools (Federal base system (FBS), residential exchange, and new resources) used to serve sales load, and then allocating 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 Directive Step. 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 Directive Step of RAM2014 performs these rate adjustments. The amount of PF Public rate protection, as well as the levels of the IP and NR rate is set assuming a settlement of the legal issues associated with the Residential Exchange Program.

3. Rate Design Step. In the Rate Directive Step, costs are allocated to the various rate pools, including the PF Public rate pool. Section 7(e) affords BPA wide latitude in the design of rates to collect the costs allocated to each rate pool. Additional

processing is required before the PF Public rate can be designed. The allocation of costs and credits performed in the COSA Step and Rate Directives Step are insufficient to inform the TRM rate design of the PF Public rate. The TRM specifies a cost allocation methodology different from what is used in the COSA to separate costs into the various TRM cost pools. RAM2014 accomplishes this different cost allocation through a process of mapping costs and credits to the cost pools. To provide a crosswalk between the differences between COSA allocations and TRM allocations, the mapping for each is shown in RAM2014

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. These services include Diurnal Flattening Service (DFS), Secondary Crediting Service (SCS), Forced Outage Reserves (FOR), 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, 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.

Revenue and Purchased Power Expense Forecast
The Revenue Forecast, section 4 of the Power Rate Study, presents BPA's expected level of revenue as well as purchased power expense for FY 2013-2015. FY 2013 revenues are forecast to estimate 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 that current rates will not recover BPA's revenue requirement and that 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 purchase power expenses, and 4(h)(10)(C) credits.

FY 2014-2015 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, covering the FY 2014-2015 rate period BPA proposes to use the Draft Report ASCs published by BPA on November 14, 2012.

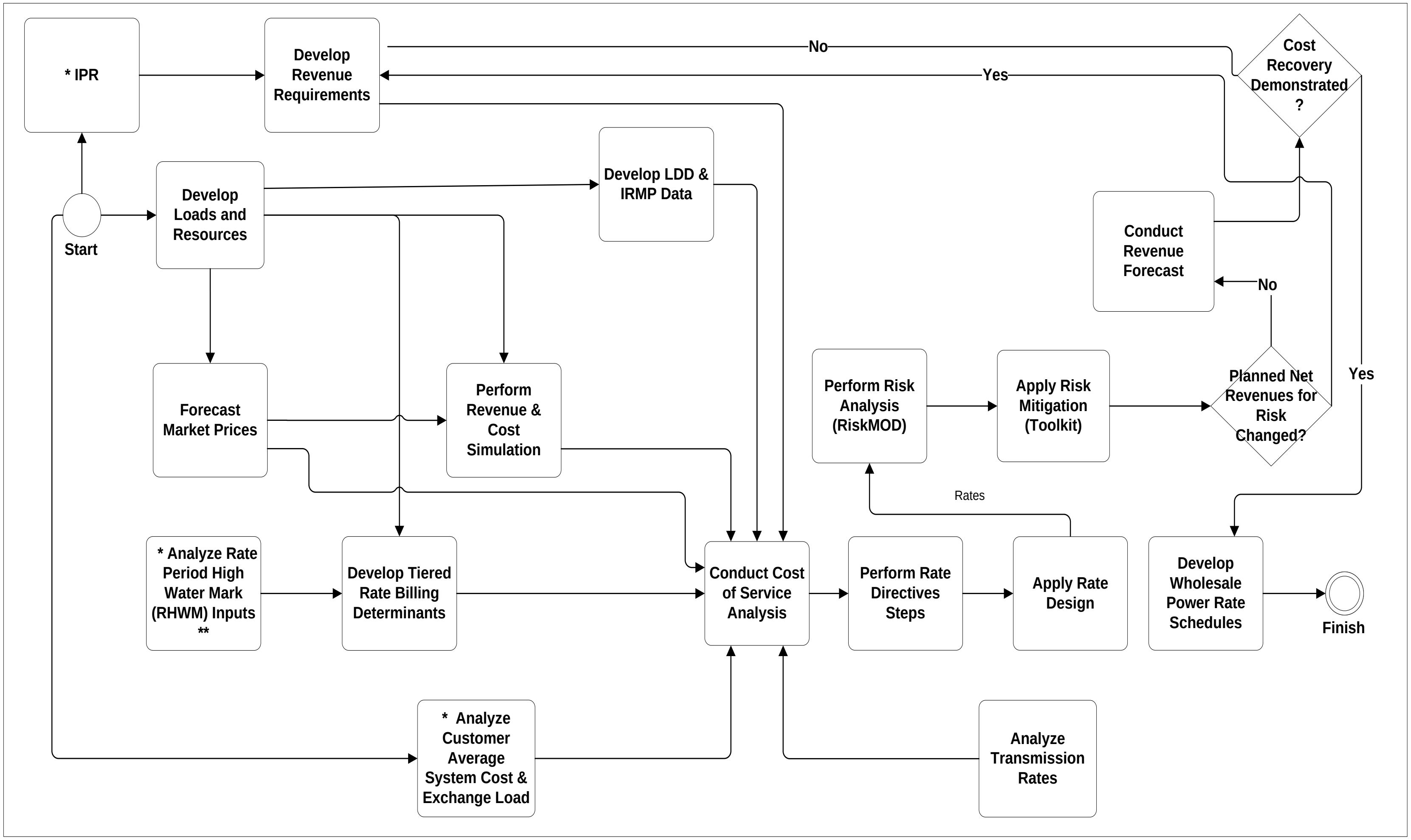
These Draft Report ASCs will be replaced with the Final Report ASCs that BPA will publish at the end of the current ASC Review Process. At the close of the ASC Review Process, BPA will incorporate into the BP-14 rate case record the final ASC Reports and the Final Proposal rates will be established using these final ASCs for FY 2014-2015.

POWER GENERATION INPUTS STUDY (BP-14-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 70 water year set are passed to RiskMod.

Rate Development Process Chart

BPA High Level Power Rates Development Process



* These Processes are not part of the 7i- - Rate Process

** RHWM inputs for the BP-12 case will not be available for the initial proposal. Proxy inputs will be developed for the initial proposal.

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SECTION 2: RATESETTING METHODOLOGY AND PROCESS

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Table Descriptions

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

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

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

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

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

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

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

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

Table 2.3.3 Computation of Low Density and Irrigation Rate Discount Costs (COSA 03)
Worksheet calculates the foregone revenue due to the Low Density Discount and the Irrigation Rate Discount. The foregone revenue must be added to the power revenue requirement as a cost

to be recovered from PF rates. A macro is used to iterate the costs of the LDD/IRD with the TRM rates so that the LDD/IRD costs are calculated with the current power rates.

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

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

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

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

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

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

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

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

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

Table 2.3.7.5 Allocation of Generation Input Related Revenue Credits (COSA 07-5)
Worksheet allocates revenue credits associated with providing generation inputs as directed by section 7(g) of the Northwest Power Act.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Table 2.4.12 IOU Reallocation Balances (RDS 12)
Reallocation of “Lookback” REP Refund amounts under the 2012 REP Settlement Agreement, Section 6, prescribes how the Settlement equitably recognized differences in outstanding

lookback obligations at the time of the Settlement. This table shows the reallocation balances through time as of the 7(i) process through 2020.

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

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

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

Table 2.4.16 Calculation of Annual Energy Rate Scalars for Second IP-PF Link Rate Calculation (RDS 16)
Worksheet calculates the annual scalar adjustments needed to scale the market price monthly diurnal energy rates such that the resultant energy rates recover the PF rate and IP rate revenue requirements at this point in the ratemaking.

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

Table 2.4.18 IP_PF Link (RDS 18)
Worksheet uses shaped energy rates from previous worksheet to calculate the IP-PF link delta. The IP-PF Link 7(c)(2) adjustment is necessary to account for the difference between the revenues expected to be recovered from the DSIs at the IP rate and the costs allocated to the DSIs at this point in the ratemaking. This difference, known as the 7(c)(2) Delta, is allocated to non-DSI rates, primarily the PF rate. The IP rate is a formula rate based on the "applicable wholesale rate," the load-weighted PF and NR rates. The interaction between the applicable wholesale rate and the IP rate has been reduced to an algebraic formula to approximate a solution, and then the RAM uses an intrinsic Excel function, "Goal Seek," to converge to a solution for each year of the rate test period

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

Table 2.4.20 REP Benefit Reconciliation (RDS 20)
Worksheet shows that computation of constant annual benefits over the rate period is equivalent with allocation of separate year costs in each separate year of the rate period.

Table 2.5.1 Cost Aggregation under Tiered Rate Methodology (DS 01)
Worksheet aggregates costs and credits to be used in the TRM ratemaking. The TRM specifies a cost allocation methodology different from what is used in the COSA to separate costs into the various TRM cost pools. The mapping of costs to the TRM cost pools includes costs passed from the Power Revenue Requirement Study, credits passed from the revenue forecast, and cost and credit line items internally computed in RAM2012. For each cost pool under TRM, costs are conveniently grouped according to their COSA classification.

Table 2.5.2 Calculation of Unused RHWM (net) Credit (DS 02)
Worksheet calculates the $/MWh value for unused Rate Period High Water Mark. That value is used to determine the reallocation adjustment to distribute costs between the Composite and Non-Slice cost pools properly.

Table 2.5.3 Calculation of Slice Return of Network Losses Adjustment (DS 03)
Worksheet calculates the value of power associated with Non-slice network losses, such that these costs can explicitly be included in the Nonslice cost pool. This leaves only system losses for which all Composite customers pay (regardless of product subscription) in the Composite cost pool, and properly accounts for Customer return of Slice-Resource losses. That value is used to determine the reallocation credit that will shift costs between the Composite and Non-Slice TRM cost pools.

Table 2.5.4 Balancing Augmentation Adjustment for Change to the Equivalent Tier 1 System Firm Critical Output (DS 04)
Worksheet calculates the change in the T1SFCO from the RHWM to 7(i) Processes, and values the difference at the system augmentation price when system augmentation amount is greater than zero.

Table 2.5.5 Calculation of Load Shaping and Demand Revenues (DS 05)
Worksheet calculates the Load Shaping and Demand revenues under the TRM rate design. These revenues are used as a credit against the costs in the Non-Slice rate pool.

Table 2.5.6 Calculation of PF Public Rates under Tiered Rate Methodology (DS 06)
Worksheet applies the costs, revenue credits and inter-rate-pool reallocations to the Composite, Non-Slice, Slice and Tier 2 TRM rate pools to produce TRM rates. The TRM rates are in the form of monthly $/percent TOCA.

Table 2.5.7.1 Calculation of Net REP Ratemaking and Recovery Demonstration (DS 07-1)
Worksheet applies all power costs and revenue credits to the PF Public rate pool. The IP revenues are calculated with a macro to arrive at the proper relationship between the PFp rate and the IP rate. The net REP benefits are used in the calculations. The worksheet demonstrates that the PFp rate using the net REP benefits is identical to the PFp calculated with BPA's standard gross REP methodology.

Table 2.5.7.2 TRM PFp Revenues Equal to Non-TRM PFp Revenues (DS 07-2)
Worksheet demonstrates that the TRM revenues from Table 2.5.5 are equal to the non-TRM revenues from Table 2.5.6.1.

Table 2.5.8.1 Calculation of Priority Firm Public Tier 1 Rate Equivalent Components (DS 08-1)
Worksheet calculates the energy and demand components for a PF Public rate that is equivalent to a Tier 1 PF rate. The monthly energy Load Shaping rates are adjusted by a scalar in all periods so that they and the monthly demand rates will recover the Tier 1 PF revenue requirement.

Table 2.5.8.2 Calculation of Priority Firm Public Melded Rate Equivalent Components (DS 08-2)
Worksheet calculates the energy and demand components for a PF Public rate that is equivalent to a melded Tier 1 and Tier 2 PF rate. The monthly energy Load Shaping rates are adjusted by a scalar in all periods so that they and the monthly demand rates will recover the Tier 1 and Tier 2 PF revenue requirement. These monthly energy PF rates are necessary to calculate the Industrial Firm Power rates.

Table 2.5.8.3 Calculation of Industrial Firm Power Rate Components (DS 08-3)
Worksheet calculates the Industrial Firm Power (IP) rate monthly energy and demand components. The IP rate is a formula rate derived from the "applicable wholesale rate." In this rate proceeding, with no NR load, the applicable wholesale rate is the melded PF Public rate. The monthly IP energy rates are set equal to the melded PF rate, plus the DSI value of reserve (VOR), plus the Industrial Margin, plus the Settlement Charge.

Table 2.5.8.4 Calculation of New Resource Rate Components (DS 08-4)
Worksheet calculates the energy and demand components for the New Resources (NR) rate. The monthly energy Load Shaping rates are adjusted by a scalar in all periods so that they and the monthly demand rates will recover the NR revenue requirement.

Table 2.5.8.5 Calculation of the Load Shaping True-up Rate (DS 08-5)
Worksheet calculates the Load Shaping True-up rate by comparing the non-slice Tier 1 market energy revenue (the non-slice Tier 1 loads times the market rates) with the non-slice Tier 1 energy revenue at Tier 1 rates. The difference in the form of a $/MWh is the Load Shaping True-up rate.

Table 2.5.9.1 Allocated Costs and Unit Costs, Priority Firm Power Rates (DS 09-1)
Table provides a summary of the various COSA cost allocations and Rate Design Adjustments associated with Priority Firm Public Power and Priority Firm Exchange Power. A percent contribution to the final Priority Firm Preference Power rate and Priority Firm Exchange Power rate for each COSA cost allocation and Rate Design Adjustment is calculated.

Table 2.5.9.2 Allocated Costs and Unit Costs, Industrial Firm Power (DS 09-2)
Table provides a summary of the various COSA cost allocations and Rate Design Adjustments associated with Industrial Firm Power. A percent contribution to the final Industrial Firm Power rate for each COSA cost allocation and Rate Design Adjustment is calculated.

Table 2.5.9.3 Allocated Costs and Unit Costs, New Resource Firm Power (DS 09-3)
Table provides a summary of the various COSA cost allocations and Rate Design Adjustments associated with New Resource Firm Power. A percent contribution to the final New Resource Firm Power rate for each COSA cost allocation and Rate Design Adjustment is calculated.

Table 2.5.9.4 Resource Cost Contribution (DS 09-4)
Table provides a summary of the percentages of each resource pool, FBS, Residential Exchange, and New Resources, used in ratemaking to serve each of the rate pools, PF, IP, NR, and FPS.

Rate Data Input
Disaggregated Loads
Test Period October 2013 - September 2015
(MWh)

	A	B	C	E	F
5				2014	2015
6	Preference			61,677,950	62,502,370
7		Slice Block		15,842,157	16,625,913
8		Slice (non-block)		17,051,591	16,423,689
9		Load Following - System Shape		28,505,395	28,590,478
10		Load Following - Load Shaping		126,121	177,871
11		Tier 2 (Block)		152,687	684,419
12	Industrial			2,733,123	2,733,123
13		Smelter		2,628,000	2,628,000
14		Other Industrial		105,123	105,123
15	New Resource			9	9
16	Firm Power and Services			7,630,380	7,462,399
17		Intraregional Transfer		808,609	808,610
18			WNP3	729,769	729,770
19			Dittmer Station Service	78,840	78,840
28		FBS Obligation		6,334,119	6,164,089
29			Canadian Entitlement	4,241,418	4,073,436
30			USBR Pump Load	1,543,212	1,543,212
31			Hungry Horse	66,243	66,243
32			Upper Baker	11,228	11,228
33			Non-Treaty Storage	126,418	124,370
34			Libby Coordination	345,600	345,600
39		Seasonal or Capacity Exchange		614,069	614,069
40			Riverside Capacity	43,650	43,650
41			Riverside Seasonal	37,188	37,188
42			Pasadena Capacity	9,900	0
43			Pasadena Seasonal	21,960	21,960
44			PG&E	234,264	231,784
45			Intertie Losses	10,409	10,037
52	Conservation			-260,321	-260,321

Rate Data Input
Disaggregated Resources
Test Period October 2013 - September 2015
(MWh)

	A	B	C	E	F
6				2014	2015
7	Hydro			60,658,056	59,564,825
8		Regulated		57,558,358	56,465,127
9		Independent		3,099,698	3,099,698
10			Cowlitz Falls	229,919	229,919
11			Idaho Falls	122,312	122,312
12			PreAct	2,747,467	2,747,467
20		Hydro Other		1,453,600	1,448,592
21			Canadian Entitlement	1,194,400	1,189,392
22			Libby Coordination	259,200	259,200
23			Other	0	0
31	Non Hydro			10,501,420	9,451,434
32		Water		23,039	23,039
33			Dworshak/Clearwater Small Hydropower	23,039	23,039
34			Elwha Hydro	0	0
35			Glines Canyon Hydro	0	0
43		Thermal		9,022,800	7,687,488
44			Columbia Generating Station	9,022,800	7,687,488
54		Wind		403,655	403,655
55			Foote Creek 1	35,366	35,366
56			Foote Creek 2	4,162	4,162
57			Foote Creek 4	38,785	38,785
58			Stateline Wind Project	181,202	181,202
59			Condon Wind Project	84,510	84,510
60			Klondike I	59,631	59,631
65		Renewable		168,358	168,358
66			Georgia-Pacific Paper (Wauna)	168,331	168,331
67			Fourmile Hill Geothermal	0	0
68			Ashland Solar Project	27	27
69			White Bluffs Solar	0	0

Rate Data Input
Disaggregated Resources
Test Period October 2013 - September 2015
(MWh)

	A	B	C	E	F
6				2014	2015
76	Contracts			883,568	1,168,894
77		Imports		410,712	396,392
78			Riverside Exchange Energy	64,339	64,339
79			Pasadena Exchange Energy	16,388	13,991
80			BC Hydro Power Purchase	8,760	8,760
81			Slice Return of Losses	321,224	309,302
82				0	0
88		Seasonal or Capacity Exchange		472,856	325,742
89			Riverside Capacity	43,650	43,651
90			Riverside Seasonal	37,173	37,173
91			Pasadena Capacity	9,900	150
92			Pasadena Seasonal	21,813	18,622
93			PG&E	226,246	226,145
94			PacifiCorp	134,073	0
99		Tier2		0	446,760
100			Short Term	0	0
101			Load Growth	0	0
102			Vintage 1	0	0
103			Vintage 2	0	0
104			Vintage 3	0	0
110	Augmentation and Balancing			1,412,313	4,126,489
111		System Augmentation		1,285,876	4,000,051
112		Balancing		0	0
113		Tier 1 Resources		126,437	126,437
114			Klondike III	124,234	124,234
115			Rocky Brook	2,203	2,203
116					
117	Transmission Losses			(2,080,346)	(2,093,242)

Rate Data Input
Exchange ASCs, Loads, and Gross Costs
Test Period October 2013 - September 2015

	B	D		E	
7	**Exchange ASCs ($/MWh)**		**2014**		**2015**
8					
9	Avista Corporation	$	57.13	$	57.13
10	Idaho Power Company	$	49.69	$	49.69
11	NorthWestern Energy, LLC	$	70.62	$	70.62
12	PacifiCorp	$	66.11	$	66.11
13	Portland General Electric Company	$	67.76	$	67.76
14	Puget Sound Energy, Inc.	$	76.80	$	76.80
15	Clark Public Utilities	$	47.91	$	47.91
17	Snohomish County PUD No 1	$	-	$	-
18					
19	**Exchange Loads (GWh)**		**2014**		**2015**
20					
21	Avista Corporation		3,912		3,912
22	Idaho Power Company		6,433		6,433
23	NorthWestern Energy, LLC		674		674
24	PacifiCorp		9,333		9,333
25	Portland General Electric Company		8,768		8,768
26	Puget Sound Energy, Inc.		12,602		12,602
27	Clark Public Utilities		2,543		2,527
29	Snohomish County PUD No 1		0		0
30			44,265		44,249
31					
32	**Exchange Resource Cost ($000)**		**2014**		**2015**
33					
34	Avista Corporation	$	223,492	$	223,492
35	Idaho Power Company	$	319,676	$	319,676
36	NorthWestern Energy, LLC	$	47,573	$	47,573
37	PacifiCorp	$	616,976	$	616,976
38	Portland General Electric Company	$	594,150	$	594,150
39	Puget Sound Energy, Inc.	$	967,867	$	967,867
40	Clark Public Utilities	$	121,818	$	121,067
42	Snohomish County PUD No 1	$	-	$	-
43		$	2,891,552	$	2,890,801

Energy Allocation Factor
Power Sales and Resources
Test Period October 2013 - September 2015
(aMW)

	B	C	E	F
4			**2014**	**2015**
5	**Sales**			
6	Public			
7		Load Following System Shape	3,254	3,264
8		Load Following Load Shaping	14	20
9		Tier 2 (block)	17	78
10		Block Service	0	0
11		Slice (output energy)	1,947	1,875
12		Slice (block)	1,808	1,898
13		Undistributted Conservation	(30)	(30)
14	Exports			
15		BC Hydro (Cdn Entitlement)	484	465
16		Non-Treaty Storage	14	14
17		Libby Coordination	39	39
18		Pasadena Capacity	1.1	0
19		Pasadena Seasonal	2.5	3
20		Riverside Capacity	5	5
21		Riverside Seasonal	4	4
22		PG&E	27	26
23		Intertie Losses	1	1
24	Intra-regional Transfers			
25		Avista (WNP#3 Settle.)	83	83
26		Dittmer/Substration Sale	9	9
27	Other Loads			
28		USBR Pump Load	176	176
29		Hungry Horse	8	8
30		Upper Baker	1	1
31		Direct Service Industries	312	312
32		New Resource	0.0	0
33	Total Firm Obligations		**8,179**	**8,253**
34				
35	**Resources**			
36	Hydro			
37		Regulated	6,571	6,446
38		Independent		
39		Cowlitz Falls	26	26
40		Idaho Falls	14	14
41		PreAct	314	314
42		Non-Fed CER (Canada)	136	136
43		Libby Coordination	30	30
44	Other Hydro Resources			
45				

Energy Allocation Factor
Power Sales and Resources
Test Period October 2013 - September 2015
(aMW)

	B	C	E	F
4			**2014**	**2015**
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)	19	19
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	7
62		Pasadena Exchange Energy	2	2
63		BC Hydro Power Purchase	1	1
64		Riverside Capacity	5	5
65		Riverside Seasonal	4	4
66		Pasadena Capacity	1	0
67		Pasadena Seasonal	2	2
68		Slice Losses Return	37	35
69	Regional Transfers (In)			
70		PG&E	26	26
71		PacifiCorp	15	0
72	Large Thermal		1,030	878
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		18	80
80	Federal Trans. Losses		(237)	(239)
81	Total Net Resources		**8,084**	**7,849**
82				
83	Total Firm Surplus/Deficit		**(95)**	**(404)**

Energy Allocation Factor
Aggregated Loads and Resources
Test Period October 2013 - September 2015
(aMW)

	B	C	D	E
4			**2014**	**2015**
7	**Loads**			
8	Priority Firm - 7(b) Loads			
9		Slice (block)	1,861	1,953
10		Load Following System Shape	3,348	3,358
11		Load Following Load Shaping	15	21
12		Slice (output energy)	2,003	1,929
13		Tier 2	17.94	80
14		Undistributted Conservation	(31)	(31)
15		5(c) Exchange	5,200	5,198
16	Industrial Firm - 7(c) Loads			
17		Direct Service Industries	321	321
18	New Resources - 7(f) Loads			
19		NR	0.001	0.001
20	Surplus Firm - SP Loads			
21		Avista (WNP#3 Settle.)	86	86
22		Dittmer/Substation Sale	9	9
23	Total Loads		**12,830**	**12,925**
24				
25	**Resources**			
26	Federal Base System			
27		Hydro	7,050	6,925
28		Other Resources		
29		Small Thermal & Misc.		
30		Combustion Turbines		
31		Renewables	0	0
32		Cogeneration		
33		Imports	23	21
34		Regional Transfers (In)	41	26
35		Large Thermal	1,030	878
36		Non-Utility Generation	0	0
37		Slice Loss Return	37	35
38		Augmentation Purchases	95	404
39		Tier 2 Purchases	18	80

Energy Allocation Factor
Aggregated Loads and Resources
Test Period October 2013 - September 2015
(aMW)

	B	C	D	E
4			**2014**	**2015**
40	less: FBS Obligations			
41		BC Hydro (Cdn Entitlement)	(498)	(478)
42		Non-Treaty Storage	(15)	(15)
43		Libby Coordination	(41)	(41)
44		Hungry Horse	(8)	(8)
45		Upper Baker	(1)	(1)
46		USBR Pump Load	(181)	(181)
47	less: FBS Uses			
48		Pasadena	(4)	(3)
49		Riverside	(9)	(9)
50		PG&E	(28)	(27)
51		Intertie Losses	(1)	(1)
52	Exchange Resources			
53		5(c) Exchange	5,200	5,198
54	New Resources			
55		Cowlitz Falls	26	26
56		Idaho Falls	14	14
57		Foote Creek 1	4	4
58		Foote Creek 2	0	0
59		Foote Creek 4	4	4
60		Stateline Wind Project	21	21
61		Condon Wind Project	10	10
62		Klondike I	7	7
63		Klondike III	14	14
64		Georgia-Pacific Paper (Wauna)	19	19
65		Fourmile Hill Geothermal	0	0
66		Ashland Solar Project	0	0
67		White Bluffs Solar	0	0
68		Dworshak/Clearwater Small Hydropower	3	3
69		Elwha Hydro	0	0
70		Glines Canyon Hydro	0	0
71		Rocky Brook	0	0
72	Total Resources		**12,830**	**12,925**

Energy Allocation Factor
Calculation of Energy Allocation Factors
Test Period October 2013 - September 2015

	B	C	D
4		**2014**	**2015**
5			
6	**Loads (after adjustments)**		
7	Public	7,215	7,311
8	Exchange	5,200	5,198
9	DSI	321	321
10	NR	0.001	0.001
11	FPS	95	95
12			
13	Load Pools -- Program Case		
14	Priority Firm - 7(b) Loads	12,414	12,509
15	Industrial Firm - 7(c) Loads	321	321
16	New Resources - 7(f) Loads	0.001	0.001
17	Surplus Firm - SP Loads	95	95
18	Total Firm Loads	12,830	12,925
19	Secondary	2,319	2,301
20	Surplus Firm - SP Loads (for rate protection)	95	95
21			
22	**Resources (after adjustments)**		
23	Federal Base System	7,508	7,605
24	Exchange Resources	5,200	5,198
25	New Resources	123	123
26	Total Firm Resources	12,830	12,925
27			
28	Allocators -- Program Case		
29	Federal Base System		
30	Priority Firm - 7(b) Loads	7,508	7,605
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	4,906	4,904
36	Industrial Firm - 7(c) Loads	226	226
37	New Resources - 7(f) Loads	0.0007	0.0007
38	Surplus Firm - SP Loads	67	67
39	New Resources		
40	Priority Firm - 7(b) Loads	0	0
41	Industrial Firm - 7(c) Loads	95	95
42	New Resources - 7(f) Loads	0	0
43	Surplus Firm - SP Loads	28	28

Energy Allocation Factor
Calculation of Energy Allocation Factors
Test Period October 2013 - September 2015

	B	C	D
4		**2014**	**2015**
44			
45	**Allocation Factors -- Program Case with Exchange**		
46	Federal Base System + NR		
47	Priority Firm - 7(b) Loads	0.9839	0.9841
48	Industrial Firm - 7(c) Loads	0.0124	0.0122
49	New Resources - 7(f) Loads	0.0000	0.0000
50	Surplus Firm - SP Loads	0.0037	0.0036
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	0.9436	0.9435
58	Industrial Firm - 7(c) Loads	0.0436	0.0436
59	New Resources - 7(f) Loads	0.0000	0.0000
60	Surplus Firm - SP Loads	0.0129	0.0129
61	New Resources		
62	Priority Firm - 7(b) Loads	0.0000	0.0000
63	Industrial Firm - 7(c) Loads	0.7717	0.7717
64	New Resources - 7(f) Loads	0.0000	0.0000
65	Surplus Firm - SP Loads	0.2283	0.2283
66	Conservation & General		
67	Priority Firm - 7(b) Loads	0.9676	0.9678
68	Industrial Firm - 7(c) Loads	0.0250	0.0248
69	New Resources - 7(f) Loads	0.0000	0.0000
70	Surplus Firm - SP Loads	0.0074	0.0073
81	Surplus Deficit		
82	Priority Firm - 7(b) Loads	0.9748	0.9750
83	Industrial Firm - 7(c) Loads	0.0252	0.0250
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	0.6553	0.6567
91	Industrial Firm - 7(c) Loads	0.0405	0.0406
92	New Resources - 7(f) Loads	0.0000	0.0000
93	Secondary Sales	0.3042	0.3027

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2013 - September 2015
($ 000)

	B	D	E
4		**2014**	**2015**
5	**Power System Generation Resources**		
6	**Operating Generation**		
7	Columbia Generating Station (WNP-2)	312,918	355,675
8	Bureau of Reclamation	140,601	143,033
9	Corps of Engineers	225,687	231,878
10	Billing Credits Generation	5,825	5,935
11	Cowlitz Falls O&M	3,401	3,427
12	Idaho Falls Bulb Turbine	4,648	4,880
13	Bureau O&M - Elwha	-	1
14	Clearwater Hatchery Generation	1,060	1,080
15	New Resources Integration Wheeling	941	983
16	Wauna	10,125	10,315
17	Other New Resources	-	-
18			
19	**Operating Generation Settlement Payment**		
20	Operating Generation Settlement Payment (Colville)	21,404	21,905
21			
22	**Non-Operating Generation**		
23	Trojan Decomissioning	1,500	1,500
24	WNP-1&3 Decomissioning	706	728
25			
26	**Contracted and Augmentation Power Purchases**		
27	Augmentation Power Purchases	27,622	123,283
28	Balancing Purchases	31,941	27,492
29	PNCA Headwater Benefits	2,957	3,030
30	Tier 1 Augmentation Resources (Klondike III)	10,000	9,997
31	Hedging/Mitigation	35,043	-
32	Other Committed Purchase (excl. Hedging)	-	-
33	Bookout Adj to Contracted Power Purchases	-	-
34			
35	**Exchanges and Settlements**		
36	Residential Exchange (IOU)	197,500	197,500
37	Residential Exchange (COU)	1,429	1,420
38	Residential Exchange (Refund)	76,538	76,538
39	Residential Exchange Program Support	973	996
40	Residential Exchange Interest Accrual	1,400	1,400
41			
42	**Renewable and Conservation Generation**		
43	Renewables R&D	4,944	5,045
44	Renewable Generation	29,798	30,150
45	Generation Conservation R&D	872	890
46	DSM Technology	-	-
47	Conservation Acquisition	16,444	16,754
48	Low Income Energy Efficiency	5,155	5,252
49	Reimbursable Energy Efficiency Development	11,859	12,083
50	Legacy Conservation	1,031	1,050
51	Market Transformation	13,919	14,180

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2013 - September 2015
($ 000)

	B	D	E
4		**2014**	**2015**
52			
53	**Transmission Acquisition and Ancillary Services**		
54	Trans & Ancillary Svcs	61,177	59,990
55	Trans & Ancillary Svcs (sys oblig)	37,347	37,911
56	Third Party GTA Wheeling	55,533	56,578
57	Power 3rd Party Trans & Ancillary Svcs	2,288	2,333
58	Trans Acq Generation Integration	11,242	11,454
59	Power Telemetering/Equipment Replacement	52	53
60			
61	**Power Non-Generation Operations**		
62	Efficiencies Program	-	-
63	Systems Operations R&D	-	-
64	Information Technology	6,602	6,735
65	Generation Project Coordination	6,826	6,968
66	Slice costs Charged to Slice Customers	-	-
67	Slice Implementation	1,099	1,126
68			
69	**PS Scheduling**		
70	Operations Scheduling	10,398	10,621
71	Scheduling R&D	-	-
72	Operations Planning	7,641	7,948
73			
74	**PS Marketing and Business Support**		
75	Sales and Support	20,951	21,339
76	Strategy, Finance & Risk Mgmt	18,299	19,373
77	Executive and Administrative Svcs	4,157	4,360
78	Conservation Support	9,094	9,309
79			
80	**Fish and Wildlife/USF&W/Planning Council/Env Req.**		
81	Fish and Wildlife	254,000	260,000
82	USF&W Lower Snake Hatcheries	30,670	31,670
83	Planning Council	10,568	10,799
84	Environmental Requirements	300	300
85			
86	**BPA Internal Support**		
87	Additional Post-Retirement Contribution	18,501	18,819
88	Agency Svs for Power for Rev Req schedule	44,815	46,494
89	Agency Svs for Energy Efficiency for Rev Req schedule	10,287	10,721

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2013 - September 2015
($ 000)

	B	D	E
4		**2014**	**2015**
90			
91	**Bad Debt Expense/Other**		
92	Bad Debt Expense (composite)	-	-
93	Bad Debt Expense (non-slice)	-	-
94	Other Income, Expenses, Adjustments (composite)	-	-
95	Other Income, Expenses, Adjustments (non-slice)	-	-
96			
97	**Non-Federal Debt Service**		
98	**Energy Northwest Debt Service**		
99	CGS Debt Service	88,425	77,686
100	WNP-1 Debt Service	249,161	185,460
101	WNP-3 Debt Service	165,932	165,403
102	EN Retired Debt	-	-
103			
104	**Non-Energy Northwest Debt Service**		
105	Conservation (CARES) Debt Service	2,418	312
106	Cowlitz Falls (Lewis County) Debt Service	7,114	7,122
107	Northern Wasco Debt Service	1,931	1,929
108			
109	**Depreciation and Amortization**		
110	**Depreciation**		
111	Depreciation - BPA	12,466	14,448
112	Depreciation - Corps	87,752	90,927
113	Depreciation - Bureau	27,447	29,076
114			
115	**Amortization**		
116	Amortization - Legacy Conservation	13,930	9,649
117	Amortization - Conservation Acquisitions	43,854	43,218
118	Amortization - CRFM	6,613	6,613
119	Amortization - Fish & Widlife	32,065	34,695
120			
121	**Interest Expense**		
122	**Net Interest**		
123	Interest On Appropriated Funds	223,187	220,893
124	Capitalization Adjustment	(45,937)	(45,937)
125	Interest On Treasury Bonds	68,929	84,766
126	Capitalized Bond Premium	-	-
127	AFUDC	(9,651)	(8,823)
128	Interest Earned on BPA Fund for Power (composite)	(8,668)	(14,827)
129	Interest Earned on BPA Fund for Power (non-slice)	2,214	3,618

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2013 - September 2015
($ 000)

	B	D	E
4		**2014**	**2015**
130			
131	**Net Interest into Cost Pools**		
132	Power Net Interest - Hydro Allocation	187,113	195,597
133	Power Net Interest - Fish & Wildlife Allocation	19,788	20,095
134	Power Net Interest - Conservation Allocation	19,765	20,682
135	Power Net Interest - BPA Programs Allocation	3,408	3,317
136			
137	**Net Interest into Cost Pools 7b2**		
138	Power Net Interest Hydro 7b2 Allocation	187,113	195,597
139	Power Net Interest Fish & Wildlife 7b2 Allocation	19,788	20,095
140	Power Net Interest BPA Programs 7b2 Allocation	23,173	23,999
141			
142	**Net Revenue**		
143	**Minimum Required Net Revenue**		
144	Repayment of Treasury Borrowings	29,950	117,700
145	Payment of Irrigation Assistance	52,427	51,989
146	Depreciation (MRNR - Reverse sign)	(127,665)	(134,451)
147	Amortization (MRNR - Reverse sign)	(96,462)	(94,175)
148	Capitalization Adjustment (MRNR - Reverse Sign)	45,937	45,937
149	Capitalized Bond Premium (Reverse Sign)	-	-
150	Repayment of Federal Appropriations	92,288	9,476
151	Accrual Revenues (MRNR Adjustment - Reverse Sign)	3,524	3,524
152	Prepay Revenue Credits	-	-
153	Revenue Financing Requirement	-	-
154	Depreciation Exceeds Cash Expense	0	(0)
155			
156	**Minimum Net Revenue into Cost Pools**		
157	Power MNetRev - Hydro Allocation	-	-
158	Power MNetRev - Fish & Wildlife Allocation	-	-
159	Power MNetRev - Conservation Allocation	-	-
160	Power MNetRev - BPA Programs Allocation	-	-
161			
162	**Minimum Net Revenue into Cost Pools 7b2**		
163	Power MNetRev - Hydro 7b2 Allocation	-	-
164	Power MNetRev - Fish & Wildlife 7b2 Allocation	-	-
165	Power MNetRev - PBA Programs 7b2 Allocation	-	-
166			
167	**Planned Net Revenues for Risk into Cost Pools**		
168	Power PNetRev - Hydro Allocation	-	-
169	Power PNetRev - Fish & Wildlife Allocation	-	-
170	Power PNetRev - Conservation Allocation	-	-
171	Power PNetRev - BPA Programs Allocation	-	-
172			
173	**Planned Net Revenues for Risk into Cost Pools 7b2**		
174	Power PNetRev - Hydro 7b2 Allocation	-	-
175	Power PNetRev - Fish & Wildlife 7b2 Allocation	-	-
176	Power PNetRev - BPA Programs 7b2 Allocation	-	-

Cost of Service Analysis
Disaggregated Costs and Credits
Test Period October 2013 - September 2015
($ 000)

	B	D	E
4		**2014**	**2015**
177			
178	**Internally Computed Line Items**		
179	Augmentation Power Purchases	27,622	123,283
180	Balancing Purchases	66,985	27,492
181	Secondary Energy Credit	(329,284)	(341,136)
182	Low Density Discount Costs	36,123	37,261
183	Irrigation Rate Mitigation Costs	19,794	19,794
184	**Charges/Credits to Tiered Rate Pools**		
185	Firm Surplus and Secondary Credit (from unused RHWM)	(2,944)	(1,220)
186	Balancing Augmentation	11,343	(20,289)
187	Transmission Loss Adjustment	(27,826)	(28,402)
188	Demand Revenue	60,932	61,568
189	Load Shaping Revenue	5,888	26,150
190	**Tier 2 and RSS Charges/Credits to Tiered Rate Pools**		
191	Augmentation RSS & RSC Adder	2,511	2,511
192	Tier 2 Purchase Costs	5,207	26,442
193	Tier 2 Rate Design Adjustments (Cost)	207	949
194	Tier 2 Other Costs	-	-
195			
196	**Revenue Credits / Rate Design Adjustments**		
197	Downstream Benefits and Pumping Power	(15,393)	(15,394)
198	Generation Inputs for Ancillary and Other Services Revenue	(123,007)	(128,444)
199	4(h)(10)(c)	(95,302)	(92,383)
200	Colville and Spokane Settlements	(4,600)	(4,600)
201	Green Tags (FBS resources)	-	-
202	Green Tags (New resources)	(1,061)	(1,107)
203	Energy Efficiency Revenues	(11,859)	(12,083)
204	Miscellaneous Credits (incl. GTA)	(3,370)	(3,395)
205	Pre-sub/Hungry Horse	(1,842)	(1,909)
206	Other Locational/Seasonal Exchange	(701)	(701)
207	Upper Baker	(422)	(446)
208	WNP3 Settlement	(29,163)	(29,163)
209	Other Long-Term Contracts	-	-
210	Network Wind Integration & Shaping	-	-
211	**Tier 2**		
212	Composite Augmentation RSS Revenue Debit/(Credit)	(2,018)	(2,018)
213	Composite Tier 2 RSS Revenue Debit/(Credit)	(23)	(103)
214	Composite Tier 2 Rate Design Adjustment Debit/(Credit)	(184)	(846)
215	Composite Non-Federal RSS Revenue Debit/(Credit)	(573)	(880)
216	Non-Slice Augmentation RSC Revenue Debit/(Credit)	(493)	(493)
217	Non-Slice Tier 2 RSC Revenue Debit/(Credit)	-	-
218	Non-Slice Tier 2 Rate Design Debit/(Credit)	-	-
219	Non-Slice Non-Federal RSC Revenue Debit/(Credit)	221	267

Cost of Service Analysis
Calculation of Initial Allocation Power Rates
Test Period October 2013 - September 2015
($ 000, aMW, $/MWh)

	B	C		D	
5	**Initial Allocation of Net Revenue Requirement ($000)**		**2014**		**2015**
6	Unbifurcated Priority Firm - 7(b) Loads.......................................	$	4,373,930	$	4,436,073
7	Industrial Firm - 7(c) Loads...	$	178,053	$	178,503
8	New Resources - 7(f) Loads...	$	0.5707	$	0.5721
9	Surplus Firm - SP Loads..	$	29,163	$	29,163
10	Total...	$	4,581,148	$	4,643,739
11					
12					
13	**Energy Billing Determinants (aMW)**		**2014**		**2015**
14					
15	Unbifurcated Priority Firm - 7(b) Loads.......................................		12,064		12,157
16	Industrial Firm - 7(c) Loads...		312		312
17	New Resources - 7(f) Loads...		0.001		0.001
18					
19					
20	**Average Power Rates ($/MWh)**		**2014**		**2015**
21					
22	Unbifurcated Priority Firm - 7(b) Loads.......................................		41.39		41.66
23	Industrial Firm - 7(c) Loads...		65.15		65.31
24	New Resources - 7(f) Loads...		65.15		65.31

Cost of Service Analysis
Cost Pool Aggregation
Test Period October 2013 - September 2015
($ 000)

	B	D	E
3		**2014**	**2015**
4			
5	**Federal Base System**	**1,965,626**	**2,044,234**
6	Hydro	730,244	753,729
7	Operating Expense	543,131	558,132
8	Net Interest	187,113	195,597
9	PNRR	-	-
10	MRNR	-	-
11	BPA Fish and Wildlife Program	316,720	325,888
12	Operating Expense	296,932	305,793
13	Net Interest	19,788	20,095
14	PNRR	-	-
15	MRNR	-	-
16	Trojan	1,500	1,500
17	WNP #1	249,867	186,188
18	WNP #2	401,343	433,360
19	WNP #3	165,932	165,403
20	System Augmentation	27,622	123,283
21	Balancing	66,985	27,492
22	Tier 2 Costs	5,414	27,391
23			
24	**New Resources**	**73,962**	**74,929**
25	Idaho Falls	4,648	4,880
26	Tier 1 Aug (Klondike III)	10,000	9,997
27	Cowlitz Falls	10,515	10,549
28	Other NR	48,799	49,503
29			
30	**Residential Exchange**	**2,893,925**	**2,893,197**
31			
32	**Conservation**	**154,453**	**150,035**
33	Operating Expense	134,688	129,353
34	Net Interest	19,765	20,682
35	PNRR	-	-
36	MRNR	-	-
37			
38	**BPA Programs**	**155,163**	**161,548**
39	Operating Expense	151,755	158,231
40	Net Interest	3,408	3,317
41	PNRR	-	-
42	MRNR	-	-
43			
44			
45	**Transmission**	**167,640**	**168,319**
46	TBL Transmission/Ancillary Services	109,818	109,408
47	3Rd Party Trans/Ancillary Services	2,288	2,333
48	General Transfer Agreements	55,533	56,578
49			
50	**Total PBL Revenue Requirement**	**5,410,769**	**5,492,261**
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

Cost of Service Analysis
Computation of Low Density and Irrigation Rate Discount Costs
Test Period October 2013 - September 2015
($ 000)

	B		D		E	F	G	H
18	**Program Totals**		**2014**		**2015**			
19	**Low Density Discount Expenses........................**	**$**	**36,123**	**$**	**37,261**			
20	**Irrigation Rate Discount...................................**	**$**	**19,794**	**$**	**19,794**			
21								
22								
23	**TRM Costs after Adjustments**		**2014**		**2015**			
24	**Composite..**	$	2,325,269	$	2,334,404			
25	**Non-Slice...**	$	(261,483)	$	(262,895)			
26	**Slice...**	$	-	$	-			
27	**Tier 2...**	$	5,414	$	27,391			
28	**Total Costs**	$	2,069,199	$	2,098,900			
29								
30	**Low Density Discount**							
31	**Customer Charge LDD**		**2014**		**2015**			
32	**TOCA LDD Offest %..**		1.62%		1.66%			
33	**LDD Customer Charge ($000).........................**	$	33,449	$	34,395			
34								
35	**Irrigation Rate Discount**							
36	**IRD Percentage..**		37.06%					
37	**Total Irrigation Load (MWh)..........................**		1,881,605					
38	**RT1SC...**		7,116					
39	**Irrigation Load Weighted LDD.......................**		4.90%					
40								
41			**2014**		**2015**			
42	**Hours...**		8784		8760			
43	**IRD TOCA..**		3.01029%		3.01853%			
44	**Composite Revenue...**	$	71,056,602	$	71,251,103			
45	**Non-Slice Revenue..**	$	(10,978,753)	$	(11,008,805)			
46	**Load Shaping Revenue......................................**	$	(3,899,053)	$	(4,048,357)			
47	**Total after LDD...**	$	53,426,034	$	53,440,438			
48								
49	**Irrigation Rate Discount...................................**		**10.52**					
50								
51								

Cost of Service Analysis
Computation of Low Density and Irrigation Rate Discount Costs
Test Period October 2013 - September 2015
($ 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-13	18,068	(2,934)	$ 9.86	$ 31.30	$ 86,320
54	Oct-13	-	1,481	$ 9.86	$ 28.06	$ 41,543
55	Nov-13	14,583	(9,150)	$ 10.24	$ 32.51	$ (148,154)
56	Nov-13	-	(818)	$ 10.24	$ 29.90	$ (24,457)
57	Dec-13	26,831	58	$ 11.26	$ 35.78	$ 304,176
58	Dec-13	-	4,829	$ 11.26	$ 31.97	$ 154,378
59	Jan-14	29,995	(3,059)	$ 11.29	$ 35.86	$ 228,962
60	Jan-14	-	5,301	$ 11.29	$ 30.24	$ 160,275
61	Feb-14	15,913	2,124	$ 10.83	$ 34.39	$ 245,379
62	Feb-14	-	4,772	$ 10.83	$ 29.75	$ 141,985
63	Mar-14	19,694	460	$ 9.31	$ 29.53	$ 196,935
64	Mar-14	-	1,206	$ 9.31	$ 25.90	$ 31,232
65	Apr-14	22,261	11,149	$ 8.16	$ 25.85	$ 469,886
66	Apr-14	-	6,852	$ 8.16	$ 21.20	$ 145,292
67	May-14	21,984	(20,795)	$ 7.09	$ 22.45	$ (310,960)
68	May-14	-	(9,190)	$ 7.09	$ 15.31	$ (140,673)
69	Jun-14	19,308	(6,814)	$ 7.52	$ 23.79	$ (16,926)
70	Jun-14	-	245	$ 7.52	$ 17.42	$ 4,261
71	Jul-14	24,361	(5,632)	$ 9.84	$ 31.17	$ 64,193
72	Jul-14	-	7,680	$ 9.84	$ 26.86	$ 206,307
73	Aug-14	19,727	3,129	$ 10.66	$ 33.90	$ 316,362
74	Aug-14	-	6,831	$ 10.66	$ 28.60	$ 195,374
75	Sep-14	17,993	196	$ 10.74	$ 34.16	$ 199,949
76	Sep-14	-	4,189	$ 10.74	$ 29.37	$ 123,018
77	**Total**					**$ 2,674,656**

Cost of Service Analysis
Computation of Low Density and Irrigation Rate Discount Costs
Test Period October 2013 - September 2015
($ 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-14	17,895	(2,393)	$ 9.86	$ 31.30	$ 101,536
80	Oct-14	-	1,884	$ 9.86	$ 28.06	$ 52,864
81	Nov-14	11,457	(9,278)	$ 10.24	$ 32.51	$ (184,326)
82	Nov-14	-	(358)	$ 10.24	$ 29.90	$ (10,694)
83	Dec-14	32,877	434	$ 11.26	$ 35.78	$ 385,740
84	Dec-14	-	4,611	$ 11.26	$ 31.97	$ 147,435
85	Jan-15	30,641	(3,374)	$ 11.29	$ 35.86	$ 224,955
86	Jan-15	-	5,242	$ 11.29	$ 30.24	$ 158,502
87	Feb-15	15,916	1,882	$ 10.83	$ 34.39	$ 237,074
88	Feb-15	-	4,658	$ 10.83	$ 29.75	$ 138,586
89	Mar-15	19,902	386	$ 9.31	$ 29.53	$ 196,700
90	Mar-15	-	1,048	$ 9.31	$ 25.90	$ 27,142
91	Apr-15	23,204	11,319	$ 8.16	$ 25.85	$ 481,969
92	Apr-15	-	6,914	$ 8.16	$ 21.20	$ 146,606
93	May-15	20,316	(21,827)	$ 7.09	$ 22.45	$ (345,967)
94	May-15	-	(9,338)	$ 7.09	$ 15.31	$ (142,935)
95	Jun-15	25,671	(6,727)	$ 7.52	$ 23.79	$ 32,975
96	Jun-15	-	27	$ 7.52	$ 17.42	$ 478
97	Jul-15	26,477	(5,533)	$ 9.84	$ 31.17	$ 88,092
98	Jul-15	-	8,031	$ 9.84	$ 26.86	$ 215,732
99	Aug-15	20,751	3,722	$ 10.66	$ 33.90	$ 347,370
100	Aug-15	-	7,315	$ 10.66	$ 28.60	$ 209,199
101	Sep-15	18,144	802	$ 10.74	$ 34.16	$ 222,264
102	Sep-15	-	4,575	$ 10.74	$ 29.37	$ 134,363
103	**Total**					**$ 2,865,661**

Cost of Service Analysis
Allocation of Costs
Test Period October 2013 - September 2015
($ 000)

	B	C		D	
4	**Costs ($000)**		**2014**		**2015**
5	**FBS..**	$	1,965,626	$	2,044,234
6	**New Resources......................................**	$	73,962	$	74,929
7	**Residential Exchange...........................**	$	2,893,925	$	2,893,197
8	**Conservation...**	$	154,453	$	150,035
9	**BPAPrograms.......................................**	$	155,163	$	161,548
10	**Transmission...**	$	167,640	$	168,319
11	**Irrigation/Low Density Discounts.......**	$	55,918	$	57,055
12	Total..	$	5,466,687	$	5,549,316
13					
14	**Cost Allocation**				
15					
16	**FBS..**	$	1,965,626	$	2,044,234
17					
18	**Federal Base System Allocators...........**		**2014**		**2015**
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............................**		**2014**		**2015**
26	Priority Firm - 7(b) Loads......................	$	1,965,626	$	2,044,234
27	Industrial Firm - 7(c) Loads...................	$	-	$	-
28	New Resources - 7(f) Loads...................	$	-	$	-
29	Surplus Firm - SP Loads........................	$	-	$	-
30	Total..	$	1,965,626	$	2,044,234
31					
32					
33	**Irrigation/Low Density Discounts.......**	$	55,918	$	57,055
34					
35	**Irrigation/LDD Allocators..................**		**2014**		**2015**
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...........**		**2014**		**2015**
43	Priority Firm - 7(b) Loads......................	$	55,918	$	57,055
44	Industrial Firm - 7(c) Loads...................	$	-	$	-
45	New Resources - 7(f) Loads...................	$	-	$	-
46	Surplus Firm - SP Loads........................	$	-	$	-
47	Total..	$	55,918	$	57,055

Cost of Service Analysis
Allocation of Costs
Test Period October 2013 - September 2015
($ 000)

	B		C		D
4	**Costs ($000)**		**2014**		**2015**
5	**FBS...**	$	1,965,626	$	2,044,234
6	**New Resources.......................................**	$	73,962	$	74,929
7	**Residential Exchange.............................**	$	2,893,925	$	2,893,197
8	**Conservation..**	$	154,453	$	150,035
9	**BPAPrograms..**	$	155,163	$	161,548
10	**Transmission..**	$	167,640	$	168,319
11	**Irrigation/Low Density Discounts.........**	$	55,918	$	57,055
12	Total...	$	5,466,687	$	5,549,316
13					
14	**Cost Allocation (continued)**				
15					
16	**New Resources.......................................**	$	73,962	$	74,929
17					
18	**New Resources Allocators**		**2014**		**2015**
19	Priority Firm - 7(b) Loads.......................		0.0000		0.0000
20	Industrial Firm - 7(c) Loads.....................		0.7717		0.7717
21	New Resources - 7(f) Loads....................		0.00000247		0.00000247
22	Surplus Firm - SP Loads..........................		0.2283		0.2283
23	Total...		1.0000		1.0000
24					
25	**New Resources Cost Allocation...........**		**2014**		**2015**
26	Priority Firm - 7(b) Loads.......................	$	-	$	-
27	Industrial Firm - 7(c) Loads.....................	$	57,076	$	57,822
28	New Resources - 7(f) Loads....................	$	0.1829	$	0.1853
29	Surplus Firm - SP Loads..........................	$	16,886	$	17,106
30	Total...	$	73,962	$	74,929
31					
32					
33	**Residential Exchange.............................**	$	2,893,925	$	2,893,197
34	Costs Functionalized to Transmission.....	$	(177,503)	$	(177,440)
35	Costs Functionalized to Generation.........	$	2,716,422	$	2,715,757
36					
37	**Residential Exchange Allocators**		**2014**		**2015**
38	Priority Firm - 7(b) Loads.......................		0.9436		0.9435
39	Industrial Firm - 7(c) Loads.....................		0.0436		0.0436
40	New Resources - 7(f) Loads....................		0.00000014		0.00000014
41	Surplus Firm - SP Loads..........................		0.0129		0.0129
42	Total...		1.0000		1.0000
43					
44	**Residential Exchange Cost Allocation**		**2014**		**2015**
45	Priority Firm - 7(b) Loads.......................	$	2,563,108	$	2,562,427
46	Industrial Firm - 7(c) Loads.....................	$	118,311	$	118,323
47	New Resources - 7(f) Loads....................	$	0.379	$	0.379
48	Surplus Firm - SP Loads..........................	$	35,003	$	35,007
49	Total...	$	2,716,422	$	2,715,757

Cost of Service Analysis
Allocation of Costs
Test Period October 2013 - September 2015
($ 000)

	B		C		D
4	**Costs ($000)**		**2014**		**2015**
5	**FBS..**	$	1,965,626	$	2,044,234
6	**New Resources................................**	$	73,962	$	74,929
7	**Residential Exchange.......................**	$	2,893,925	$	2,893,197
8	**Conservation....................................**	$	154,453	$	150,035
9	**BPAPrograms..................................**	$	155,163	$	161,548
10	**Transmission...................................**	$	167,640	$	168,319
11	**Irrigation/Low Density Discounts...**	$	55,918	$	57,055
12	Total..	$	5,466,687	$	5,549,316
13					
14	**Cost Allocation (continued)**				
15					
16	**Conservation....................................**	$	154,453	$	150,035
17					
18	**BPAPrograms..................................**	$	155,163	$	161,548
19					
20	**Transmission...................................**	$	167,640	$	168,319
21					
22					
23	**Conservation & General Allocators**		**2014**		**2015**
24	Priority Firm - 7(b) Loads.................		0.9676		0.9678
25	Industrial Firm - 7(c) Loads..............		0.0250		0.0248
26	New Resources - 7(f) Loads..............		0.0000		0.0000
27	Surplus Firm - SP Loads...................		0.0074		0.0073
28	Total..		1.0000		1.0000
29					
30	**Conservation Cost Allocation..........**		**2014**		**2015**
31	Priority Firm - 7(b) Loads.................	$	149,444	$	145,206
32	Industrial Firm - 7(c) Loads..............	$	3,865	$	3,727
33	New Resources - 7(f) Loads..............	$	0	$	0
34	Surplus Firm - SP Loads...................	$	1,143	$	1,103
35	Total..	$	154,453	$	150,035
36					
37	**BPA Programs Cost Allocation.......**		**2014**		**2015**
38	Priority Firm - 7(b) Loads.................	$	150,131	$	156,348
39	Industrial Firm - 7(c) Loads..............	$	3,883	$	4,013
40	New Resources - 7(f) Loads..............	$	0	$	0
41	Surplus Firm - SP Loads...................	$	1,149	$	1,187
42	Total..	$	155,163	$	161,548
43					
44	**Transmission Cost Allocation..........**		**2014**		**2015**
45	Priority Firm - 7(b) Loads.................	$	162,204	$	162,901
46	Industrial Firm - 7(c) Loads..............	$	4,195	$	4,181
47	New Resources - 7(f) Loads..............	$	0	$	0
48	Surplus Firm - SP Loads...................	$	1,241	$	1,237
49	Total..	$	167,640	$	168,319

Cost of Service Analysis
Allocation of Costs Summary
Test Period October 2013 - September 2015
($ 000)

	B		C		D
4	**Costs ($000)**		**2014**		**2015**
5	**FBS...**	$	1,965,626	$	2,044,234
6	**New Resources.......................................**	$	73,962	$	74,929
7	**Residential Exchange............................**	$	2,893,925	$	2,893,197
8	**Conservation..**	$	154,453	$	150,035
9	**BPAPrograms..**	$	155,163	$	161,548
10	**Transmission..**	$	167,640	$	168,319
11	**Irrigation/Low Density Discounts........**	$	55,918	$	57,055
12	Total..	$	5,466,687	$	5,549,316
13					
14	**Cost Allocation (continued)**				
15					
16					
17	**Initial Cost Allocation (Costs /$1000)**		**2014**		**2015**
18	Priority Firm - 7(b) Loads.......................	$	5,046,432	$	5,128,171
19	Industrial Firm - 7(c) Loads...................	$	187,329	$	188,065
20	New Resources - 7(f) Loads...................	$	0.60	$	0.60
21	Surplus Firm - SP Loads.........................	$	55,422	$	55,640
22	Total Costs Functionalized to Power......	$	5,289,183	$	5,371,876
23					
24					
25					
26	REP Cost Functionalized to Transmissio	$	177,503	$	177,440
27					
28	Total COSA Revenue Requirement	$	5,466,687	$	5,549,316

Cost of Service Analysis
General Revenue Credits
Test Period October 2013 - September 2015
($ 000)

	B		C		D
5	**General Revenue Credits ($000))**		**2014**		**2015**
6					
7	**FBS..........**	**$**	**(115,501)**	**$**	**(113,326)**
8	Hydro and Renewable..........	$	(19,993)	$	(19,994)
9	Downstream Benefits and Pumping Power..........	$	(15,393)	$	(15,394)
10	Colville and Spokane Settlements..........	$	(4,600)	$	(4,600)
11	Green Tags (FBS resources)..........	$	-	$	-
12	Fish and Wildlife..........	$	(95,302)	$	(92,383)
13	4(h)(10)(c)..........	$	(95,302)	$	(92,383)
14	Tier 2 Adjustment..........	$	(207)	$	(949)
15	**Contract Obligations..........**	**$**	**(2,966)**	**$**	**(3,056)**
16	Pre-sub/Hungry Horse..........	$	(1,842)	$	(1,909)
17	Other Locational/Seasonal Exchange..........	$	(701)	$	(701)
18	Upper Baker..........	$	(422)	$	(446)
19	**New Resources..........**	**$**	**(1,061)**	**$**	**(1,107)**
20	Green Tags (New resources)..........	$	(1,061)	$	(1,107)
21	**Conservation..........**	**$**	**(11,859)**	**$**	**(12,083)**
22	Energy Efficiency Revenues..........	$	(11,859)	$	(12,083)
23	**BPAPrograms..........**	**$**	**-**	**$**	**-**
24	**Transmission..........**	**$**	**(3,370)**	**$**	**(3,395)**
25	Miscellaneous Credits (incl. GTA)..........	$	(3,370)	$	(3,395)
26					
27	**Other Revenue Credits ($ 000))**		**2014**		**2015**
28	Secondary Revenue..........	**$**	**(449,919)**	**$**	**(466,114)**
29	Incl. Slice..........	$	(449,919)	$	(466,114)
30	Generation Inputs for Ancillary and Other Services Revenue..	**$**	**(123,007)**	**$**	**(128,444)**
31	Composite Non-Federal RSS Revenue Debit/(Credit)..........	**$**	**(573)**	**$**	**(880)**
32	Non-Slice Non-Federal RSC Revenue Debit/(Credit)..........	**$**	**221**	**$**	**267**
33	Network Wind Integration & Shaping..........	**$**	**-**	**$**	**-**
34	**Contract Revenue from Other Long-term Sales..........**	**$**	**(29,163)**	**$**	**(29,163)**
35	WNP3 Settlement..........	$	(29,163)	$	(29,163)
36	Other Long-Term Contracts..........	$	-	$	-
37					
38	**Total Revenue Credits**	$	(737,199)	$	(757,300)

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2013 - September 2015
($ 000)

	B		C		D
4	**Allocation of Revenue Requirement**		**2014**		**2015**
5	Priority Firm - 7(b) Loads.......................................	$	5,046,432	$	5,128,171
6	Industrial Firm - 7(c) Loads....................................	$	187,329	$	188,065
7	New Resources - 7(f) Loads....................................	$	1	$	1
8	Surplus Firm - SP Loads...	$	55,422	$	55,640
9	Total..	$	5,289,183	$	5,371,876
10					
11	**General Revenue Credits ($000))**		**2014**		**2015**
12					
13	**FBS..**	**$**	**(118,467)**	**$**	**(116,382)**
14	Hydro and Renewable.......................................	$	(19,993)	$	(19,994)
15	Downstream Benefits and Pumping Power..	$	(15,393)	$	(15,394)
16	Colville and Spokane Settlements................	$	(4,600)	$	(4,600)
17	Green Tags (FBS resources)........................	$	-	$	-
18	Fish and Wildlife...	$	(95,302)	$	(92,383)
19	4(h)(10)(c)...	$	(95,302)	$	(92,383)
20	Tier 2 Adjustment..	$	(207)	$	(949)
21	Contract Obligations..	$	(2,966)	$	(3,056)
22	Pre-sub/Hungry Horse.................................	$	(1,842)	$	(1,909)
23	Other Locational/Seasonal Exchange...........	$	(701)	$	(701)
24	Upper Baker..	$	(422)	$	(446)
25					
26	**Federal Base System Allocators**		**2014**		**2015**
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**		**2014**		**2015**
34	Priority Firm - 7(b) Loads.......................................	$	(118,467)	$	(116,382)
35	Industrial Firm - 7(c) Loads....................................	$	-	$	-
36	New Resources - 7(f) Loads....................................	$	-	$	-
37	Surplus Firm - SP Loads...	$	-	$	-
38	Total..	$	(118,467)	$	(116,382)
39					
40	**Allocation of Revenue Requirement**		**2014**		**2015**
41	Priority Firm - 7(b) Loads.......................................	$	4,927,965	$	5,011,789
42	Industrial Firm - 7(c) Loads....................................	$	187,329	$	188,065
43	New Resources - 7(f) Loads....................................	$	1	$	1
44	Surplus Firm - SP Loads...	$	55,422	$	55,640
45	Total..	$	5,170,716	$	5,255,495

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2013 - September 2015
($ 000)

	B	C		D	
40	**Allocation of Revenue Requirement**		**2014**		**2015**
41	Priority Firm - 7(b) Loads.......................................	$	4,927,965	$	5,011,789
42	Industrial Firm - 7(c) Loads....................................	$	187,329	$	188,065
43	New Resources - 7(f) Loads....................................	$	1	$	1
44	Surplus Firm - SP Loads...	$	55,422	$	55,640
45	Total...	$	5,170,716	$	5,255,495
46					
47					
48	**General Revenue Credits (/$1000))**		**2014**		**2015**
49					
50	**Transmission...**	**$**	**(3,370)**	**$**	**(3,395)**
51	Miscellaneous Credits (incl. GTA)...................	$	(3,370)	$	(3,395)
52					
53	**Conservation & General Cost Allocators**		**2014**		**2015**
54	Priority Firm - 7(b) Loads.......................................		0.9676		0.9678
55	Industrial Firm - 7(c) Loads....................................		0.0250		0.0248
56	New Resources - 7(f) Loads....................................		0.0000		0.0000
57	Surplus Firm - SP Loads...		0.0074		0.0073
58	Total...		1.0000		1.0000
59					
60	**FBS Contract Obligation Revenue Allocation**		**2014**		**2015**
61	Priority Firm - 7(b) Loads.......................................	$	(3,261)	$	(3,286)
62	Industrial Firm - 7(c) Loads....................................	$	(84)	$	(84)
63	New Resources - 7(f) Loads....................................	$	(0)	$	(0)
64	Surplus Firm - SP Loads...	$	(25)	$	(25)
65	Total...	$	(3,370)	$	(3,395)
66					
67	**Allocation of Revenue Requirement**		**2014**		**2015**
68	Priority Firm - 7(b) Loads.......................................	$	4,924,704	$	5,008,503
69	Industrial Firm - 7(c) Loads....................................	$	187,244	$	187,981
70	New Resources - 7(f) Loads....................................	$	1	$	1
71	Surplus Firm - SP Loads...	$	55,397	$	55,615
72	Total...	$	5,167,346	$	5,252,100

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2013 - September 2015
($ 000)

	B		C		D
4	**Allocation of Revenue Requirement**		**2014**		**2015**
5	Priority Firm - 7(b) Loads................................	$	4,924,704	$	5,008,503
6	Industrial Firm - 7(c) Loads.............................	$	187,244	$	187,981
7	New Resources - 7(f) Loads............................	$	1	$	1
8	Surplus Firm - SP Loads..................................	$	55,397	$	55,615
9	Total...	$	5,167,346	$	5,252,100
10					
11					
12	**General Revenue Credits ($000))**		**2014**		**2015**
13					
14	**New Resources...**	**$**	**(1,061)**	**$**	**(1,107)**
15	Green Tags (New resources)......................	$	(1,061)	$	(1,107)
16					
17					
18	**New Resources Cost Allocators**		**2014**		**2015**
19	Priority Firm - 7(b) Loads................................		0.0000		0.0000
20	Industrial Firm - 7(c) Loads.............................		0.7717		0.7717
21	New Resources - 7(f) Loads............................		0.000002		0.000002
22	Surplus Firm - SP Loads..................................		0.2283		0.2283
23	Total...		1.0000		1.0000
24					
25	**New Resources Allocation**		**2014**		**2015**
26	Priority Firm - 7(b) Loads................................	$	-	$	-
27	Industrial Firm - 7(c) Loads.............................	$	(819)	$	(855)
28	New Resources - 7(f) Loads............................	$	(0.003)	$	(0.003)
29	Surplus Firm - SP Loads..................................	$	(242)	$	(253)
30	Total...	$	(1,061)	$	(1,107)
31					
32	**Allocation of Revenue Requirement**		**2014**		**2015**
33	Priority Firm - 7(b) Loads................................	$	4,924,704	$	5,008,503
34	Industrial Firm - 7(c) Loads.............................	$	186,425	$	187,126
35	New Resources - 7(f) Loads............................	$	0.598	$	0.600
36	Surplus Firm - SP Loads..................................	$	55,155	$	55,362
37	Total...	$	5,166,285	$	5,250,992
38					

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2013 - September 2015
($ 000)

	B	C	D
32	**Allocation of Revenue Requirement**	**2014**	**2015**
33	Priority Firm - 7(b) Loads................................	$ 4,924,704	$ 5,008,503
34	Industrial Firm - 7(c) Loads.............................	$ 186,425	$ 187,126
35	New Resources - 7(f) Loads............................	$ 0.598	$ 0.600
36	Surplus Firm - SP Loads.................................	$ 55,155	$ 55,362
37	Total..	$ 5,166,285	$ 5,250,992
39			
40	**General Revenue Credits (/$1000))**	**2014**	**2015**
41			
42	**Conservation...**	**$ (11,859)**	**$ (12,083)**
43	Energy Efficiency Revenues.......................	$ (11,859)	$ (12,083)
44			
45			
46	**Conservation & General Cost Allocators**	**2014**	**2015**
47	Priority Firm - 7(b) Loads................................	0.9676	0.9678
48	Industrial Firm - 7(c) Loads.............................	0.0250	0.0248
49	New Resources - 7(f) Loads............................	0.0000001	0.0000001
50	Surplus Firm - SP Loads.................................	0.0074	0.0073
51	Total..	1.0000	1.0000
52			
53	**Conservation Allocation**	**2014**	**2015**
54	Priority Firm - 7(b) Loads................................	$ (11,474)	$ (11,694)
55	Industrial Firm - 7(c) Loads.............................	$ (297)	$ (300)
56	New Resources - 7(f) Loads............................	$ (0.001)	$ (0.001)
57	Surplus Firm - SP Loads.................................	$ (88)	$ (89)
58	Total..	$ (11,859)	$ (12,083)
59			
60	**Allocation of Revenue Requirement**	**2014**	**2015**
61	Priority Firm - 7(b) Loads................................	$ 4,913,230	$ 4,996,809
62	Industrial Firm - 7(c) Loads.............................	$ 186,128	$ 186,826
63	New Resources - 7(f) Loads............................	$ 0.597	$ 0.599
64	Surplus Firm - SP Loads.................................	$ 55,067	$ 55,273
65	Total..	$ 5,154,426	$ 5,238,909

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2013 - September 2015
($ 000)

	B		C		D
4	**Allocation of Revenue Requirement**		**2014**		**2015**
5	Priority Firm - 7(b) Loads..	$	4,913,230	$	4,996,809
6	Industrial Firm - 7(c) Loads...	$	186,128	$	186,826
7	New Resources - 7(f) Loads..	$	0.5966	$	0.5988
8	Surplus Firm - SP Loads..	$	55,067	$	55,273
9	Total..	$	5,154,426	$	5,238,909
10					
11	**General Revenue Credits (/$1000))**		**2014**		**2015**
12					
13	**Generation Inputs..**	**$**	**(123,007)**	**$**	**(128,444)**
14					
15	**Network Wind Integration Shaping Revenues..............**	**$**	**-**	**$**	**-**
16					
17	**Credit Due to Idaho Deemer Account............................**	**$**	**-**	**$**	**-**
19					
20	**Conservation & General Cost Allocators**		**2014**		**2015**
21	Priority Firm - 7(b) Loads..		0.9676		0.9678
22	Industrial Firm - 7(c) Loads...		0.0250		0.0248
23	New Resources - 7(f) Loads..		0.0000001		0.0000001
24	Surplus Firm - SP Loads..		0.0074		0.0073
25	Total..		1.0000		1.0000
26					
27	**Gen Inputs & Wind Integration Credit Allocation**		**2014**		**2015**
28	Priority Firm - 7(b) Loads..	$	(119,018)	$	(124,310)
29	Industrial Firm - 7(c) Loads...	$	(3,078)	$	(3,190)
30	New Resources - 7(f) Loads..	$	(0)	$	(0)
31	Surplus Firm - SP Loads..	$	(911)	$	(944)
32	Total..	$	(123,007)	$	(128,444)
33					
34	**Allocation of Revenue Requirement**		**2014**		**2015**
35	Priority Firm - 7(b) Loads..	$	4,794,211	$	4,872,500
36	Industrial Firm - 7(c) Loads...	$	183,050	$	183,636
37	New Resources - 7(f) Loads..	$	0.5867	$	0.5886
38	Surplus Firm - SP Loads..	$	54,156	$	54,329
39	Total..	$	5,031,419	$	5,110,465
40					

Cost of Service Analysis
Allocation of Revenue Credits
Test Period October 2013 - September 2015
($ 000)

	B		C		D
34	**Allocation of Revenue Requirement**		**2014**		**2015**
35	Priority Firm - 7(b) Loads..	$	4,794,211	$	4,872,500
36	Industrial Firm - 7(c) Loads..	$	183,050	$	183,636
37	New Resources - 7(f) Loads...	$	0.5867	$	0.5886
38	Surplus Firm - SP Loads...	$	54,156	$	54,329
39	Total..	$	5,031,419	$	5,110,465
41					
42	**Other Revenue Credits**		**2014**		**2015**
43	Composite Non-Federal RSS Revenue Debit/(Credit)..	$	(573)	$	(880)
44	Non-Slice Non-Federal RSC Revenue Debit/(Credit)...	$	221	$	267
45					
46					
47	**Conservation & General Cost Allocators**		**2014**		**2015**
48	Priority Firm - 7(b) Loads..		0.9676		0.9678
49	Industrial Firm - 7(c) Loads..		0.0250		0.0248
50	New Resources - 7(f) Loads...		0.0000001		0.0000001
51	Surplus Firm - SP Loads...		0.0074		0.0073
52	Total..		1.0000		1.0000
53					
54	**Non-Federal RSS Revenues**		**2014**		**2015**
55	Priority Firm - 7(b) Loads..	$	(341)	$	(593)
56	Industrial Firm - 7(c) Loads..	$	(9)	$	(15)
57	New Resources - 7(f) Loads...	$	(0.0000)	$	(0.0000)
58	Surplus Firm - SP Loads...	$	(3)	$	(5)
59	Total..	$	(352)	$	(612)
60					
61	**Allocation of Revenue Requirement**		**2014**		**2015**
62	Priority Firm - 7(b) Loads..	$	4,793,870	$	4,871,907
63	Industrial Firm - 7(c) Loads..	$	183,042	$	183,621
64	New Resources - 7(f) Loads...	$	0.5867	$	0.5885
65	Surplus Firm - SP Loads...	$	54,154	$	54,325
66	Total..	$	5,031,067	$	5,109,853

Cost of Service Analysis
Calculation and Allocation of Secondary Revenue Credit
Test Period October 2013 - September 2015
(aMW, $ 000)

	C		D		E
4	**General Revenue Credits ($000))**		**2014**		**2015**
9					
10	BPA Secondary Sales Post-Slice (aMW)		1696.9		1684.2
11					
12	Slice Percentage		26.8126%		26.8126%
13					
14	BPA Secondary Sales Pre-Slice, aMW (row 1 * (1-row 3))		2318.6		2301.2
15					
16	aMW to GWh Multiplier		8.760		8.760
17					
18	BPA Secondary Sales Pre-Slice GWh (row 5 * row 7)		20311.1		20158.9
19					
20	Secondary Sales Price	$	22.15	$	23.12
21	Adhoc Addition to Secondary (includes other commited sales)		-		-
22	BPA Secondary Sales Pre-Slice $000 (includes other commited sales)	$	449,919	$	466,114
23					
24	BPA Secondary Sales Allocated to 7b3 Rate Protection	$	-	$	-
25					
26	**BPA Secondary Sales Available as Revenue Credit (row 13 - row 15)**	**$**	**449,919**	**$**	**466,114**
27					
28	Slice Portion of Secondary	$	120,635	$	124,977
29					
30	**Federal Base System + NR Cost Allocators**		**2014**		**2015**
31	Priority Firm - 7(b) Loads..........		0.9839		0.9841
32	Industrial Firm - 7(c) Loads..........		0.0124		0.0122
33	New Resources - 7(f) Loads..........		0.0000		0.0000
34	Surplus Firm - SP Loads..........		0.0037		0.0036
35	Total..........		1.0000		1.0000
36					
37					
38	**Allocation of Secondary Revenues Credit**		**2014**		**2015**
39	Priority Firm - 7(b) Loads..........	$	(442,692)	$	(458,720)
40	Industrial Firm - 7(c) Loads..........	$	(5,577)	$	(5,705)
41	New Resources - 7(f) Loads..........	$	(0.0179)	$	(0.0183)
42	Surplus Firm - SP Loads..........	$	(1,650)	$	(1,688)
43	Total..........	$	(449,919)	$	(466,114)
44					
45	**Allocation of Revenue Requirement**		**2014**		**2015**
46	Priority Firm - 7(b) Loads..........	$	4,351,178	$	4,413,187
47	Industrial Firm - 7(c) Loads..........	$	177,465	$	177,915
48	New Resources - 7(f) Loads..........	$	0.5688	$	0.5702
49	Surplus Firm - SP Loads..........	$	52,504	$	52,637
50	Total..........	$	4,581,148	$	4,643,739

Cost of Servise Analysis
Calculation and Allocation of FPS Revenue Deficiency Delta
Test Period October 2013 - September 2015
($ 000)

	B		C		D
5	**Allocation of Revenue Requirement**		2014		2015
6	Priority Firm - 7(b) Loads	$	4,351,178	$	4,413,187
7	Industrial Firm - 7(c) Loads	$	177,465	$	177,915
8	New Resources - 7(f) Loads	$	0.5688	$	0.5702
9	Surplus Firm - SP Loads	$	52,504	$	52,637
10	Total	$	4,581,148	$	4,643,739
11					
12	**Contract Revenue from Other Long-term Sales**	**$**	**(29,163)**	**$**	**(29,163)**
13	WNP3 Settlement	$	(29,163)	$	(29,163)
14	Other Long-Term Contracts	$	-	$	-
15					
16	**Calculation of FPS Revenue Deficiency**		2014		2015
17	Surplus Firm - SP Loads	$	52,504	$	52,637
18					
19	**Deficiency**	**$**	**23,340**	**$**	**23,473**
20					
21					
22					
23	**Surplus Deficit Cost Allocators**		2014		2015
24	Priority Firm - 7(b) Loads		0.9748		0.9750
25	Industrial Firm - 7(c) Loads		0.0252		0.0250
26	New Resources - 7(f) Loads		0.0000001		0.0000001
27	Surplus Firm - SP Loads		-1.0000		-1.0000
28	Total		0.0000		0.0000
29					
30	**Surplus Deficit Cost Allocation**		2014		2015
31	Priority Firm - 7(b) Loads	$	22,752	$	22,886
32	Industrial Firm - 7(c) Loads	$	588	$	587
33	New Resources - 7(f) Loads	$	0.0019	$	0.0019
34	Surplus Firm - SP Loads	$	(23,340)	$	(23,473)
35	Total	$	-	$	-
36					
37					
38	**Initial Allocation of Net Revenue Requirement**		2014		2015
39	Priority Firm - 7(b) Loads	$	4,373,930	$	4,436,073
40	Industrial Firm - 7(c) Loads	$	178,053	$	178,503
41	New Resources - 7(f) Loads	$	0.5707	$	0.5721
42	Surplus Firm - SP Loads	$	29,163	$	29,163
43	Total	$	4,581,148	$	4,643,739

Cost of Service Analysis
Calculation of Initial Allocation Power Rates
Test Period October 2013 - September 2015
($ 000, aMW, $/MWh)

	B	C		D	
5	**Initial Allocation of Net Revenue Requirement ($000)**		**2014**		**2015**
6	Unbifurcated Priority Firm - 7(b) Loads.......................................	$	4,373,930	$	4,436,073
7	Industrial Firm - 7(c) Loads...	$	178,053	$	178,503
8	New Resources - 7(f) Loads...	$	0.5707	$	0.5721
9	Surplus Firm - SP Loads..	$	29,163	$	29,163
10	Total...	$	4,581,148	$	4,643,739
11					
12					
13	**Energy Billing Determinants (aMW)**		**2014**		**2015**
14					
15	Unbifurcated Priority Firm - 7(b) Loads.......................................		12,064		12,157
16	Industrial Firm - 7(c) Loads...		312		312
17	New Resources - 7(f) Loads...		0.001		0.001
18					
19					
20	**Average Power Rates ($/MWh)**		**2014**		**2015**
21					
22	Unbifurcated Priority Firm - 7(b) Loads.......................................		41.39		41.66
23	Industrial Firm - 7(c) Loads...		65.15		65.31
24	New Resources - 7(f) Loads...		65.15		65.31

Rate Directive Step
Calculation of DSI VOR and Net Industrial Margin
Test Period October 2013 - September 2015

	B	C	D	E	F	G	H	I
5								
6	Operating Reserves - Supplemental							
8			Embedded Cost $/kW/Mo			$ 7.26		
9								
10	1) Assumed DSI sale					312	aMW	
11	Assumed Wheel Turning Load					6	aMW	
12	Interruptible Load					306		
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					$ 2,665,875	per year	
17	Value converted to $/MWh on total load					$ 0.975	$/MWh	
18								
19					industrial margin	0.709		
20								
21					**net industrial margin**	**$ (0.266)**		

Rate Directive Step
Calculation of Annual Energy Rate Scalars for First IP-PF Link Calculation
Test Period October 2013 - September 2015

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
6	**Load Shaping Rate**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**					
7	HLH (mills/kWh)		31.30	32.51	35.78	35.86	34.39	29.53	25.85	22.45	23.79	31.17	33.90	34.16					
8	LLH (mills/kWh)		28.06	29.90	31.97	30.24	29.75	25.90	21.20	15.31	17.42	26.86	28.60	29.37					
9	Demand Rate ($/kW/mo)		9.86	10.24	11.26	11.29	10.83	9.31	8.16	7.09	7.52	9.84	10.66	10.74					
10																			
11																			
12	**Unbifurcated PF+NR Load**		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				**2014**	
13	**2014**	HLH	4830	5511	6100	5802	5045	5289	4848	5416	5025	5398	5173	4729				Energy (GWH)	105683
14		LLH	3049	3870	4399	4091	3395	3554	3127	3730	3180	3629	3290	3201				Allocated Cost	**$ 4,441,487**
15		Demand	825	685	1218	1373	768	895	990	775	677	928	750	749				Rate Scalar	**11.88**
16	Revenue at marginal Rates		$ 244,876	$ 301,914	$ 372,582	$ 347,269	$ 282,805	$ 256,591	$ 199,704	$ 184,180	$ 180,069	$ 274,843	$ 277,420	$ 263,594			**$ 3,185,848**		
17			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				**2015**	
18	**2015**	HLH	4900	5524	6304	6046	5152	5392	4959	5257	4843	5454	5300	4591				Energy (GWH)	106492
19		LLH	3104	3988	4403	4224	3460	3613	3185	3709	3025	3482	3391	3188				Allocated Cost	**$ 4,503,538**
20		Demand	811	473	1446	1368	755	885	993	610	883	950	751	740				Rate Scalar	**12.08**
21	Revenue at marginal Rates		$ 248,439	$ 303,674	$ 382,564	$ 359,958	$ 288,274	$ 261,056	$ 203,830	$ 179,125	$ 174,570	$ 272,854	$ 284,609	$ 258,395			**$ 3,217,349**		
43																			
50																			
51		**IP Load**	**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				**2014**	
52	**2014**	HLH	133	123	127	129	118	132	128	127	126	127	131	122				Energy (GWH)	2733
53		LLH	98	103	104	103	92	100	97	105	97	105	101	104				Allocated Cost	**$ 110,497**
54		Demand	0	0	0	0	0	0	0	0	0	0	0	0				Rate Scalar	**11.61**
55	Revenue at marginal Rates		$ 6,935	$ 7,072	$ 7,878	$ 7,732	$ 6,801	$ 6,485	$ 5,362	$ 4,458	$ 4,703	$ 6,787	$ 7,343	$ 7,198			**$ 78,755**		
56			**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**				**2015**	
57	**2015**	HLH	133	123	127	129	118	132	128	127	126	127	131	122				Energy (GWH)	2733
58		LLH	98	103	104	103	92	100	97	105	97	105	101	104				Allocated Cost	**$ 111,038**
59		Demand	0	0	0	0	0	0	0	0	0	0	0	0				Rate Scalar	**11.81**
60	Revenue at marginal Rates		$ 6,935	$ 7,072	$ 7,878	$ 7,732	$ 6,801	$ 6,485	$ 5,362	$ 4,458	$ 4,703	$ 6,787	$ 7,343	$ 7,198			**$ 78,755**		

Rate Directive Step
Calculation of Monthly Energy Rate Scalars for First IP-PF Link Calculation
Test Period October 2013 - September 2015
($/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)		31.30	32.51	35.78	35.86	34.39	29.53	25.85	22.45	23.79	31.17	33.90	34.16				
7	LLH (mills/kWh)		28.06	29.90	31.97	30.24	29.75	25.90	21.20	15.31	17.42	26.86	28.60	29.37				
8	Demand Rate ($/kW/mo)		9.86	10.24	11.26	11.29	10.83	9.31	8.16	7.09	7.52	9.84	10.66	10.74				
9																		
10																		
11	**Unbifurcated PF/NR**		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
12	**2014**	HLH	43.18	44.39	47.66	47.74	46.27	41.41	37.74	34.33	35.68	43.05	45.78	46.04				**2014**
13		LLH	39.94	41.78	43.85	42.12	41.63	37.78	33.08	27.19	29.30	38.74	40.48	41.25				**11.88**
14		Demand	9.86	10.24	11.26	11.29	10.83	9.31	8.16	7.09	7.52	9.84	10.66	10.74				**Scalar**
15			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
16	**2015**	HLH	43.38	44.59	47.85	47.94	46.46	41.61	37.93	34.53	35.87	43.24	45.97	46.23				**2015**
17		LLH	40.14	41.98	44.05	42.32	41.83	37.98	33.28	27.39	29.50	38.94	40.68	41.45				**12.08**
18		Demand	9.86	10.24	11.26	11.29	10.83	9.31	8.16	7.09	7.52	9.84	10.66	10.74				**Scalar**
36																		
42																		
43		**IP**	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
44	**2014**	HLH	42.91	44.13	47.39	47.47	46.00	41.15	37.47	34.06	35.41	42.78	45.51	45.77				**2014**
45		LLH	39.67	41.51	43.58	41.85	41.36	37.51	32.81	26.92	29.03	38.47	40.21	40.98				**11.61**
46		Demand	9.86	10.24	11.26	11.29	10.83	9.31	8.16	7.09	7.52	9.84	10.66	10.74				**Scalar**
47			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
48	**2015**	HLH	43.11	44.32	47.59	47.67	46.20	41.34	37.67	34.26	35.61	42.98	45.71	45.97				**2015**
49		LLH	39.87	41.71	43.78	42.05	41.56	37.71	33.01	27.12	29.23	38.67	40.41	41.18				**11.81**
50		Demand	9.86	10.24	11.26	11.29	10.83	9.31	8.16	7.09	7.52	9.84	10.66	10.74				**Scalar**

Table 2.4.4

Rate Directive Step
Calculation of First IP-PF Link Delta
Test Period October 2013 - September 2015
($ 000)

	B	C	D	E	F	G	H
4						**FY 2014**	**FY 2015**
5							
6	1 IP Allocated Costs					178,053	178,503
7	2 IP Revenues @ Net Margin					(728)	(728)
8	3 adjustment					1,431	1,528
9	4 IP Marginal Cost Rate Revenues					78,755	78,755
10	5 PF/NR Marginal Cost Rate Revenues					3,185,848	3,217,349
11	6 PF/NR Allocated Energy Costs					4,373,931	4,436,073
12	7 Numerator: 1-2-3-((4/5)*6)					69,226	69,116
13	8						
14	9 PF Allocation Factor for Delta					0.999999917	0.999999918
15	10 NR Allocation Factor for Delta					0.000000083	0.000000082
16	11 Total Allocation Factors for Delta					1.000000000	1.000000000
17	12 Denominator: 1.0 + ((9/11)*(4/5))					1.0247	1.0245
18	13						
19	14 DELTA: (7/12)					**67,556**	**67,465**
20							
21						-0.267	-0.266
22							

Rate Directive Step
Reallocation of First IP-PF Link Delta and Recalculation of Rates
Test Period October 2013 - September 2015
($ 000, aMW, $/MWh)

	B		C		D
5	**Initial Allocation of Net Revenue Requirement)**		**2014**		**2015**
6	Unbifurcated Priority Firm - 7(b) Loads..............................	$	4,373,930	$	4,436,073
7	Industrial Firm - 7(c) Loads...	$	178,053	$	178,503
8	New Resources - 7(f) Loads..	$	0.5707	$	0.5721
9	Surplus Firm - SP Loads..	$	29,163	$	29,163
10	Total..	$	4,581,148	$	4,643,739
11					
12					
13	**First IP-PF Link Delta**	**$**	**67,556**	**$**	**67,465**
14					
15					
16	**7(c)(2) Delta Cost Allocators**		**2014**		**2015**
17	Unbifurcated Priority Firm - 7(b) Loads..............................		0.999999917		0.999999918
18	Industrial Firm - 7(c) Loads...		-1.000000000		-1.000000000
19	New Resources - 7(f) Loads..		0.000000083		0.000000082
20					
21	**7(c)(2) Delta Cost Allocation**		**2014**		**2015**
22	Unbifurcated Priority Firm - 7(b) Loads..............................	$	67,556	$	67,465
23	Industrial Firm - 7(c) Loads...	$	(67,556)	$	(67,465)
24	New Resources - 7(f) Loads..	$	0.006	$	0.006
25	Total..	$	(0)	$	(0)
26					
27	**Cost Allocation After 7c2 Delta ($ 000)**		**2014**		**2015**
28	Unbifurcated Priority Firm - 7(b) Loads..............................	$	4,441,486	$	4,503,537
29	Industrial Firm - 7(c) Loads...	$	110,497	$	111,038
30	New Resources - 7(f) Loads..	$	0.576	$	0.578
31	Surplus Firm - SP Loads..	$	29,163	$	29,163
32	Total..	$	4,581,148	$	4,643,739
33					
34	**Energy Billing Determinants (aMW)**		**2014**		**2015**
35	Unbifurcated Priority Firm - 7(b) Loads..............................		12,064		12,157
36	Industrial Firm - 7(c) Loads...		312.0003992		312.0003992
37	New Resources - 7(f) Loads..		0.001		0.001
38					
39					
40	**Average Power Rates ($/MWh)**		**2014**		**2015**
41					
42	Unbifurcated Priority Firm - 7(b) Loads..............................		42.03		42.29
43	Industrial Firm - 7(c) Loads...		40.43		40.63
44	New Resources - 7(f) Loads..		65.79		65.94
45					
46					
47	Base PF Exchange Rate w/o Transmission Adder...............		**42.16**		

Rate Directive Step
Calculation of IP Floor Calculation
Test Period October 2013 - September 2015

	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]		3,112	4,337	3,176	2,290	7,449	5,466
18	2	IP-83 Rates		4.62	2.21	14.70	12.20	7.34	
19	3	Revenue		14,378	9,584	46,684	27,944	54,674	153,264
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]		28.04					
36	20	Floor Rate (mills/kWh)[8]		20.91					
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 2013 - September 2015

Industrial Firm Power Floor Rate Test	A	B	C
	Total Energy	**TOTALS**	**Average Rate**
1 IP Billing Determinants	5,466		
2 Floor Rate (mills/kWh)	20.91		
3 Value of Reserves Credit (mills/kWh)			
4 Revenue at Floor Rate Less VOR Credit	114,302	114,302	20.91
5 IP Revenue Under Proposed Rates		221,535	40.53
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 2013 - September 2015

	B	C	D	E	F
9		**Cost Allocation After 7c2 Delta**	**2014**	**2015**	Total
10		Unbifurcated Priority Firm - 7(b) Loads..............................	$ 4,441,486	$ 4,503,537	$ 8,945,023
11					
12		**Energy Billing Determinants (aMW)**	**2014**	**2015**	
13		Unbifurcated Priority Firm - 7(b) Loads..............................	12,064	12,157	
14					
15					
16		**Average Power Rates**	**2014**	**2015**	
17					
18		Unbifurcated Priority Firm - 7(b) Loads..............................	42.03	42.29	
25					
26			(GWh)		
27		Two Year PF Public Load T1	122823		
28		Two Year PF Public Load T2	837		
29		Two Year IOU PF Exchange Load	83445		
30		Two Year COU PF Exchange Load	5070		
31		Total Two-Year Unbifurcated PF Load	212174		
32					
33					
34		T 2 Costs	$ 32,804		
35		T 1 Costs	$ 8,912,219		
36		Total	$ 8,945,023		
37					
45		Total PF Costs Minus PF T2 Costs	$ 8,912,219		
46		Total PF Load Minus PF T2 Load	211,337		
47		COU Base PF w/o Transmission	42.17		
48		Exchange Transmission Adder	4.01		
49		**COU Base PFx**	**46.18**		
50					
51					
52		Two Year COU PF Exchange Load	5070		
53		Two Year Base PF Public Exchange T2 Revenue	$ 213,789		
54					
55		Total PF Costs Minus COU PFx Revenue	$ 8,731,235		
56		Total PF Loads Minus COU PFx Loads	207,105		
57		IOU Base PF w/o Transmission	42.16		
58		Exchange Transmission Adder	4.01		
59		**IOU Base PFx**	**46.17**		
60					

Rate Directive Step
Calculation of IOU REP Benefits in Rates
Test Period October 2013 - September 2015

	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		$197,500		
19	Refund Amount*		$76,538		
20	REP Recovery Amount		$274,038		
21					
26					
27					
28			**2014**		**2015**
29			($000)		($000)
30	IOU Unconstrained Benefits	$	843,467	$	843,467
31	REP Recovery Amount	**$**	**274,038**	**$**	**274,038**
32	Rate Protection Delta	$	569,429	$	569,429
33					
34	**Refund of Initial EOFY2011 Lookback Completed by end of FY 2019*				

Rate Directive Step
Calculation of REP Base Exchange Benefits
Test Period October 2013 - September 2015

	B	C	D	E	F	G	H	I	J	K	L
5	**IOU Base PFx**	**46.17**									
6	**COU Base PFx**	**46.18**		**ASCs**			**Exchange Loads**			**Unconstrained Benefits**	
7										(load * (ASC - Base PFx)	
8				**2014**	**2015**		**2014**	**2015**		**2014**	**2015**
9											
10											
11	Avista Corporation	1		57.13	57.13		3,912	3,912		$ 42,881	$ 42,881
12	Idaho Power Company	1		49.69	49.69		6,433	6,433		$ 22,655	$ 22,655
13	NorthWestern Energy,	1		70.62	70.62		674	674		$ 16,472	$ 16,472
14	PacifiCorp	1		66.11	66.11		9,333	9,333		$ 186,105	$ 186,105
15	Portland General Elect	1		67.76	67.76		8,768	8,768		$ 189,324	$ 189,324
16	Puget Sound Energy, I	1		76.80	76.80		12,602	12,602		$ 386,031	$ 386,031
17	Clark Public Utilities	1		47.91	47.91		2,543	2,527		$ 4,397	$ 4,370
18	Franklin	0		0.00	0.00		0	0		$ -	$ -
19	Snohomish County PU	0		45.15	45.15		0	0		$ -	$ -
31	Total									**$ 847,864**	**$ 847,837**
32											
33									IOU	**$ 843,467**	**$ 843,467**

Rate Directive Step
Calculation of Utility Specific PF Exchange Rates and REP Benefits
Test Period October 2013 - September 2015

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
4	**Initial Allocations**				**FY 2014**	**FY 2015**	**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	57.13	46.17	3,912	3,912	3,912	$ 42,881			$ 28,949	$ 3,891	8.39	54.56	$ 10,041
9	Idaho Power Company	1	49.69	46.17	6,433	6,433	6,433	$ 22,655			$ 15,294	$ 2,056	2.70	48.87	$ 5,305
10	NorthWestern Energy, LLC	1	70.62	46.17	674	674	674	$ 16,472			$ 11,120	$ 1,495	18.73	64.89	$ 3,857
11	PacifiCorp	1	66.11	46.17	9,333	9,333	9,333	$ 186,105			$ 125,640	$ 16,887	15.27	61.44	$ 43,577
12	Portland General Electric Company	1	67.76	46.17	8,768	8,768	8,768	$ 189,324			$ 127,813	$ 17,180	16.54	62.70	$ 44,331
13	Puget Sound	1	76.8	46.17	12,602	12,602	12,602	$ 386,031			$ 260,611	$ 35,029	23.46	69.63	$ 90,390
14	Clark Public Utilities	1	47.91	46.18	2,543	2,527	2,535	$ 4,384			$ 2,959		1.17	47.35	$ 1,424
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							$ 847,850	$197,500	$76,538	$ 572,388	$76,538			$ 198,924
18															
19	rounding to	4	places =	$21			IOU Σ(g)	$ 843,467	$197,500	$274,038	$ 569,429	IOU Σ(j)		IOU REP	$ 197,500
20							COU Σ(g)	$ 4,384		$1,424	$ 2,959	COU Σ(j)		COU REP	$ 1,424
21															
22	**IOU Reallocations**														
23			**Interim**				**Final**	**Final**	**Final**		**Final**			**FY 2014**	**FY 2015**
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		$ 10,041	$ 2,005	$ 98	$ 8,134	$ 34,747	8.88	55.0508		$ 8,134		Avista	$ 8,134	$ 8,134
28	Idaho Power Company		$ 5,305	$ 2,652	$ -	$ 2,652	$ 20,003	3.11	49.2777		$ 2,652		Idaho Power	$ 2,652	$ 2,652
29	NorthWestern Energy, LLC		$ 3,857	$ (766)	$ 390	$ 5,013	$ 11,458	17.01	63.1780		$ 5,013		NorthWestern	$ 5,013	$ 5,013
30	PacifiCorp		$ 43,577	$ 8,443	$ 425	$ 35,559	$ 150,545	16.13	62.2997		$ 35,560		PacifiCorp	$ 35,560	$ 35,560
31	Portland General Electric Company		$ 44,331	$ 1,238	$ 3,775	$ 46,868	$ 142,456	16.25	62.4150		$ 46,867		Portland	$ 46,867	$ 46,867
32	Puget Sound		$ 90,390	$ -	$ 8,883	$ 99,273	$ 286,757	22.75	68.9227		$ 99,273		Puget Sound	$ 99,273	$ 99,273
33	Total		$ 197,500	$ 13,571	$ 13,571	$ 197,500	$ 645,967				$ 197,500		IOU REP	$ 197,500	$ 197,500
34															
35													Clark	$ 1,429	$ 1,420
36													Franklin	$ -	$ -
37	**IOU Reallocation Adjustments**												Snohomish	$ -	$ -
38			Avista Corporati	o Power Comp	Western Energy	PacifiCorp	eneral Electric	Puget Sound	Total				COU REP	$ 1,429	$ 1,420
39			$ 2,005	$ 2,652	$ (766)	$ 8,443	$ 1,238	$ -					Total REP	$ 198,929	$ 198,920
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			$ 139	$ (41)				$ 98				Refund Amt	$ 76,538	$ 76,538
42	Idaho Power Company								$ -				REP Cost	$ 275,466	$ 275,457
43	NorthWestern Energy, LLC		$ 56	$ 49		$ 235	$ 51	$ -	$ 390						
44	PacifiCorp			$ 602	$ (177)				$ 425						
45	Portland General Electric Company		$ 641	$ 613	$ (180)	$ 2,701			$ 3,775						
46	Puget Sound		$ 1,308	$ 1,249	$ (368)	$ 5,507	$ 1,187		$ 8,883						
47			$ 2,005	$ 2,652	$ (766)	$ 8,443	$ 1,238	$ -	$ 13,571						

Rate Directive Step
IOU Reallocation Balances
Test Period October 2013 - September 2015

	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	$ 2,652,347	$ 1,241,047	$ 2,652,347	$ 1,198,708	$ 39,829,475
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	$ 2,652,347	$ 1,155,099	$ 2,652,347	$ 1,110,182	$ 36,790,061
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	$ 2,652,347	$ 1,063,917	$ 2,652,347	$ 1,016,264	$ 33,565,546
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	$ 2,652,347	$ 967,181	$ 2,652,347	$ 916,626	$ 30,144,658
53	NorthWestern Energy, LLC	$ -	$ -	$ -	$ -	$ -
54	PacifiCorp	$ -	$ 249,591	$ -	$ 257,078	$ 8,826,357
55	Portland General Electric Company	$ -	$ -	$ -	$ -	$ -
56						
57						

Rate Directive Step
Calculation and Allocation of the Increase in PF Exchange Revenue Requirement Due to REP Settlement
Test Period October 2013 - September 2015

	B		C		D
4	**Cost Allocation After 7c2 Delta**		**2014**		**2015**
5	Priority Firm Public - 7(b) Loads..	$	2,581,173	$	2,632,223
6	Priority Firm Exchange - 7(b) Loads..................................	$	1,860,313	$	1,871,315
7	Industrial Firm - 7(c) Loads...	$	110,497	$	111,038
8	New Resources - 7(f) Loads...	$	0.576	$	0.578
9	Surplus Firm - SP Loads..	$	29,163	$	29,163
10	Total..	$	4,581,148	$	4,643,739
11					
12					
13	**Calc Rate Protection to PFx Rate**		**2014**		**2015**
14	Unconstrained Benefits	$	847,864	$	847,837
15	REP Recovery Amount plus COU Benefits	$	(275,466)	$	(275,457)
16	delta	$	572,398	$	572,379
17					
18					
19	**Allocation Factors**		**2014**		**2015**
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**		**2014**		**2015**
27	Priority Firm Public - 7(b) Loads..	$	(572,398)	$	(572,379)
28	Priority Firm Exchange - 7(b) Loads..................................	$	572,398	$	572,379
29	Industrial Firm - 7(c) Loads...	$	-	$	-
30	New Resources - 7(f) Loads...	$	-	$	-
31	Total..	$	-	$	-
32					
33					
34	**Cost Allocation After Rate Protection to PFx**		**2014**		**2015**
35	Priority Firm Public - 7(b) Loads..	$	2,008,776	$	2,059,843
36	Priority Firm Exchange - 7(b) Loads..................................	$	2,432,710	$	2,443,694
37	Industrial Firm - 7(c) Loads...	$	110,497	$	111,038
38	New Resources - 7(f) Loads...	$	0.576	$	0.578
39	Surplus Firm - SP Loads..	$	29,163	$	29,163
40	Total..	$	4,581,148	$	4,643,739
41					
42					
43	**Energy Billing Determinants (aMW)**		**2014**		**2015**
44	Priority Firm Public - 7(b) Loads..		7,011		7,105
45	Priority Firm Exchange - 7(b) Loads..................................		5,053		5,051
46	Industrial Firm - 7(c) Loads...		312		312
47	New Resources - 7(f) Loads...		0.001		0.001
48					
50					
51	**Average Power Rates**		**2014**		**2015**
52	Priority Firm Public - 7(b) Loads..		32.71		33.09
53	Priority Firm Exchange - 7(b) Loads..................................		58.97		59.24
54	Industrial Firm - 7(c) Loads...		40.43		40.63
55	New Resources - 7(f) Loads...		65.79		65.94

Rate Directive Step
Calculation of PF, IP and NR Rate Contribution to Net REP Benefit Costs
Test Period October 2013 - September 2015

	B	C		D	
25			**2014**		**2015**
26	WP-10 Average IOU REP Benefits (before Lookback recovery	$	265,847	$	265,847
27					
28	WP-10 7b3 Supplemental Rate Charge	$	7.38	$	7.38
29	IP/NR REP Surcharge	$	7.65	$	7.65
30	IP Load		2,733		2,733
31	NR Load		0		0
32	REP Surharge Revenue from IP Rate	$	20,900	$	20,900
33	REP Surharge Revenue from NR Rate	$	0	$	0
34					
35	Amount of REP Recovery remaining after IP/NR REP Surchar	$	254,566	$	254,558
36	Remaining REP Recovery in PF, IP and NR Rates ($/MWh)	$	3.97	$	3.92
37					
38	Before Reallocation				
39	IP REP Recovery Amount in Rates	$	31,746	$	31,607
40	NR REP Recovery Amount in Rates	$	0	$	0
41					
42	After Reallocation				
43	IP REP Recovery Amount in Rates	$	20,010	$	20,021
44	NR REP Recovery Amount in Rates	$	0	$	0
45					
46					
47	Reallocation that Should be in Rates		**2014**		**2015**
48	Priority Firm Public - 7(b) Loads...	$	243,720	$	243,850
49	Industrial Firm - 7(c) Loads...	$	31,746	$	31,607
50	New Resources - 7(f) Loads..	$	0.102	$	0.101
51		$	275,466	$	275,457
52					
53	Adjustment Necessary to Achieve Reallocation		**2014**		**2015**
54	Priority Firm Public - 7(b) Loads...	$	(20,010)	$	(20,021)
55	Industrial Firm - 7(c) Loads...	$	20,010	$	20,021
56	New Resources - 7(f) Loads..	$	0.064	$	0.064
57		$	0	$	(0)
58					
59			**2014**		**2015**
60	PF Contribution to Net REP Benefits $/MWh..........................		3.97		3.92
61	IP Contribution to Net REP Benefits $/MWh...........................		11.62		11.56
62	NR Contribution to Net REP Benefits $/MWh.........................		11.62		11.56

Rate Directive Step
Reallocation of Rate Protection Provided by the IP and NR Rates
Test Period October 2013 - September 2015

	B	C		D	
4	**Cost Allocation After Rate Protection Provided by PFx**		**2014**		**2015**
5	Priority Firm Public - 7(b) Loads..	$	2,008,776	$	2,059,843
6	Priority Firm Exchange - 7(b) Loads...	$	2,432,710	$	2,443,694
7	Industrial Firm - 7(c) Loads..	$	110,497	$	111,038
8	New Resources - 7(f) Loads...	$	0.576	$	0.578
9	Surplus Firm - SP Loads...	$	29,163	$	29,163
10	Total..	$	4,581,148	$	4,643,739
11					
12					
13					
14	**Allocation of Rate Protection Provided by IP and NR**		**2014**		**2015**
15	Priority Firm Public - 7(b) Loads..	$	(20,010)	$	(20,021)
16					
17	Industrial Firm - 7(c) Loads..	$	20,010	$	20,021
18	New Resources - 7(f) Loads...	$	0.064	$	0.064
19	Total..	$	0	$	(0)
20					
21					
22	**Cost Allocation After Rate Protection Provided by IP and NR**		**2014**		**2015**
23	Priority Firm Public - 7(b) Loads..	$	1,988,766	$	2,039,823
24	Priority Firm Exchange - 7(b) Loads...	$	2,432,710	$	2,443,694
25	Industrial Firm - 7(c) Loads..	$	130,507	$	131,058
26	New Resources - 7(f) Loads...	$	0.640	$	0.642
27	Surplus Firm - SP Loads...	$	29,163	$	29,163
28	Total..	$	4,581,148	$	4,643,739
29					
30					
31	**Energy Billing Determinants (aMW)**		**2014**		**2015**
32	Priority Firm Public - 7(b) Loads..		7,011		7,105
33	Priority Firm Exchange - 7(b) Loads...		5,053		5,051
34	Industrial Firm - 7(c) Loads..		312		312
35	New Resources - 7(f) Loads...		0.001		0.001
36					
38					
39	**Average Power Rates After Rate Protection Reallocations**		**2014**		**2015**
40	Priority Firm Public - 7(b) Loads..		32.38		32.77
41	Priority Firm Exchange - 7(b) Loads...		58.97		59.24
42	Industrial Firm - 7(c) Loads..		47.75		47.95
43	New Resources - 7(f) Loads...		73.11		73.27

Rate Directive Step
Calculation of Annual Energy Rate Scalars for Second IP-PF Link Calculation
Test Period October 2013 - September 2015

	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)		31.30	32.51	35.78	35.86	34.39	29.53	25.85	22.45	23.79	31.17	33.90	34.16					
8	LLH (mills/kWh)		28.06	29.90	31.97	30.24	29.75	25.90	21.20	15.31	17.42	26.86	28.60	29.37					
9	Demand Rate ($/kW/mo)		9.86	10.24	11.26	11.29	10.83	9.31	8.16	7.09	7.52	9.84	10.66	10.74					
10																			
11		**PF+NR Load**	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				**2014**	
12	**2014**	HLH	2807	3203	3545	3372	2932	3074	2817	3147	2921	3137	3006	2749				Energy (GWH)	61418
13		LLH	1772	2249	2556	2378	1973	2066	1817	2168	1848	2109	1912	1860				Allocated Cost	$ 2,013,152
14		Demand	479	398	708	798	446	520	575	451	394	539	436	435				Rate Scalar	2.63
15	Revenue at marginal Rates		$ 142,310	$ 175,458	$ 216,526	$ 201,816	$ 164,352	$ 149,118	$ 116,058	$ 107,037	$ 104,647	$ 159,725	$ 161,223	$ 153,188			$ 1,851,458		
16			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				**2015**	
17	**2015**	HLH	2864	3229	3684	3534	3011	3151	2899	3073	2830	3188	3098	2683				Energy (GWH)	62242
18		LLH	1814	2331	2573	2469	2023	2112	1861	2168	1768	2035	1982	1863				Allocated Cost	$ 2,063,901
19		Demand	474	276	845	800	441	517	580	356	516	555	439	432				Rate Scalar	2.95
20	Revenue at marginal Rates		$ 145,207	$ 177,491	$ 223,601	$ 210,388	$ 168,490	$ 152,582	$ 119,134	$ 104,695	$ 102,033	$ 159,477	$ 166,348	$ 151,027			$ 1,880,473		
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				**2014**	
26	**2014**	HLH	133	123	127	129	118	132	128	127	126	127	131	122				Energy (GWH)	2733
27		LLH	98	103	104	103	92	100	97	105	97	105	101	104				Allocated Cost	$ 106,122
28		Demand	0	0	0	0	0	0	0	0	0	0	0	0				Rate Scalar	10.01
29	Revenue at marginal Rates		$ 6,935	$ 7,072	$ 7,878	$ 7,732	$ 6,801	$ 6,485	$ 5,362	$ 4,458	$ 4,703	$ 6,787	$ 7,343	$ 7,198			$ 78,755		
30			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				**2015**	
31	**2015**	HLH	133	123	127	129	118	132	128	127	126	127	131	122				Energy (GWH)	2733
32		LLH	98	103	104	103	92	100	97	105	97	105	101	104				Allocated Cost	$ 106,981
33		Demand	0	0	0	0	0	0	0	0	0	0	0	0				Rate Scalar	10.33
34	Revenue at marginal Rates		$ 6,935	$ 7,072	$ 7,878	$ 7,732	$ 6,801	$ 6,485	$ 5,362	$ 4,458	$ 4,703	$ 6,787	$ 7,343	$ 7,198			$ 78,755		
35																			

Rate Directive Step
Calculation of Monthly Energy Rate Scalars for Second IP-PF Link Rate Calculation
Test Period October 2013 - Septmentber 2015

	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)		31.30	32.51	35.78	35.86	34.39	29.53	25.85	22.45	23.79	31.17	33.90	34.16				
7	LLH (mills/kWh)		28.06	29.90	31.97	30.24	29.75	25.90	21.20	15.31	17.42	26.86	28.60	29.37				
8	Demand Rate ($/kW/mo)		9.86	10.24	11.26	11.29	10.83	9.31	8.16	7.09	7.52	9.84	10.66	10.74				
9																		
10																		
11	**Unbifurcated PF /NR**		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
12	**2014**	HLH	33.93	35.14	38.41	38.49	37.02	32.17	28.49	25.08	26.43	33.80	36.53	36.79				**2014**
13		LLH	30.69	32.53	34.60	32.87	32.38	28.53	23.83	17.94	20.05	29.49	31.23	32.00				**2.63**
14		Demand	9.86	10.24	11.26	11.29	10.83	9.31	8.16	7.09	7.52	9.84	10.66	10.74				**Scalar**
15			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
16	**2015**	HLH	34.25	35.46	38.72	38.80	37.33	32.48	28.80	25.40	26.74	34.11	36.84	37.10				**2015**
17		LLH	31.01	32.85	34.92	33.19	32.70	28.85	24.15	18.26	20.37	29.81	31.55	32.32				**2.95**
18		Demand	9.86	10.24	11.26	11.29	10.83	9.31	8.16	7.09	7.52	9.84	10.66	10.74				**Scalar**
19																		
20																		
21		**IP**	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
22	**2014**	HLH	41.31	42.53	45.79	45.87	44.40	39.55	35.87	32.46	33.81	41.18	43.91	44.17				**2010**
23		LLH	38.07	39.91	41.98	40.25	39.76	35.91	31.21	25.32	27.43	36.87	38.61	39.38				**10.01**
24		Demand	9.86	10.24	11.26	11.29	10.83	9.31	8.16	7.09	7.52	9.84	10.66	10.74				**Scalar**
25			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep				
26	**2015**	HLH	41.63	42.84	46.10	46.19	44.71	39.86	36.18	32.78	34.12	41.49	44.22	44.48				**2011**
27		LLH	38.39	40.23	42.30	40.57	40.08	36.23	31.53	25.64	27.75	37.19	38.93	39.70				**10.33**
28		Demand	9.86	10.24	11.26	11.29	10.83	9.31	8.16	7.09	7.52	9.84	10.66	10.74				**Scalar**

Rate Directive Step
Calculation of Second IP-PF Link Delta
Test Period October 2013 - September 2015

	B	C	D	E	F	G	H
4						**FY 2014**	**FY 2015**
5							
6	1	IP Allocated Costs				110,497	111,038
7	2	IP Revenues @ Net Margin				(728)	(728)
8	3	adjustment				1,208	1,252
9	4	IP Marginal Cost Rate Revenues				78,755	78,755
10	5	PF/NR Marginal Cost Rate Revenues				1,851,458	1,880,473
11	6	PF Allocated Energy Costs				1,988,767	2,039,824
12	7	Numerator: 1-2-3-((4/5)*6)				25,422	25,086
13	8						
14	9	PF Allocation Factor for Delta				0.999999917	0.999999918
15	10	NR Allocation Factor for Delta				0.000000083	0.000000082
16	11	Total Allocation Factors for Delta				1.000000000	1.000000000
17	12	Denominator: 1.0 + ((9/11)*(4/5))				1.0425	1.0419
18	13						
19	14	DELTA: (7/12)				**24,385**	**24,077**
20							
21						-0.266	-0.266
22							

Rate Directive Step
Reallocation of IP-PF Link Delta and Recalculation of Rates
Test Period October 2013 - September 2015

	B	C		D		E
4	**Cost Allocation After Rate Protection Provided by IP and NR**		**2014**		**2015**	
5	Priority Firm Public - 7(b) Loads	$	1,988,766	$	2,039,823	
6	Priority Firm Exchange - 7(b) Loads	$	2,432,710	$	2,443,694	
7	Industrial Firm - 7(c) Loads	$	130,507	$	131,058	
8	New Resources - 7(f) Loads	$	0.640	$	0.642	
9	Surplus Firm - SP Loads	$	29,163	$	29,163	
10	Total	$	4,581,148	$	4,643,739	
11						
12						
13	IP-PF Link Delta	$	24,385	$	24,077	
14						
15			**2014**		**2015**	
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**		**2014**		**2015**	
22	Priority Firm Public - 7(b) Loads	$	24,385	$	24,077	
23	Priority Firm Exchange - 7(b) Loads	$	-	$	-	
24	Industrial Firm - 7(c) Loads	$	(24,385)	$	(24,077)	
25	New Resources - 7(f) Loads	$	0.003	$	0.003	
26	Total	$	0	$	(0)	
27						
28						
29	**Cost Allocation After Second IP-PF Link**		**2014**		**2015**	
30	Priority Firm Public - 7(b) Loads	$	2,013,151	$	2,063,900	
31	Priority Firm Exchange - 7(b) Loads	$	2,432,710	$	2,443,694	
32	Industrial Firm - 7(c) Loads	$	106,122	$	106,981	
33	New Resources - 7(f) Loads	$	0.644	$	0.645	
34	Surplus Firm - SP Loads	$	29,163	$	29,163	
35	Total	$	4,581,148	$	4,643,739	
36						
37						
38	**Energy Billing Determinants (aMW)**		**2014**		**2015**	
39	Priority Firm Public - 7(b) Loads		7,011		7,105	
40	Priority Firm Exchange - 7(b) Loads		5,053		5,051	
41	Industrial Firm - 7(c) Loads		312		312	
42	New Resources - 7(f) Loads		0.001		0.001	
43						
45						
46	**Average Power Rates After Second IP-PF Link**		**2014**		**2015**	Average
47	Priority Firm Public - 7(b) Loads		32.78		33.16	**32.97**
48	Priority Firm Exchange - 7(b) Loads		58.97		59.24	**59.10**
49	Industrial Firm - 7(c) Loads		38.83		39.14	**38.99**
50	New Resources - 7(f) Loads		73.50		73.66	**73.58**

Rate Design Step
REP Benefit Reconciliation
Test Period October 2013 to September 2015

	B	D	E	F	G	H	I	J	K	L
4		**2014**	**2015**	**Avg**				**2014**	**2015**	**Avg**
5	Resource Costs	2,891,552	2,890,801	2,891,177			PFx Alloc Cost	(2,432,710)	(2,443,694)	
6	PFx Revenues	(2,610,213)	(2,621,134)	(2,615,674)			Exch Tmn Cost	(177,503)	(177,440)	
7	REP Benefits	281,339	269,667	275,503				(2,610,213)	(2,621,134)	(2,615,674)
8										
9	**REP Benefits**						**PFx Revenues**			
10	Avista Corporation	8,134	8,134				Avista Corporation	215,358	215,358	
11	Idaho Power Company	2,652	2,652				Idaho Power Company	317,023	317,023	
12	NorthWestern Energy, LLC	5,013	5,013				NorthWestern Energy, LLC	42,560	42,560	
13	PacifiCorp	35,560	35,560				PacifiCorp	581,416	581,416	
14	Portland General Electric Company	46,867	46,867				Portland General Electric Compa	547,283	547,283	
15	Puget Sound Energy, Inc.	99,273	99,273				Puget Sound Energy, Inc.	868,594	868,594	
16	IOU REP	197,500	197,500	197,500			IOU REP	2,572,234	2,572,234	2,572,234
17										
18	Clark Public Utilities	1,429	1,420				Clark Public Utilities	120,389	119,647	
19	Franklin	-	-				Franklin	-	-	
20	Snohomish County PUD No 1	-	-				Snohomish County PUD No 1	-	-	
21	COU REP	1,429	1,420	1,424			COU REP	120,389	119,647	120,018
22										
23	Refund Amounts	76,538	76,538				Refund Amounts	(76,538)	(76,538)	
24	Total REP	275,466	275,457	275,462			Total REP	2,616,086	2,615,344	2,615,715
25				(41)				5,872	(5,790)	41
26										
27	**For Slice True-Up**									100.00%
28	IOU REP	197,500	197,500							
29	COU REP	1,429	1,420							
30	Refund Amounts	76,538	76,538							
31	Total REP	275,466	275,457							

Table 2.5.1

Rate Design Step
Cost Aggregation under Tiered Rate Methodology
Test Period October 2013 to September 2015

	A	B	C	D	E	G	H
4						**2014**	**2015**
5		**Composite**					
6			Federal Base System				
7				Hydro			
8					Operating Expense	543,131	558,132
9					Interest	187,113	195,597
10					MRNR	-	-
11				Fish & Wildlife			
12					Operating Expense	296,932	305,793
13					Interest	19,788	20,095
14					MRNR	-	-
15				Trojan		1,500	1,500
16				WNP #1		249,867	186,188
17				Columbia Generating Station		401,343	433,360
18				WNP #3		165,932	165,403
19				Augmentation		27,622	123,283
20			Residentail Exchange Program				
21				REP Net Cost		2,891,552	2,890,801
22				REP Net Cost		(2,610,213)	(2,621,134)
23				Program Support		973	996
24				Settlement Interest Accrual		1,400	1,400
25			NewResources				
26				Cowlitz		10,515	10,549
27				Idaho		4,648	4,880
28				Tier 1 Aug (Klondike III)		12,512	12,508
29				Other		48,799	49,503
30			Conservation				
31				Operating Expense		134,688	129,353
32				Interest		19,765	20,682
33				MRNR		-	-
34			BPAPrograms				
35				Operating Expense		151,755	158,231
36				Interest		3,408	3,317
37				MRNR		-	-
39			Transmission				
40				Transmission and Ancillary Services		48,641	49,418
41				General Transfer Agreements		55,533	56,578
42			Nonslice Interest and MRNR Allocated to Cost Pools				
43				Interest on BPA fund Credit to Nonslice		(2,214)	(3,618)
44				Accrual Revenue (MRNR Adjustment)		(3,524)	(3,524)
45			**Total**			**2,661,465**	**2,749,291**

Rate Design Step
Cost Aggregation under Tiered Rate Methodology
Test Period October 2013 to September 2015

	A	B	C	D	E	G	H
4						**2014**	**2015**
46		**Non-Slice**					
47			FBS				
48				Balancing Purchases from Risk Mod		31,941	27,492
49				Balancing in Revenue Requirement		35,043	-
50				PNRR			
51					Hydro	-	-
52					Fish & Wildlife	-	-
53			Conservation				
54				PNRR		-	-
55			BPAPrograms				
56				Hedging Mitigation		-	-
57				Bad Debt		-	-
58				PNRR		-	-
59			Transmission				
60				Transmission and Ancillary Services		61,177	59,990
61				Third-party T&A		2,288	2,333
62			Nonslice Interest and MRNR				
63				BPA Fund		2,214	3,618
64				Non-Slice MRNR Adjustment		3,524	3,524
65			**Total**			**136,188**	**96,957**
66		**Slice**					
67			BPAPrograms				
68				Other Slice Costs		-	-
69			**Total**			-	-
70		**Tier 2**					
71			FBS				
72				Tier 2 Purchase Costs		5,207	26,442
73				Tier 2 Rate Design Adjustments		207	949
74				Tier 2 Other Costs		-	-
75			**Total**			**5,414**	**27,391**

Table 2.5.1

Rate Design Step
Cost Aggregation under Tiered Rate Methodology
Test Period October 2013 to September 2015

	A	B	C	D	E	G	H
4						**2014**	**2015**
76		**Rate Direct/Design Adjustments**					
77			Credits Allocated Against Cost Pools				
78				FBS (excluding T2 Adjustment)		(115,295)	(112,377)
79				Contract Obligations		(2,264)	(2,355)
80				New Resources		(1,061)	(1,107)
81				Conservation		(11,859)	(12,083)
82				BPAPrograms		-	-
83				Transmission		(3,370)	(3,395)
84							
85			Secondary Energy Credit (includes pre-sale)			(449,919)	(466,114)
86			Generation Inputs Credit			(123,007)	(128,444)
87			Network Wind Credit			-	-
88			Composite revenues associated with firm surplus sales			(29,163)	(29,163)
89			Non-slice revenues associated with firm surplus sales			(701)	(701)
90							
91			Low Density Discount			36,123	37,261
92			Irrigation Rate Mitigation Costs			19,794	19,794
93							
94			Composite Augmentation RSS Revenue Debit/(Credit)			(2,018)	(2,018)
95			Composite Tier 2 RSS Revenue Debit/(Credit)			(23)	(103)
96			Composite Tier 2 Rate Design Adjustment Debit/(Credit)			(184)	(846)
97			Composite Non-Federal RSS Revenue Debit/(Credit)			(573)	(880)
98			Non-Slice Augmentation RSC Revenue Debit/(Credit)			(493)	(493)
99			Non-Slice Tier 2 RSC Revenue Debit/(Credit)			-	-
100			Non-Slice Tier 2 Rate Design Debit/(Credit)			-	-
101			Non-Slice Non-Federal RSC Revenue Debit/(Credit)			221	267
102							
103			Firm Surplus and Secondary Credit (from unused RHWM)			(2,944)	(1,220)
104			Demand Revenue			60,932	61,568
105			Load Shaping Revenue			5,888	26,150
106							

Table 2.5.2

Rate Design Step
Unused RHWM (net) Credit Computation
Test Period October 2013 to September 2015

	B		C		D
4			**2014**		**2015**
5	Secondary (aMW)		2,319		2,301
6	T1SFCO (aMW)		7,059		7,059
7	RHWM Augmentation (aMW)		57		57
8	RP Augmentation (aMW)		-		-
9	System Augmentation (aMW)		95		404
10	Augmentation Base (aMW)		152		461
11	IP and NR Loads contributing to avoided cost		321		321
12					
13	Value of Secondary	$	22.15	$	23.12
14	Value of T1SFCO ($/MWh)	$	29.06	$	29.06
15	Value of Augmentation	$	33.14	$	34.81
16					
17	Secondary (MWh)		20,311,081		20,158,934
18	T1SFCO (MWh)		61,835,360		61,835,360
19	RHWM Augmentation (MWh)		499,670		499,670
20	Augmentation Base (MWh)		1,333,097		4,041,163
21	IP and NR Loads (MWh)		2,812,443		2,812,443
22					
23	Unused RHWM (MWh)		929,253		688,017
24					
25	Unused Secondary		302,785		222,502
26	Unused T1SFCO		921,804		682,502
27	Unused Augmentation		7,449		5,515
28					
29	Value of Unused	$	33,741,720	$	25,170,231
30	Value of System Augmentation not Purchased	$	30,797,569	$	23,950,555
31					
32	Net Credit/(Cost)	$	2,944,151	$	1,219,676
33					
34	$/MWh value of Unused RHWM	**$**	**36.43**		

Table 2.5.3

Rate Design Step
Slice Return of Network Losses Adjustment
Test Period October 2013 - September 2015

	B	C	D
4		**2014**	**2015**
5	Non Slice Loads (MWh)	44,473,673	45,394,262
6	Loss Percent Assumption	1.90%	1.90%
7	Implied Non Slice Losses	845,000	862,491
8	Average Slice&Non-Slice Tier 1 Rate	32.93	32.93
9	Implied Cost/Credit ($1000)	27,826	28,402

Table 2.5.4

Rate Design Step
Balancing Augmentation Adjustment for Change to the Equivalent Tier 1 System Firm Critical Output
Test Period October 2013 - September 2015

	A	B	C	E	F	G
4				**2014**	**2015**	
5		**Table 3.1**				
6			Regulated	6,571	6,446	
7			Independent	354	354	
8		**Table 3.2**				
9			Ashland Solar Project	0	0	
10			Columbia Generating Station	1,030	878	
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	0	0	
16			Foote Creek 4	4	4	
17			Fourmile Hill Geothermal	-	-	
18			Georgia-Pacific Paper (Wauna)	19	19	
19			Glines Canyon Hydro	-	-	
20			Klondike I	7	7	
21			Stateline Wind Project	21	21	
22		**Table 3.3**				
23			Canadian Entitlement	136	136	
24			Libby Coordination	30	30	
25			BC Hydro Power Purchase	1	1	
26			Pasadena Capacity	1	0	
27			Pasadena Seasonal	2	2	
28			Pasadena Exchange Energy	2	2	
29			PacifiCorp (So Idaho)	-	-	
30			Riverside Capacity	5	5	
31			Riverside Seasonal	4	4	
32			Riverside Exchange Energy	7	7	
33			Sierra Pacific (Wells)	-	-	
34			PacifiCorp	15	-	
35		**Table 3.4**				
36			USBR Pump Load	176	176	
37			Canadian Entitlement	484	465	
38			Non-Treaty Storage	14	14	
39			Libby Coordination	39	39	
40			Hungry Horse	8	8	
41			Riverside Capacity	5	5	
42			Riverside Seasonal	4	4	
43			Pasadena Capacity	1	-	
44			Pasadena Seasonal	3	3	
45			Sierra Pacific (Wells)	-	-	
46			Intertie Losses	0.4	0.4	
47			WNP3	83	83	
48			PacifiCorp	-	-	
49			PacifiCorp (So Idaho)	-	-	
50			Upper Baker	1	1	
51			Dittmer Station Service	9	9	
52						
53			Federal Power Deliveries			
54			Preference	7,041	7,135	
55			Tier 2	17	78	
56			Net Preference	7,023	7,057	
57			Industrial	312	312	
58			New Resource	0	0	
59			Intraregional Transfer	92	92	
60			FBS Obligation	723	704	
61			Seasonal or Capacity Exchange	70	70	
62			Conservation Augmentation	(30)	(30)	
63			Transmission Losses Before Slice Return	238	238	
64			Slice Return of Losses	37	35	
65			Transmission Losses After Slice Return	201	203	
66						
67		**Annual T1SFCO**		7,197	6,921	
68		**RHWM Process T1SFCO (annual)**		7,183	6,935	
69		**Difference**		14	(14)	
70		**Augmentation Price (Secondary in the case Augmentation is zero)**		$ 33.14	$ 34.81	
71		**Hours**		8,760	8,760	
72		**Credit/Cost to Balancing Augmentation**		$ 4,067,758	$ (4,281,804)	

Table 2.5.5

Rate Design Step
Calculation of Load Shaping and Demand Revenuest
Test Period October 2013 - September 2015

	B	E	F	G	H	I	J	K	L
5	**2014**	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-13	479,250	$ 9.86	$ 4,725,406	(99,467)	152,129	$ 31.30	$ 28.06	$ 1,155,411
7	Nov-13	397,809	$ 10.24	$ 4,073,566	(292,456)	120,716	$ 32.51	$ 29.90	$ (5,898,348)
8	Dec-13	707,561	$ 11.26	$ 7,967,136	43,723	372,206	$ 35.78	$ 31.97	$ 13,463,828
9	Jan-14	798,084	$ 11.29	$ 9,010,374	7,184	424,413	$ 35.86	$ 30.24	$ 13,091,887
10	Feb-14	446,411	$ 10.83	$ 4,834,631	189,227	346,482	$ 34.39	$ 29.75	$ 16,815,342
11	Mar-14	519,943	$ 9.31	$ 4,840,668	153,781	251,399	$ 29.53	$ 25.90	$ 11,052,378
12	Apr-14	575,465	$ 8.16	$ 4,695,793	514,162	364,601	$ 25.85	$ 21.20	$ 21,020,646
13	May-14	450,549	$ 7.09	$ 3,194,395	(1,072,951)	(475,010)	$ 22.45	$ 15.31	$ (31,360,153)
14	Jun-14	393,552	$ 7.52	$ 2,959,513	(661,247)	(130,963)	$ 23.79	$ 17.42	$ (18,012,445)
15	Jul-14	539,237	$ 9.84	$ 5,306,091	(608,280)	123,303	$ 31.17	$ 26.86	$ (15,648,171)
16	Aug-14	436,067	$ 10.66	$ 4,648,473	(203,324)	169,946	$ 33.90	$ 28.60	$ (2,032,228)
17	Sep-14	435,410	$ 10.74	$ 4,676,302	(89,713)	180,616	$ 34.16	$ 29.37	$ 2,240,115
18	**Total**			**$ 60,932,348**					**$ 5,888,261**
19									
20	**2015**	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-14	473,830	$ 9.86	$ 4,671,966	(62,911)	177,979	$ 31.30	$ 28.06	$ 3,024,970
22	Nov-14	276,246	$ 10.24	$ 2,828,761	(294,797)	194,602	$ 32.51	$ 29.90	$ (3,765,254)
23	Dec-14	845,343	$ 11.26	$ 9,518,560	133,538	361,885	$ 35.78	$ 31.97	$ 16,347,445
24	Jan-15	799,780	$ 11.29	$ 9,029,517	48,756	458,531	$ 35.86	$ 30.24	$ 15,614,376
25	Feb-15	441,042	$ 10.83	$ 4,776,490	226,106	374,206	$ 34.39	$ 29.75	$ 18,908,420
26	Mar-15	517,027	$ 9.31	$ 4,813,521	191,091	279,007	$ 29.53	$ 25.90	$ 12,869,203
27	Apr-15	580,410	$ 8.16	$ 4,736,146	545,434	386,284	$ 25.85	$ 21.20	$ 22,288,707
28	May-15	356,242	$ 7.09	$ 2,525,756	(1,084,799)	(429,832)	$ 22.45	$ 15.31	$ (30,934,454)
29	Jun-15	516,333	$ 7.52	$ 3,882,827	(613,510)	(144,271)	$ 23.79	$ 17.42	$ (17,108,600)
30	Jul-15	555,284	$ 9.84	$ 5,463,999	(586,083)	142,736	$ 31.17	$ 26.86	$ (14,434,306)
31	Aug-15	438,692	$ 10.66	$ 4,676,454	(176,265)	190,690	$ 33.90	$ 28.60	$ (521,667)
32	Sep-15	432,416	$ 10.74	$ 4,644,151	(61,247)	202,693	$ 34.16	$ 29.37	$ 3,860,886
33	**Total**			**$ 61,568,150**					**$ 26,149,726**

Rate Design Step
Calculation of PF Preference Rates under Tiered Rate Methodology
Test Period October 2013 - September 2015

	B		C		D		E
5	**Costs ($000)**		**2014**		**2015**		**Rate Period**
6	**Composite....**	$	2,661,465	$	2,749,291	$	5,410,755
7	**Non-Slice....**	$	136,188	$	96,957	$	233,145
8	**Slice....**	$	-	$	-	$	-
9	**Tier 2....**	$	5,414	$	27,391	$	32,804
13							
14	**Revenues from Rate Pools to Composite Cost Pool**		**2014**		**2015**		**Rate Period**
15	DSI Revenue Credit....	**$**	**(106,564)**	**$**	**(106,564)**	**$**	**(213,129)**
16	Exchange Revenues....	**$**	**-**	**$**	**-**	**$**	**-**
17	New Resource Revenues....	**$**	**(0.64)**	**$**	**(0.65)**	**$**	**(1)**
18	FPS Revenues....	$	(29,163)	$	(29,163)	$	(58,327)
19	Non-Federal RSS Revenues....	$	(573)	$	(880)	$	(1,453)
20	Other Credits....	$	(256,857)	$	(259,761)	$	(516,617)
21	Tiered Rate Elements....					$	-
22	Unused RHWM Credit Reallocation....	$	(2,944)	$	(1,220)	$	(4,164)
23	Balancing Augmentation Adjustment Reallocation....	$	11,343	$	(20,289)	$	(8,945)
24	Composite Augmentation RSS Revenue Debit/(Credit)....	$	(2,018)	$	(2,018)	$	(4,036)
25	Composite Tier 2 RSS Revenue Debit/(Credit)....	$	(23)	$	(103)	$	(126)
26	Composite Tier 2 Rate Design Adjustment Debit/(Credit)	$	(184)	$	(846)	$	(1,030)
27	Transmission Losses Adjustment Reallocation....	$	(27,826)	$	(28,402)	$	(56,228)
28	Total....	$	(414,810)	$	(449,246)	$	(864,056)
29							
30	**Rate Discount Costs Applied to Composite Pool**		**2014**		**2015**		**Rate Period**
31	Irigation Rate Discout Costs....	$	19,794	$	19,794	$	39,589
32	Low Density Discount Costs....	$	36,123	$	37,261	$	73,384
33	Total....	$	55,918	$	57,055	$	112,973
34							
35			**2014**		**2015**		**Rate Period**
36	**Composite....**	$	2,302,573	$	2,357,100	$	4,659,672

Rate Design Step
Calculation of PF Preference Rates under Tiered Rate Methodology
Test Period October 2013 - September 2015

	B	C	D	E
5	**Costs ($000)**	**2014**	**2015**	**Rate Period**
6	**Composite**	$ 2,661,465	$ 2,749,291	$ 5,410,755
7	**Non-Slice**	$ 136,188	$ 96,957	$ 233,145
8	**Slice**	$ -	$ -	$ -
9	**Tier 2**	$ 5,414	$ 27,391	$ 32,804
37				
38	**Non-Slice Revenues, Credits, and Costs**	**2014**	**2015**	**Rate Period**
39	Secondary Revenue	$ (329,284)	$ (341,136)	$ (670,421)
40	Unused RHWM Credit Reallocation	$ 2,944	$ 1,220	$ 4,164
41	FPS Revenues not classified as Obligations in TRM	$ (701)	$ (701)	$ (1,402)
42	Non-federal RSC Revenues	$ 221	$ 267	$ 488
43	Network Wind Integration	$ -	$ -	$ -
44	Load Shaping Revenue	$ (5,888)	$ (26,150)	$ (32,038)
45	Balancing Augmentation Adjustment Reallocation	$ (11,343)	$ 20,289	$ 8,945
46	Demand Revenue	$ (60,932)	$ (61,568)	$ (122,500)
47	Non-Slice Augmentation RSC Revenue Debit/(Credit)	$ (493)	$ (493)	$ (987)
48	Non-Slice Tier 2 RSC Revenue Debit/(Credit)	$ -	$ -	$ -
49	Non-Slice Tier 2 Rate Design Debit/(Credit)	$ -	$ -	$ -
50	Transmission Losses Adjustment Reallocation	$ 27,826	$ 28,402	$ 56,228
51	Total	$ (377,651)	$ (379,871)	$ (757,523)
52				
53		**2014**	**2015**	**Rate Period**
54	**Non-Slice**	$ (241,463)	$ (282,915)	$ (524,378)

Rate Design Step
Calculation of PF Preference Rates under Tiered Rate Methodology
Test Period October 2013 - September 2015

	B	C		D		E	
5	**Costs ($000)**		**2014**		**2015**	**Rate Period**	
6	**Composite.....**	$	2,661,465	$	2,749,291	$	5,410,755
7	**Non-Slice.....**	$	136,188	$	96,957	$	233,145
8	**Slice.....**	$	-	$	-	$	-
9	**Tier 2.....**	$	5,414	$	27,391	$	32,804
55							
56	**TRM Costs after Adjustments**		**2014**		**2015**	**Rate Period**	
57	**Composite.....**	$	2,302,573	$	2,357,100	$	4,659,672
58	**Non-Slice.....**	$	(241,463)	$	(282,915)	$	(524,378)
59	**Slice.....**	$	-	$	-	$	-
60	**Tier 2.....**	$	5,414	$	27,391	$	32,804
61	**Total Costs**	$	2,066,523	$	2,101,576	$	4,168,099
62							
63	**Billing Determinants**		**2014**		**2015**	**Rate Period**	
64	**TOCA.....**		98.5093		98.8963		98.7028
65	**Non-slice TOCA.....**		71.6967		72.0837		71.8902
66	**Slice Percentage.....**		26.8126		26.8126		26.8126
67							
68	**Annual TRM Rates ($000/percent)**		**2014**		**2015**	**Rate Period**	
69	**Composite.....**	$	23,374	$	23,834	$	23,605
70	**Non-Slice.....**	$	(3,368)	$	(3,925)	$	(3,647)
71	**Slice.....**	$	-	$	-	$	-
72							
73	**Monthly TRM Rates ($/percent)**		**2014**		**2015**	**Rate Period**	
74	**Composite.....**		1,947,848		1,986,172		1,967,048
75	**Non-Slice.....**		(280,654)		(327,067)		(303,923)
76	**Slice.....**		-		-		-
77							
78	**Tier 2 Rates ($/MWh)**		**2014**		**2015**	**Rate Period**	
79	**Tier 2 Short Term.....**	$	35.46	$	37.21	$	36.34
80	**Tier 2 Load Growth.....**	$	35.46	$	41.64	$	41.64
81	**Tier 2 Vintage 2014.....**	$	-	$	41.52	$	41.52

Rate Design Step
Table Showing Net REP Rate Calculation Yields Identical Rates as Gross REP Calculations
Test period October 2013 - September 2015
($ 000, $/MWh)

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
11			2014	2015		PF p	IP	NR	FPS				PF p	IP	NR
12	GENERATION ENERGY														
13													123,660	5,466	0.01752
14	Federal Base System														
15	Hydro		730,244	753,729		1,483,973	0.0	0.0	0				12.00	0.00	0.00
16	Fish & Wildlife		316,720	325,888		642,609	0.0	0.0	0				5.20	0.00	0.00
17	Trojan		1,500	1,500		3,000	0.0	0.0	0				0.02	0.00	0.00
18	WNP #1		249,867	186,188		436,055	0.0	0.0	0				3.53	0.00	0.00
19	WNP #2		401,343	433,360		834,703	0.0	0.0	0				6.75	0.00	0.00
20	WNP #3		165,932	165,403		331,335	0.0	0.0	0				2.68	0.00	0.00
21	System Augmentation		27,622	123,283		150,905	0.0	0.0	0				1.22	0.00	0.00
22	Balancing Power Purchases		66,985	27,492		94,476	0.0	0.0	0				0.76	0.00	0.00
23	Tier 2 Costs		5,414	27,391		32,804	0.0	0.0	0				0.27	0.00	0.00
24	Total Federal Base System		1,965,626	2,044,234		4,009,860	0.0	0.0	0.0				32.43	0.00	0.00
25															
26	New Resources		73,962	74,929		148,891	0.0	0.0	0		PFx Revenue		1.20	0.00	0.00
27	Residential Exchange		2,716,422	2,715,757		555,775	0.0	0.0	0		4,876,404		4.49	0.00	0.00
28	Conservation		154,453	150,035		304,488	0.0	0.0	0				2.46	0.00	0.00
29	BPA Programs & Transmission		322,802	329,867		652,669	0.0	0.0	0		NR Revenue		5.28	0.00	0.00
30	TOTAL COSA ALLOCATIONS		5,233,265	5,314,821		5,671,682	0	0	0		1.3		45.86	0.00	0.00
31															
32															
33	Nonfirm Excess Revenue Credit		(449,919)	(466,114)		(916,033)	0.0	0.0	0.0				-7.41	0.00	0.00
34	LDD/IRD Expense		55,918	57,055		112,973	0.0						0.91	0.00	0.00
35	Other Revenue Credits		(258,117)	(262,023)		(520,140)	0.0	0.0	0.0				-4.21	0.00	0.00
36						0	0.0						0.00	0.00	0.00
37	SP Revenue Surplus/Dfct Adj.		0	0		(58,327)	0	0.0	58,327				-0.47	0.00	0.00
38						(1.3)		1.2891					0.00	0.00	73.58
39	IP Rate Revenue		0	0		(213,103)	213,103						-1.72	38.99	0.00
40															
41	TOTAL RATE DESIGN ADJUSTMENTS		(652,118)	(671,082)		(1,594,631)	213,103	1.3	58,327				-12.90	38.99	73.58
42															
43	Total Generation		4,581,148	4,643,739									**32.97**	**38.99**	**73.58**
44			**PFp Revenue Recovery**			**4,077,051**	213,103	1.3	58,327						

Table 2.5.7.2

Rate Design Step
Demonstration that TRM PFp Rates Collect the Same Revenue Requirement as the Non-TRM PFp Rate
Test Period October 1, 2013 to September 30, 2015

Proof: TRM PF Revenues = Non-TRM PF Revenues

	B	C	D	E	F	G
4						
5						
6		**Proof: TRM PF Revenues = Non-TRM PF Revenues**				
7						
8			2014	2015		
9		Composite Revenue..............................	$ 2,325,269	$ 2,334,404		
10		Non-Slice Revenue...............................	$ (261,483)	$ (262,895)		
11		Slice Revenue...	$ -	$ -		
12		Tier 2..	$ 5,414	$ 27,391		
13		Load Shaping Revenue..........................	$ 5,888	$ 26,150		
14		Demand Revenue..................................	$ 60,932	$ 61,568		
15		Total TRM PF Revenue	$ 2,136,020	$ 2,186,618		
16						
17		Slice Portion of Secondary Revenue......	$ (120,635)	$ (124,977)		
18		Total Net TRM PF Revenue	$ 2,015,385	$ 2,061,641		
19						
20					PF Rate	
21		Total TRM PF Revenue Analogous to w/ Slice PF		$ 4,077,025	32.97	
22						
23		w/ Slice PF Public Rate Revenue from "Net REP" Table		**$ 4,077,051**	32.97	
24			delta	$ 26		
25						
26						

Rate Design Step
Calculation of Priority Firm Tier 1 Equivalent Rate Components
Test Period October 2013 - September 2015

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14		
15	HLH (mills/kWh)	31.30	32.51	35.78	35.86	34.39	29.53	25.85	22.45	23.79	31.17	33.90	34.16		
16	LLH (mills/kWh)	28.06	29.90	31.97	30.24	29.75	25.90	21.20	15.31	17.42	26.86	28.60	29.37		
17	Demand Rate ($/kW/mo)	9.86	10.24	11.26	11.29	10.83	9.31	8.16	7.09	7.52	9.84	10.66	10.74		
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)	5,629	6,395	7,190	6,866	5,906	6,185	5,676	6,182	5,711	6,285	6,064	5,394		122,823
22	LLH (GWh)	3,556	4,548	5,098	4,815	3,968	4,146	3,649	4,303	3,587	4,113	3,862	3,693		Tier 1 Demand (MW/mo)
23	Demand (MW)	953	674	1,553	1,598	887	1,037	1,156	807	910	1,095	875	868		12,412
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)	$ 176,203	$ 207,898	$ 257,232	$ 246,190	$ 203,096	$ 182,674	$ 146,751	$ 138,773	$ 135,897	$ 195,875	$ 205,539	$ 184,235		$ 3,585,298
29	LLH ($000)	$ 99,788	$ 135,991	$ 162,986	$ 145,600	$ 118,055	$ 107,388	$ 77,366	$ 65,875	$ 62,490	$ 110,476	$ 110,463	$ 108,455		Demand Revenue ($000)
30	Demand ($000)	$ 9,397	$ 6,902	$ 17,486	$ 18,040	$ 9,611	$ 9,654	$ 9,432	$ 5,720	$ 6,842	$ 10,770	$ 9,325	$ 9,320		$ 122,500
31															$ 3,707,799
32															Tier 1 Revenue Requirement (RR) ($000)
33															**$ 4,044,247**
34															Tier 1 RR less Demand Revenue ($000)
35															$ 3,921,746
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)	34.04	35.25	38.52	38.60	37.13	32.27	28.59	25.19	26.53	33.91	36.64	36.90		(2.74)
38	LLH (mills/kWh)	30.80	32.64	34.71	32.98	32.49	28.64	23.94	18.05	20.16	29.60	31.34	32.11		
39	Demand ($/kW/mo)	9.86	10.24	11.26	11.29	10.83	9.31	8.16	7.09	7.52	9.84	10.66	10.74		
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)	$ 191,628	$ 225,408	$ 276,961	$ 265,019	$ 219,299	$ 199,606	$ 162,282	$ 155,715	$ 151,524	$ 213,118	$ 222,180	$ 199,030		$ 3,921,893
45	LLH ($000)	$ 109,533	$ 148,454	$ 176,955	$ 158,793	$ 128,928	$ 118,749	$ 87,365	$ 77,665	$ 72,319	$ 121,746	$ 121,046	$ 118,573		Allocated Cost Demand ($000)
46	Demand ($000)	$ 9,397	$ 6,902	$ 17,486	$ 18,040	$ 9,611	$ 9,654	$ 9,432	$ 5,720	$ 6,842	$ 10,770	$ 9,325	$ 9,320		$ 122,500
47															$ 4,044,394
48	Average Slice&Non-Slice Tier 1 Rate														
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 3,921,893	31.93												
51	Allocated Cost Demand	$ 122,500	1.00												
52	Total Allocated Costs	$ 4,044,394	32.93												
53															
54	Tier 1 Energy (GWh)		122,823												
55	Market Energy Delta (mills/kWh)		(2.74)												

Rate Design Step
Calculation of Priority Firm Public Melded Rate Equivalent Components
Test Period October 2013 - September 2015

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14		
15	HLH (mills/kWh)	31.30	32.51	35.78	35.86	34.39	29.53	25.85	22.45	23.79	31.17	33.90	34.16		
16	LLH (mills/kWh)	28.06	29.90	31.97	30.24	29.75	25.90	21.20	15.31	17.42	26.86	28.60	29.37		
17	Demand Rate ($/kW/mo)	9.86	10.24	11.26	11.29	10.83	9.31	8.16	7.09	7.52	9.84	10.66	10.74		
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)	5,671	6,432	7,230	6,906	5,943	6,225	5,716	6,220	5,751	6,325	6,104	5,432		123,660
22	LLH (GWh)	3,586	4,580	5,130	4,846	3,996	4,178	3,678	4,335	3,617	4,144	3,894	3,723		Tier 1 Demand (MW/mo)
23	Demand (MW)	953	674	1,553	1,598	887	1,037	1,156	807	910	1,095	875	868		12,412
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)	$ 177,495	$ 209,101	$ 258,644	$ 247,616	$ 204,357	$ 183,848	$ 147,779	$ 139,637	$ 136,837	$ 197,114	$ 206,887	$ 185,541		$ 3,609,430
29	LLH ($000)	$ 100,625	$ 136,946	$ 163,997	$ 146,548	$ 118,874	$ 108,198	$ 77,981	$ 66,374	$ 63,001	$ 111,318	$ 111,359	$ 109,353		Demand Revenue ($000)
30	Demand ($000)	$ 9,397	$ 6,902	$ 17,486	$ 18,040	$ 9,611	$ 9,654	$ 9,432	$ 5,720	$ 6,842	$ 10,770	$ 9,325	$ 9,320		$ 122,500
31															$ 3,731,930
32															Tier 1&2 Revenue Requirement (RR) ($000)
33															$ 4,077,051
34															T1&2RR less Demand Revenue ($000)
35															$ 3,954,551
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)	34.09	35.30	38.57	38.65	37.18	32.32	28.64	25.24	26.58	33.96	36.69	36.95		(2.79)
38	LLH (mills/kWh)	30.85	32.69	34.76	33.03	32.54	28.69	23.99	18.10	20.21	29.65	31.39	32.16		
39	Demand ($/kW/mo)	9.86	10.24	11.26	11.29	10.83	9.31	8.16	7.09	7.52	9.84	10.66	10.74		
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)	$ 193,316	$ 227,033	$ 278,843	$ 266,898	$ 220,958	$ 201,200	$ 163,705	$ 156,996	$ 152,859	$ 214,782	$ 223,942	$ 200,712		$ 3,954,502
45	LLH ($000)	$ 110,630	$ 149,725	$ 178,309	$ 160,069	$ 130,022	$ 119,853	$ 88,244	$ 78,470	$ 73,091	$ 122,881	$ 122,223	$ 119,741		Allocated Cost Demand ($000)
46	Demand ($000)	$ 9,397	$ 6,902	$ 17,486	$ 18,040	$ 9,611	$ 9,654	$ 9,432	$ 5,720	$ 6,842	$ 10,770	$ 9,325	$ 9,320		$ 122,500
47															$ 4,077,002
48	Average Slice&Non-Slice Tier 1&2 Rate														
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 3,954,502	31.98												
51	Allocated Cost Demand	$ 122,500	0.99												
52	Total Allocated Costs	$ 4,077,002	32.97												
53															
54	Tier 1&2 Energy (GWh)		123,660												
55	PF Melded Equivalent Energy Scalar (mills/kWh)		(2.79)												

Rate Design Step
Calculation of Industrial Firm Power Rate Components
Test Period October 2013 - September 2015

Load Shaping Rate	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14
HLH (mills/kWh)	34.09	35.30	38.57	38.65	37.18	32.32	28.64	25.24	26.58	33.96	36.69	36.95
LLH (mills/kWh)	30.85	32.69	34.76	33.03	32.54	28.69	23.99	18.10	20.21	29.65	31.39	32.16
Demand Rate ($/kW/mo)	9.86	10.24	11.26	11.29	10.83	9.31	8.16	7.09	7.52	9.84	10.66	10.74

IP Billing Determinants	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	Totals
													IP Energy (GWh)
HLH (GWh)	267	246	255	257	237	265	257	254	253	254	263	243	5,466
LLH (GWh)	197	206	208	206	183	199	193	210	195	211	202	207	
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)	$ 9,085	$ 8,679	$ 9,823	$ 9,940	$ 8,807	$ 8,550	$ 7,347	$ 6,406	$ 6,717	$ 8,629	$ 9,643	$ 8,982	$ 172,763
LLH ($000)	$ 6,077	$ 6,725	$ 7,224	$ 6,818	$ 5,968	$ 5,713	$ 4,631	$ 3,804	$ 3,938	$ 6,242	$ 6,341	$ 6,673	Demand Rev ($000)
Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
													$ 172,763

VOR	(0.98)
Industrial Margin (mills/kWh)	0.709
Net industrial Margin	(0.266)
Settlement Charge	**7.647**

IP Rate	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
HLH (mills/kWh)	41.47	42.68	45.95	46.03	44.56	39.70	36.02	32.62	33.96	41.34	44.07	44.33
LLH (mills/kWh)	38.23	40.07	42.14	40.41	39.92	36.07	31.37	25.48	27.59	37.03	38.77	39.54
Demand ($/kW/mo)	9.86	10.24	11.26	11.29	10.83	9.31	8.16	7.09	7.52	9.84	10.66	10.74

Revenues @ Posted IP Rate	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	Allocated Cost Energy ($000)
HLH ($000)	$ 11,052	$ 10,494	$ 11,703	$ 11,838	$ 10,556	$ 10,503	$ 9,240	$ 8,279	$ 8,581	$ 10,504	$ 11,583	$ 10,776	$ 213,104
LLH ($000)	$ 7,531	$ 8,243	$ 8,758	$ 8,342	$ 7,322	$ 7,182	$ 6,055	$ 5,355	$ 5,376	$ 7,796	$ 7,831	$ 8,204	Allocated Cost Demand ($000)
Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
													$ 213,104

Average IP Rate	($000)	(mills/kWh)
Allocated Cost Energy	$ 213,104	38.99
Allocated Cost Demand	$ -	-
Total Allocated Costs	$ 213,104	38.99
IP Energy (GWh)		5,466
Industrial Margin (mills/kWh)		0.71
VOR		(0.98)
Settlement Charge		7.65

Rate Design Step
Calculation of New Resource Rate Components
Test Period October 2013 - September 2015

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14		
15	HLH (mills/kWh)	31.30	32.51	35.78	35.86	34.39	29.53	25.85	22.45	23.79	31.17	33.90	34.16		
16	LLH (mills/kWh)	28.06	29.90	31.97	30.24	29.75	25.90	21.20	15.31	17.42	26.86	28.60	29.37		
17	Demand Rate ($/kW/mo)	9.86	10.24	11.26	11.29	10.83	9.31	8.16	7.09	7.52	9.84	10.66	10.74		
18															
19															**Totals**
20	NR Determinants	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		NR Energy (GWh)
21	HLH (GWh)	0.0009	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008	0.0008		0.0175
22	LLH (GWh)	0.0006	0.0007	0.0007	0.0007	0.0006	0.0007	0.0006	0.0007	0.0006	0.0007	0.0007	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)	$ 0.0270	$ 0.0255	$ 0.0292	$ 0.0298	$ 0.0264	$ 0.0246	$ 0.0215	$ 0.0183	$ 0.0194	$ 0.0259	$ 0.0282	$ 0.0273		$ 0.5050
29	LLH ($000)	$ 0.0175	$ 0.0197	$ 0.0215	$ 0.0198	$ 0.0171	$ 0.0169	$ 0.0129	$ 0.0103	$ 0.0109	$ 0.0176	$ 0.0188	$ 0.0188		Demand Revenue ($000)
30	Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
31															$ 0.5050
32															NR Revenue Requirement (RR) ($000)
33															$ 1.2891
34															NR RR less Demand Revenue ($000)
35															$ 1.2891
36	NR Rates	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Market Energy Delta (mills/kWh)
37	HLH (mills/kWh)	76.05	77.26	80.53	80.61	79.14	74.28	70.60	67.20	68.54	75.92	78.65	78.91		(44.75)
38	LLH (mills/kWh)	72.81	74.65	76.72	74.99	74.50	70.65	65.95	60.06	62.17	71.61	73.35	74.12		
39	Demand ($/kW/mo)	9.86	10.24	11.26	11.29	10.83	9.31	8.16	7.09	7.52	9.84	10.66	10.74		
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)	$ 0.0657	$ 0.0606	$ 0.0657	$ 0.0671	$ 0.0608	$ 0.0618	$ 0.0587	$ 0.0548	$ 0.0559	$ 0.0632	$ 0.0654	$ 0.0631		$ 1.2891
45	LLH ($000)	$ 0.0454	$ 0.0491	$ 0.0516	$ 0.0492	$ 0.0429	$ 0.0462	$ 0.0401	$ 0.0404	$ 0.0388	$ 0.0470	$ 0.0481	$ 0.0474		Allocated Cost Demand ($000)
46	Demand ($000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
47															$ 1.2891
48		Average NR Rate													
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 1.2891	73.58												
51	Allocated Cost Demand	$ -	-												
52	Total Allocated Costs	$ 1.2891	73.58												
53															
54		NR Energy (GWh)	0.0175												
55															

Rate Design Step
Calculation of Priority Firm Tier 1 Equivalent Rate Components
Test Period October 2013 - September 2015

	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
13															
14	Load Shaping Rate	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14		
15	HLH (mills/kWh)	31.30	32.51	35.78	35.86	34.39	29.53	25.85	22.45	23.79	31.17	33.90	34.16		
16	LLH (mills/kWh)	28.06	29.90	31.97	30.24	29.75	25.90	21.20	15.31	17.42	26.86	28.60	29.37		
17	Demand Rate ($/kW/mo)	9.86	10.24	11.26	11.29	10.83	9.31	8.16	7.09	7.52	9.84	10.66	10.74		
18															
19															**Totals**
20	Classic Billing Determinants	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP		Tier 1 Energy (GWh) [FAT1L]
21	HLH (GWh) [FMDT1L]	4,134	4,506	5,264	5,285	4,600	4,587	4,114	3,795	3,855	4,311	4,333	3,951		89,868
22	LLH (GWh) [FMDT1L]	2,712	3,402	3,901	3,861	3,182	3,199	2,751	2,795	2,544	3,053	2,923	2,807		Tier 1 Demand (MW/mo)
23	Demand (MW)	953	674	1,553	1,598	887	1,037	1,156	807	910	1,095	875	868		12,412
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)	$ 129,406	$ 146,499	$ 188,342	$ 189,519	$ 158,183	$ 135,467	$ 106,371	$ 85,187	$ 91,727	$ 134,368	$ 146,881	$ 134,970		$ 2,637,205
29	LLH ($000)	$ 76,097	$ 101,727	$ 124,701	$ 116,744	$ 94,657	$ 82,864	$ 58,322	$ 42,794	$ 44,323	$ 82,009	$ 83,607	$ 82,442		Demand Revenue ($000)
30	Demand ($000)	$ 9,397	$ 6,902	$ 17,486	$ 18,040	$ 9,611	$ 9,654	$ 9,432	$ 5,720	$ 6,842	$ 10,770	$ 9,325	$ 9,320		$ 122,500
31															$ 2,759,705
32															Tier 1 Non-Slice PF Public RR minus Tier 2 Costs
33															$ 3,024,058
34															Tier 1 RR less Demand Revenue ($000) [BLFRnD]
35															$ 2,901,557
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)	34.24	35.45	38.72	38.80	37.33	32.47	28.79	25.39	26.73	34.11	36.84	37.10		(2.94)
38	LLH (mills/kWh)	31.00	32.84	34.91	33.18	32.69	28.84	24.14	18.25	20.36	29.80	31.54	32.31		
39	Demand ($/kW/mo)	9.86	10.24	11.26	11.29	10.83	9.31	8.16	7.09	7.52	9.84	10.66	10.74		
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)	$ 141,561	$ 159,739	$ 203,841	$ 205,070	$ 171,723	$ 148,941	$ 118,451	$ 96,345	$ 103,045	$ 147,059	$ 159,639	$ 146,600		$ 2,901,463
45	LLH ($000)	$ 84,070	$ 111,729	$ 136,168	$ 128,094	$ 104,011	$ 92,271	$ 66,411	$ 51,011	$ 51,803	$ 90,985	$ 92,201	$ 90,694		Allocated Cost Demand ($000)
46	Demand ($000)	$ 9,397	$ 6,902	$ 17,486	$ 18,040	$ 9,611	$ 9,654	$ 9,432	$ 5,720	$ 6,842	$ 10,770	$ 9,325	$ 9,320		$ 122,500
47															$ 3,023,963
48	Average Non-Slice Tier 1 Rate														
49		($000)	(mills/kWh)												
50	Allocated Cost Energy	$ 2,901,463	32.29												
51	Allocated Cost Demand	$ 122,500	1.36												
52	Total Allocated Costs	$ 3,023,963	33.65												
53															
54	Tier 1 Energy (GWh) [FAT1L]		89,868												
55	Load Shaping True-up Rate (mills/kWh) [LSTUR]		(2.94)												

Rate Design Study
Allocated Cost and Unit Cost Priority Firm Rates
Test Period October 2013 - September 2015

	A	B	C	PF Public		PF Exchange	
	ALLOCATED	UNIT	PERCENT	ALLOCATED		ALLOCATED	
	COSTS	COSTS	CONTRIBUTION	COSTS		COSTS	
GENERATION ENERGY	($ Thousands)	(Mills/kWh)	(Percent)				
Federal Base System							
Hydro	1,483,973	6.994	16.59%	864,891	6.994	619,082	6.994
Fish & Wildlife	642,609	3.029	7.18%	374,526	3.029	268,083	3.029
Trojan	3,000	0.014	0.03%	1,748	0.014	1,252	0.014
WNP #1	436,055	2.055	4.87%	254,142	2.055	181,913	2.055
WNP #2	834,703	3.934	9.33%	486,483	3.934	348,220	3.934
WNP #3	331,335	1.562	3.70%	193,109	1.562	138,226	1.562
System Augmentation	150,905	0.711	1.69%	87,950	0.711	62,954	0.711
Balancing Power Purchases	94,476	0.445	1.06%	55,063	0.445	39,413	0.445
Tier 2 Costs	32,804	0.155	0.37%	19,119	0.155	13,685	0.155
Total Federal Base System	4,009,860	18.899	44.83%	2,337,032	18.899	1,672,828	18.899
New Resources							
Gross Residential Exchange	5,125,535	24.157	57.30%	2,987,271	24.157	2,138,264	24.157
Conservation	294,650	1.389	3.29%	171,729	1.389	122,922	1.389
BPA Programs	306,479	1.444	3.43%	178,623	1.444	127,857	1.444
Power Transmission	325,104	1.532	3.63%	189,478	1.532	135,627	1.532
TOTAL COSA ALLOCATIONS	10,061,629	47.422	112.48%	5,864,131	47.422	4,197,498	47.422
Nonfirm Excess Revenue Credit	(901,412)	-4.248	-10.08%	(525,362)	-4.248	(376,050)	-4.248
Low Density Discount Expense	112,973	0.532	1.26%	65,843	0.532	47,130	0.532
Other Revenue Credits	(508,825)	-2.398	-5.69%	(296,554)	-2.398	(212,271)	-2.398
Irrigation Rate Mitigation Expense							
SP Revenue Surplus/Dfct Adj.	45,638	0.215	0.51%	26,599	0.215	19,039	0.215
7(c)(2) Delta Adjustment	135,020	0.636	1.51%	78,693	0.636	56,328	0.636
7(c)(2) Floor Rate Adjustment							
TOTAL RATE DESIGN ADJUSTMENTS	(1,116,606)	-5.263	-12.48%	(650,782)	-5.263	(465,824)	-5.263
Total Generation	8,945,023	**42.1588**	100.00%	5,213,350	**42.16**	3,731,674	**42.16**
REP Settlement Rate Protection Adjustment				(1,184,807)	-9.581	1,144,777	1,144,777
7(b)(2) - 7(c)(2) Industrial Adjustment				48,462	0.392	1	0.000
Total Generation				**4,077,004**	**32.97**	4,876,452	**55.09**
Total Transmission						354,944	4.010
						5,231,395	**59.10**

Rate Design Study
Allocated Cost and Unit Costs for Industrial Firm Power Rate
Test Period October 2013 - September 2015

	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	114,898	21.019	53.91%
28	Gross Residential Exchange	236,634	43.290	111.03%
29	Conservation	7,592	1.389	3.56%
30	BPA Programs	7,895	1.444	3.70%
31	Power Transmission	8,376	1.532	3.93%
32	TOTAL COSA ALLOCATIONS	375,394	68.675	176.13%
33				
34	Nonfirm Excess Revenue Credit	(11,282)	-2.064	-5.29%
35				
36	Other Revenue Credits	(8,732)	-1.597	-4.10%
37				
38	SP Revenue Surplus/Dfct Adj.	1,176	0.215	0.55%
39	7(c)(2) Delta Adjustment	(135,020)	-24.701	-63.35%
40	7(c)(2) Floor Rate Adjustment			
41	TOTAL RATE DESIGN ADJSTMTS	(153,859)	-28.147	-72.19%
42	Total Generation	221,535	40.528	103.94%
43				
55	Total Allocated & Adjusted Costs	221,535	40.528	103.94%
56				
57	Settlement Adjustments			
58	REP Settlement Rate Protection Adjustment	40,030	7.323	18.78%
59	7(b)(2) - 7(c)(2) Industrial Adjustment	(48,462)	-8.866	-22.74%
60		213,103	**38.99**	100.00%
61				
62	Billing Determinants:			
63	Energy (GwH)	5,466		

Rate Design Study
Allocated Costs and Unit Costs for New Resources Firm Power Rate
Test Period October 2013 - September 2015

	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	0.3683	21.019	28.57%
27	Gross Residential Exchange	0.7584	43.290	58.83%
28	Conservation	0.0243	1.389	1.89%
29	BPA Programs	0.0522	2.977	4.05%
30	TOTAL COSA ALLOCATIONS	1.2032	68.675	93.33%
31				
32	Nonfirm Excess Revenue Credit	(0.0362)	-2.064	-2.81%
33				
34	Other Revenue Credits	(0.0280)	-1.597	-2.17%
35				
36	SP Revenue Surplus/Dfct Adj.	0.0038	0.215	0.29%
37	7(c)(2) Delta Adjustment	0.0111	0.636	0.86%
38	7(c)(2) Floor Rate Adjustment			
39	TOTAL RATE DESIGN ADJSTMTS	(0.0492)	-2.810	-3.82%
40	Total Generation Energy	1.1540	65.865	89.51%
41				
50				
51	Total Allocated & Adjusted Costs	1.1540	65.865	89.51%
52	Settlement Adjustments			
53	REP Settlement Rate Protection Adjustment	0.1283	7.323	9.95%
54	7(b)(2) - 7(c)(2) Industrial Adjustment	0.0069	0.392	0.53%
55				
56	Total With 7(b)(2) Adjustments	1.2891	**73.58**	100.00%
57				
58	Billing Determinant / Energy (GWh)	0.01752		

Rate Design Study
Resource Cost Percent Contribution to Load Pools
Test Period October 2013 - September 2015

	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	2,337,032	2,987,271		5,324,302		43.89%	56.11%		100.00%
18	Priority Firm - Exchange	1,672,828	2,138,264		3,811,093		43.89%	56.11%		100.00%
19	Priority Firm Power - Total	4,009,860	5,125,535		9,135,395		43.89%	56.11%		100.00%
20	Industrial Firm Power		236,634	114,898	351,531			67.32%	32.68%	100.00%
21	New Resources Firm		0.758	0	1			67.32%	32.68%	100.00%
22	Firm Power Products and Services		70,009	33,993	104,002			67.32%	32.68%	100.00%
23										
24										
25	**TOTALS**	**4,009,860**	**5,432,179**	**148,891**	**9,590,929**		**41.81%**	**56.64%**	**1.55%**	**100.00%**
26										
27					217,641					
28										
29				Average Cost of Resources	44.07					
30										
31				Average Cost to Serve Load Growth	39.04					

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SECTION 3: RATE DESIGN

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 includes the calculation of the Tier 1 Demand rate.

Table 3.5 Tier 2 Rate Revenues
Table summarizes the Tier 2 rate-related revenues and adjustments to Tier 1 cost pools.

Table 3.6 Tier 2 Rate Inputs
Table lists prices used for Tier 2 surplus credit or deficit debit and to calculate the TSS cost adder.

Table 3.7 Inputs to TSS Rate and Charge
Table shows the costs used as the numerator and the megawatthours sold as the denominator for the TSS rate. The transaction values are used to calculate the charge cap.

Table 3.8 Tier 2 Short-Term Rate Costing Table
Table is the costing table used to calculate the Tier 2 Short-Term rates for each year of the rate period.

Table 3.9 Tier 2 Load Growth Rate Costing Table
Table is the costing table used to calculate the Tier 2 Load Growth rates for each year of the rate period.

Table 3.10 Tier 2 VRI - 2014 Costing Table
Table is the costing table used to calculate the VRI - 2014 rates for reach year of the rate period.

Table 3.11 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 3.12 Total Remarketing Credits
Table summarizes the source of power for meeting the different Tier 2 loads. Includes purchases both executed and forecast, remarketed power from other Tier 2 cost pools, remarketed power from non-Federal resources with DFS.

Table 3.13 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 3.14 Customers Receiving a Tier 2 Rate Remarketing Credit
List of customers' remarketed VR1-2014 purchases and forecast credits.

Table 3.15 Customers Receiving an LGR Allocation
List of Load Growth Rate customers and their forecast billing adjustments.

Table 3.16 Weighted LDD for IRD Eligible Utilities
Table shows the weighted LDD calculation for all IRD eligible utilities using the customers' CHWM contracts.

Table 3.17 Rates and Charges for RSS and Related Services in FY2014 and FY2015
Table summarizes the RSS model 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 3.18 Customers Receiving a Non-Federal Resource with DFS Remarketing Credit
List of customers' remarketed Non-Federal resources with DFS and forecast credits.

Table 3.19 Transmission Scheduling Service OATI Registration-Fee Customer List
List of OATI fee customers.

Table 3.1

Summary RSS Revenue Credits for Tier 1 Cost Pools

	A	B	C	D	E	F	G	H
1					2014	2015	2016	2017
2	TRM	COSA	AggregationKey	Category				
3	C	RDS	CNTA	Augmentation RSS & RSC Adder	2,511.3	2,511.3	2,511.3	2,511.3
4	C	RDS	CD2RCF	Composite Augmentation RSS Revenue Debit/(Credit)	-2,018.0	-2,018.0	-2,018.0	-2,018.0
5	2.0	RDS	2D2RCF	Composite Tier 2 RSS Revenue Debit/(Credit)	0.0	0.0	0.0	0.0
6	C	RDS	CD2RCN	Composite Non-Federal RSS Revenue Debit/(Credit)	-573.4	-879.8	-879.8	-879.8
7	N	RDS	ND2RNF	Non-Slice Augmentation RSC Revenue Debit/(Credit)	-493.3	-493.3	-493.3	-493.3
8	2.0	RDS	2D2RNF	Non-Slice Tier 2 RSC Revenue Debit/(Credit)	0.0	0.0	0.0	0.0
9	N	RDS	ND2RNN	Non-Slice Non-Federal RSC Revenue Debit/(Credit)	221.1	267.4	267.4	267.4
10								
11								
12								
13					Table 3.2			
14				Tier 2 Overhead Adder Inputs				

Table 3.2

Tier 2 Overhead Adder Inputs

	D	E	F	G	H
15		**WP-14**			
16		**FY2014**		**FY2015**	
17	**Line Item**	**FY2014**	**Total Forecast Sales (MWh)**	**FY2015**	**Total Forecast Sales (MWh)**
18	Executive and Administrative Services	$ 4,157,033	78,985,427	$ 4,360,146	79,693,606
19	Generation Project Coordination	$ 6,826,271		$ 6,968,124	
20	Sales & Support	$ 20,950,525		$ 21,338,766	
21	Strategy, Finance & Risk Mgmt	$ 18,299,293		$ 19,373,348	
22	Agency Services G&A	$ 44,815,176		$ 46,493,765	

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
5	Oct-13	29.95	26.96		December	$ 35.76	$ 31.97
6	Nov-13	31.04	28.48		January	$ 35.88	$ 30.23
7	Dec-13	34.89	31.47		February	$ 34.39	$ 29.76
8	Jan-14	34.92	29.91		March	$ 29.58	$ 25.93
9	Feb-14	33.99	29.65		April	$ 25.92	$ 21.24
10	Mar-14	29.09	25.57		May	$ 22.51	$ 15.34
11	Apr-14	26.57	21.71		June	$ 23.88	$ 17.48
12	May-14	22.74	15.83		July	$ 31.27	$ 26.94
13	Jun-14	23.26	17.05		August	$ 33.88	$ 28.60
14	Jul-14	30.98	26.99		September	$ 34.15	$ 29.36
15	Aug-14	33.46	28.30				
16	Sep-14	33.27	28.79				
17	Oct-14	32.65	29.16				
18	Nov-14	33.99	31.33				
19	Dec-14	36.66	32.48				
20	Jan-15	36.80	30.56				
21	Feb-15	34.78	29.86				
22	Mar-15	29.98	26.23				
23	Apr-15	25.13	20.70				
24	May-15	22.16	14.79				
25	Jun-15	24.33	17.79				
26	Jul-15	31.35	26.73			Year	$/MWh
27	Aug-15	34.33	28.90		FY 2014 Aurora flat annual Block		28.38
28	Sep-15	35.04	29.95		FY 2015 Aurora flat annual Block		29.27

Table 3.4

Tier 1 Demand Rates

	A	B	C	D	E	F	G	H	I	J	K
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)	2014		2005	100.00		Oct	31.31	8.44%	$ 9.86
3		Cost of Debt	4.57%	/1	2006	103.26		Nov	32.54	8.77%	$ 10.24
4					2007	106.30		Dec	35.76	9.64%	$ 11.26
5		Inflation Rate	1.88%		2008	108.62		Jan	35.88	9.67%	$ 11.29
6		Insurance Rate	0.25%	/2	2009	109.62		Feb	34.39	9.27%	$ 10.83
7					2010	110.66		Mar	29.58	7.97%	$ 9.31
8		Debt Finance Period (years)	30	/2	2011	113.36		Apr	25.92	6.99%	$ 8.16
9		Plant Lifecycle (years)	30	/2		101.88%	5-year Ave.	May	22.51	6.07%	$ 7.09
10								Jun	23.88	6.44%	$ 7.52
11		Plant in service 2014 Vintaged Heat Rate Btu/kWh	8,650	/2				Jul	31.27	8.43%	$ 9.84
12								Aug	33.88	9.13%	$ 10.66
13		Existing Fixed Fuel $/kW/yr with 10000 Heat Rate 2006$	$ 33.70	/2	Chained GDP IPD from BEA -- Table 1.1.9.			Sep	34.15	9.20%	$ 10.74
14		New Fixed Fuel $/kW/yr with 10000 Heat Rate 2006$	$ 45.95	/2	Implicit Price Deflators for Gross Domestic					Average $/kW/mo	$ 9.73
15		Existing Fixed Fuel $/kW/yr with 10000 Heat Rate 2014$	$ 39.13		Product - Last Revised August 29, 2012						
16		New Fixed Fuel $/kW/yr with 10000 Heat Rate 2014$	$ 53.35								
17		Average of Existing and New with 10000 Heat Rate 2014$	$ 46.24								
18		Average of Existing and New with 8650 Heat Rate 2014$	$ 40.00								
19											
20		All-in Nominal Capital Cost LMS100 $/kW	$ 1,105.00	/2	End of Fiscal Year	Midyear Assessed Value	Debt Payment	Fixed O&M	Insurance	Fixed Fuel	Cash Expense Each Year
21		Fixed O&M $/kW/yr 2014$	$ 9.29	/3	2014	$ 1,086.58	$68.40	$ 9.29	$ 2.72	$ 36.00	$116.40
22		Fixed Fuel adjusted for 10% capacity release credit $/kW/yr	$ 36.00		2015	$ 1,049.75	$68.40	$ 9.47	$ 2.62	$ 36.68	$117.17
23										Rate Period Average Expense $/kW/year	$ 116.78
24	/1 Source BPA FY 2012 Third-Party Tax-Exempt Borrowing Rate Forecast 30-year										
25	/2 Source NWPCC Microfin Model with 100% PUD ownership at 4.57% with plant in service 2014 and PNWE fixed fuel. Version 15.0.1										
26	/3 Source NWPCC Microfin Model assumption of $8/kW/yr in 2006$										

Table 3.5

Tier 2 Rate Revenues

	A	B	E	F
1		Hours	8,760	8,760
2		Notice		40816
3		Fiscal Year	FY2014	FY2015
4		Rate Period	WP-14	
5		ShortTerm Rate $/MWh	$ 35.46	$ 37.21
6		LoadGrowth Rate $/MWh	$ 35.46	$ 41.64
7		Vintage.1 Rate $/MWh	N/A	$ 41.52
8				
9		**ShortTerm**		
10		Portfolio Purchased aMW	0.000	0.000
11		Portfolio Purchased MWh	0	0
12		Portfolio Obligation /w Losses aMW	16.585	31.341
13		Portfolio Obligation /w Losses MWh	145,285	274,547
14		Portfolio Billing Determinant aMW	16.117	30.457
15		Portfolio Billing Determinant MWh	141,188	266,805
16		RECs MWh	0	0
17		Base Power Purchase Cost	$ -	$ -
18		Rate Design Components	$ 191,078	$ 369,902
19		Other Costs	$ -	$ -
20		Rate $/MWh	$ 35.46	$ 37.21
21		Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (169,900)	$ (329,881)
22		Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
23		Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (21,178)	$ (40,021)
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	$ 5,006,511	$ 9,927,811
27		Remarketing Credit	$ -	$ -
28		Remarekting Charge	$ -	$ -
29		Forecast Power Purchase Costs	$ 4,577,702	$ 7,346,211
30				
31		**LoadGrowth**		
32		Portfolio Purchased aMW	0.000	0.000
33		Portfolio Purchased MWh	0	0
34		Portfolio Obligation /w Losses aMW	1.351	1.722
35		Portfolio Obligation /w Losses MWh	11,835	15,085
36		Portfolio Billing Determinant aMW	1.313	1.673
37		Portfolio Billing Determinant MWh	11,501	14,659
38		RECs MWh	0	0
39		Base Power Purchase Cost	$ -	$ 1,713,456
40		Rate Design Components	$ 15,565	$ 20,324
41		Other Costs	$ -	$ -
42		Rate $/MWh	$ 35.46	$ 41.64
43		Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (13,840)	$ (18,125)
44		Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
45		Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (1,725)	$ (2,199)
46		Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -
47		Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -
48		Total LoadGrowth Rate Revenue	$ 407,826	$ 610,415
49		Remarketing Credit	$ -	$ -
50		Remarekting Charge	$ -	$ 123,763
51		Forecast Power Purchase Costs	$ 372,896	$ -

Table 3.5(continued)

Tier 2 Rate Revenues

	A	B	E	F
1		Hours	8,760	8,760
2		Notice		Sep 30, 2011
3		Fiscal Year	FY2014	FY2015
4		Rate Period	WP-14	
5		ShortTerm Rate $/MWh	$ 35.46	$ 37.21
6		LoadGrowth Rate $/MWh	$ 35.46	$ 41.64
7		Vintage.1 Rate $/MWh	N/A	$ 41.52
8				
9		**Vintage.1**		
10		Portfolio Purchased aMW		46.000
11		Portfolio Purchased MWh		402,960
12		Portfolio Obligation /w Losses aMW		47.335
13		Portfolio Obligation /w Losses MWh		414,655
14		Portfolio Billing Determinant aMW		46.000
15		Portfolio Billing Determinant MWh		402,961
16		RECs MWh		0
17		Base Power Purchase Cost		$ 15,763,795
18		Rate Design Components		$ 558,671
19		Other Costs		$ -
20		Rate $/MWh		$ 41.52
21		Tier 2 Composite Overhead Adjustment Debit/(Credit)		$ (498,226)
22		Tier 2 Non-Slice Risk Adjustment Debit/(Credit)		$ -
23		Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)		$ (60,444)
24		Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)		$ -
25		Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)		$ -
26		Total Vintage.1 Rate Revenue		$ 16,730,955
27		Remarketing Credit		$ 1,224,851
28		Remarekting Charge		$ -
29		Forecast Power Purchase Costs		$ 312,919
30				
31		Total Tier 2 Revenue Collection	$ 5,414,338	$ 27,392,944
32				
33		Total Tier 2 Adjustments and Credits*		
34		Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (183,740)	$ (846,232)
35		Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
36		Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (22,903)	$ (102,664)
37		Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -
38		Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -

Table 3.6

Tier 2 Rate Inputs

	A	B	C	D	E
1	**Fiscal Year**	**$/MWh TSS Rate**	**Aurora Flat Annual Block Market Forecast ($/MWh)**	**Augmentation Price ($/MWh)**	**Augmentation Amount (MWh)**
4	FY2014	$ 0.15	$ 28.36	$ 33.14	715,990
5	FY2015	$ 0.15	$ 29.35	$ 34.81	3,420,312
6					
7					
8					
9					
10					
11					
12					
13			**Table 3.7**		
14		**Inputs to TSS Rate and Charge**			
15	**PTK Costs FY2014**	**PTK Costs FY2015**	**FY2011 Scheduled (MWh)**	**FY2012 Scheduled (MWh)**	
16	$5,044,034	$5,133,306	33,980,349	32,035,871	

Table 3.8

Tier 2 Short-Term Rate Costing Table

	A	B	C	D	E
1		ST.1.2012_2014	ST.1.2012_2014	ST.1.2012_2014	ST.2.2015_201
2	Hours	8,784	8,760	8760	8760
3	Notice	Nov 1, 2009			Nov 1, 2011
4	Fiscal Year	FY2012	FY2013	FY2014	FY2015
5	Rate Period	WP-12		WP-14	
6					
7	**Total Forecast Expected Cost**	$ 8,604,281	$ 22,981,774	$ 5,005,809.97	$ 9,926,888.26
8	Base Power Purchase Cost (Provided by PTL)	$ 8,444,938	$ 22,276,330	$ -	$ -
9	Power Purchase Cost	$ 8,444,938	$ 22,276,330	$ -	$ -
10	Transmission	$ -	$ -	$ -	$ -
11	*Third Party PTP*				
12	*Ancillary Services*				
13	Scheduling, System Control, Dispatch Services				
14	Operating Reserves (Spinning and Non-Spinning)				
15	Within Hour Balancing				
16	*Other BA Losses*				
17	Rate Design Components (Provided by PFR & PTM)	$ 159,343	$ 705,445	$ 191,078.32	$ 369,901.62
18	Resource Support Services	$ 42,574	$ 108,570	$ 21,178.14	$ 40,020.74
19	Diurnal Flattening Service	$ -	$ -	$ -	$ -
20	*DFS Energy (Variable)*				
21	*DFS Capacity (Fixed)*				
22	Forced Outage Reserve	$ -	$ -	$ -	$ -
23	*Forced Outage Reserve Capacity (Fixed)*				
24	Transmission Scheduling Services	$ 42,574	$ 108,570	$ 21,178.14	$ 40,020.74
25	*Transmission Curtailment Management Service Capacity (Fixed)*				
26	*Transmission Curtailment Management Service Energy (Variable)*				
27	*Alternative Transmission Path Costs*				
28	*Generation Imbalance*				
29	*TSS - Overhead*	$ 42,574	$ 108,570	$ 21,178.14	$ 40,020.74
30	Resource Shaping Charge	$ -	$ -	$ -	$ -
31	Tier 2 Overhead	$ 214,642	$ 557,099	$ 169,900.19	$ 329,880.88
32	Risk Adder	$ -	$ -	$ -	$ -
33	Carbon Costs Passthrough			$ -	$ -
34		$ -	$ -		
35	Renewable Energy Credits (MWh)	0	0	0	0
36	Quantity Purchased (MWh)	193,248	484,428	0	0
37	Tier 2 Obligation w/o losses (Billing Determinant)	185,105	472,041	141,188	266,805
38	Tier 2 Obligation w losses	190,323	485,357	145,285	274,547
39	Energy (Short)/Long (MWh)	-2,925	929	-145,285	-274,547
40	Composite Cost Pool Augmentation (MWh)	0	1,544,244		
41	Energy Short (MWh)			-145,285	-274,547
42	Energy to be Remarketed (MWh)			0	0
43	Remarketing Available (MWh)			7,735	66,215
44	Total Tier 2 Pool Shortfall (MWh)			-157,119	-286,242
45	Augmentation Price ($/MWh)	$ 37.78	$ 42.84	$ 33.14	$ 34.81
46	Flat Block RSC ($/MWh)	$ 33.46	$ 37.87	$ 28.36	$ 29.35
47	Remarketing value ($/MWh)	$ -	$ -	$ 33.14	$ 34.81
48	Remarketed Purchase (MWh)			7,152	63,510
49	Remarketed Purchase Cost			$ 237,029.67	$2,210,775.37
50	Remaining Shortfall (MWh)			-138,132	-211,037
51	Remaining Shortfall Cost			$4,577,701.98	$7,346,211.27
52	Tier 2 Balancing Adjustment Debit/(Credit)	$ (97,873)	$ 39,776		
53	Remarketing Treatment (Remove From Rate)				
54	Additional Remarketing (MWh)				
55					
56	Total Fixed Costs	$ 8,604,281	$ 22,981,774	$ 5,005,810	$ 9,926,888
57					
58	**Billing Components**				
59	ShortTerm ($/MWh)	$ 46.48	$ 48.69	$ 35.46	$ 37.21
60	Remarketing Credit			$ -	$ -
61	Remarekting Charge			$ -	$ -
62					
63	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (214,642)	$ (557,099)	$ (169,900)	$ (329,881)
64	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -	$ -	$ -
65	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (42,574)	$ (108,570)	$ (21,178)	$ (40,021)
66	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ (39,776)		

Table 3.9

Tier 2 Load Growth Rate Costing Table

	A	D	E
1			
2			
3		LG.3.2012_2028	LG.3.2012_2028
4	Hours	8,760	8,760
5	Notice		Sep 30, 2011
6	Fiscal Year	FY2014	FY2015
7	Rate Period	WP-14	
8			
9	**Total Forecast Expected Cost**	$ 407,769.02	$ 1,733,779.88
10	Base Power Purchase Cost (Provided by PTL)	$ -	$ 1,713,456.00
11	Power Purchase Cost	$ -	$ 1,713,456.00
12	Transmission	$ -	$ -
13	*Third Party PTP*		
14	*Ancillary Services*		
15	Scheduling, System Control, Dispatch Services		
16	Operating Reserves (Spinning and Non-Spinning)		
17	Within Hour Balancing		
18	*Other BA Losses*		
19	Rate Design Components (Provided by PFR & PTM)	$ 15,565.08	$ 20,323.88
20	Resource Support Services	$ 1,725.15	$ 2,198.90
21	Diurnal Flattening Service	$ -	$ -
22	*DFS Energy (Variable)*		
23	*DFS Capacity (Fixed)*		
24	Forced Outage Reserve	$ -	$ -
25	*Forced Outage Reserve Capacity (Fixed)*		
26	Transmission Scheduling Services	$ 1,725.15	$ 2,198.90
27	*Transmission Curtailment Management Service Capacity (Fixed)*		
28	*Transmission Curtailment Management Service Energy (Variable)*		
29	*Alternative Transmission Path Costs*		
30	*Generation Imbalance*		
31	*TSS - Overhead*	$ 1,725.15	$ 2,198.90
32	Resource Shaping Charge	$ -	$ -
33	Tier 2 Overhead	$ 13,839.92	$ 18,124.98
34	Risk Adder	$ -	$ -
35	Carbon Costs Passthrough	$ -	$ -
36			
37	Renewable Energy Credits (MWh)	0	0
38	Quantity Purchased (MWh)	0	43,800
39	Tier 2 Obligation w/o losses (Billing Determinant)	11,501	14,659
40	Tier 2 Obligation w losses	11,835	15,085
41	Energy (Short)/Long (MWh)	-11,835	28,715
42	Composite Cost Pool Augmentation (MWh)		
43	Energy Short (MWh)	-11,835	0
44	Energy to be Remarketed (MWh)	0	28,715
45	Remarketing Available (MWh)	7,735	66,215
46	Total Tier 2 Pool Shortfall (MWh)	-157,119	-286,242
47	Augmentation Price ($/MWh)	$ 33.14	$ 34.81
48	Flat Block RSC ($/MWh)	$ 28.36	$ 29.35
49	Remarketing value ($/MWh)	$ 33.14	$ 34.81
50	Remarketed Purchase (MWh)	583	0
51	Remarketed Purchase Cost	$ 19,308.24	$ -
52	Remaining Shortfall (MWh)	-11,252	0
53	Remaining Shortfall Cost	$ 372,895.71	$ -
54	Tier 2 Balancing Adjustment Debit/(Credit)		
55	Remarketing Treatment (Remove From Rate)		Yes
56	Additional Remarketing - Vintage Only (MWh)		
57			
58	Total Fixed Costs	$ 407,769	$ 1,733,780
59			
60	**Billing Components**		
61	LoadGrowth ($/MWh)	$ 35.46	$ 41.64
62	Remarketing Credit	$ -	$ -
63	Remarekting Charge	$ -	$ 123,762.86
64			
65	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (13,840)	$ (18,125)
66	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
67	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (1,725)	$ (2,199)
68	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)		

Table 3.10

Tier 2 VR1-2014 Rate Costing Table

	A	E
1		V.1.2014_2016
2	Hours	8,760
3	Notice	
4	Fiscal Year	FY2015
5	Rate Period	
6		
7	**Total Forecast Expected Cost**	$ 16,729,554.75
8	Base Power Purchase Cost (Provided by PTL)	$ 15,763,795.20
9	Power Purchase Cost	$ 15,763,795.20
10	Transmission	$ -
11	*Third Party PTP*	
12	*Ancillary Services*	
13	Scheduling, System Control, Dispatch Services	
14	Operating Reserves (Spinning and Non-Spinning)	
15	Within Hour Balancing	
16	*Other BA Losses*	
17	Rate Design Components (Provided by PFR & PTM)	$ 558,670.53
18	Resource Support Services	$ 60,444.20
19	Diurnal Flattening Service	$ -
20	*DFS Energy (Variable)*	
21	*DFS Capacity (Fixed)*	
22	Forced Outage Reserve	$ -
23	*Forced Outage Reserve Capacity (Fixed)*	
24	Transmission Scheduling Services	$ 60,444.20
25	*Transmission Curtailment Management Service Capacity (Fixed)*	
26	*Transmission Curtailment Management Service Energy (Variable)*	
27	*Alternative Transmission Path Costs*	
28	*Generation Imbalance*	
29	*TSS - Overhead*	$ 60,444.20
30	Resource Shaping Charge	$ -
31	Tier 2 Overhead	$ 498,226.33
32	Risk Adder	$ -
33	Carbon Costs Passthrough	$ -
34		
35	Renewable Energy Credits (MWh)	0
36	Quantity Purchased (MWh)	402,960
37	Tier 2 Obligation w/o losses (Billing Determinant)	402,961
38	Tier 2 Obligation w losses	414,655
39	Energy (Short)/Long (MWh)	-11,695
40	Composite Cost Pool Augmentation (MWh)	
41	Energy Short (MWh)	-11,695
42	Energy to be Remarketed (MWh)	0
43	Remarketing Available (MWh)	66,215
44	Total Tier 2 Pool Shortfall (MWh)	-286,242
45	Augmentation Price ($/MWh)	$ 34.81
46	Flat Block RSC ($/MWh)	$ 29.35
47	Remarketing value ($/MWh)	$ 34.81
48	Remarketed Purchase (MWh)	2,705
49	Remarketed Purchase Cost	$ 94,170.10
50	Remaining Shortfall (MWh)	-8,989
51	Remaining Shortfall Cost	$ 312,918.93
52	Tier 2 Balancing Adjustment Debit/(Credit)	
53	Remarketing Treatment (Remove From Rate)	No
54	Additional Remarketing (MWh)	35,187
55		
56	Total Fixed Costs	$ 16,729,555
57		
58	**Billing Components**	
59	Vintage.1 ($/MWh)	$ 41.52
60	Remarketing Credit	$ 1,224,851.05
61	Remarekting Charge	$ -
62		
63	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (498,226)
64	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -
65	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (60,444)
66	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	

Table 3.11

Tier 2 Purchases Made by BPA

	A	B	C	D	E	F	G	H	I	J
1	1	2	3	4	5	6	7	8	9	10
2	**start_date**	**maturity_date**	**trade_date**	**internal_portfolio**	**tran_status**	**hours**	**price**	**revenue**	**position**	**choice**
8	10/1/2014	9/30/2015	12/14/2011	Vintage T2	Validated	8760	$39.12	$ (15,763,795)	46.00	Seller's Choice
9	10/1/2014	9/30/2015	12/20/2011	Load Growth T2	Validated	8760	$39.12	$ (1,713,456)	5.00	Seller's Choice
10										
11										
12										
13										
14										
15										
16										
17				**Table 3.11(continued)**						
18				**Tier 2 Purchases**						
19	11	12	13	14	15	16	17	18	19	
20	**product**	**term**	**Description**	**reference**	**tran_num**	**buy_sell**	**RIS**	**deal_num**	**pt_of_receipt_loc**	
21	FLAT	Strip	Energy	Energy	245588	Buy	79510	245280	MID-C	
22	FLAT	Strip	Energy	Energy	245587	Buy	79572	245587	MID-C	

Table 3.12

Total Remarketing Charges and Credits

	A	B	C	D	E
1	Rate Period			WP-14	
2	Fiscal Year			FY2014	FY2015
3	ShortTerm Remarket (MWh)			0	0
4	LoadGrowth Remarket (MWh)			0	28,715
5	Vintage.1 Remarket (MWh)			0	35,187
6	Non-Federal Remarket (MWh)			7,735	2,313
7				7,735	66,215
8					
9	ShortTerm Purchase of Remarket (MWh)			7,152	63,510
10	LoadGrowth Purchase of Remarket (MWh)			583	0
11	Vintage.1 Purchase of Remarket (MWh)			0	2,705
12	BPA Purchase of Remarket (MWh)			0	0
13				7,735	66,215
14					
15	ShortTerm Remarket Credit			$ -	$ -
16	ShortTerm Remarket Charge			$ -	$ -
17	LoadGrowth Remarket Credit			$ -	$ -
18	LoadGrowth Remarket Charge			$ -	$ 123,763
19	Vintage.1 Remarket Credit			$ -	$ 1,224,851
20	Vintage.1 Remarket Charge			$ -	$ -
21	Non-Federal Resource Remarketing Credit			$ 256,338	$ 80,516
22					
23	ShortTerm Open Position (MWh)			138,132	211,037
24	LoadGrowth Open Position (MWh)			11,252	0
25	Vintage.1 Open Position (MWh)			0	8,989
26	BPA Purchase of Remarket (MWh)			0	0
27	Total Open Position (MWh)			149,384	220,027

Table 3.13

Tier 2 Load Obligations

	A	B	C	D	E	F	G
5		**Sorting Key**	**Rate Pool**	**Fiscal Year**	**aMW Quantity w/o Losses**	**aMW Quantity w/ Losses (1)**	
6		LG.1.2012_2028_FY2012	LG.1.2012_2028	FY2012	0.000	0.000	
7		LG.2.2012_2028_FY2013	LG.2.2012_2028	FY2013	2.678	2.754	
8		LG.3.2012_2028_FY2014	LG.3.2012_2028	FY2014	1.313	1.351	
9		LG.3.2012_2028_FY2015	LG.3.2012_2028	FY2015	1.673	1.722	
23		ST.1.2012_2014_FY2012	ST.1.2012_2014	FY2012	21.073	21.667	
24		ST.1.2012_2014_FY2013	ST.1.2012_2014	FY2013	53.886	55.406	
25		ST.1.2012_2014_FY2014	ST.1.2012_2014	FY2014	16.117	16.585	
26		ST.2.2015_2019_FY2015	ST.2.2015_2019	FY2015	30.457	31.341	
42		V.1.2014_2016_FY2014	V.1.2014_2016	FY2014	0.000	0.000	
43		V.1.2014_2016_FY2015	V.1.2014_2016	FY2015	46.000	47.335	
44							
45							
46	*Notes*						
47	(1) Baed on a losses factor of 2.82%						
48	(2) Based on estimates of A-HWM load for FY 2014. Actual A-RHWM load for FY 2014 shall be calculated as per the T						

Table 3.14

Customers Receiving a VR1-2014 tier 2 Remarketing Credit

	A	B	C	D	E	F	G	H
1			2014	2015				
2	Vintage Rate Remarketing Credit		$0	$1,224,851				
3								
4					2014	2015	2014	2015
5	**Customers Remarketing**	Remarketing Amount	Remarketing Amount	Allocation	Remarket Credit	Remarket Credit	Remarket	Remarket
6	**Vintage1-2014 Purchases**	aMW	MWH	Percentage	Allocation	Allocation	Monthly Credit	Monthly Credit
7	Burley, City of	1.000	$8,760	25.84%	$0	$316,499	$0	$26,375
8	Ellensburg, City of	0.346	$3,031	8.94%	$0	$109,509	$0	$9,126
9	Wells Rural Electric Company	1.416	$12,404	36.59%	$0	$448,163	$0	$37,347
10	Peninsula Light Company, Inc.	0.612	$5,361	15.81%	$0	$193,697	$0	$16,141
11	Columbia Rural Electric Association, Inc.	0.496	$4,345	12.82%	$0	$156,983	$0	$13,082
12	Total	3.87	33901	1		$1,224,851		

Table 3.15

Customers Receiving an Load Growth Rate Allocation

	Load Growth Pool Members	AHWML <1 aMW	Allocation Percentage	Initial Stranded Cost Allocation	Cost Cap Reallocation	Customer Billing Adjustment
10055	Albion, City of	0.01	0.09%	105	4	109
10005	Alder Mutual	0.043	0.36%	450	17	467
10015	Asotin PUD #1	0.007	0.06%	73	3	76
10059	Bandon, City of	0.259	2.19%	2,709	105	2,813
10025	Benton REA	0	0.00%	0	0	0
10061	Blaine, City of	0.425	3.59%	4,445	171	4,617
10065	Cascade Locks, City o	0	0.00%	0	0	0
10068	Chewelah, City of	0	0.00%	0	0	0
10109	Columbia Basin Elec	0.688	5.81%	7,196	278	7,473
10111	Columbia Power Coop	0.046	0.39%	481	19	500
10116	Consolidated Irrig Dis	0.532	4.50%	5,564	–4,560	1,004
10378	Coulee Dam, City of	0.154	1.30%	1,611	62	1,673
10070	Declo, City of	0.011	0.09%	115	4	119
10071	Drain, City of	0	0.00%	0	0	0
10142	East End Mutual Elect	0.105	0.89%	1,098	42	1,141
10144	Eatonville, City of	0.234	1.98%	2,447	94	2,542
10156	Elmhurst Mutual P &	0.712	6.02%	7,447	287	7,734
10174	Farmers Elec Coop	0.012	0.10%	126	5	130
10177	Ferry County PUD #1	0.449	3.79%	4,696	181	4,877
10190	Grant County PUD #2	0.488	4.12%	5,104	197	5,301
10197	Harney Elec Coop	0	0.00%	0	0	0
10597	Hermiston, City of	0	0.00%	0	0	0
10202	Hood River Elec Coop	0.438	3.70%	4,581	177	4,758
10230	Kittitas County PUD #	0.574	4.85%	6,004	232	6,235
10235	Lakeview L & P (WA	0	0.00%	0	0	0
10242	Lost River Elec Coop	0	0.00%	0	0	0
10246	Mason County PUD #	0.494	4.18%	5,167	199	5,366
10256	Midstate Elec Coop	0.497	4.20%	5,198	201	5,399
10080	Milton, Town of	0.065	0.55%	680	26	706
10082	Minidoka, City of	0.015	0.13%	157	6	163
10260	Modern Elec Coop	0.561	4.74%	5,868	226	6,094
10083	Monmouth, City of	0.34	2.87%	3,556	137	3,693
10273	Nespelem Valley Elec	0.688	5.81%	7,196	278	7,473
10284	Ohop Mutual Light	0.782	6.61%	8,179	316	8,495
10288	Orcas P & L	0	0.00%	0	0	0
10291	Oregon Trail Coop	0	0.00%	0	0	0
10304	Parkland L & W	0.518	4.38%	5,418	209	5,627
10086	Plummer, City of	0.271	2.29%	2,834	109	2,944
10338	Riverside Elec Coop	0	0.00%	0	0	0
10342	Salem Elec Coop	0.467	3.95%	4,884	188	5,073
10352	Skamania PUD #1	0	0.00%	0	0	0
10360	Southside Elec Lines	0	0.00%	0	0	0
10379	Steilacoom, Town of	0.134	1.13%	1,402	54	1,456
10095	Sumas, Town of	0.167	1.41%	1,747	67	1,814
10097	Troy, City of	0.177	1.50%	1,851	71	1,923
10172	U.S. Air Force, Fairch	0	0.00%	0	0	0
10406	U.S. DOE Albany	0.061	0.52%	638	25	663
10326	U.S. Navy, Bremertor	0	0.00%	0	0	0
10409	U.S. Navy, Bangor	0	0.00%	0	0	0
10408	U.S. Navy, Everett	0	0.00%	0	0	0
10482	Umpqua Indian Utility	0.044	0.37%	460	18	478
10440	Wahkiakum PUD #1	0.47	3.97%	4,916	190	5,105
10442	Wasco Elec Coop	0.518	4.38%	5,418	209	5,627
11680	Weiser, City of	0.377	3.19%	3,943	152	4,095
	Total	11.833	100.00%	123,763	0	123,763

Table 3.16

Weighted LDD for IRD Eligible Utilities

	A	B	C	D	E	F	G	H	I	J	K
1				Monthly Irrigation Rate Mitigation Amounts for Exhibit D of the Region Dialogue Contracts (in MWh)							
2				May	June	July	August	September	TOTAL	LDD	
3	203	10024	Benton PUD	53115.401	75243.324	89003.560	62842.958	32033.957	312239.200	0.00%	0.000
4	233	10183	Franklin PUD	13084.284	22897.496	23715.264	22079.728	12630.475	94407.247	0.00%	0.000
5	250	10231	Klickitat	3082.499	4137.060	5575.639	4578.816	4258.715	21632.729	7.00%	1514.291
6	266	10286	Okanogan PUD	7203.742	10441.534	14718.217	12876.538	10168.120	55408.151	0.00%	0.000
7	303	10025	Benton REA	11147.270	18681.537	24281.424	19190.846	9599.780	82900.857	6.50%	5388.556
8	306	10027	Big Bend	32097.789	47948.108	50352.318	47379.798	31891.527	209669.540	7.00%	14676.868
9	311	10391	United	5273.820	10806.706	12770.236	9182.704	6236.687	44270.153	3.50%	1549.455
10	312	10046	Central Elec	4687.388	8675.756	9539.100	10094.599	8088.614	41085.457	7.00%	2875.982
11	318	10109	Columbia Basin	4185.302	5469.756	4513.543	3665.441	3266.293	21100.335	7.00%	1477.023
12	321	10111	Columbia Power	706.641	866.742	1530.227	1432.169	691.870	5227.649	7.00%	365.935
13	324	10113	Columbia REA	21258.914	30832.646	36368.973	29431.678	16763.751	134655.962	7.00%	9425.917
14	337	10173	Fall River	721.884	12605.402	20135.316	9028.407	1818.987	44309.996	7.00%	3101.700
15	341	10197	Harney	19540.495	20142.982	26028.119	22023.182	12164.427	99899.205	7.00%	6992.944
16	348	10209	Inland	10963.601	14641.767	12471.610	11584.325	10451.398	60112.701	7.00%	4207.889
17	359	10242	Lost River	3725.641	9902.214	10705.288	8479.424	4746.327	37558.894	6.50%	2441.328
18	361	10256	Midstate	7679.733	8829.777	11222.582	9712.913	4044.309	41489.314	7.00%	2904.252
19	367	10273	Nespelem	1216.565	1778.549	2517.152	2274.786	1734.973	9522.025	7.00%	666.542
20	371	10291	OTEC	4715.415	7780.401	10076.149	7938.224	5750.412	36260.601	6.00%	2175.636
21	379	10331	Raft River	23443.131	30794.718	32636.209	27344.114	18868.686	133086.858	7.00%	9316.080
22	335	10142	East End	1061.340	1353.162	1240.237	1171.183	943.562	5769.484	3.00%	173.085
23	381	10338	Riverside	528.123	986.578	1167.444	906.478	566.587	4155.210	3.00%	124.656
24	385	10360	Southside	2180.245	5429.243	5273.390	4387.577	2738.885	20009.340	4.00%	800.374
25	384	10343	Salmon River	1257.157	2671.504	2659.622	2533.409	1383.969	10505.661	5.00%	525.283
26	386	10369	Surprise Valley	6464.252	9066.424	11421.596	11671.642	7586.987	46210.901	7.00%	3234.763
27	388	10388	Umatilla	39288.078	52679.345	55478.176	49073.469	32253.359	228772.427	6.00%	13726.346
28	394	10442	Wasco	1883.529	2101.872	2215.155	1766.387	1766.387	9733.330	7.00%	681.333
29	396	10446	Wells	846.538	1717.671	1928.492	1812.765	865.874	7171.340	5.50%	394.424
30		10502	Yakama Power	1463.062	1175.985	1228.497	1619.426	1702.727	7189.697	0.00%	0.000
31	390	10436	Vigilante	5362.005	10090.787	11936.481	8014.268	3459.717	38863.258	7.00%	2720.428
32	483	10258	Mission Valley	1857.275	3714.55	6500.462	5571.825	742.91	18387.022	6.50%	1195.156
33									Wt. LDD	4.9%	

Table 3.17

Rates and Charges for RSS and Related Services in FY 2014 and FY 2015

	A	B	C	D	E	F
1	**Purchaser**	**Resource Name**	**Services & RSC**	**Applicable Year(s)**	**"ResourceInput " Tab Adj. for Schedule Annual aMW**	**Exh. A FY2014 Annual aMW**
2	Benton Rural Electric Association	Unspecified Resource Amounts	TSS TCMS	FY2014&FY2015	N/A	1.402
3	Big Bend Electric Cooperative	Unspecified Resource Amounts	TSS TCMS	FY2014&FY2015	N/A	1.652
4	Tier 1	Klondike 3	DFS TSS TCMS RSC	FY2014&FY2015	14.761	15.967
5	City of Bonners Ferry	Moyie River	GMS	FY2014&FY2015	N/A	1.881
6	City of Centralia	Yelm	GMS	FY2014&FY2015	N/A	7.114
7	City of Centralia	Unspecified Resource Amounts	GMS	FY2014&FY2015	N/A	0.676
8	City of Cheney	Unspecified Resource Amounts	TSS TCMS	FY2014&FY2015	N/A	0.967
9	City of Forest Grove	Priest Rapids	SCS	FY2014&FY2015	N/A	1.481
10	City of Forest Grove	Wanapum	SCS	FY2014&FY2015	N/A	1.454
11	The City of McMinnville, a municipal corporation of the St	Priest Rapids	SCS	FY2014&FY2015	N/A	1.481
12	The City of McMinnville, a municipal corporation of the St	Wanapum	SCS	FY2014&FY2015	N/A	1.454
13	City of Milton-Freewater	Priest Rapids	SCS	FY2014&FY2015	N/A	1.481
14	City of Milton-Freewater	Wanapum	SCS	FY2014&FY2015	N/A	1.454
15	City of Richland, Washington	Unspecified Resource Amounts	TSS	FY2014&FY2015	N/A	4.528
16	Public Utility District No. 1 of Clallam County	Packwood Lake	DFS FOR TSS TCMS RSC	FY2014&FY2015	1.370	0.673
17	Columbia Rural Electric Association	Walla Walla	DFS FOR RSC	FY2014&FY2015	1.103	1.228
18	Flathead Electric Cooperative, Inc.	Flathead County Landfill	DFS FOR RSC	FY2014&FY2015	0.921	0.811
19	Idaho County Light & Power Cooperative Association, Inc.	Unspecified Resource Amounts	TSS TCMS	FY2014&FY2015	N/A	0.531
20	Public Utility District No. 1 of Kittitas County	Priest Rapids	SCS	FY2014&FY2015	N/A	0.484
21	Public Utility District No. 1 of Kittitas County	Wanapum	SCS	FY2014&FY2015	N/A	0.494
22	Lower Valley Energy, Inc.	Unspecified Resource Amounts	TSS TCMS	FY2014&FY2015	N/A	2.460
23	Public Utility District No. 3 of Mason County	Packwood Lake	SCS TSS TCMS	FY2014&FY2015	N/A	0.656
24	Public Utility District No. 3 of Mason County	Nine Canyon Wind	DFS TSS TCMS RSC	FY2014&FY2015	1.247	0.809
25	Public Utility District No. 3 of Mason County	White Creek Wind	DFS TSS TCMS RSC	FY2015	1.061	0.000
26	Mission Valley Power	Kerr	TSS TCMS	FY2014&FY2015	N/A	9.657
27	PNGC	Lake Creek (MT)	SCS	FY2014&FY2015	N/A	1.530
28	PNGC	Chester Hydro	DFS TSS TCMS RSC	FY2014&FY2015	0.706	0.967
29	PNGC	Island Park	SCS	FY2014&FY2015	N/A	0.992
30	PNGC	Unspecified	TSS TCMS	FY2014&FY2015	N/A	25.857
31	Northern Wasco County People's Utility District	McNary Fishway	GMS	FY2014&FY2015	N/A	4.404
32	Peninsula Light Company	Harvest Wind	DFS TSS TCMS RSC	FY2015	1.081	0.000
33	Peninsula Light Company	Unspecified Resource Amounts	TSS TCMS	FY2014&FY2015	N/A	0.454
34	United Electric Co-op, Inc.	Unspecified Resource Amounts	TSS TCMS	FY2014&FY2015	N/A	1.547
35	Vera Water & Power	Unspecified Resource Amounts	TSS TCMS	FY2014&FY2015	N/A	0.054
36	Wells Rural Electric Company	Unspecified Resource Amounts	TSS TCMS	FY2014&FY2015	N/A	0.229

Table 3.17(continued)

Rates and Charges for RSS and Related Services in FY 2014 and FY 2015

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T
1	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	SCS $/MWh Equiv.	GMS $/mo	GMS $/MWh Equiv.	Revenue Credit to Composite Cost Pool FY 2014	Revenue Credit to Non-Slice Cost Pool FY2014	Revenue Credit to Composite Cost Pool FY 2015	Revenue Credit to Non-Slice Cost Pool FY2015	Forecast Total $/MWh Equivalent Rate
2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 216	$ 0.15	$ -	$ -	$-	$ -	$ -	$ -	$ 2,594	$ -	$ 2,594	$ -	$ 0.15
3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 90	$ 0.15	$ -	$ -	$-	$ -	$ -	$ -	$ 1,085	$ -	$ 1,085	$ -	$ 0.15
4	$ 2.84	$ 136,557	$ 12.67	$ 41,110	$ 3.82	$ -	$ -	$ 990	$ 0.09	$ -	$ -	$-	$ -	$ -	$ -	$ 2,017,984	$ 493,322	$ 2,017,984	$ 493,322	$ 19.42
5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$-	$ -	$ 828	$ 0.60	$ 9,936	$ -	$ 9,936	$ -	$ 0.60
6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$-	$ -	$ 3,448	$ 0.66	$ 41,373	$ -	$ 41,373	$ -	$ 0.66
7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$-	$ -	$ 408	$ 0.67	$ 4,892	$ -	$ 4,892	$ -	$ 0.67
8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 108	$ 0.15	$ -	$ -	$-	$ -	$ -	$ -	$ 1,292	$ -	$ 1,292	$ -	$ 0.15
9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$681	$ 0.63	$ -	$ -	$ 8,170	$ -	$ 8,170	$ -	$ 0.63
10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$671	$ 0.63	$ -	$ -	$ 8,046	$ -	$ 8,046	$ -	$ 0.63
11	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$681	$ 0.63	$ -	$ -	$ 8,170	$ -	$ 8,170	$ -	$ 0.63
12	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$671	$ 0.63	$ -	$ -	$ 8,046	$ -	$ 8,046	$ -	$ 0.63
13	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$681	$ 0.63	$ -	$ -	$ 8,170	$ -	$ 8,170	$ -	$ 0.63
14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$671	$ 0.63	$ -	$ -	$ 8,046	$ -	$ 8,046	$ -	$ 0.63
15	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 248	$ 0.15	$ -	$ -	$-	$ -	$ -	$ -	$ 2,975	$ -	$ 2,975	$ -	$ 0.15
16	$ 1.20	$ 6,413	$ 6.41	$(15,169)	$ (15.16)	$ 347.00	$ 0.35	$ 74	$ 0.07	$ -	$ -	$-	$ -	$ -	$ -	$ 96,397	$(182,023)	$ 96,397	$ (182,023)	$ (7.13)
17	$ 0.21	$ 1,400	$ 1.74	$ 3,485	$ 4.33	$ 451.00	$ 0.56	$ -	$ -	$ -	$ -	$-	$ -	$ -	$ -	$ 24,206	$ 41,824	$ 24,206	$ 41,824	$ 6.84
18	$ 0.13	$ 1,660	$ 2.47	$ (3,025)	$ (4.50)	$ 509.00	$ 0.76	$ -	$ -	$ -	$ -	$-	$ -	$ -	$ -	$ 27,112	$ (36,296)	$ 27,112	$ (36,296)	$ (1.14)
19	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 29	$ 0.15	$ -	$ -	$-	$ -	$ -	$ -	$ 349	$ -	$ 349	$ -	$ 0.15
20	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$223	$ 0.63	$ -	$ -	$ 2,681	$ -	$ 2,681	$ -	$ 0.63
21	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$227	$ 0.63	$ -	$ -	$ 2,723	$ -	$ 2,723	$ -	$ 0.63
22	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 135	$ 0.15	$ -	$ -	$-	$ -	$ -	$ -	$ 1,616	$ -	$ 1,616	$ -	$ 0.15
23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 72	$ 0.15	$ -	$ -	$308	$ 0.64	$ -	$ -	$ 4,553	$ -	$ 4,553	$ -	$ 0.79
24	$ 3.25	$ 11,596	$ 12.74	$ (8,874)	$ (9.75)	$ -	$ -	$ 89	$ 0.10	$ -	$ -	$-	$ -	$ -	$ -	$ 175,700	$(106,492)	$ 175,700	$ (106,492)	$ 6.34
25	$ 3.06	$ 10,129	$ 13.07	$ (2,612)	$ (3.37)	$ -	$ -	$ 101	$ 0.13	$ -	$ -	$-	$ -	$ -	$ -	$ -	$ -	$ 151,244	$ (31,345)	$ 12.89
26	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 990	$ 0.14	$ -	$ -	$-	$ -	$ -	$ -	$ 11,880	$ -	$ 11,880	$ -	$ 0.14
27	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$664	$ 0.59	$ -	$ -	$ 7,972	$ -	$ 7,972	$ -	$ 0.59
28	$ 1.46	$ 4,243	$ 8.23	$ 5,154	$ 10.00	$ -	$ -	$ 106	$ 0.21	$ -	$ -	$-	$ -	$ -	$ -	$ 61,229	$ 61,854	$ 61,229	$ 61,854	$ 19.90
29	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$437	$ 0.60	$ -	$ -	$ 5,248	$ -	$ 5,248	$ -	$ 0.60
30	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 990	$ 0.04	$ -	$ -	$-	$ -	$ -	$ -	$ 11,880	$ -	$ 11,880	$ -	$ 0.04
31	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$-	$ -	$ 2,131	$ 0.66	$ 25,567	$ -	$ 25,567	$ -	$ 0.66
32	$ 3.03	$ 10,433	$ 13.22	$ (1,240)	$ (1.57)	$ -	$ -	$ 109	$ 0.14	$ -	$ -	$-	$ -	$ -	$ -	$ -	$ -	$ 155,177	$ (14,875)	$ 14.82
33	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 25	$ 0.15	$ -	$ -	$-	$ -	$ -	$ -	$ 298	$ -	$ 298	$ -	$ 0.15
34	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 85	$ 0.15	$ -	$ -	$-	$ -	$ -	$ -	$ 1,016	$ -	$ 1,016	$ -	$ 0.15
35	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3	$ 0.15	$ -	$ -	$-	$ -	$ -	$ -	$ 35	$ -	$ 35	$ -	$ 0.15
36	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13	$ 0.15	$ -	$ -	$-	$ -	$ -	$ -	$ 150	$ -	$ 150	$ -	$ 0.15

Table 3.18

Customers Receiving a Non-Federal Resource forecast credits w/DFS.

	A	B	C	D	E	F
1			2014	2015		
2	Non-Federal Resource Remarketing Credit		$256,338	$80,516		
3						
4		2014	2014	2014	2014	2014
5		Remarketing amount aMW	Remarketing Amount	Allocation	Remarket Credit	Remarket
6	**Customers Remarketing 2014 Non-Federal Resource Purchases**		MWH	Percentage	Allocation	Monthly Credit
7	Flathead Electric Cooperative, Inc.	0.811	7,104	91.85%	$235,436	$19,619.68
8	Public Utility District No. 3 of Mason County, Washington: Nine Canyon Resource	0.072	631	8.15%	$20,902	$1,741.82
9	Total	0.883	7,735	1	$256,338	
10						
11						
12		2015	2015	2015	2015	2015
13		Remarketing amount aMW	Remarketing Amount	Allocation	Remarket Credit	Remarket
14	**Customers Remarketing 2015 Non-Federal Resource Purchases**		MWH	Percentage	Allocation	Monthly Credit
15	Public Utility District No. 3 of Mason County, Washington: White Creek Resource	0.264	2,313	100.00%	$80,516	$6,709.67
16	Total	0.264	2,313			

Table 3.19

Transmission Scheduling Service OATI Registration-Fee Customer List

	A	B	C
1			
2			
3	**Customer**	**FY14 Charge**	**FY15 Charge**
4	Benton Rural Electric Association	$150	$150
5	Big Bend Electric Cooperative	$150	$0
6	Centralia, City of	$150	$150
7	City of Cheney	$150	$150
8	Idaho County Light & Power Cooperative Association, Inc.	$150	$0
9	Inland Power and Light Company	$150	$0
10	Lower Valley Energy,Inc	$150	$0
11	Mission Valley Power	$150	$150
12	Peninsula Light Company	$150	$150
13	Public Utility District No. 1 of Clallam County	$150	$150
14	Public Utility District No. 3 of Mason County	$150	$150
15	Richland, City of	$150	$150
16	United Electric Co-op, Inc.	$150	$0
17	Vera Water & Power	$150	$0
18	Wells Rural Electric Company	$150	$0

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 2014-2015
Table shows calculation of CHWM revenues at proposed rates.

Table 4.4 Load Shaping and Demand revenue – FY 2014-2015
Table shows calculation of CHWM revenues at proposed rates.

Table 4.5 Irrigation Rate Discount (IRD) – FY 2014-2015
Table shows calculation of IRD credit at proposed rates.

Table 4.6 Low Density Discount (LDD) – FY 2014-2015
Table shows calculation of LDD credit at proposed rates.

Table 4.7 Tier 2 revenue – FY 2014-2015
Table shows calculation of CHWM revenues at proposed rates.

Table 4.8 Direct Service Industries (DSI) revenues – FY 2014-2015
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**													**2013**	
2	**Category**	**201210**	**201211**	**201212**	**201301**	**201302**	**201303**	**201304**	**201305**	**201306**	**201307**	**201308**	**201309**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 189,667	$ 189,667	$ 189,667	$ 189,667	$ 189,667	$ 189,667	$ 189,667	$ 189,667	$ 189,667	$ 189,667	$ 189,667	$ 189,667	$ 2,276,003	6,959
4	Non-Slice Revenue	$ (27,330)	$ (27,330)	$ (27,330)	$ (27,330)	$ (27,330)	$ (27,330)	$ (27,330)	$ (27,330)	$ (27,330)	$ (27,330)	$ (27,330)	$ (27,330)	$ (327,962)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
6	Load Shaping Revenue	$ 2,635	$ (4,959)	$ 18,699	$ 17,828	$ 22,853	$ 17,174	$ 26,368	$ (43,567)	$ (25,966)	$ (24,451)	$ (1,671)	$ (7,877)	$ (2,934)	6
7	Demand Revenue	$ 4,524	$ 3,846	$ 7,088	$ 7,696	$ 4,519	$ 5,033	$ 5,226	$ 3,677	$ 3,425	$ 5,521	$ 6,044	$ 3,663	$ 60,262	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,976)	$ (4,447)	$ (5,122)	$ (4,203)	$ (2,557)	$ (19,305)	-
9	Low Density Discount	$ (2,666)	$ (2,278)	$ (3,110)	$ (2,915)	$ (2,997)	$ (2,835)	$ (3,247)	$ (1,919)	$ (2,518)	$ (2,681)	$ (3,138)	$ (2,640)	$ (32,944)	-
10	Tier 2	$ 2,010	$ 2,010	$ 2,010	$ 2,010	$ 2,010	$ 2,010	$ 2,010	$ 2,010	$ 2,010	$ 2,010	$ 2,010	$ 2,010	$ 24,123	54
11	RSS (Non-Federal)	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 317	-
12	**PF customers (TRM) sub-total**	**$ 168,866**	**$ 160,983**	**$ 187,050**	**$ 186,982**	**$ 188,748**	**$ 183,746**	**$ 192,720**	**$ 119,589**	**$ 134,867**	**$ 137,640**	**$ 161,405**	**$ 154,963**	**$ 1,977,561**	**7,018**
13	1) **DSIs sub-total**	**$ 9,048**	**$ 8,300**	**$ 9,105**	**$ 8,825**	**$ 8,239**	**$ 8,819**	**$ 8,117**	**$ 7,394**	**$ 7,122**	**$ 8,672**	**$ 9,258**	**$ 8,873**	**$ 101,772**	**320**
14	**FPS sub-total**	**$ 228**	**$ 228**	**$ 228**	**$ 228**	**$ 228**	**$ 228**	**$ 228**	**$ 228**	**$ 228**	**$ 228**	**$ 228**	**$ 228**	**$ 2,738**	**9**
15	**Short-term market sales sub-total**	**$ 21,100**	**$ 16,685**	**$ 20,404**	**$ 38,898**	**$ 34,287**	**$ 40,271**	**$ 34,369**	**$ 42,719**	**$ 50,893**	**$ 43,028**	**$ 20,482**	**$ 8,633**	**$ 371,769**	**1,861**
16	**Long Term Contractual Obligations sub-total**	**$ 41**	**$ 6,675**	**$ 6,859**	**$ 6,848**	**$ 6,262**	**$ 3,425**	**$ 3,336**	**$ 79**	**$ 85**	**$ 82**	**$ 62**	**$ 39**	**$ 33,793**	**62**
17	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**505**
18	**Renewable Energy Certificates sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,070**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,070**	**16**
19	GTA Delivery charge	$ 165	$ 165	$ 165	$ 165	$ 165	$ 165	$ 165	$ 165	$ 165	$ 165	$ 165	$ 165	$ 1,980	-
20	Miscellaneous Credits	$ 119	$ 119	$ 119	$ 119	$ 119	$ 119	$ 119	$ 119	$ 119	$ 119	$ 119	$ 119	$ 1,428	-
21	Slice True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (8,097)	$ (8,097)	-
22	**Other Sales sub-total**	**$ 284**	**$ 284**	**$ 284**	**$ 284**	**$ 284**	**$ 284**	**$ 284**	**$ 284**	**$ 284**	**$ 284**	**$ 284**	**$ (7,813)**	**$ (4,689)**	**-**
23	**Gross Sales**	**$199,568**	**$193,154**	**$223,931**	**$242,066**	**$238,048**	**$237,843**	**$239,054**	**$170,294**	**$193,480**	**$189,934**	**$191,720**	**$164,922**	**$2,484,015**	**9,791**
24	Energy Efficiency Revenues	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 11,500	-
25	Irrigation Pumping Power	$ 79	$ 1	$ 1	$ 1	$ 1	$ 9	$ 84	$ 181	$ 216	$ 275	$ 256	$ 181	$ 1,284	174
26	Reserve Energy	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 8,718	3
27	Downstream Benefits	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 5,282	-
28	Upper Baker Revenues	$ -	$ 96	$ 101	$ 99	$ 101	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 397	1
29	**Miscellaneous Revenues**	**$2,204**	**$2,221**	**$2,227**	**$2,224**	**$2,227**	**$2,134**	**$2,209**	**$2,306**	**$2,341**	**$2,400**	**$2,381**	**$2,306**	**$27,181**	**178**
30	Regulating Reserve	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 6,601	-
31	Variable Energy Resource Balancing Service Reserve - Wind	$ 4,713	$ 4,713	$ 4,713	$ 4,713	$ 4,713	$ 4,713	$ 4,713	$ 4,713	$ 4,713	$ 4,595	$ 4,595	$ 4,595	$ 56,199	-
32	Variable Energy Resource Balancing Service Reserve - Wind Forecast Risk Adjustm	$ 21	$ 21	$ 211	$ 211	$ 242	$ 242	$ 242	$ 242	$ 242	$ 303	$ 377	$ 377	$ 2,733	-
33	Committed Intra-Hour Scheduling Pilot Adjustment	$ (240)	$ (240)	$ (240)	$ (240)	$ (240)	$ (240)	$ (352)	$ (352)	$ (352)	$ (352)	$ (352)	$ (352)	$ (3,548)	-
34	VERBS Supplemental Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
35	VERBS for Solar	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 3	$ 3	$ 9	-
36	Dispatchable Energy Resource Balancing Service Reserve inc	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 4,576	-
37	Dispatchable Energy Resource Balancing Service Reserve dec	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 1,177	-
38	Operating Reserve - Spinning	$ 2,106	$ 2,247	$ 2,720	$ 2,471	$ 2,478	$ 2,429	$ 2,552	$ 2,376	$ 2,490	$ 2,489	$ 2,223	$ 2,013	$ 28,595	-
39	Operating Reserve - Supplemental	$ 1,790	$ 1,910	$ 2,311	$ 2,099	$ 2,106	$ 2,064	$ 2,169	$ 2,019	$ 2,116	$ 2,115	$ 1,889	$ 1,710	$ 24,300	-
40	Operating Reserve - Spinning Adjustment for WNP-3 Settlement contracts with Avist	$ -	$ (50)	$ (50)	$ (50)	$ (49)	$ (25)	$ (25)	$ -	$ -	$ -	$ -	$ -	$ (250)	-
41	Operating Reserve - Supplemental Adjustment for WNP-3 Settlement contracts with	$ -	$ (43)	$ (43)	$ (43)	$ (41)	$ (21)	$ (21)	$ -	$ -	$ -	$ -	$ -	$ (212)	-
42	Synchronous Condensing	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 1,880	-
43	Generation Dropping	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 377	-
44	Energy Imbalance	$ 16	$ 75	$ 47	$ 25	$ (57)	$ 143	$ 236	$ 67	$ 62	$ 56	$ (4)	$ 9	$ 676	-
45	Generation Imbalance	$ 231	$ 301	$ 278	$ 240	$ 277	$ 312	$ 366	$ 538	$ 577	$ 347	$ 283	$ 395	$ 4,146	-
46	Persitent Deviation - Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	Persitent Deviation - Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
48	Station Service	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 2,950	9
49	Redispatch	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 400	-
50	COE/Reclamation Network/Delivery Facilities Segmentation	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 7,105	-
51	Operating Reserve - Energy	$ 56	$ 60	$ 78	$ 79	$ 54	$ 49	$ 36	$ 35	$ 38	$ 108	$ 71	$ 65	$ 729	-
52	**Generation Inputs / Inter-business line**	**$ 10,783**	**$ 11,083**	**$ 12,114**	**$ 11,594**	**$ 11,573**	**$ 11,756**	**$ 12,006**	**$ 11,728**	**$ 11,975**	**$ 11,749**	**$ 11,175**	**$ 10,905**	**$ 138,442**	**9**
53	4(h)(10)(c)	$ 9,995	$ 3,763	$ 6,584	$ 8,765	$ 7,243	$ 5,374	$ 5,556	$ 5,558	$ 5,558	$ 8,780	$ 5,615	$ 8,607	$ 81,399	-
54	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
55	**Treasury Credits**	**$ 6,125**	**$ 7,602**	**$ 8,766**	**$ 7,718**	**$ 7,128**	**$ 7,370**	**$ 6,435**	**$ 6,498**	**$ 6,650**	**$ 6,174**	**$ 5,944**	**$ 8,936**	**$ 85,999**	**-**
56	**Augmentation Power Purchase total**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
57	**Balancing Power Purchase sub-total**	$ 715	$ 5,929	$ 14,111	$ 5,802	$ 4,204	$ 2,687	$ 1,952	$ 109	$ 1,229	$ 1,915	$ 5,576	$ 6,178	$ 50,409	199
58	**Other Power Purchase total**	**$ 1,952**	**$ 8,750**	**$ 9,079**	**$ 9,320**	**$ 8,753**	**$ 9,320**	**$ 9,320**	**$ 1,952**	**$ 1,952**	**$ 1,952**	**$ 1,952**	**$ 1,952**	**$ 66,251**	**139**
59	**Power Purchases**	**$ 2,667**	**$ 14,679**	**$ 23,190**	**$ 15,122**	**$ 12,957**	**$ 12,007**	**$ 11,272**	**$ 2,061**	**$ 3,180**	**$ 3,867**	**$ 7,528**	**$ 8,130**	**$ 116,660**	**338**
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**													**2014**	
2	**Category**	**201310**	**201311**	**201312**	**201401**	**201402**	**201403**	**201404**	**201405**	**201406**	**201407**	**201408**	**201409**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 192,307	$ 192,307	$ 192,307	$ 192,307	$ 192,307	$ 192,307	$ 192,307	$ 192,307	$ 192,307	$ 192,307	$ 192,307	$ 192,307	$ 2,307,680	7,010
4	Non-Slice Revenue	$ (27,872)	$ (27,872)	$ (27,872)	$ (27,872)	$ (27,872)	$ (27,872)	$ (27,872)	$ (27,872)	$ (27,872)	$ (27,872)	$ (27,872)	$ (27,872)	$ (334,463)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
6	Load Shaping Revenue	$ (1,162)	$ (1,162)	$ (1,162)	$ (1,162)	$ (1,162)	$ (1,162)	$ (1,162)	$ (1,162)	$ (1,162)	$ (1,162)	$ (1,162)	$ (1,162)	$ (13,944)	14
7	Demand Revenue	$ 4,966	$ 4,966	$ 4,966	$ 4,966	$ 4,966	$ 4,966	$ 4,966	$ 4,966	$ 4,966	$ 4,966	$ 4,966	$ 4,966	$ 59,590	-
8	Irrigation Rate Discount	$ (1,609)	$ (1,609)	$ (1,609)	$ (1,609)	$ (1,609)	$ (1,609)	$ (1,609)	$ (1,609)	$ (1,609)	$ (1,609)	$ (1,609)	$ (1,609)	$ (19,305)	-
9	Low Density Discount	$ (2,517)	$ (2,517)	$ (2,517)	$ (2,517)	$ (2,517)	$ (2,517)	$ (2,517)	$ (2,517)	$ (2,517)	$ (2,517)	$ (2,517)	$ (2,517)	$ (30,199)	-
10	Tier 2	$ 591	$ 591	$ 591	$ 591	$ 591	$ 591	$ 591	$ 591	$ 591	$ 591	$ 591	$ 591	$ 7,097	17
11	RSS (Non-Federal)	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 309	-
12	**PF customers (TRM) sub-total**	**$ 164,730**	**$ 164,730**	**$ 164,730**	**$ 164,730**	**$ 164,730**	**$ 164,730**	**$ 164,730**	**$ 164,730**	**$ 164,730**	**$ 164,730**	**$ 164,730**	**$ 164,730**	**$ 1,976,765**	**7,042**
13	1) **DSIs sub-total**	**$ 8,270**	**$ 8,270**	**$ 8,270**	**$ 8,270**	**$ 8,270**	**$ 8,270**	**$ 8,270**	**$ 8,270**	**$ 8,270**	**$ 8,270**	**$ 8,270**	**$ 8,270**	**$ 99,244**	**312**
14	**FPS sub-total**	**$ 234**	**$ 249**	**$ 269**	**$ 264**	**$ 254**	**$ 249**	**$ 234**	**$ 244**	**$ 249**	**$ 259**	**$ 249**	**$ 249**	**$ 2,997**	**8**
15	**Short-term market sales sub-total**	**$ 27,440**	**$ 27,440**	**$ 27,440**	**$ 27,440**	**$ 27,440**	**$ 27,440**	**$ 27,440**	**$ 27,440**	**$ 27,440**	**$ 27,440**	**$ 27,440**	**$ 27,440**	**$ 329,284**	**1,697**
16	**Long Term Contractual Obligations sub-total**	**$ 41**	**$ 5,893**	**$ 6,053**	**$ 6,042**	**$ 5,532**	**$ 3,026**	**$ 2,931**	**$ 79**	**$ 85**	**$ 82**	**$ 62**	**$ 39**	**$ 29,865**	**59**
17	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**500**
18	**Renewable Energy Certificates sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,061**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,061**	**14**
19	GTA Delivery charge	$ 165	$ 190	$ 215	$ 225	$ 200	$ 180	$ 145	$ 170	$ 175	$ 180	$ 195	$ 175	$ 2,215	-
20	Miscellaneous Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
21	Slice True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
22	**Other Sales sub-total**	**$ 165**	**$ 190**	**$ 215**	**$ 225**	**$ 200**	**$ 180**	**$ 145**	**$ 170**	**$ 175**	**$ 180**	**$ 195**	**$ 175**	**$ 2,215**	**-**
23	**Gross Sales**	**$200,880**	**$206,773**	**$206,977**	**$206,971**	**$206,426**	**$204,957**	**$203,751**	**$200,934**	**$200,950**	**$200,962**	**$200,947**	**$200,903**	**$2,441,432**	**9,632**
24	Energy Efficiency Revenues	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 11,500	-
25	Irrigation Pumping Power	$ 85	$ 1	$ 1	$ 1	$ 1	$ 10	$ 90	$ 195	$ 235	$ 300	$ 279	$ 196	$ 1,393	174
26	Reserve Energy	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 8,718	3
27	Downstream Benefits	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 5,282	-
28	Upper Baker Revenues	$ -	$ 101	$ 108	$ 105	$ 109	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 422	1
29	**Miscellaneous Revenues**	**$2,210**	**$2,227**	**$2,233**	**$2,231**	**$2,235**	**$2,135**	**$2,215**	**$2,320**	**$2,360**	**$2,425**	**$2,404**	**$2,321**	**$32,597**	**178**
30	Regulating Reserve	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 6,601	-
31	Variable Energy Resource Balancing Service Reserve - Wind	$ 4,515	$ 4,515	$ 4,515	$ 4,515	$ 4,515	$ 4,515	$ 4,515	$ 4,515	$ 4,683	$ 4,683	$ 4,683	$ 4,683	$ 54,851	-
32	Variable Energy Resource Balancing Service Reserve - Wind Forecast Risk Adjustm	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
33	Committed Intra-Hour Scheduling Pilot Adjustment	$ (239)	$ (239)	$ (239)	$ (239)	$ (239)	$ (239)	$ (239)	$ (239)	$ (239)	$ (239)	$ (239)	$ (239)	$ (2,866)	-
34	VERBS Supplemental Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
35	VERBS for Solar	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 40	-
36	Dispatchable Energy Resource Balancing Service Reserve inc	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 4,576	-
37	Dispatchable Energy Resource Balancing Service Reserve dec	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 1,177	-
38	Operating Reserve - Spinning	$ 1,973	$ 2,152	$ 2,452	$ 2,473	$ 2,351	$ 2,292	$ 2,270	$ 2,285	$ 2,451	$ 2,347	$ 2,149	$ 1,951	$ 27,146	-
39	Operating Reserve - Supplemental	$ 1,677	$ 1,829	$ 2,083	$ 2,102	$ 1,998	$ 1,948	$ 1,929	$ 1,942	$ 2,083	$ 1,994	$ 1,826	$ 1,658	$ 23,069	-
40	Operating Reserve - Spinning Adjustment for WNP-3 Settlement contracts with Avist	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
41	Operating Reserve - Supplemental Adjustment for WNP-3 Settlement contracts with	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
42	Synchronous Condensing	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 1,880	-
43	Generation Dropping	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 377	-
44	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
45	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	Persitent Deviation - Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	Persitent Deviation - Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
48	Station Service	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 2,949	9
49	Redispatch	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 400	-
50	COE/Reclamation Network/Delivery Facilities Segmentation	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 7,105	-
51	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
52	**Generation Inputs / Inter-business line**	**$ 10,018**	**$ 10,349**	**$ 10,903**	**$ 10,943**	**$ 10,716**	**$ 10,608**	**$ 10,567**	**$ 10,596**	**$ 11,071**	**$ 10,878**	**$ 10,511**	**$ 10,146**	**$ 127,305**	**9**
53	4(h)(10)(c)	$ 9,853	$ 7,619	$ 9,791	$ 11,780	$ 9,751	$ 8,521	$ 6,321	$ 5,955	$ 6,277	$ 5,638	$ 5,817	$ 7,978	$ 95,302	-
54	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
55	**Treasury Credits**	**$ 10,237**	**$ 8,003**	**$ 10,174**	**$ 12,163**	**$ 10,135**	**$ 8,904**	**$ 6,704**	**$ 6,338**	**$ 6,660**	**$ 6,021**	**$ 6,201**	**$ 8,361**	**$ 99,902**	**-**
56	**Augmentation Power Purchase total**	$ 2,301	$ 2,301	$ 2,301	$ 2,301	$ 2,301	$ 2,301	$ 2,301	$ 2,301	$ 2,301	$ 2,301	$ 2,301	$ 2,301	$ 27,611	95
57	**Balancing Power Purchase sub-total**	$ 2,662	$ 2,662	$ 2,662	$ 2,662	$ 2,662	$ 2,662	$ 2,662	$ 2,662	$ 2,662	$ 2,662	$ 2,662	$ 2,662	$ 31,941	170
58	**Other Power Purchase total**	**$ 591**	**$ 6,154**	**$ 6,429**	**$ 6,618**	**$ 6,155**	**$ 6,618**	**$ 6,618**	**$ 591**	**$ 591**	**$ 591**	**$ 591**	**$ 591**	**$ 42,140**	**69**
59	**Power Purchases**	**$ 5,554**	**$ 11,116**	**$ 11,392**	**$ 11,581**	**$ 11,117**	**$ 11,581**	**$ 11,581**	**$ 5,554**	**$ 5,554**	**$ 5,554**	**$ 5,554**	**$ 5,554**	**$ 101,693**	**334**
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**													**2015**	
2	**Category**	**201410**	**201411**	**201412**	**201501**	**201502**	**201503**	**201504**	**201505**	**201506**	**201507**	**201508**	**201509**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 193,062	$ 193,062	$ 193,062	$ 193,062	$ 193,062	$ 193,062	$ 193,062	$ 193,062	$ 193,062	$ 193,062	$ 193,062	$ 193,062	$ 2,316,746	7,037
4	Non-Slice Revenue	$ (28,022)	$ (28,022)	$ (28,022)	$ (28,022)	$ (28,022)	$ (28,022)	$ (28,022)	$ (28,022)	$ (28,022)	$ (28,022)	$ (28,022)	$ (28,022)	$ (336,268)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
6	Load Shaping Revenue	$ 888	$ 888	$ 888	$ 888	$ 888	$ 888	$ 888	$ 888	$ 888	$ 888	$ 888	$ 888	$ 10,658	20
7	Demand Revenue	$ 5,016	$ 5,016	$ 5,016	$ 5,016	$ 5,016	$ 5,016	$ 5,016	$ 5,016	$ 5,016	$ 5,016	$ 5,016	$ 5,016	$ 60,192	-
8	Irrigation Rate Discount	$ (1,609)	$ (1,609)	$ (1,609)	$ (1,609)	$ (1,609)	$ (1,609)	$ (1,609)	$ (1,609)	$ (1,609)	$ (1,609)	$ (1,609)	$ (1,609)	$ (19,305)	-
9	Low Density Discount	$ (2,704)	$ (2,704)	$ (2,704)	$ (2,704)	$ (2,704)	$ (2,704)	$ (2,704)	$ (2,704)	$ (2,704)	$ (2,704)	$ (2,704)	$ (2,704)	$ (32,451)	-
10	Tier 2	$ 2,775	$ 2,775	$ 2,775	$ 2,775	$ 2,775	$ 2,775	$ 2,775	$ 2,775	$ 2,775	$ 2,775	$ 2,775	$ 2,775	$ 33,304	79
11	RSS (Non-Federal)	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 317	-
12	**PF customers (TRM) sub-total**	**$ 169,433**	**$ 169,433**	**$ 169,433**	**$ 169,433**	**$ 169,433**	**$ 169,433**	**$ 169,433**	**$ 169,433**	**$ 169,433**	**$ 169,433**	**$ 169,433**	**$ 169,433**	**$ 2,033,193**	**7,137**
13	1) **DSIs sub-total**	**$ 8,270**	**$ 8,270**	**$ 8,270**	**$ 8,270**	**$ 8,270**	**$ 8,270**	**$ 8,270**	**$ 8,270**	**$ 8,270**	**$ 8,270**	**$ 8,270**	**$ 8,270**	**$ 99,244**	**312**
14	**FPS sub-total**	**$ 244**	**$ 254**	**$ 274**	**$ 269**	**$ 259**	**$ 254**	**$ 244**	**$ 249**	**$ 254**	**$ 264**	**$ 254**	**$ 254**	**$ 3,074**	**9**
15	**Short-term market sales sub-total**	**$ 28,428**	**$ 28,428**	**$ 28,428**	**$ 28,428**	**$ 28,428**	**$ 28,428**	**$ 28,428**	**$ 28,428**	**$ 28,428**	**$ 28,428**	**$ 28,428**	**$ 28,428**	**$ 341,136**	**1,684**
16	**Long Term Contractual Obligations sub-total**	**$ 41**	**$ 5,893**	**$ 6,053**	**$ 6,042**	**$ 5,532**	**$ 3,026**	**$ 2,931**	**$ 79**	**$ 85**	**$ 82**	**$ 62**	**$ 39**	**$ 29,865**	**74**
17	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**475**
18	**Renewable Energy Certificates sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,107**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,107**	**11**
19	GTA Delivery charge	$ 165	$ 190	$ 215	$ 225	$ 200	$ 185	$ 145	$ 170	$ 180	$ 185	$ 195	$ 175	$ 2,230	-
20	Miscellaneous Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
21	Slice True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
22	**Other Sales sub-total**	**$ 165**	**$ 190**	**$ 215**	**$ 225**	**$ 200**	**$ 185**	**$ 145**	**$ 170**	**$ 180**	**$ 185**	**$ 195**	**$ 175**	**$ 2,230**	**-**
23	**Gross Sales**	**$206,581**	**$212,469**	**$212,673**	**$212,667**	**$212,122**	**$210,704**	**$209,451**	**$206,629**	**$206,650**	**$206,662**	**$206,642**	**$206,599**	**$2,509,849**	**9,702**
24	Energy Efficiency Revenues	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 11,500	-
25	Irrigation Pumping Power	$ 85	$ 1	$ 1	$ 1	$ 1	$ 10	$ 90	$ 195	$ 235	$ 300	$ 279	$ 196	$ 1,394	174
26	Reserve Energy	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 8,718	3
27	Downstream Benefits	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 5,282	-
28	Upper Baker Revenues	$ -	$ 110	$ 115	$ 110	$ 111	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 446	1
29	**Miscellaneous Revenues**	**$2,210**	**$2,236**	**$2,241**	**$2,236**	**$2,238**	**$2,135**	**$2,215**	**$2,320**	**$2,360**	**$2,425**	**$2,404**	**$2,321**	**$32,621**	**178**
30	Regulating Reserve	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 6,601	-
31	Variable Energy Resource Balancing Service Reserve - Wind	$ 4,683	$ 4,683	$ 4,866	$ 4,866	$ 4,866	$ 5,022	$ 5,022	$ 5,022	$ 5,144	$ 5,144	$ 5,144	$ 5,144	$ 59,610	-
32	Variable Energy Resource Balancing Service Reserve - Wind Forecast Risk Adjustm	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
33	Committed Intra-Hour Scheduling Pilot Adjustment	$ (239)	$ (239)	$ (239)	$ (239)	$ (239)	$ (239)	$ (239)	$ (239)	$ (239)	$ (239)	$ (239)	$ (239)	$ (2,866)	-
34	VERBS Supplemental Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
35	VERBS for Solar	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 40	-
36	Dispatchable Energy Resource Balancing Service Reserve inc	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 4,576	-
37	Dispatchable Energy Resource Balancing Service Reserve dec	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 1,177	-
38	Operating Reserve - Spinning	$ 2,019	$ 2,203	$ 2,509	$ 2,531	$ 2,406	$ 2,346	$ 2,323	$ 2,338	$ 2,508	$ 2,401	$ 2,199	$ 1,997	$ 27,779	-
39	Operating Reserve - Supplemental	$ 1,716	$ 1,872	$ 2,132	$ 2,151	$ 2,045	$ 1,994	$ 1,974	$ 1,987	$ 2,131	$ 2,041	$ 1,869	$ 1,697	$ 23,607	-
40	Operating Reserve - Spinning Adjustment for WNP-3 Settlement contracts with Avist	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
41	Operating Reserve - Supplemental Adjustment for WNP-3 Settlement contracts with	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
42	Synchronous Condensing	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 1,880	-
43	Generation Dropping	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 377	-
44	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
45	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	Persitent Deviation - Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	Persitent Deviation - Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
48	Station Service	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 2,949	9
49	Redispatch	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 400	-
50	COE/Reclamation Network/Delivery Facilities Segmentation	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 7,105	-
51	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
52	**Generation Inputs / Inter-business line**	**$ 5,588**	**$ 5,928**	**$ 6,494**	**$ 6,535**	**$ 6,304**	**$ 6,193**	**$ 6,150**	**$ 6,179**	**$ 6,492**	**$ 6,295**	**$ 5,921**	**$ 5,547**	**$ 133,234**	**9**
53	4(h)(10)(c)	$ 10,100	$ 7,516	$ 8,517	$ 10,839	$ 8,823	$ 7,685	$ 6,021	$ 5,770	$ 6,645	$ 5,507	$ 5,520	$ 9,440	$ 92,383	-
54	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
55	**Treasury Credits**	**$ 10,483**	**$ 7,900**	**$ 8,900**	**$ 11,222**	**$ 9,207**	**$ 8,068**	**$ 6,404**	**$ 6,154**	**$ 7,029**	**$ 5,890**	**$ 5,903**	**$ 9,824**	**$ 96,983**	**-**
56	**Augmentation Power Purchase total**	$ 10,273	$ 10,273	$ 10,273	$ 10,273	$ 10,273	$ 10,273	$ 10,273	$ 10,273	$ 10,273	$ 10,273	$ 10,273	$ 10,273	$ 123,273	404
57	**Balancing Power Purchase sub-total**	$ 2,291	$ 2,291	$ 2,291	$ 2,291	$ 2,291	$ 2,291	$ 2,291	$ 2,291	$ 2,291	$ 2,291	$ 2,291	$ 2,291	$ 27,492	144
58	**Other Power Purchase total**	**$ 2,775**	**$ 2,775**	**$ 2,775**	**$ 2,775**	**$ 2,775**	**$ 2,775**	**$ 2,775**	**$ 2,775**	**$ 2,775**	**$ 2,775**	**$ 2,775**	**$ 2,775**	**$ 33,304**	**-**
59	**Power Purchases**	**$ 15,339**	**$ 15,339**	**$ 15,339**	**$ 15,339**	**$ 15,339**	**$ 15,339**	**$ 15,339**	**$ 15,339**	**$ 15,339**	**$ 15,339**	**$ 15,339**	**$ 15,339**	**$ 184,068**	**548**
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**													**2013**	
2	**Category**	**201210**	**201211**	**201212**	**201301**	**201302**	**201303**	**201304**	**201305**	**201306**	**201307**	**201308**	**201309**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 189,667	$ 189,667	$ 189,667	$ 189,667	$ 189,667	$ 189,667	$ 189,667	$ 189,667	$ 189,667	$ 189,667	$ 189,667	$ 189,667	$ 2,276,003	6,959
4	Non-Slice Revenue	$ (27,330)	$ (27,330)	$ (27,330)	$ (27,330)	$ (27,330)	$ (27,330)	$ (27,330)	$ (27,330)	$ (27,330)	$ (27,330)	$ (27,330)	$ (27,330)	$ (327,962)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
6	Load Shaping Revenue	$ 2,635	$ (4,959)	$ 18,699	$ 17,828	$ 22,853	$ 17,174	$ 26,368	$ (43,567)	$ (25,966)	$ (24,451)	$ (1,671)	$ (7,877)	$ (2,934)	6
7	Demand Revenue	$ 4,524	$ 3,846	$ 7,088	$ 7,696	$ 4,519	$ 5,033	$ 5,226	$ 3,677	$ 3,425	$ 5,521	$ 6,044	$ 3,663	$ 60,262	-
8	Irrigation Rate Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,976)	$ (4,447)	$ (5,122)	$ (4,203)	$ (2,557)	$ (19,305)	-
9	Low Density Discount	$ (2,666)	$ (2,278)	$ (3,110)	$ (2,915)	$ (2,997)	$ (2,835)	$ (3,247)	$ (1,919)	$ (2,518)	$ (2,681)	$ (3,138)	$ (2,640)	$ (32,944)	-
10	Tier 2	$ 2,010	$ 2,010	$ 2,010	$ 2,010	$ 2,010	$ 2,010	$ 2,010	$ 2,010	$ 2,010	$ 2,010	$ 2,010	$ 2,010	$ 24,123	54
11	RSS (Non-Federal)	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 26	$ 317	-
12	**PF customers (CHWM) sub-total**	**$ 168,866**	**$ 160,983**	**$ 187,050**	**$ 186,982**	**$ 188,748**	**$ 183,746**	**$ 192,720**	**$ 119,589**	**$ 134,867**	**$ 137,640**	**$ 161,405**	**$ 154,963**	**$ 1,977,561**	**7,018**
13	1) **DSIs sub-total**	**$ 9,048**	**$ 8,300**	**$ 9,105**	**$ 8,825**	**$ 8,239**	**$ 8,819**	**$ 8,117**	**$ 7,394**	**$ 7,122**	**$ 8,672**	**$ 9,258**	**$ 8,873**	**$ 101,772**	**320**
14	**FPS sub-total**	**$ 228**	**$ 228**	**$ 228**	**$ 228**	**$ 228**	**$ 228**	**$ 228**	**$ 228**	**$ 228**	**$ 228**	**$ 228**	**$ 228**	**$ 2,738**	**9**
15	**Short-term market sales sub-total**	**$ 21,100**	**$ 16,685**	**$ 20,404**	**$ 38,898**	**$ 34,287**	**$ 40,271**	**$ 34,369**	**$ 42,719**	**$ 50,893**	**$ 43,028**	**$ 20,482**	**$ 8,633**	**$ 371,769**	**1,861**
16	**Long Term Contractual Obligations sub-total**	**$ 41**	**$ 6,675**	**$ 6,859**	**$ 6,848**	**$ 6,262**	**$ 3,425**	**$ 3,336**	**$ 79**	**$ 85**	**$ 82**	**$ 62**	**$ 39**	**$ 33,793**	**62**
17	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**505**
18	**Renewable Energy Certificates sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,070**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,070**	**16**
19	GTA Delivery charge	$ 165	$ 165	$ 165	$ 165	$ 165	$ 165	$ 165	$ 165	$ 165	$ 165	$ 165	$ 165	$ 1,980	-
20	Miscellaneous Credits	$ 119	$ 119	$ 119	$ 119	$ 119	$ 119	$ 119	$ 119	$ 119	$ 119	$ 119	$ 119	$ 1,428	-
21	Slice True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (8,097)	$ (8,097)	-
22	**Other Sales sub-total**	**$ 284**	**$ 284**	**$ 284**	**$ 284**	**$ 284**	**$ 284**	**$ 284**	**$ 284**	**$ 284**	**$ 284**	**$ 284**	**$ (7,813)**	**$ (4,689)**	**-**
23	**Gross Sales**	**$199,568**	**$193,154**	**$223,931**	**$242,066**	**$238,048**	**$237,843**	**$239,054**	**$170,294**	**$193,480**	**$189,934**	**$191,720**	**$164,922**	**$2,484,015**	**9,791**
24	Energy Efficiency Revenues	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 11,500	-
25	Irrigation Pumping Power	$ 79	$ 1	$ 1	$ 1	$ 1	$ 9	$ 84	$ 181	$ 216	$ 275	$ 256	$ 181	$ 1,284	174
26	Reserve Energy	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 8,718	3
27	Downstream Benefits	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 5,282	-
28	Upper Baker Revenues	$ -	$ 96	$ 101	$ 99	$ 101	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 397	1
29	**Miscellaneous Revenues**	**$2,204**	**$2,221**	**$2,227**	**$2,224**	**$2,227**	**$2,134**	**$2,209**	**$2,306**	**$2,341**	**$2,400**	**$2,381**	**$2,306**	**$27,181**	**178**
30	Regulating Reserve	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 550	$ 6,601	-
31	Variable Energy Resource Balancing Service Reserve - Wind	$ 4,713	$ 4,713	$ 4,713	$ 4,713	$ 4,713	$ 4,713	$ 4,713	$ 4,713	$ 4,713	$ 4,595	$ 4,595	$ 4,595	$ 56,199	-
32	Variable Energy Resource Balancing Service Reserve - Wind Forecast Risk Adjustm	$ 21	$ 21	$ 211	$ 211	$ 242	$ 242	$ 242	$ 242	$ 242	$ 303	$ 377	$ 377	$ 2,733	-
33	Committed Intra-Hour Scheduling Pilot Adjustment	$ (240)	$ (240)	$ (240)	$ (240)	$ (240)	$ (240)	$ (352)	$ (352)	$ (352)	$ (352)	$ (352)	$ (352)	$ (3,548)	-
34	VERBS Supplemental Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
35	VERBS for Solar	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 3	$ 3	$ 9	-
36	Dispatchable Energy Resource Balancing Service Reserve inc	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 381	$ 4,576	-
37	Dispatchable Energy Resource Balancing Service Reserve dec	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 98	$ 1,177	-
38	Operating Reserve - Spinning	$ 2,106	$ 2,247	$ 2,720	$ 2,471	$ 2,478	$ 2,429	$ 2,552	$ 2,376	$ 2,490	$ 2,489	$ 2,223	$ 2,013	$ 28,595	-
39	Operating Reserve - Supplemental	$ 1,790	$ 1,910	$ 2,311	$ 2,099	$ 2,106	$ 2,064	$ 2,169	$ 2,019	$ 2,116	$ 2,115	$ 1,889	$ 1,710	$ 24,300	-
40	Operating Reserve - Spinning Adjustment for WNP-3 Settlement contracts with Avist	$ -	$ (50)	$ (50)	$ (50)	$ (49)	$ (25)	$ (25)	$ -	$ -	$ -	$ -	$ -	$ (250)	-
41	Operating Reserve - Supplemental Adjustment for WNP-3 Settlement contracts with	$ -	$ (43)	$ (43)	$ (43)	$ (41)	$ (21)	$ (21)	$ -	$ -	$ -	$ -	$ -	$ (212)	-
42	Synchronous Condensing	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 157	$ 1,880	-
43	Generation Dropping	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 31	$ 377	-
44	Energy Imbalance	$ 16	$ 75	$ 47	$ 25	$ (57)	$ 143	$ 236	$ 67	$ 62	$ 56	$ (4)	$ 9	$ 676	-
45	Generation Imbalance	$ 231	$ 301	$ 278	$ 240	$ 277	$ 312	$ 366	$ 538	$ 577	$ 347	$ 283	$ 395	$ 4,146	-
46	Persitent Deviation - Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	Persitent Deviation - Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
48	Station Service	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 246	$ 2,950	9
49	Redispatch	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 400	-
50	COE/Reclamation Network/Delivery Facilities Segmentation	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 592	$ 7,105	-
51	Operating Reserve - Energy	$ 56	$ 60	$ 78	$ 79	$ 54	$ 49	$ 36	$ 35	$ 38	$ 108	$ 71	$ 65	$ 729	-
52	**Generation Inputs / Inter-business line**	**$ 10,783**	**$ 11,083**	**$ 12,114**	**$ 11,594**	**$ 11,573**	**$ 11,756**	**$ 12,006**	**$ 11,728**	**$ 11,975**	**$ 11,749**	**$ 11,175**	**$ 10,905**	**$ 138,442**	**9**
53	4(h)(10)(c)	$ 9,995	$ 3,763	$ 6,584	$ 8,765	$ 7,243	$ 5,374	$ 5,556	$ 5,558	$ 5,558	$ 8,780	$ 5,615	$ 8,607	$ 81,399	-
54	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
55	**Treasury Credits**	**$ 6,125**	**$ 7,602**	**$ 8,766**	**$ 7,718**	**$ 7,128**	**$ 7,370**	**$ 6,435**	**$ 6,498**	**$ 6,650**	**$ 6,174**	**$ 5,944**	**$ 8,936**	**$ 85,999**	**338**
56	**Augmentation Power Purchase sub-total**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
57	**Balancing Power Purchase sub-total**	$ 715	$ 5,929	$ 14,111	$ 5,802	$ 4,204	$ 2,687	$ 1,952	$ 109	$ 1,229	$ 1,915	$ 5,576	$ 6,178	$ 50,409	199
58	**Other Power Purchase sub-total**	**$ 1,952**	**$ 8,750**	**$ 9,079**	**$ 9,320**	**$ 8,753**	**$ 9,320**	**$ 9,320**	**$ 1,952**	**$ 1,952**	**$ 1,952**	**$ 1,952**	**$ 1,952**	**$ 66,251**	**139**
59	**Power Purchases**	**$ 2,667**	**$ 14,679**	**$ 23,190**	**$ 15,122**	**$ 12,957**	**$ 12,007**	**$ 11,272**	**$ 2,061**	**$ 3,180**	**$ 3,867**	**$ 7,528**	**$ 8,130**	**$ 116,660**	**338**
60															
61	1) Revenues are split evenly over 12 months of FY. Difference of $100K in 2014 and 2015 is due to rounding. Ties to Table 4.8 Direct Service Industries (DSI) revenues – FY 2013-2015														

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														2014	
2	Category		201310	201311	201312	201401	201402	201403	201404	201405	201406	201407	201408	201409	$ (000's)	aMW
3		Composite Revenue	$ 193,751	$ 193,751	$ 193,751	$ 193,751	$ 193,751	$ 193,751	$ 193,751	$ 193,751	$ 193,751	$ 193,751	$ 193,751	$ 193,751	$ 2,325,015	7,010
4		Non-Slice Revenue	$ (21,791)	$ (21,791)	$ (21,791)	$ (21,791)	$ (21,791)	$ (21,791)	$ (21,791)	$ (21,791)	$ (21,791)	$ (21,791)	$ (21,791)	$ (21,791)	$ (261,487)	-
5		Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
6		Load Shaping Revenue	$ 491	$ 491	$ 491	$ 491	$ 491	$ 491	$ 491	$ 491	$ 491	$ 491	$ 491	$ 491	$ 5,888	14
7		Demand Revenue	$ 5,078	$ 5,078	$ 5,078	$ 5,078	$ 5,078	$ 5,078	$ 5,078	$ 5,078	$ 5,078	$ 5,078	$ 5,078	$ 5,078	$ 60,932	-
8		Irrigation Rate Discount	$ (1,650)	$ (1,650)	$ (1,650)	$ (1,650)	$ (1,650)	$ (1,650)	$ (1,650)	$ (1,650)	$ (1,650)	$ (1,650)	$ (1,650)	$ (1,650)	$ (19,794)	-
9		Low Density Discount	$ (3,010)	$ (3,010)	$ (3,010)	$ (3,010)	$ (3,010)	$ (3,010)	$ (3,010)	$ (3,010)	$ (3,010)	$ (3,010)	$ (3,010)	$ (3,010)	$ (36,119)	-
10		Tier 2	$ 451	$ 451	$ 451	$ 451	$ 451	$ 451	$ 451	$ 451	$ 451	$ 451	$ 451	$ 451	$ 5,414	17
11		RSS (Non-Federal)	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 29	$ 352	-
12		**PF customers (CHWM) sub-total**	**$ 173,350**	**$ 173,350**	**$ 173,350**	**$ 173,350**	**$ 173,350**	**$ 173,350**	**$ 173,350**	**$ 173,350**	**$ 173,350**	**$ 173,350**	**$ 173,350**	**$ 173,350**	**$ 2,080,201**	**7,042**
13	1)	**DSIs sub-total**	**$ 8,878**	**$ 8,878**	**$ 8,878**	**$ 8,878**	**$ 8,878**	**$ 8,878**	**$ 8,878**	**$ 8,878**	**$ 8,878**	**$ 8,878**	**$ 8,878**	**$ 8,878**	**$ 106,537**	**312**
14		**FPS sub-total**	**$ 234**	**$ 249**	**$ 269**	**$ 264**	**$ 254**	**$ 249**	**$ 234**	**$ 244**	**$ 249**	**$ 259**	**$ 249**	**$ 249**	**$ 2,997**	**8**
15		**Short-term market sales sub-total**	**$ 27,440**	**$ 27,440**	**$ 27,440**	**$ 27,440**	**$ 27,440**	**$ 27,440**	**$ 27,440**	**$ 27,440**	**$ 27,440**	**$ 27,440**	**$ 27,440**	**$ 27,440**	**$ 329,284**	**1,697**
16		**Long Term Contractual Obligations sub-total**	**$ 41**	**$ 5,893**	**$ 6,053**	**$ 6,042**	**$ 5,532**	**$ 3,026**	**$ 2,931**	**$ 79**	**$ 85**	**$ 82**	**$ 62**	**$ 39**	**$ 29,865**	**59**
17		**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**500**
18		**Renewable Energy Certificates sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,061**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,061**	**14**
19		GTA Delivery charge	$ 165	$ 190	$ 215	$ 225	$ 200	$ 180	$ 145	$ 170	$ 175	$ 180	$ 195	$ 175	$ 2,215	-
20		Miscellaneous Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
21		Slice True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
22		**Other Sales sub-total**	**$ 165**	**$ 190**	**$ 215**	**$ 225**	**$ 200**	**$ 180**	**$ 145**	**$ 170**	**$ 175**	**$ 180**	**$ 195**	**$ 175**	**$ 2,215**	**-**
23	**Gross Sales**		**$210,108**	**$216,000**	**$216,205**	**$216,199**	**$215,654**	**$214,185**	**$212,978**	**$210,161**	**$210,177**	**$210,189**	**$210,174**	**$210,131**	**$2,552,160**	**9,632**
24		Energy Efficiency Revenues	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 11,859	-
25		Irrigation Pumping Power	$ 85	$ 1	$ 1	$ 1	$ 1	$ 10	$ 90	$ 195	$ 235	$ 300	$ 279	$ 196	$ 1,393	174
26		Reserve Energy	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 8,718	3
27		Downstream Benefits	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 5,282	-
28		Upper Baker Revenues	$ -	$ 101	$ 108	$ 105	$ 109	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 422	1
29	**Miscellaneous Revenues**		**$2,210**	**$2,227**	**$2,233**	**$2,231**	**$2,235**	**$2,135**	**$2,215**	**$2,320**	**$2,360**	**$2,425**	**$2,404**	**$2,321**	**$27,674**	**178**
30		Regulating Reserve	$ 499	$ 499	$ 499	$ 499	$ 499	$ 499	$ 499	$ 499	$ 499	$ 499	$ 499	$ 499	$ 5,983	-
31		Variable Energy Resource Balancing Service Reserve - Wind	$ 4,260	$ 4,260	$ 4,260	$ 4,260	$ 4,260	$ 4,260	$ 4,260	$ 4,260	$ 4,420	$ 4,420	$ 4,420	$ 4,420	$ 51,764	-
32		Variable Energy Resource Balancing Service Reserve - Wind Forecast Risk Adjustm	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
33		Committed Intra-Hour Scheduling Pilot Adjustment	$ (176)	$ (176)	$ (176)	$ (176)	$ (176)	$ (176)	$ (176)	$ (176)	$ (176)	$ (176)	$ (176)	$ (176)	$ (2,109)	-
34		VERBS Supplemental Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
35		VERBS for Solar	$ 4	$ 4	$ 4	$ 4	$ 4	$ 4	$ 4	$ 4	$ 4	$ 4	$ 4	$ 4	$ 45	-
36		Dispatchable Energy Resource Balancing Service Reserve inc	$ 449	$ 449	$ 449	$ 449	$ 449	$ 449	$ 449	$ 449	$ 449	$ 449	$ 449	$ 449	$ 5,392	-
37		Dispatchable Energy Resource Balancing Service Reserve dec	$ 43	$ 43	$ 43	$ 43	$ 43	$ 43	$ 43	$ 43	$ 43	$ 43	$ 43	$ 43	$ 512	-
38		Operating Reserve - Spinning	$ 1,910	$ 2,084	$ 2,374	$ 2,394	$ 2,276	$ 2,220	$ 2,198	$ 2,213	$ 2,373	$ 2,272	$ 2,080	$ 1,889	$ 26,284	-
39		Operating Reserve - Supplemental	$ 1,749	$ 1,908	$ 2,173	$ 2,192	$ 2,084	$ 2,032	$ 2,012	$ 2,026	$ 2,173	$ 2,080	$ 1,905	$ 1,730	$ 24,064	-
40		Operating Reserve - Spinning Adjustment for WNP-3 Settlement contracts with Avist	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
41		Operating Reserve - Supplemental Adjustment for WNP-3 Settlement contracts with	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
42		Synchronous Condensing	$ 132	$ 132	$ 132	$ 132	$ 132	$ 132	$ 132	$ 132	$ 132	$ 132	$ 132	$ 132	$ 1,580	-
43		Generation Dropping	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 335	-
44		Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
45		Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46		Persitent Deviation - Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47		Persitent Deviation - Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
48		Station Service	$ 200	$ 200	$ 200	$ 200	$ 200	$ 200	$ 200	$ 200	$ 200	$ 200	$ 200	$ 200	$ 2,406	9
49		Redispatch	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 400	-
50		COE/Reclamation Network/Delivery Facilities Segmentation	$ 529	$ 529	$ 529	$ 529	$ 529	$ 529	$ 529	$ 529	$ 529	$ 529	$ 529	$ 529	$ 6,353	-
51		Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
52	**Generation Inputs / Inter-business line**		**$ 9,661**	**$ 9,993**	**$ 10,549**	**$ 10,588**	**$ 10,361**	**$ 10,253**	**$ 10,211**	**$ 10,240**	**$ 10,708**	**$ 10,514**	**$ 10,147**	**$ 9,781**	**$ 123,007**	**9**
53		4(h)(10)(c)	$ 9,853	$ 7,619	$ 9,791	$ 11,780	$ 9,751	$ 8,521	$ 6,321	$ 5,955	$ 6,277	$ 5,638	$ 5,817	$ 7,978	$ 95,302	-
54		Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
55	**Treasury Credits**		**$ 10,237**	**$ 8,003**	**$ 10,174**	**$ 12,163**	**$ 10,135**	**$ 8,904**	**$ 6,704**	**$ 6,338**	**$ 6,660**	**$ 6,021**	**$ 6,201**	**$ 8,361**	**$ 99,902**	**-**
56		**Augmentation Power Purchase sub-total**	$ 2,301	$ 2,301	$ 2,301	$ 2,301	$ 2,301	$ 2,301	$ 2,301	$ 2,301	$ 2,301	$ 2,301	$ 2,301	$ 2,301	$ 27,611	95
57		**Balancing Power Purchase sub-total**	$ 2,662	$ 2,662	$ 2,662	$ 2,662	$ 2,662	$ 2,662	$ 2,662	$ 2,662	$ 2,662	$ 2,662	$ 2,662	$ 2,662	$ 31,941	170
58		**Other Power Purchase sub-total**	**$ 434**	**$ 5,996**	**$ 6,271**	**$ 6,461**	**$ 5,997**	**$ 6,461**	**$ 6,461**	**$ 434**	**$ 434**	**$ 434**	**$ 434**	**$ 434**	**$ 40,250**	**69**
59	**Power Purchases**		**$ 5,397**	**$ 10,959**	**$ 11,234**	**$ 11,423**	**$ 10,960**	**$ 11,423**	**$ 11,423**	**$ 5,397**	**$ 5,397**	**$ 5,397**	**$ 5,397**	**$ 5,397**	**$ 99,803**	**334**
60																
61	1) Revenues are split evenly over 12 months of FY. Difference of $100K in 20															

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**													**2015**	
2	**Category**	**201410**	**201411**	**201412**	**201501**	**201502**	**201503**	**201504**	**201505**	**201506**	**201507**	**201508**	**201509**	**$ (000's)**	**aMW**
3	Composite Revenue	$ 194,512	$ 194,512	$ 194,512	$ 194,512	$ 194,512	$ 194,512	$ 194,512	$ 194,512	$ 194,512	$ 194,512	$ 194,512	$ 194,512	$ 2,334,149	7,037
4	Non-Slice Revenue	$ (21,908)	$ (21,908)	$ (21,908)	$ (21,908)	$ (21,908)	$ (21,908)	$ (21,908)	$ (21,908)	$ (21,908)	$ (21,908)	$ (21,908)	$ (21,908)	$ (262,899)	-
5	Slice	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
6	Load Shaping Revenue	$ 2,179	$ 2,179	$ 2,179	$ 2,179	$ 2,179	$ 2,179	$ 2,179	$ 2,179	$ 2,179	$ 2,179	$ 2,179	$ 2,179	$ 26,150	20
7	Demand Revenue	$ 5,131	$ 5,131	$ 5,131	$ 5,131	$ 5,131	$ 5,131	$ 5,131	$ 5,131	$ 5,131	$ 5,131	$ 5,131	$ 5,131	$ 61,568	-
8	Irrigation Rate Discount	$ (1,650)	$ (1,650)	$ (1,650)	$ (1,650)	$ (1,650)	$ (1,650)	$ (1,650)	$ (1,650)	$ (1,650)	$ (1,650)	$ (1,650)	$ (1,650)	$ (19,794)	-
9	Low Density Discount	$ (3,105)	$ (3,105)	$ (3,105)	$ (3,105)	$ (3,105)	$ (3,105)	$ (3,105)	$ (3,105)	$ (3,105)	$ (3,105)	$ (3,105)	$ (3,105)	$ (37,257)	-
10	Tier 2	$ 2,283	$ 2,283	$ 2,283	$ 2,283	$ 2,283	$ 2,283	$ 2,283	$ 2,283	$ 2,283	$ 2,283	$ 2,283	$ 2,283	$ 27,391	79
11	RSS (Non-Federal)	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 51	$ 612	-
12	**PF customers (CHWM) sub-total**	**$ 177,493**	**$ 177,493**	**$ 177,493**	**$ 177,493**	**$ 177,493**	**$ 177,493**	**$ 177,493**	**$ 177,493**	**$ 177,493**	**$ 177,493**	**$ 177,493**	**$ 177,493**	**$ 2,129,920**	**7,137**
13	1) **DSIs sub-total**	**$ 8,878**	**$ 8,878**	**$ 8,878**	**$ 8,878**	**$ 8,878**	**$ 8,878**	**$ 8,878**	**$ 8,878**	**$ 8,878**	**$ 8,878**	**$ 8,878**	**$ 8,878**	**$ 106,537**	**312**
14	**FPS sub-total**	**$ 244**	**$ 254**	**$ 274**	**$ 269**	**$ 259**	**$ 254**	**$ 244**	**$ 249**	**$ 254**	**$ 264**	**$ 254**	**$ 254**	**$ 3,074**	**9**
15	**Short-term market sales sub-total**	**$ 28,428**	**$ 28,428**	**$ 28,428**	**$ 28,428**	**$ 28,428**	**$ 28,428**	**$ 28,428**	**$ 28,428**	**$ 28,428**	**$ 28,428**	**$ 28,428**	**$ 28,428**	**$ 341,136**	**1,684**
16	**Long Term Contractual Obligations sub-total**	**$ 41**	**$ 5,893**	**$ 6,053**	**$ 6,042**	**$ 5,532**	**$ 3,026**	**$ 2,931**	**$ 79**	**$ 85**	**$ 82**	**$ 62**	**$ 39**	**$ 29,865**	**74**
17	**Canadian Entitlement Return**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**475**
18	**Renewable Energy Certificates sub-total**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,107**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,107**	**11**
19	GTA Delivery charge	$ 165	$ 190	$ 215	$ 225	$ 200	$ 185	$ 145	$ 170	$ 180	$ 185	$ 195	$ 175	$ 2,230	-
20	Miscellaneous Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
21	Slice True up	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
22	**Other Sales sub-total**	**$ 165**	**$ 190**	**$ 215**	**$ 225**	**$ 200**	**$ 185**	**$ 145**	**$ 170**	**$ 180**	**$ 185**	**$ 195**	**$ 175**	**$ 2,230**	**-**
23	**Gross Sales**	**$215,249**	**$221,137**	**$221,341**	**$221,335**	**$220,790**	**$219,372**	**$218,120**	**$215,298**	**$215,319**	**$215,331**	**$215,311**	**$215,267**	**$2,613,870**	**9,702**
24	Energy Efficiency Revenues	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 958	$ 12,083	-
25	Irrigation Pumping Power	$ 85	$ 1	$ 1	$ 1	$ 1	$ 10	$ 90	$ 195	$ 235	$ 300	$ 279	$ 196	$ 1,394	174
26	Reserve Energy	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 727	$ 8,718	3
27	Downstream Benefits	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 440	$ 5,282	-
28	Upper Baker Revenues	$ -	$ 110	$ 115	$ 110	$ 111	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 446	1
29	**Miscellaneous Revenues**	**$2,210**	**$2,236**	**$2,241**	**$2,236**	**$2,238**	**$2,135**	**$2,215**	**$2,320**	**$2,360**	**$2,425**	**$2,404**	**$2,321**	**$27,923**	**178**
30	Regulating Reserve	$ 499	$ 499	$ 499	$ 499	$ 499	$ 499	$ 499	$ 499	$ 499	$ 499	$ 499	$ 499	$ 5,983	-
31	Variable Energy Resource Balancing Service Reserve - Wind	$ 4,420	$ 4,420	$ 4,591	$ 4,591	$ 4,591	$ 4,737	$ 4,737	$ 4,737	$ 4,851	$ 4,851	$ 4,851	$ 4,851	$ 56,233	-
32	Variable Energy Resource Balancing Service Reserve - Wind Forecast Risk Adjustm	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
33	Committed Intra-Hour Scheduling Pilot Adjustment	$ (176)	$ (176)	$ (176)	$ (176)	$ (176)	$ (176)	$ (176)	$ (176)	$ (176)	$ (176)	$ (176)	$ (176)	$ (2,109)	-
34	VERBS Supplemental Service	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
35	VERBS for Solar	$ 4	$ 4	$ 4	$ 4	$ 4	$ 4	$ 4	$ 4	$ 4	$ 4	$ 4	$ 4	$ 45	-
36	Dispatchable Energy Resource Balancing Service Reserve inc	$ 449	$ 449	$ 449	$ 449	$ 449	$ 449	$ 449	$ 449	$ 449	$ 449	$ 449	$ 449	$ 5,392	-
37	Dispatchable Energy Resource Balancing Service Reserve dec	$ 43	$ 43	$ 43	$ 43	$ 43	$ 43	$ 43	$ 43	$ 43	$ 43	$ 43	$ 43	$ 512	-
38	Operating Reserve - Spinning	$ 1,955	$ 2,133	$ 2,429	$ 2,451	$ 2,329	$ 2,272	$ 2,249	$ 2,264	$ 2,428	$ 2,325	$ 2,129	$ 1,933	$ 26,897	-
39	Operating Reserve - Supplemental	$ 1,790	$ 1,953	$ 2,224	$ 2,244	$ 2,133	$ 2,080	$ 2,059	$ 2,073	$ 2,223	$ 2,129	$ 1,949	$ 1,770	$ 24,625	-
40	Operating Reserve - Spinning Adjustment for WNP-3 Settlement contracts with Avista	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
41	Operating Reserve - Supplemental Adjustment for WNP-3 Settlement contracts with	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
42	Synchronous Condensing	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 131	$ 1,578	-
43	Generation Dropping	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 28	$ 335	-
44	Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
45	Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
46	Persitent Deviation - Energy Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
47	Persitent Deviation - Generation Imbalance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
48	Station Service	$ 200	$ 200	$ 200	$ 200	$ 200	$ 200	$ 200	$ 200	$ 200	$ 200	$ 200	$ 200	$ 2,406	9
49	Redispatch	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 33	$ 400	-
50	COE/Reclamation Network/Delivery Facilities Segmentation	$ 512	$ 512	$ 512	$ 512	$ 512	$ 512	$ 512	$ 512	$ 512	$ 512	$ 512	$ 512	$ 6,148	-
51	Operating Reserve - Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
52	**Generation Inputs / Inter-business line**	**$ 9,889**	**$ 10,230**	**$ 10,969**	**$ 11,010**	**$ 10,778**	**$ 10,813**	**$ 10,769**	**$ 10,798**	**$ 11,227**	**$ 11,029**	**$ 10,654**	**$ 10,279**	**$ 128,444**	**9**
53	4(h)(10)(c)	$ 10,100	$ 7,516	$ 8,517	$ 10,839	$ 8,823	$ 7,685	$ 6,021	$ 5,770	$ 6,645	$ 5,507	$ 5,520	$ 9,440	$ 92,383	-
54	Colville and Spokane Settlements	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 383	$ 4,600	-
55	**Treasury Credits**	**$ 10,483**	**$ 7,900**	**$ 8,900**	**$ 11,222**	**$ 9,207**	**$ 8,068**	**$ 6,404**	**$ 6,154**	**$ 7,029**	**$ 5,890**	**$ 5,903**	**$ 9,824**	**$ 96,983**	**-**
56	**Augmentation Power Purchase sub-total**	$ 10,273	$ 10,273	$ 10,273	$ 10,273	$ 10,273	$ 10,273	$ 10,273	$ 10,273	$ 10,273	$ 10,273	$ 10,273	$ 10,273	$ 123,273	404
57	**Balancing Power Purchase sub-total**	$ 2,291	$ 2,291	$ 2,291	$ 2,291	$ 2,291	$ 2,291	$ 2,291	$ 2,291	$ 2,291	$ 2,291	$ 2,291	$ 2,291	$ 27,492	144
58	**Other Power Purchase sub-total**	**$ 2,203**	**$ 2,203**	**$ 2,203**	**$ 2,203**	**$ 2,203**	**$ 2,203**	**$ 2,203**	**$ 2,203**	**$ 2,203**	**$ 2,203**	**$ 2,203**	**$ 2,203**	**$ 26,442**	**-**
59	**Power Purchases**	**$ 14,767**	**$ 14,767**	**$ 14,767**	**$ 14,767**	**$ 14,767**	**$ 14,767**	**$ 14,767**	**$ 14,767**	**$ 14,767**	**$ 14,767**	**$ 14,767**	**$ 14,767**	**$ 177,206**	**548**
60															
61	1) Revenues are split evenly over 12 months of FY. Difference of $100K in 20														

Table 4.3 – Composite and Non-slice revenue – FY 2014-2015

	A	B	C	D	E	F	G
1	**Table 4.3 – Composite and Non-slice revenue – FY 2014-2015**						
2	Table shows calculation of CHWM revenues at proposed rates.						
3							
4	**Billing Determinants**	**FY 2014**		**FY 2015**		**Rate Period**	
5	**TOCA...**	98.509260	A)	98.896260	A)	98.702760	
6	**Non-slice TOCA...**	71.696660	B)	72.083660	B)	71.890160	
7	**Slice Percentage..**	26.812600		26.812600		26.812600	
8							
9	**Annual TRM Rates ($000)**	**FY 2014**		**FY 2015**		**Rate Period**	
10	**Composite...**	$ 23,374		$ 23,829		$ 23,602	C)
11	**Non-Slice...**	$ (3,368)		$ (3,925)		$ (3,647)	D)
12	**Slice...**	$ -		$ -		$ -	
13							
14	**Yearly Revenues (Yearly TOCA * Rate Period rate)**	**FY 2014**		**FY 2015**			
15	**Composite (A * C)..**	$ 2,325,015	E)	$ 2,334,149	E)		
16	**Non-Slice (B * D)..**	$ (261,487)	E)	$ (262,899)	E)		
17	**Slice...**	$ -		$ -			
18							
19	**Monthly Revenues (Yearly Revenues / 12)**	**FY 2014**		**FY 2015**			
20	**Composite (E / 12)...**	$ 193,751		$ 194,512			
21	**Non-Slice (E / 12)..**	$ (21,791)		$ (21,908)			
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 2014-2015

	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 2014-2015**														
2	Table shows calculation of CHWM revenues at proposed rates.														
3															
4															
5	**FY 2014**		**Oct-12**	**Nov-12**	**Dec-12**	**Jan-13**	**Feb-13**	**Mar-13**	**Apr-13**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**	**Total**
6	Load Shaping HLH (MWh)	A)	(99,467)	(292,456)	43,723	7,184	189,227	153,781	514,162	(1,072,951)	(661,247)	(608,280)	(203,324)	(89,713)	
7	Load Shaping LLH (MWh)	B)	152,129	120,716	372,206	424,413	346,482	251,399	364,601	(475,010)	(130,963)	123,303	169,946	180,616	
8	Load Shaping HLH Rate ($/MWh)	C)	$ 31.30	$ 32.51	$ 35.78	$ 35.86	$ 34.39	$ 29.53	$ 25.85	$ 22.45	$ 23.79	$ 31.17	$ 33.90	$ 34.16	
9	Load Shaping LLH Rate ($/MWh)	D)	$ 28.06	$ 29.90	$ 31.97	$ 30.24	$ 29.75	$ 25.90	$ 21.20	$ 15.31	$ 17.42	$ 26.86	$ 28.60	$ 29.37	
10	Load Shaping Revenue (A * C) + (B * D)		$ 1,155,411	$ (5,898,348)	$ 13,463,828	$ 13,091,887	$ 16,815,342	$ 11,052,378	$ 21,020,646	$ (31,360,153)	$ (18,012,445)	$ (15,648,171)	$ (2,032,228)	$ 2,240,115	$ 5,888,261
11															
12	Demand (kW)	E)	479,250	397,809	707,561	798,084	446,411	519,943	575,465	450,549	393,552	539,237	436,067	435,410	
13	Demand Rate ($/kW-mo.)	F)	$ 9.86	$ 10.24	$ 11.26	$ 11.29	$ 10.83	$ 9.31	$ 8.16	$ 7.09	$ 7.52	$ 9.84	$ 10.66	$ 10.74	
14	Demand Revenue (E * F)		$ 4,725,406	$ 4,073,566	$ 7,967,136	$ 9,010,374	$ 4,834,631	$ 4,840,668	$ 4,695,793	$ 3,194,395	$ 2,959,513	$ 5,306,091	$ 4,648,473	$ 4,676,302	$ 60,932,348
15															
16															
17															
18															
19	**FY 2015**		**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**	**Total**
20	Load Shaping HLH (MWh)	A)	(62,911)	(294,797)	133,538	48,756	226,106	191,091	545,434	(1,084,799)	(613,510)	(586,083)	(176,265)	(61,247)	
21	Load Shaping LLH (MWh)	B)	177,979	194,602	361,885	458,531	374,206	279,007	386,284	(429,832)	(144,271)	142,736	190,690	202,693	
22	Load Shaping HLH Rate ($/MWh)	C)	$ 31.30	$ 32.51	$ 35.78	$ 35.86	$ 34.39	$ 29.53	$ 25.85	$ 22.45	$ 23.79	$ 31.17	$ 33.90	$ 34.16	
23	Load Shaping LLH Rate ($/MWh)	D)	$ 28.06	$ 29.90	$ 31.97	$ 30.24	$ 29.75	$ 25.90	$ 21.20	$ 15.31	$ 17.42	$ 26.86	$ 28.60	$ 29.37	
24	Load Shaping Revenue (A * C) + (B * D)		$ 3,024,970	$ (3,765,254)	$ 16,347,445	$ 15,614,376	$ 18,908,420	$ 12,869,203	$ 22,288,707	$ (30,934,454)	$ (17,108,600)	$ (14,434,306)	$ (521,667)	$ 3,860,886	$ 26,149,726
25															
26	Demand (kW)	E)	473,830	276,246	845,343	799,780	441,042	517,027	580,410	356,242	516,333	555,284	438,692	432,416	
27	Demand Rate ($/kW-mo.)	F)	$ 9.86	$ 10.24	$ 11.26	$ 11.29	$ 10.83	$ 9.31	$ 8.16	$ 7.09	$ 7.52	$ 9.84	$ 10.66	$ 10.74	
28	Demand Revenue (E * F)		$ 4,671,966	$ 2,828,761	$ 9,518,560	$ 9,029,517	$ 4,776,490	$ 4,813,521	$ 4,736,146	$ 2,525,756	$ 3,882,827	$ 5,463,999	$ 4,676,454	$ 4,644,151	$ 61,568,150
29															
30	*Ties to Table 4.2, Revenue at Proposed Rates, lines 6-7*														

Table 4.5 – Irrigation Rate Discount (IRD) – FY 2014-2015

	A	B	C	D	E	F	G	H
1	**Table 4.5 – Irrigation Rate Discount (IRD) – FY 2014-2015**							
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**	7,116						
8	**Annual NonSlice Dollar Amount**	2,067,647						
9	**Average Hours in Rate Period**	8784						
10	**Implied Discount ($/MWh)**	**10.52**	A)					
11								
12								
13								
14	**FY 2014**	**May-13**	**Jun-13**	**Jul-13**	**Aug-13**	**Sep-13**		**TOTAL**
15	IRD Monthly Loads (MWh)	290,041	433,464	499,210	409,669	249,220	B)	
16	IRD credit ($) (A * B)	$ (3,051,233)	$ (4,560,037)	$ (5,251,694)	$ (4,309,719)	$ (2,621,797)		**$ (19,794,480)**
17								
18								
19	**FY2015**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**		**TOTAL**
20	IRD Monthly Loads (MWh)	290,041	433,464	499,210	409,669	249,220	B)	
21	IRD credit ($) (A * B)	$ (3,051,233)	$ (4,560,037)	$ (5,251,694)	$ (4,309,719)	$ (2,621,797)		**$ (19,794,480)**
22								
23								
24	*Ties to Table 4.2, Revenue at Proposed Rates, line 8*							
25								

Table 4.6 – Low Density Discount (LDD) – FY 2012-2013

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	**Table 4.6 – Low Density Discount (LDD) – FY 2014-2015**														
2	Table shows calculation of LDD credit at proposed rates.														
3															
4	Low Density Discount														
5	Customer Charge LDD	**FY 2014**	**FY 2015**												
6	TOCA LDD Offset %..	1.62%	1.66%	**A)**											
7															
8	TRM Costs after Adjustments														
9	Composite...	$ 2,325,269	$ 2,334,404												
10	Non-Slice...	$ (261,483)	$ (262,895)												
11	Slice...	$ -	$ -												
12		$ 2,063,786	$ 2,071,509	**B)**											
13															
14	LDD discount - Composite portion (A * B)........................	$ 33,448.79	$ 34,395.20	**C)**											
15	LDD discount (Demand/Load Shaping portion)................	$ 2,674.59	$ 2,865.60	**D) below**											
16	**Total LDD discount (C + D)..**	**$ 36,123.38**	**$ 37,260.80**												
17															
18	**Demand and Load Shaping Discount Detail**														
19	**FY 2014**	**Oct-13**	**Nov-13**	**Dec-13**	**Jan-14**	**Feb-14**	**Mar-14**	**Apr-14**	**May-14**	**Jun-14**	**Jul-14**	**Aug-14**	**Sep-14**		
20	Demand BD (kW)	18,068	14,583	26,831	29,995	15,913	19,694	22,261	21,984	19,308	24,361	19,727	17,993		
21	Load Shaping BD HLH (MWh)	(2,934)	(9,150)	58	(3,059)	2,124	460	11,149	(20,795)	(6,814)	(5,632)	3,129	196		
22	Load Shaping BD LLH (MWh)	1,481	(818)	4,829	5,301	4,772	1,206	6,852	(9,190)	245	7,680	6,831	4,189		
23	Demand Rate	$ 9.86	$ 10.24	$ 11.26	$ 11.29	$ 10.83	$ 9.31	$ 8.16	$ 7.09	$ 7.52	$ 9.84	$ 10.66	$ 10.74		
24	Load Shaping Rate (HLH)	$ 31.30	$ 32.51	$ 35.78	$ 35.86	$ 34.39	$ 29.53	$ 25.85	$ 22.45	$ 23.79	$ 31.17	$ 33.90	$ 34.16		
25	Load Shaping Rate (LLH)	$ 28.06	$ 29.90	$ 31.97	$ 30.24	$ 29.75	$ 25.90	$ 21.20	$ 15.31	$ 17.42	$ 26.86	$ 28.60	$ 29.37		
26	LDD credit (Demand/Load Shaping portion)	$ 127,865	$ (172,594)	$ 458,545	$ 389,256	$ 387,365	$ 228,168	$ 615,112	$ (451,681)	$ (12,638)	$ 270,467	$ 511,750	$ 322,975	$ 2,674,589	
27														$ 2,674.59	**D)**
28	**FY 2015**	**Oct-14**	**Nov-14**	**Dec-14**	**Jan-15**	**Feb-15**	**Mar-15**	**Apr-15**	**May-15**	**Jun-15**	**Jul-15**	**Aug-15**	**Sep-15**		
29	Demand BD (kW)	17,895	11,457	32,877	30,641	15,916	19,902	23,204	20,316	25,671	26,477	20,751	18,144		
30	Load Shaping BD HLH (MWh)	(2,393)	(9,278)	434	(3,374)	1,882	386	11,319	(21,827)	(6,727)	(5,533)	3,722	802		
31	Load Shaping BD LLH (MWh)	1,884	(358)	4,611	5,242	4,658	1,048	6,914	(9,338)	27	8,031	7,315	4,575		
32	Demand Rate	$ 9.86	$ 10.24	$ 11.26	$ 11.29	$ 10.83	$ 9.31	$ 8.16	$ 7.09	$ 7.52	$ 9.84	$ 10.66	$ 10.74		
33	Load Shaping Rate (HLH)	$ 31.30	$ 32.51	$ 35.78	$ 35.86	$ 34.39	$ 29.53	$ 25.85	$ 22.45	$ 23.79	$ 31.17	$ 33.90	$ 34.16		
34	Load Shaping Rate (LLH)	$ 28.06	$ 29.90	$ 31.97	$ 30.24	$ 29.75	$ 25.90	$ 21.20	$ 15.31	$ 17.42	$ 26.86	$ 28.60	$ 29.37		
35	LDD credit(Demand/Load Shaping portion)	$ 154,402	$ (195,004)	$ 533,168	$ 383,475	$ 375,660	$ 223,843	$ 628,508	$ (488,950)	$ 33,479	$ 303,791	$ 556,587	$ 356,636	$ 2,865,596	
36														$ 2,865.60	**D)**
37	**LDD credit is negative revenue*														
38	*Ties to Table 4.2, Revenue at Proposed Rates, line 9*														

Table 4.7 – Tier 2 revenue – FY 2014-2015

	A	B	C
1	**Table 4.7 – Tier 2 revenue – FY 2014-2015**		
2	Table shows calculation of CHWM revenues at proposed rates.		
3			
4	**Fiscal Year**		
5	**Rate Period**	**FY2014**	**FY2015**
6			
7	Base Power Purchase Cost	$ -	$ -
8	Rate Design Components	$ 191,078	$ 369,902
9	Other Costs	$ -	$ -
10	Rate $/MWh	**$ 35.46**	**$ 37.21**
11	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (169,900)	$ (329,881)
12	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
13	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (21,178)	$ (40,021)
14	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -
15	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -
16	Total ST.1.2012_2014 Revenue	$ 5,006,511	$ 9,927,811
17			
18	Base Power Purchase Cost	$ -	$ 1,713,456
19	Rate Design Components	$ 15,565	$ 20,324
20	Other Costs	$ -	$ -
21	Rate $/MWh	**$ 35.46**	**$ 41.64**
22	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ (13,840)	$ (18,125)
23	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
24	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ (1,725)	$ (2,199)
25	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -
26	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -
27	Total LG.3.2012_2028 Revenue	$ 407,826	$ 610,415
28			
29	Base Power Purchase Cost	$ -	$ 15,763,795
30	Rate Design Components	$ -	$ 558,671
31	Other Costs	$ -	$ -
32	Rate $/MWh	$ -	**$ 41.52**
33	Tier 2 Composite Overhead Adjustment Debit/(Credit)	$ -	$ (498,226)
34	Tier 2 Non-Slice Risk Adjustment Debit/(Credit)	$ -	$ -
35	Tier 2 Composite Cost Pool RSS Revenue Debit/(Credit)	$ -	$ (60,444)
36	Tier 2 Composite Cost Pool Balancing Adjustment Debit/(Credit)	$ -	$ -
37	Tier 2 Non-Slice Cost Pool Balancing Debit/(Credit)	$ -	$ -
38	Total V.1.2014_2016 Revenue	$ -	$ 16,730,955
39			
40	**Total Tier 2 Revenue Collection**	**$ 5,414,338**	**$ 27,269,181**
41			
42			
43			
44	*Ties to Table 4.2, Revenue at Proposed Rates, line 10*		
45			

Table 4.8 – Direct Service Industries (DSI) revenues – FY 2013-2015

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
Table 4.8 – Direct Service Industries (DSI) revenues – FY 2013-2015														
Table shows calculation of DSI revenues at current and proposed rates.														
FY 2013		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Total**
HLH rate (per MWh)	A)	38.51	39.02	41.75	40.68	41.58	40.22	38.18	35.71	36.62	42.72	45.00	44.10	
LLH rate (per MWh)	B)	31.85	32.05	34.04	32.35	33.82	32.98	31.06	25.05	23.67	30.56	32.8	34.24	
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	
HLH consumption (MWh)	D)	147,096	128,200	128,200	133,328	123,072	133,328	133,328	133,328	128,200	129,792	134,784	119,808	1,572,464
LLH consumption (MWh)	E)	106,236	102,881	110,252	105,124	92,304	104,804	97,432	105,124	102,560	102,336	97,344	104,832	1,231,228
Demand (kW)	F)	-	-	-	-	-	-	-	-	-	-	-	-	-
HLH revenues (A * D)	G)	5,664,667	5,002,364	5,352,350	5,423,783	5,117,334	5,362,452	5,090,463	4,761,143	4,694,684	5,544,714	6,065,280	5,283,533	63,362,767
LLH revenues (B * E)	H)	3,383,617	3,297,320	3,752,978	3,400,761	3,121,721	3,456,419	3,026,238	2,633,356	2,427,595	3,127,388	3,192,883	3,589,448	38,409,725
Demand revenues (C * F)	I)	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL forecast revenues (G + H + I)	J)	$ 9,048,284	$ 8,299,684	$ 9,105,328	$ 8,824,544	$ 8,239,055	$ 8,818,872	$ 8,116,701	$ 7,394,499	$ 7,122,279	$ 8,672,102	$ 9,258,163	$ 8,872,980	$ 101,772,492
TOTAL revenues adjusting for actuals	K)	$ 9,048,284	$ 8,299,684	$ 9,105,328	$ 8,824,544	$ 8,239,055	$ 8,818,872	$ 8,116,701	$ 7,394,499	$ 7,122,279	$ 8,672,102	$ 9,258,163	$ 8,872,980	**$ 101,772,492**
FY 2014 - current rates		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Total**
HLH rate (per MWh)	A)	38.51	39.02	41.75	40.68	41.58	40.22	38.18	35.71	36.62	42.72	45.00	44.10	
LLH rate (per MWh)	B)	31.85	32.05	34.04	32.35	33.82	32.98	31.06	25.05	23.67	30.56	32.80	34.24	
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	
HLH consumption (MWh)	D)	134,784	124,800	124,800	129,792	119,808	129,792	129,792	129,792	124,800	129,792	129,792	124,800	1,532,544
LLH consumption (MWh)	E)	97,344	100,152	107,328	102,336	89,856	102,024	94,848	102,336	99,840	102,336	102,336	102,336	1,203,072
Demand (kW)	F)													
HLH revenues (A * D)	G)	5,190,532	4,869,696	5,210,400	5,279,939	4,981,617	5,220,234	4,955,459	4,634,872	4,570,176	5,544,714	5,840,640	5,503,680	61,801,958
LLH revenues (B * E)	H)	3,100,406	3,209,872	3,653,445	3,310,570	3,038,930	3,364,752	2,945,979	2,563,517	2,363,213	3,127,388	3,356,621	3,503,985	37,538,676
Demand revenues (C * F)	I)	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL revenues (G + H + I)		$ 8,290,938	$ 8,079,568	$ 8,863,845	$ 8,590,508	$ 8,020,547	$ 8,584,986	$ 7,901,437	$ 7,198,389	$ 6,933,389	$ 8,672,102	$ 9,197,261	$ 9,007,665	$ 99,340,635
FY 2015 - current rates		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Total**
HLH rate (per MWh)	A)	38.51	39.02	41.75	40.68	41.58	40.22	38.18	35.71	36.62	42.72	45.00	44.10	
LLH rate (per MWh)	B)	31.85	32.05	34.04	32.35	33.82	32.98	31.06	25.05	23.67	30.56	32.80	34.24	
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	
HLH consumption (MWh)	D)	134,784	124,800	124,800	129,792	119,808	129,792	129,792	129,792	124,800	129,792	129,792	124,800	1,532,544
LLH consumption (MWh)	E)	97,344	100,152	107,328	102,336	89,856	102,024	94,848	102,336	99,840	102,336	102,336	102,336	1,203,072
Demand (kW)	F)													
HLH revenues (A * D)	G)	5,190,532	4,869,696	5,210,400	5,279,939	4,981,617	5,220,234	4,955,459	4,634,872	4,570,176	5,544,714	5,840,640	5,503,680	61,801,958
LLH revenues (B * E)	H)	3,100,406	3,209,872	3,653,445	3,310,570	3,038,930	3,364,752	2,945,979	2,563,517	2,363,213	3,127,388	3,356,621	3,503,985	37,538,676
Demand revenues (C * F)	I)	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL revenues (G + H + I)		$ 8,290,938	$ 8,079,568	$ 8,863,845	$ 8,590,508	$ 8,020,547	$ 8,584,986	$ 7,901,437	$ 7,198,389	$ 6,933,389	$ 8,672,102	$ 9,197,261	$ 9,007,665	$ 99,340,635
FY 2014 - proposed rates		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Total**
HLH rate (per MWh)	A)	38.99	38.99	38.99	38.99	38.99	38.99	38.99	38.99	38.99	38.99	38.99	38.99	
LLH rate (per MWh)	B)	38.99	38.99	38.99	38.99	38.99	38.99	38.99	38.99	38.99	38.99	38.99	38.99	
Demand rate (kw/Mo)	C)	9.86	10.24	11.26	11.29	10.83	9.31	8.16	7.09	7.52	9.84	10.66	10.74	
HLH consumption (MWh)	D)	134,784	124,800	124,800	129,792	119,808	129,792	129,792	129,792	124,800	129,792	129,792	124,800	1,532,544
LLH consumption (MWh)	E)	97,344	100,152	107,328	102,336	89,856	102,024	94,848	102,336	99,840	102,336	102,336	102,336	1,203,072
HLH revenues (A * D)	G)	5,255,228	4,865,952	4,865,952	5,060,590	4,671,314	5,060,590	5,060,590	5,060,590	4,865,952	5,060,590	5,060,590	4,865,952	59,753,891
LLH revenues (B * E)	H)	3,795,443	3,904,926	4,184,719	3,990,081	3,503,485	3,977,916	3,698,124	3,990,081	3,892,762	3,990,081	3,990,081	3,990,081	46,907,777
Demand revenues (C * F)	I)	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL revenues (G + H + I)		$ 9,050,671	$ 8,770,878	$ 9,050,671	$ 9,050,671	$ 8,174,799	$ 9,038,506	$ 8,758,714	$ 9,050,671	$ 8,758,714	$ 9,050,671	$ 9,050,671	$ 8,856,033	$ 106,661,668
FY 2015 - proposed rates		**Oct**	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Total**
HLH rate (per MWh)	A)	38.99	38.99	38.99	38.99	38.99	38.99	38.99	38.99	38.99	38.99	38.99	38.99	
LLH rate (per MWh)	B)	38.99	38.99	38.99	38.99	38.99	38.99	38.99	38.99	38.99	38.99	38.99	38.99	
Demand rate (kw/Mo)	C)	9.86	10.24	11.26	11.29	10.83	9.31	8.16	7.09	7.52	9.84	10.66	10.74	
HLH consumption (MWh)	D)	134,784	124,800	124,800	129,792	119,808	129,792	129,792	129,792	124,800	129,792	129,792	124,800	1,532,544
LLH consumption (MWh)	E)	97,344	100,152	107,328	102,336	89,856	102,024	94,848	102,336	99,840	102,336	102,336	102,336	1,203,072
HLH revenues (A * D)	G)	5,255,228	4,865,952	4,865,952	5,060,590	4,671,314	5,060,590	5,060,590	5,060,590	4,865,952	5,060,590	5,060,590	4,865,952	59,753,891
LLH revenues (B * E)	H)	3,795,443	3,904,926	4,184,719	3,990,081	3,503,485	3,977,916	3,698,124	3,990,081	3,892,762	3,990,081	3,990,081	3,990,081	46,907,777
Demand revenues (C * F)	I)	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL revenues (G + H + I)		$ 9,050,671	$ 8,770,878	$ 9,050,671	$ 9,050,671	$ 8,174,799	$ 9,038,506	$ 8,758,714	$ 9,050,671	$ 8,758,714	$ 9,050,671	$ 9,050,671	$ 8,856,033	$ 106,661,668

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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 CY 2011 - 2012 Two-Year Average Exchange Loads
Table lists the monthly two-year average Exchange Loads based on actual loads as submitted by Exchanging Utilities.

Table 8.2 Forecast ASCs
Table lists the monthly Forecasted ASCs as determined through the ASC review process.

Table 8.1

REP Residential Exchange Loads[1] (MWh)

	Oct-13	Nov-13	Dec-13	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	FY 2014
Avista	447,124	408,529	383,838	334,246	294,458	255,741	250,334	279,308	274,995	258,809	304,706	419,903	3,911,991
Idaho Power	619,031	556,535	522,929	440,655	421,511	480,504	587,718	698,318	655,490	503,535	409,289	537,887	6,433,404
NorthWestern	71,513	65,563	62,413	55,101	49,399	48,469	49,960	52,290	51,445	46,382	54,009	67,109	673,650
PacifiCorp	1,032,585	858,161	827,288	717,348	653,672	662,139	749,504	782,164	734,731	639,502	675,614	999,849	9,332,559
PGE	991,771	866,512	846,193	721,344	631,204	594,476	595,660	630,762	640,972	606,838	703,952	938,770	8,768,455
Puget Sound Energy	1,392,833	1,271,884	1,260,431	1,056,549	845,884	813,843	744,524	751,692	750,966	1,317,049	1,049,872	1,346,904	12,602,430
Clark	187,180	247,131	314,041	297,712	243,707	242,828	192,228	176,015	151,647	172,641	166,514	150,999	2,542,643
Snohomish	220,985	235,306	281,499	372,100	425,555	416,839	391,704	347,426	296,656	259,438	235,837	223,088	3,706,434

	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
Avista	447,124	408,529	383,838	334,246	294,458	255,741	250,334	279,308	274,995	258,809	304,706	419,903	3,911,991
Idaho Power	619,031	556,535	522,929	440,655	421,511	480,504	587,718	698,318	655,490	503,535	409,289	537,887	6,433,404
NorthWestern	71,513	65,563	62,413	55,101	49,399	48,469	49,960	52,290	51,445	46,382	54,009	67,109	673,650
PacifiCorp	1,032,585	858,161	827,288	717,348	653,672	662,139	749,504	782,164	734,731	639,502	675,614	999,849	9,332,559
PGE	991,771	866,512	846,193	721,344	631,204	594,476	595,660	630,762	640,972	606,838	703,952	938,770	8,768,455
Puget Sound Energy	1,392,833	1,271,884	1,260,431	1,056,549	845,884	813,843	744,524	751,692	750,966	1,317,049	1,049,872	1,346,904	12,602,430
Clark	186,027	245,608	312,106	295,877	242,205	241,331	191,043	174,930	150,712	171,577	165,488	150,068	2,526,971
Snohomish	222,605	237,031	283,563	376,686	430,801	421,977	396,533	351,709	300,314	262,636	238,744	225,838	3,748,437

[1] Monthly REP Residential Exchange Loads for the IOUs are the average of the 2-years of historical loads as defined in the REP Settlement, COU Residential Exchange Loads are from the forecasted loads included in each COU's ASC filing.

Table 8.2

Forecasted ASCs[2] ($/MWh)

	FY 2014		FY 2015
Avista	57.13	**Avista**	57.13
Idaho Power	49.69	**Idaho Power**	49.69
NorthWestern	70.62	**NorthWestern**	70.62
PacifiCorp	66.11	**PacifiCorp**	66.11
PGE	67.76	**PGE**	67.76
Puget Sound Energy	76.8	**Puget Sound Energy**	76.8
Clark	47.91	**Clark**	47.91
Snohomish	45.15	**Snohomish**	45.15

[2] Forecasted ASCs are determined through the ASC review process.

BONNEVILLE POWER ADMINISTRATION

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