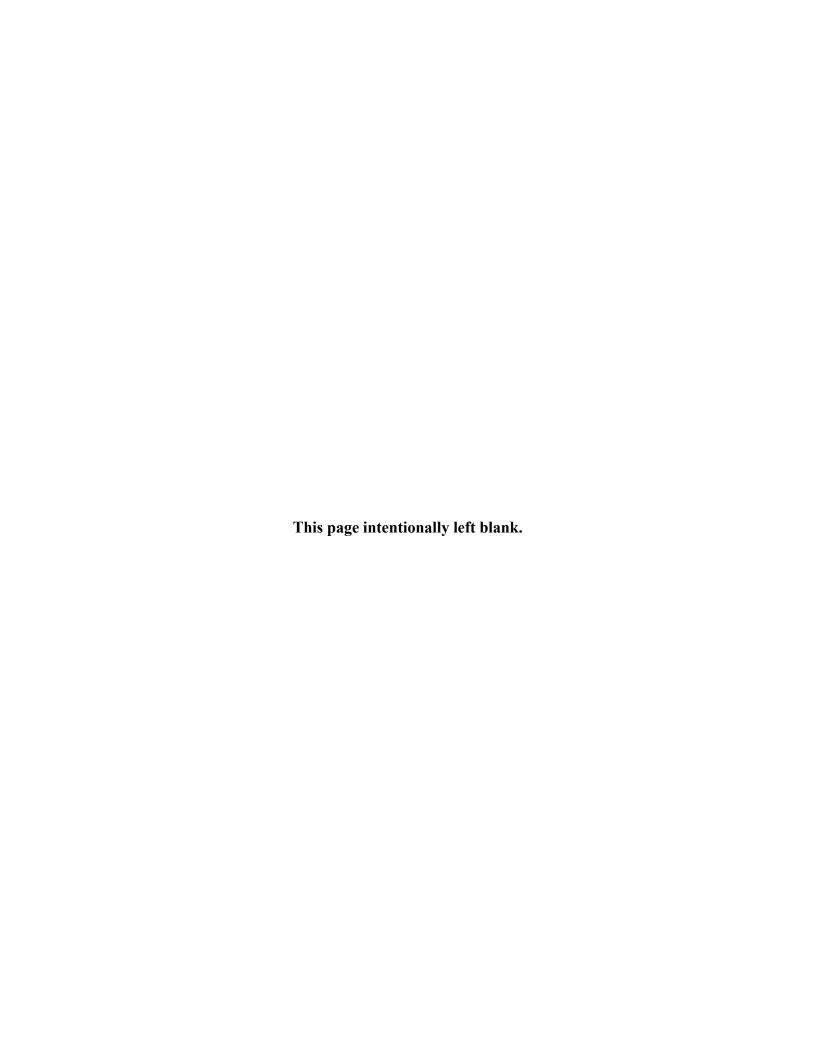
# 2010 BPA Rate Case Wholesale Power Rate Final Proposal

# WHOLESALE POWER RATE DEVELOPMENT STUDY DOCUMENTATION

July 2009

WP-10-FS-BPA-05A



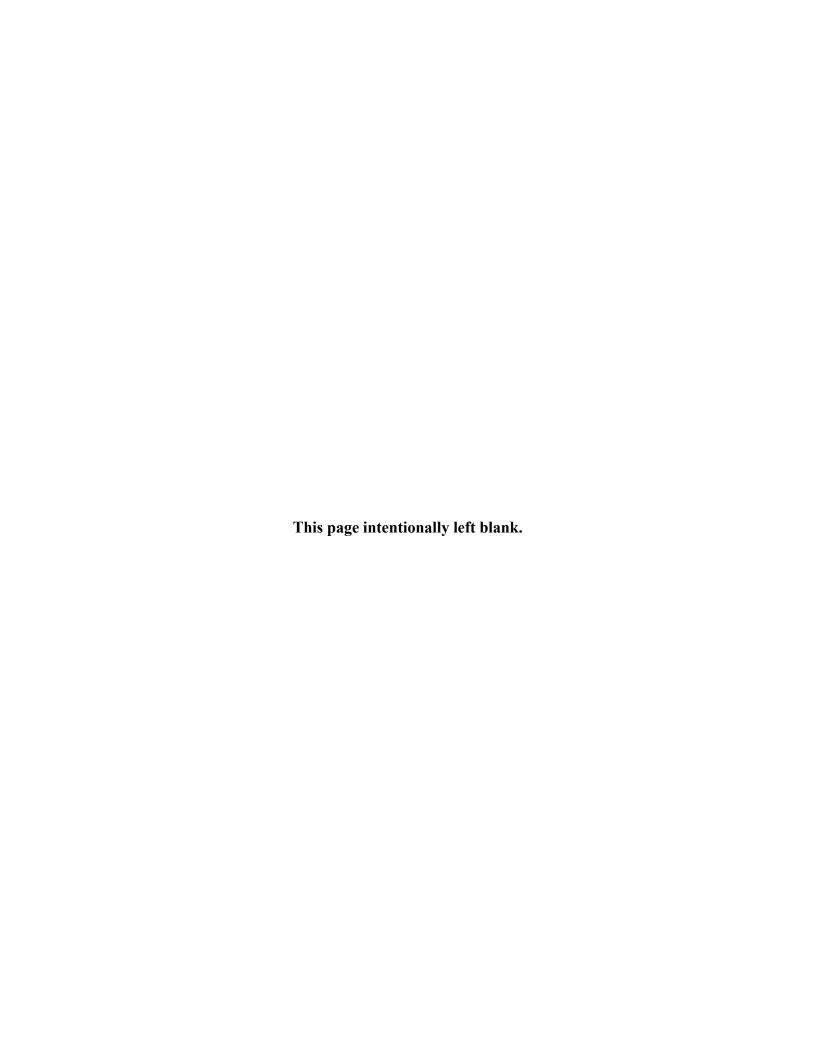


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#### COMMONLY USED ACRONYMS

AC alternating current

AFUDC Allowance for Funds Used During Construction

AGC Automatic Generation Control

ALF Agency Load Forecast (computer model)

aMW average megawatt

AMNR Accumulated Modified Net Revenues

ANR Accumulated Net Revenues
AOP Assured Operating Plan
ASC Average System Cost
ATC Accrual to Cash

BAA Balancing Authority Area
BASC BPA Average System Cost

Bcf billion cubic feet
BiOp Biological Opinion

BPA Bonneville Power Administration

Btu British thermal unit

CAISO California Independent System Operator
CBFWA COlumbia Basin Fish & Wildlife Authority
combined-cycle combustion turbine

cfs cubic feet per second

CGS Columbia Generating Station

CHJ Chief Joseph

C/M consumers per mile of line ratio for LDD

COB California-Oregon Border
COE U.S. Army Corps of Engineers
COI California-Oregon Intertie
COSA Cost of Service Analysis
COU consumer-owned utility

Council Northwest Power and Conservation Council

CP Coincidental Peak

CRAC Cost Recovery Adjustment Clause

CRC Conservation Rate Credit
CRFM Columbia River Fish Mitigation

CRITFC Columbia River Inter-Tribal Fish Commission

CSP Customer System Peak
CT combustion turbine

CY calendar year (January through December)

DC direct current

DDC Dividend Distribution Clause

dec decremental (pertains to generation movement)

DJ Dow Jones

DO Debt Optimization
DOE Department of Energy
DOP Debt Optimization Program

DSI direct-service industrial customer or direct-service industry

DSO Dispatcher Standing Order EAF energy allocation factor ECC Energy Content Curve

EIA Energy Information Administration EIS Environmental Impact Statement

EN Energy Northwest, Inc. (formerly Washington Public Power

Supply System)

EPA Environmental Protection Agency EPP Environmentally Preferred Power

EQR Electric Quarterly Report
ESA Endangered Species Act
F&O financial and operating reports

FBS Federal base system

FCRPS Federal Columbia River Power System
FCRTS Federal Columbia River Transmission System
FERC Federal Energy Regulatory Commission
FELCC firm energy load carrying capability

FPA Federal Power Act

FPS Firm Power Products and Services (rate)
FY fiscal year (October through September)
GAAP Generally Accepted Accounting Principles

GARD Generation and Reserves Dispatch (computer model)

GCL Grand Coulee

GCPs General Contract Provisions
GEP Green Energy Premium
GI Generation Integration
GRI Gas Research Institute

GRSPs General Rate Schedule Provisions

GSP Generation System Peak
GSU generator step-up transformers
GTA General Transfer Agreement

GWh gigawatthour HLH heavy load hour

HOSS Hourly Operating and Scheduling Simulator (computer model)

HYDSIM Hydro Simulation (computer model)

IDC interest during construction

inc incremental (pertains to generation movement)

IOUinvestor-owned utilityIPIndustrial Firm Power (rate)IPRIntegrated Program ReviewIRPIntegrated Resource PlanISDincremental standard deviationISOIndependent System Operator

JDA John Day

kaf thousand (kilo) acre-feet

kcfs thousand (kilo) cubic feet per second K/I kilowatthour per investment ratio for LDD

ksfd thousand (kilo) second foot day

kV kilovolt (1000 volts)

kVA kilo volt-ampere (1000 volt-amperes)

kVAr kilo-volt ampere reactive kW kilowatt (1000 watts)

kWh kilowatthour

LDD Low Density Discount

LGIP Large Generator Interconnection Procedures

LLH light load hour

LME
LOLP
loss of load probability
LRA
Load Reduction Agreement
m/kWh
mills per kilowatthour
mAE
mean absolute error
million acre-feet
MCA
Marginal Cost Analysis

MCN McNary

Mid-C Mid-Columbia

MIP Minimum Irrigation Pool
MMBtu million British thermal units
MNR Modified Net Revenues
MOA Memorandum of Agreement
MOP Minimum Operating Pool

MORC Minimum Operating Reliability Criteria

MOU Memorandum of Understanding MRNR Minimum Required Net Revenue

MVA mega-volt ampere

MVAr mega-volt ampere reactive MW megawatt (1 million watts)

MWh megawatthour

NCD non-coincidental demand

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)

NIFC Northwest Infrastructure Financing Corporation

NLSL New Large Single Load

NOAA Fisheries National Oceanographic and Atmospheric Administration

Fisheries (officially National Marine Fisheries Service)

NOB Nevada-Oregon Border

NORM Non-Operating Risk Model (computer model)

Northwest Power Act Pacific Northwest Electric Power Planning and Conservation

Act

NPCC Northwest Power and Conservation 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
OTC Operating Transfer Capability
OY operating year (August through July)

PDP proportional draft points
PF Priority Firm Power (rate)

PI Plant Information

PMA (Federal) Power Marketing Agency

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
PS BPA Power Services
PSC power sales contract
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
Reclamation U.S. Bureau of Reclamation

RD Regional Dialogue

REC Renewable Energy Certificate
REP Residential Exchange Program

RevSim Revenue Simulation Model (component of RiskMod)

RFA Revenue Forecast Application (database)

RFP Request for Proposal

Risk Model (computer model)

RiskSim Risk Simulation Model (component of RiskMod)

RMS Remote Metering System
RMSE root-mean squared error
ROD Record of Decision

RPSA Residential Purchase and Sale Agreement

RTF Regional Technical Forum

RTO Regional Transmission Operator

SCADA Supervisory Control and Data Acquisition

SCCT single-cycle combustion turbine
Slice Slice of the System (product)

SME subject matter expert

TAC Targeted Adjustment Charge

TDA The Dalles
Tcf trillion cubic feet

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
UAI Unauthorized Increase
UDC utility distribution company

URC Upper Rule Curve

USFWS U.S. Fish and Wildlife Service

VOR Value of Reserves

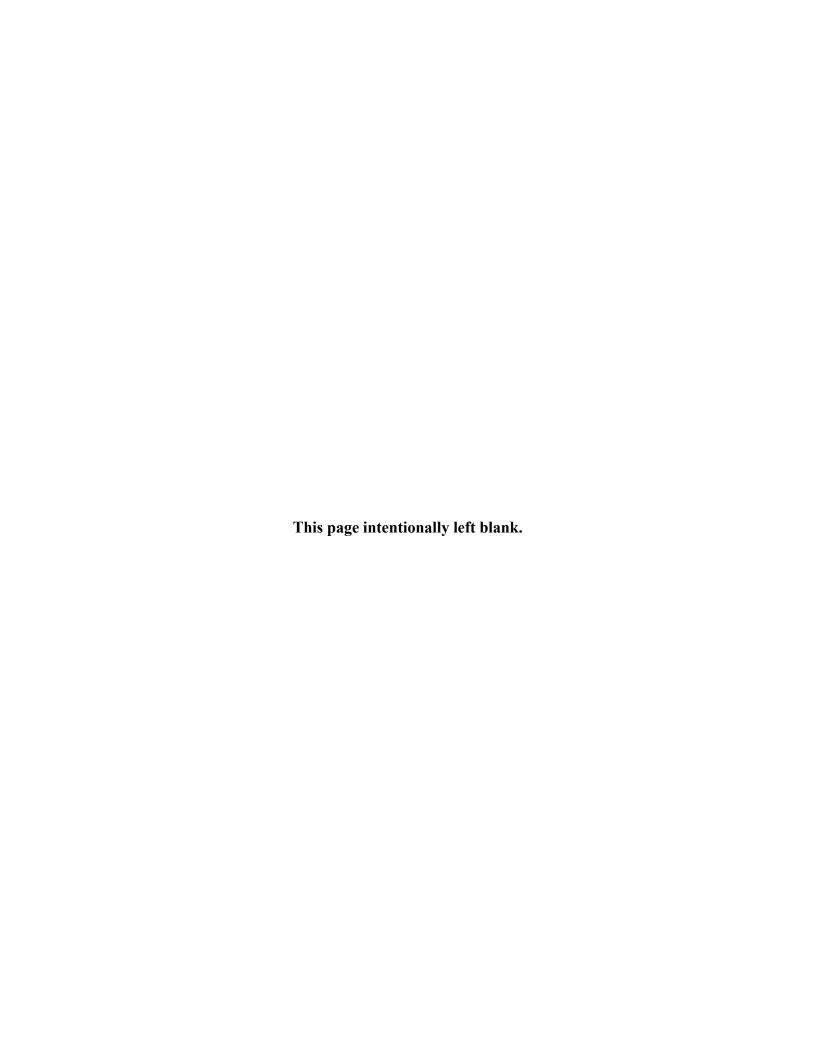
WECC Western Electricity Coordinating Council (formerly WSCC)

WIT Wind Integration Team

WPRDS Wholesale Power Rate Development Study

WREGIS Western Renewable Energy Generation Information System

WSPP Western Systems Power Pool



# DOCUMENTATION FOR THE WHOLESALE POWER RATE DEVELOPMENT STUDY

#### INTRODUCTION

The Documentation for Wholesale Power Rate Development Study (WPRDS) shows the details of the calculation of the proposed power rates.

Section 1 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 contains ratemaking tables that are the output of the Rate Analysis Model (RAM2010). The RAM2010 is a group of computer applications that perform most of the computations that determine BPA's proposed power rates. The output tables of RAM2010 include billing determinants, which are based on power sales forecasts, and revenue requirements used in the WPRDS 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 sections 7(b) and 7(c) of the Northwest Power Act. Other major tables show calculation of the Slice rate and the non-Slice rates. The final table shows the calculation of the resource cost contributions that appear in GRSP section II.C.

Section 3 documents forecasts of the Slice True-Up Adjustment Charge, both before and after the cost shift described in WPRDS section 2.15.6.

Section 4 documents revenue forecasts at both current and proposed rates for the rate period, FY 2010-2011, and at current rates for the period immediately preceding the two-year rate period, FY 2009.

Section 5 contains excerpts of the ASC customer reports.

Appendices document the section 7(c)(2) Industrial Margin Study (Appendix A) and provide further information on BPA's policy for the development of regional conservation and renewable resources (Appendices B, C, and D).



**CHAPTER 1: RATE PROCESS MODELING** 



#### 1. 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.

# LOADS AND RESOURCES STUDY (WP-10-FS-BPA-01):

# **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 Loads and Resources Study (WP-10-FS-BPA-01).

# **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 70 water years (October 1928 through September 1998). 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 2010-2011. 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-10 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 Loads and Resources Study (WP-10-FS-BPA-01).

# 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 Loads and Resources Study (WP-10-FS-BPA-01). Loads and Resources Study results are used as input into the Risk Analysis and Mitigation Study (WP-10-E-BPA-04) and the Market Price Forecast Study (WP-10-FS-BPA-03).

# **REVENUE REQUIREMENT STUDY (WP-10-FS-BPA-02):**

The Revenue Requirement Study provides BPA's generation revenue requirement for the rate test period. The revenue requirement is assigned to the resource pools for use in the Cost of Service Analysis section of the WPRDS.

The Revenue Requirement Study 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. The Repayment Program is used to determine whether a given set of annual revenues is sufficient to meet a given set of annual expenses and cover a given set of long-term obligations when applied in accordance with the requirements of DOE Order RA 6120.2. The Repayment Program also is used to determine by what minimum factor the future revenues can be multiplied to obtain a new set of revenues that will be sufficient.

# MARKET PRICE FORECAST STUDY (WP-10-FS-BPA-03):

The electric energy price results from the Market Price Forecast Study are used as price inputs for the following: (a) the secondary revenue forecast, (b) augmentation purchase costs, (c) the risk analysis, (d) the variable cost for generation input capacity, (e) utility average system costs, and (f) rate design. The tool used to calculate electric energy prices is a model of the Western Electricity Coordinating Council (WECC) power system called AURORA models wholesale electric energy transactions in a competitive pricing system. AURORA design 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 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. Over time, AURORA will add new resources and retire old resources based on the net present value of the resource.

# RISK ANALYSIS AND MITIGATION STUDY (WP-10-FS-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; a set of computer programs that manage data, referred to as Data Management Procedures; 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 70 years of historical streamflow conditions (1929-1998). 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 model to the sales and purchase amounts to calculate revenues from surplus energy sales and expenses from balancing power purchases. It also computes augmentation costs based on hydro generation data and AURORA prices under 1937 hydro conditions. The Rate Analysis Model and the Revenue Forecast Model 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<sup>xmp®</sup> 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 Loads and Resources Study (WP-10-FS-BPA-01).

# 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 the probability of making all planned Treasury payments during the rate period given the risks quantified in RiskMod and NORM and accounting for the impact of the risk mitigation tools. The ToolKit is used to demonstrate BPA's ability to meet its Treasury Payment Probability (TPP) standard for the rate proposal, given the net revenue and cash variability embodied in the distributions of operating and non-operating risks. 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.

# WHOLESALE POWER RATE DEVELOPMENT STUDY (WP-10-FS-BPA-05):

# Rate Analysis Model (RAM2010)

RAM2010, a spreadsheet-based model, has three main steps that perform the calculations necessary to develop BPA's wholesale power rates: Cost of Service Analysis (COSA), Rate Design, and Slice Separation.

- 1. Cost of Service Analysis. 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 Design. 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 Design step of RAM2010 performs these rate adjustments, including the 7(b)(2) rate test. Net exchange costs from this step are provided to the Lookback Recovery and Return Study (WP-10-FS-BPA-09) for

- calculation of the amount of exchange costs to be credited back to the COUs and the amount of exchange benefits to be distributed to the IOUs.
- 3. Slice Separation and Other Rate Design Application. In the Rate Design step, costs are allocated to the various rate pools, including the PF Preference rate pool that contains all firm PF Preference load. Section 7(e) affords BPA wide latitude in the design of rates to collect the costs allocated to each rate pool. At the end of the rate design step, BPA applies various designs to the different rates. The Slice Separation step separates the PF Slice product revenues, revenue credits, and firm loads from the overall PF Preference rate pool. What remains is the costs that must be covered by the remaining non-Slice product PF Preference load through posted PF Preference energy, demand, and load variance charges.

# **Revenue and Purchased Power Expense Forecast**

The Revenue Forecast, section 4 of the WPRDS, presents BPA's expected level of sales and revenue for the rate period, FY 2010 and FY 2011. It documents the revenues at both current and proposed rates by applying rates (PF, IP, and NR) 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 Revenue Requirement Study, WP-10-FS-BPA-02. 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 2010-2011 Average System Cost (ASC) Forecasts

The 7(b)(2) rate test requires a forecast of utility ASCs for the period FY 2010-2015. For purposes of the Initial Proposal, for the rate period BPA proposes to use the ASCs filed by utilities on October 15, 2008, with certain modifications, as "placeholders" pending the completion of the ASC Review Process. These "placeholder" ASCs will be replaced with the final ASCs established in the ASC Reports BPA publishes at the end of the current ASC Review Process. At the close of the ASC Review Process, BPA will incorporate into the WP-10 rate case record the final ASC Reports, and the Final Proposal rates will be established using these final ASCs for FY 2010-2011. The methodology and data that BPA uses to forecast utility ASCs for the rest of the 7(b)(2) rate test period, FY 2012-2015, is included in the Section 7(b)(2) Rate Test Study (WP-10-FS-BPA-06) and the Loads and Resources Study (WP-10-FS-BPA-01).

# SECTION 7(b)(2) RATE TEST STUDY (WP-10-BPA-FS-06):

The Rate Design steps of RAM2010 calculate the Program Case for the 7(b)(2) rate test. RAM2010 calculates annual Program Case rates for the rate period and the following four years, pursuant to section 7(b)(2) of the Northwest Power Act and BPA's Legal Interpretation and Implementation Methodology. The method of calculating rates and the data used to calculate rates for the Program Case of the 7(b)(2) rate test are identical to those used in calculating the actual proposed rates. The sales forecast used to develop

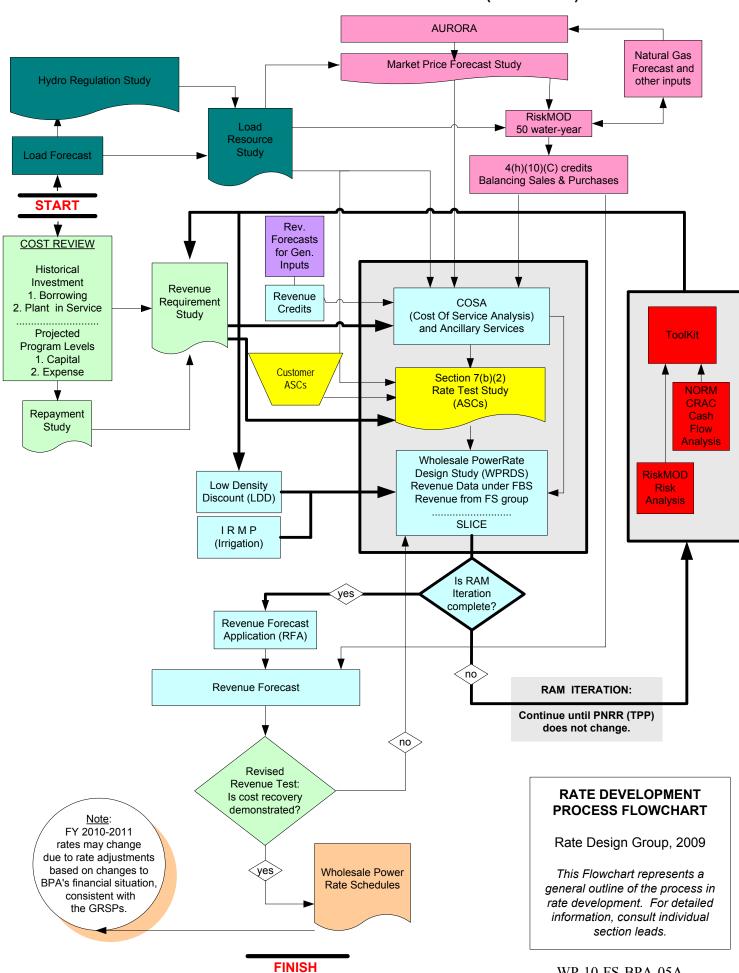
rates for the Program Case is the same forecast used to develop BPA's proposed rates. The 7(b)(2) Case section of RAM2010 calculates 7(b)(2) Case rates the same way as Program Case rates, except where section 7(b)(2) of the Northwest Power Act requires specific assumptions be made that modify the Program Case.

# **GENERATION INPUTS STUDY (WP-10-FS-BPA-08):**

# 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 loss, and 3) base cycling loss. GARD also calculates the following costs associated with deploying reserves: 1) response losses, 2) incremental cycling losses, 3) incremental spill, and 4) incremental efficiency loss. 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 FLOWCHART (version 4.1)



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**CHAPTER 2: RATE ANALYSIS MODEL** 



# **Table 2.1 (Sales 01)**

Total PF Load Forecast FY2010-11 and Non-Slice PF Load Forecast, FY2010-11.

Gigawatthour (GWh) energy sales and peak megawatt (MW)/mo. demand amounts for each month of the Rate Test Period FY 2010-11.

# **Table 2.2 (Sales 02)**

Total PF Exchange Load Forecast, FY2010-11.

GWh energy sales and peak MW/mo. demand amounts for each month of the Rate Test Period FY 2010-11.

# **Table 2.2 (Sales 03)**

Total IP Load Forecast, FY2010-11.

GWh energy sales and peak MW/mo. demand amounts for each month of the Rate Test Period FY 2010-11.

# **Table 2.2 (Sales 04)**

Total NR Load Forecast. FY2010-11.

GWh energy sales and peak MW/mo. demand amounts for each month of the Rate Test Period FY 2010-11. (Note: No sale under the NR rate schedule is forecast for this test period. In order to calculate a rate in the case where there is no actual load, the token load of 0.0001 aMW was used.)

# **Table 2.3.1 (COSA 06 FY2010)**

Itemized Revenue Requirement, FY2010.

Power Business Line (PBL) revenue requirements for the fiscal year 2010 rate test period.

# Table 2.3.2 (COSA 06 FY2010-11)

Itemized Revenue Requirement, FY2010-11.

Power Business Line (PBL) revenue requirements for the fiscal year 2011 rate test period

# **Table 2.3.3 (COSA 07)**

Functionalization of Residential Exchange Costs, FY2010-11.

REP costs are functionalized to power to comport with other functionalized costs moving through the COSA into the Rate Design Step of the RAM.

# **Table 2.3.4 (COSA 08)**

Classified Revenue Requirement, FY2010-11.

Generation costs are classified between energy, demand, and load variance for display purposes. All generation costs move through the COSA into the Rate Design Step of the RAM. Demand charge and load variance charge revenues are applied to the generation revenue requirement during the calculation of energy charges.

# **Table 2.3.5 (COSA 09)**

Functionalized Revenue Credits, FY2010-11.

Revenue credits are anticipated revenues during the rate test period. In tables that follow, these revenue credits are directly assigned to Federal Base System (FBS) power and have the effect of reducing the cost of FBS resources in the ratemaking process.

# **Table 2.3.6 (COSA 09A)**

Allocation of EE Revenue Credits to Conservation Costs, FY2010-11.

Energy Efficiency revenues are credited against conservation program costs rather than being directly assigned to Federal Base System (FBS) power as are the bulk of BPA's other revenue credits.

# **Table 2.4.1 (ALLOCATE 01)**

Energy Allocation Factors with Residential Exchange Included, FY2010-11.

Values are derived from the rate case load/resource balance and are average megawatt (aMW) at generation level (sales plus transmission losses). These EAFs are used in the resource pool to rate pool allocation determination.

# **Table 2.4.2 (ALLOCATE 02)**

Initial Rate Pool Cost Allocation, FY2010-11.

Table shows the initial allocation of the revenue requirement costs from the COSA to rate pools using the EAFs from table ALLOCATE 01.

# **Table 2.5.1 (RDS 05)**

Average Cost of Nonfirm Energy, FY2010-11.

Table calculates BPA's Average Cost of Nonfirm Energy.

# **Table 2.5.2 (RDS 06)**

Bonneville Average System Cost, FY2010-11.

Table calculates BPA's Average System Cost (BASC).

# Table 2.5.3 (RDS\_11)

Allocation of Secondary Revenues and Other Revenue Credits, FY2010-11.

Tables summarize revenue from secondary power sales and revenues from Other Revenue Credits from Table COSA 09. These revenues are then allocated to rate pools using the EAFs from table ALLOCATE 01. The allocation is based on the service provided by the FBS and NR resources to these rate pools.

# **Table 2.5.4 (RDS 17)**

Calculation of FPS (Surplus)/Shortfall, FY2010-11.

Table calculates the firm surplus sale revenue (surplus)/shortfall. Generation revenue requirement costs allocated to FPS sales in table ALLOCATE 02 are reduced by the excess revenue credit allocated to FPS sales in table RDS\_11. 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 2.5.5 (RDS 19)**

Summary of Initial Cost Allocations, FY2010-11.

Table summarizes the allocations from Tables ALLOCATE 02, RDS 11, and RDS 17, as well as allocates Low Density Discount and Irrigation Rate Mitigation costs to the PF rate pool.

# Table 2.5.6 (RDS 21)

7(C)(2) Delta Calculation and Allocation of 7(C)(2) Delta, FY2010-11.

Table solves a formula for calculating the 7(c)(2) delta appropriate for this point in the model. Table allocates the 7(c)(2) delta to PF and NR rate classes based on allocation factors developed in ALLOCATE 01.

# **Table 2.5.7 (RDS 23)**

Industrial Firm Power Floor Rate Calculation, FY2010-11.

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 2.5.8 (RDS 24)**

Industrial Firm Power Floor Rate Test, FY2010-11.

Table performs the DSI floor rate test and calculates the DSI floor rate adjustment if applicable. IP revenue under proposed rates is compared with revenue under the DSI floor rate. If DSI floor rate revenues are greater, a DSI floor rate adjustment is required. The amount of the DSI floor rate adjustment is then added to the IP allocated costs and subtracted from the other firm power rate pools allocated costs.

# Table 2.5.9 (RDS 30)

Calculation of 7(b)(2) Protection Amount, FY2010-11.

Table calculates the 7(b)(2) PF preference protection amount, based on the "7(b)(2) trigger" calculated in the 7(b)(2) rate test. The protection amount is the 7(b)(2) trigger in mills/kWh times the PF Preference billing determinants.

# **Table 2.5.9A (RDS 31)**

Allocation of 7(b)(2) Protection Amount, FY2010-11.

Table allocates the 7(b)(2) protection amount from RDS\_30 to PF Exchange, IP and NR rate pools. Allocation is based on allocation factors developed in ALLOCATE 01.

# **Table 2.5.10 (RDS 33)**

7(b)(2) Industrial Adjustment 7(c)(2) Delta Calculation, FY2010-11.

Table calculates the 7(b)(2) Industrial Adjustment 7(c)(2) Delta. The 7(b)(2) Industrial Adjustment 7(c)(2) Delta is the difference between the DSI allocated revenue requirement at this point in the modeling and the expected DSI revenues. Expected DSI revenues are; IP revenues at the PF Preference rate; plus revenues at the net industrial margin; plus 7(b)(2) protection amount allocated to the IP class.

# Table 2.6.1 (SLICESEP 01)

Slice PF Product Separation, FY2010-11.

The previous rate design steps have been accomplished using the total firm PF Preference load in the PF Preference load pool. This table recognizes the PF Slice product by removing the firm loads, allocated costs, and secondary revenue credit associated with the PF Slice product from the PF Preference load pool. Here after, the PF Preference rate will be for the non-Slice portion of the PF firm loads.

# **Table 2.6.2 (SLICESEP 02)**

After Slice Separation Step 7(c)(2) Delta Calculation, FY2010-11.

Table calculates the After Slice Separation Step Adjustment\_7(c)(2) Delta. The Slice Separation Step produces a non-Slice PF Preference rate. The After Slice Separation Step Adjustment links the IP rate to this new non-Slice PF Preference rate

# **Table 2.7 (PF 2010-11)**

Calculation of Priority Firm Preference Rate Components, FY2010-11.

Table calculates Priority Firm Preference rates. The WP-07 Supplemental FY 2009 PF Preference rates are scaled to produce rates that recover costs allocated to PF Preference energy. The demand charges are identical for all rate pools.

# Table 2.8 (Unbifurcated PF 2010-11)

Calculation of Unbifurcated Priority Firm Rate Components, FY2010-11.

Table calculates the Unbifurcated Priority Firm rates. Marginal cost rates are scaled to produce rates that recover costs allocated to the Unbifurcated PF energy. The demand charges are identical for all rate pools. A delivery change is added and the delivered Unbifurcated PF is used as the base for the utility specific PF Exchange rates.

# **Table 2.9 (REP 1)**

Calculation of Utility Specific Priority Firm Exchange Rates and Net REP Benefits, FY2010-11. All utilities with ASCs above the delivered unbifurcated Priority Firm rate will receive REP benefits. The table determines which potential exchanging utilities will be expected to participate in the REP and then calculates individual Supplemental 7(b)(3) Charges that, in total, will collect the total 7(b)(3) costs allocated to the PF Exchange rate pool. A utility's specific PF Exchange rate is the delivered unbifurcated PF rate plus their individual Supplemental 7(b)(3) Charge. The PF Exchange rates are then used to determine each exchanging utilities' REP benefits.

# Table 2.9A (Average PFx 2010)

Calculation of Average Priority Firm Exchange Rate Components, FY2010-11.

Table calculates the Average Priority Firm Exchange rate to demonstrate that costs allocated to the PF Exchange rate pool are recovered. Marginal cost rates are scaled to produce rates that recover costs allocated to PF Exchange energy. The demand charges are identical for all rate pools. While the utility specific PF Exchange rates in Table 2.9 above are used to determine REP benefits for each exchanging utility, their loadweighted average equals (with rounding) the Average PF Exchange rate calculated in this table.

# **Table 2.10 (IP 2010)**

Calculation of Industrial Firm Power Rate Components, FY2010-11.

Table calculates Industrial Firm Power rates. Marginal cost rates are scaled to produce rates that recover costs allocated to IP energy. The demand charges are identical for all rate pools.

# **Table 2.11 (NR 2010)**

Calculation of New Resource Rate Components, FY2010-11.

Table calculates New Resource rates. Marginal cost rates are scaled to produce rates that recover costs allocated to NR energy. The demand charges are identical for all rate pools.

# **Table 2.12 (PF 2010 Flat)**

Flat Priority Firm Rate Calculation, FY2010-11.

Table calculates the average annual flat Priority Firm Preference rate. The PF Preference energy and demand rates are applied to a flat load to determine an average annual flat PF Preference rate.

# **Table 2.13.1 (Slice Costing Table)**

Slice Product Pricing, FY2010-11.

Table shows the costs and revenue credits associated with the PF Slice Product and calculates a cost per month per Slice Product percent.

# Table 2.13.2 (Final Proposal With/Without 7b3 Allocation to Secondary)

Proof That Slice Product Costs are Equitable With/Without 7b3 Allocation to Secondary. Table shows the rates and revenues from the Final Proposal and from a scenario of the Final Proposal run with no 7b3 allocation to the secondary revenue credit. The calculations demonstrate that the expected changes to the Slice product costs due to allocating 7b3 costs to secondary are equal to the observed changes in Slice product costs.

# **Table 2.14.1 (RDS 60A)**

Allocated Costs and Unit Costs, Priority Firm Power, FY2010-11.

Table provides a summary of the various COSA cost allocations and Rate Design Adjustments associated with Priority Firm Power. A percent contribution to the final Priority Firm Power rate for each COSA cost allocation and Rate Design Adjustment is calculated.

# **Table 2.14.2 (RDS 60B)**

Allocated Costs and Unit Costs, Priority Firm Preference Power and Priority Firm Exchange Power, FY2010-11.

Table provides a summary of the various COSA cost allocations and Rate Design Adjustments associated with Priority Firm Preference 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 2.14.3 (RDS\_61)

Allocated Costs and Unit Costs, Industrial Firm Power, FY2010-11.

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 2.14.4 (RDS 62)

Allocated Costs and  $\overline{U}$ nit Costs, New Resource Firm Power, FY2010-11.

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 2.14.5 (RDS 63)

Resource Cost Contribution, FY2010-11.

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, FPS.



A	В	С	D	Е	F	G	Н	ī	ı	K	L	M	N	0	P Q	R
1			D	L	- 1	J	-11	Table	2.1	11	- L	111	1,	Ü	-	- 10
2								- 33.0-1							5	Sales 01
3																
4																
5						,		oad Foreca		-11						
6	GWh Energy Sales												Total			
7												Energy	3.4337			
8															<u>GWh</u>	<u>aMW</u>
10			Oct	Nov	<u>Dec</u>	Jan	<u>Feb</u>	Mar	<u>Apr</u>	May	Jun	<u>Jul</u>	Aug	Sep		
11	2010	HLH	2,852	3,105	3,489	3,466	3,089	3,114	2,693	2,918	2,849	2,910	3,026	2,721	61,370	7.006
12		LLH	1,844	2,306	2,503	2,555	2,091	2,050	1,799	2,146	1,852	2,109	1,978	1,906	- 3	,
13		Demand	8,204	9,117	9,680	9,970	9,492	8,646	7,495	7,677	7,252	8,010	7,686	7,359		
14																
15			<u>Oct</u>	Nov	<u>Dec</u>	<u>Jan</u>	<u>Feb</u>	<u>Mar</u>	<u>Apr</u>	May	<u>Jun</u>	<u>Jul</u>	<u>Aug</u>	<u>Sep</u>		
16	2011	HLH	2,837	3,190	3,517	3,496	3,114	3,143	2,648	2,847	2,777	2,934	3,100	2,745	61,447	7,014
17		LLH	1,910	2,274	2,522	2,574	2,106	2,068	1,768	2,091	1,803	2,120	1,941	1,921		
18 19		Demand	8,336	9,246	9,821	10,106	9,631	8,774	7,414	7,536	7,114	8,084	7,800	7,470		
20																
21																
22						]	Non-Slice I	PF Load Fo	recast FY	2010-11						
23								GWh Ener	rgy Sales						Total	
24															Energy	
25															<u>GWh</u>	<u>aMW</u>
26						_								_		
27	2010	111 11	Oct	Nov 2.254	<u>Dec</u>	<u>Jan</u>	<u>Feb</u>	<u>Mar</u>	<u>Apr</u>	May	<u>Jun</u>	<u>Jul</u>	<u>Aug</u>	<u>Sep</u>	47.050	£ 272
28 29	2010	HLH LLH	2,158 1,395	2,354 1,748	2,733 1,960	2,713 2,000	2,461 1,666	2,451 1,614	2,177 1,454	2,068 1,521	2,111	2,195 1,590	2,280 1,490	2,085	47,058	5,3/2
30		Demand	6,208	6,912	7,581	7,806	7,563	6,805	6,058	5,441	1,372 5,373	6,042	5,790	1,461 5,640		
31		Demand	0,200	0,712	7,501	7,000	1,303	0,003	0,050	3,771	5,515	0,042	5,170	2,040		
32			Oct	Nov	Dec	Jan	<u>Feb</u>	Mar	Apr	May	Jun	Jul	Aug	Sep		
33	2011	HLH	2,149	2,421	2,755	2,738	2,482	2,475	2,200	2,090	2,133	2,226	2,340	2,107	47,523	5,425
34		LLH	1,447	1,726	1,976	2,016	1,679	1,628	1,469	1,535	1,385	1,609	1,465	1,475	-	
35		Demand	6,315	7,017	7,694	7,915	7,675	6,909	6,158	5,531	5,464	6,134	5,887	5,735		
36																

A	В	С	D	Е	F	G	Н	I	J	K	L	M	N	0	P Q	R
1	l l	I			<u> </u>	1	<u> </u>	Tabl	e 2.2		<u> </u>					
2																Sales 02
3																
4	Total PF Exchange Load Forecast FY2010-11												Total			
5								GWh	Energy Sa	<u>ales</u>					Energy GWh	oMW
7			Oct	Nov	Dec	Jan	Feb	Mar	Apr	Mav	Jun	Jul	Aug	Sep	GWII	<u>aMW</u>
8	2010	HLH	1,785	2,030	2,615	2,889	2,710	2,533	2,288	1,516	1,262	1,227	1,633	2,006	38,924	4,443
9		LLH	1,080	1,167	1,470	1,896	1,719	1,530	1,308	950	686	692	816	1,115	,	,
10		Demand	5,934	6,279	7,966	9,035	8,729	6,370	6,195	4,249	3,585	4,090	4,833	5,912		
11																
12	2011	111.71	Oct	Nov 2020	<u>Dec</u>	<u>Jan</u>	<u>Feb</u>	<u>Mar</u>	<u>Apr</u>	<u>May</u>	<u>Jun</u>	<u>Jul</u>	<u>Aug</u>	<u>Sep</u>	20.266	4.404
13	2011	HLH LLH	1795 1087	2038 1173	2622 1475	2887 1896	2710 1720	2534 1531	2323 1330	1552 974	1307 713	1274 722	1678 842	2044 1138	39,366	4,494
15		Demand	5959	6301	7982	9027	8728	6373	6289	4344	3708	4235	4961	6017		
16		Demand	5757	0501	7702	7027	0720	0313	0207	1511	3700	1233	1701	0017		
17																Sales 03
18																
19							-			st FY2010-	11				Total	
20								GWh	Energy Sa	<u>ales</u>					Energy GWh	aMW
22			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	GWII	alvi vv
23	2010	HLH	174	154	167	161	154	174	167	161	167	167	167	161	3522	402
24		LLH	125	135	132	138	116	125	122	138	122	132	132	129		
25		Demand	402	402	402	402	402	402	402	402	402	402	402	402		
26			0.4	<b>3</b> .7	D.		Б.1	3.5		3.5	-			C		
27 28	2011	HLH	<u>Oct</u> 167	<u>Nov</u> 161	<u>Dec</u> 167	<u>Jan</u> 161	<u>Feb</u> 154	<u>Mar</u> 174	<u>Apr</u> 167	<u>May</u> 161	<u>Jun</u> 167	<u>Jul</u> 161	<u>Aug</u> 174	<u>Sep</u> 161	3522	402
29	2011	LLH	132	129	132	138	116	174	122	138	122	138	174	129	3322	402
30		Demand	402	402	402	402	402	402	402	402	402	402	402	402		
31	<u> </u>															
32																Sales 04
33								F. 4.1 NID I	1 E	- 4 EV2010	11				TF - 4 - 1	
34							1		oad Foreca Energy Sa	ast FY2010	-11				Total Energy	
36								GWI	Energy S	aics					GWh	aMW
37			<u>Oct</u>	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	<u> </u>	
38	2010	HLH	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.0009	0.0001
39		LLH	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003	0.00003		
40		Demand	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010		
41			Ont	No	Dos	Lor	Feb	Mo	A m	Mari	T	T., I	A~	Ca		
42	2011	HLH	Oct 0.00004	Nov 0.00004	<u>Dec</u> 0.00004	<u>Jan</u> 0.00004	0.00004	<u>Mar</u> 0.00004	<u>Apr</u> 0.00004	<u>May</u> 0.00004	<u>Jun</u> 0.00004	<u>Jul</u> 0.00004	<u>Aug</u> 0.00004	<u>Sep</u> 0.00004	0.0009	0.0001
44	2011	LLH	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.00004	0.0003	0.0001
45		Demand	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010	0.00010		

	A	В	С	D	Е	F	G
1		<b>Table 2.3.1</b>			L	<u>-</u> L	
3					COS	A 06 - FY2010	
3	COST OF	SERVICE AN	ALYSIS				
4	Itemized	Revenue Requ	irement				
5		FY 2010					
6							
7		<u>(\$ 000)</u>					
8							
9		A	В	$\mathbf{C}$	D	$\mathbf{E}$	
10							
11		INVEST	NET	NET	OPER	TOTAL	
12		BASE	<u>INT</u>	REVS	<b>EXP</b>	(B+C+D)	
13	1. GENERATION COSTS						
14							
15	2. FEDERAL BASE SYSTEM						
16	3. HYDRO	0	134,911	43,682	432,374	610,967	
17	4. BPA FISH & WILDLIFE PROGRAM	204,098	17,339	5,614	248,887	271,840	
18	5. TROJAN				2,200	2,200	
19	6. WNP #1				166,431	166,431	
20	7. WNP #2				493,547	493,547	
21	8. WNP #3				144,892	144,892	
22	9. SYSTEM AUGMENTATION				180,762	180,762	
23	10. BALANCING POWER PURCHASES	204.000	152.250	10.206	87,631	87,631	
24	11. TOTAL FEDERAL BASE SYSTEM	204,098	152,250	49,296	1,756,724	1,958,270	
25	12 NEW PEGOLINGEG						
26	12. NEW RESOURCES				4.700	4.700	
27	13. IDAHO FALLS				4,789	4,789	
28	14. COWLITZ FALLS				14,857	14,857	
29	15. OTHER NEW RESOURCES PURCHASES			_	62,781	62,781	
30	16. TOTAL NEW RESOURCES				82,427	82,427	
32	17. RESIDENTIAL EXCHANGE				2,120,999	2,120,999	
33	17. RESIDENTIAL EXCHANGE				2,120,999	2,120,999	
34	18. CONSERVATION		13,318	4,312	169,147	186,777	
35	10. CONSERVATION		13,310	4,312	107,147	100,///	
36	19. OTHER GENERATION COSTS						
	20. BPA PROGRAMS	18,254	1,551	502	138,219	140,272	
	21. WNP #3 PLANT	10,23 т	1,551	302	0	0	
	22. TOTAL OTHER GENERATION COSTS	18,254	1,551	502	138,219	140,272	
40		, 1	1,001	202		, - , 2	
41	23. TOTAL GENERATION COSTS	222,352	167,119	54,110	4,267,516	4,488,745	
42		,		,	,, <del>-</del>	,,	
	24. TRANSMISSION COSTS						
	25. TBL TRANSMISSION/ANCILLARY SERVIC	ES			125,940	125,940	
45					1,000	1,000	
46	27. GENERAL TRANSFER AGREEMENTS				50,690	50,690	
47	28. TOTAL TRANSMISSION COSTS			_	177,630	177,630	
48							
49	29. TOTAL PBL REVENUE REQUIREMENT	_	167,119	54,110	4,445,147	4,666,376	
50	30. BPA TRANSMISSION REVENUE REQUIREMENT		130,625	77,936	602,570	811,131	
51	(Net of Line 25)						

	A	В	С	D	Е	F	G
1		<b>Table 2.3.2</b>			I		
3					COS	A 06 - FY2011	
3		SERVICE AN					
4	Itemized	Revenue Requ	irement				
5		FY 2011					
6							
7		<u>(\$ 000)</u>					
8						-	
9		A	В	C	D	E	
10		DIVERGE	NUMBER	NIDE	OPED	TOTAL	
11		INVEST	NET	NET	OPER	TOTAL	
12	1. GENERATION COSTS	<b>BASE</b>	<u>INT</u>	<u>REVS</u>	<b>EXP</b>	(B+C+D)	
14	1. GENERATION COSTS						
15	2. FEDERAL BASE SYSTEM						
16	3. HYDRO	0	138,674	37,213	447,358	623,245	
17	4. BPA FISH & WILDLIFE PROGRAM	243,903	21,174	5,682	272,719	299,575	
18	5. TROJAN	2-13,703	21,1/7	3,002	2,300	2,300	
19	6. WNP #1				167,977	167,977	
20	7. WNP #2				551,051	551,051	
21	8. WNP #3				169,093	169,093	
22	9. SYSTEM AUGMENTATION				273,041	273,041	
	10. BALANCING POWER PURCHASES				72,108	72,108	
24	11. TOTAL FEDERAL BASE SYSTEM	243,903	159,848	42,895	1,955,647	2,158,390	
25							
26	12. NEW RESOURCES						
_	13. IDAHO FALLS				4,789	4,789	
	14. COWLITZ FALLS				14,802	14,802	
29	15. OTHER NEW RESOURCES PURCHASES			_	62,105	62,105	
30	16. TOTAL NEW RESOURCES				81,696	81,696	
31							
32	17. RESIDENTIAL EXCHANGE				2,225,993	2,225,993	
33	10 CONCEDIVATION		12.274	2.204	176 606	102.264	
34	18. CONSERVATION		12,274	3,294	176,696	192,264	
	19. OTHER GENERATION COSTS						
	20. BPA PROGRAMS	13,577	1,179	316	138,617	140,112	
	21. WNP #3 PLANT	13,377	1,1/9	310	138,017	140,112	
	22. TOTAL OTHER GENERATION COSTS	13,577	1,179	316	138,617	140,112	
40	22. TOTAL OTHER GENERATION COORS	13,377	1,17	310	150,017	170,112	
.0	23. TOTAL GENERATION COSTS	257,480	173,301	46,505	4,578,649	4,798,455	
42			, 1	. 0,2 02	-,- , 0,0 .7	-,.,,,,,	
	24. TRANSMISSION COSTS						
44		ES			124,189	124,189	
45		AS .			1,000	1,000	
46	27. GENERAL TRANSFER AGREEMENTS				51,340	51,340	
47	28. TOTAL TRANSMISSION COSTS			_	176,529	176,529	
48		_					
-	29. TOTAL PBL REVENUE REQUIREMENT		173,301	46,505	4,755,178	4,974,984	
	30. BPA TRANSMISSION REVENUE REQUIREMENT		145,757	73,507	644,203	863,467	
51	(Net of Line 25)						

	A		В	C D		Е	F	G	Н	I	J	K
1				Γable 2.3.3	<u> </u>		17.1			- 1-1		
2												COSA 07
3	Functionalization of Residential Exchange Cost	s:										
4					(\$	Thousand	s)					
5												
	Gross Residential Exchange Cost				\$	4,346,992						
7	Residential Exchange Transmission				\$	333,515	_					
8	Functionalized Residential Exchange Costs				\$	4,013,477						
9												
10												
11 12												
13			-	Гable 2.3.4								
14				1 abic 2.3.4								COSA 09
15			COST OF	SERVICE A	NAI	veie						COSA 08
16				Revenue Rec								
17		T	est Period Oct		•		1					
18		- '	est i criou oct	0001 2007 15	cpt	cmbci 201	•					
19				<u>(\$ 000)</u>								
20			Total									
21			Revenue	E	nerg	<u> </u>		Dem	and		Load '	Variance
22		Requ	<u>iirement</u>	Percent		<u>Total</u>		Percent	Total		Percent	<u>Total</u>
23												
24	1. GENERATION COSTS											
25	2. FEDERAL BASE SYSTEM											
26	3. HYDRO	\$	1,234,212	85.66%		1,057,231			\$ 165,13		0.96%	\$ 11,843
27	4. BPA FISH & WILDLIFE PROGRAM	\$	571,415	86.62%	\$	494,959		13.38%	-			
28	5. TROJAN	\$	4,500	86.62%	\$	3,898		13.38%		02		
29 30	6. WNP #1 7. WNP #2	\$ \$	334,408	86.62%	\$ \$	289,664			\$ 44,74 \$ 139,70		0.060	6 \$ 10,023
31	8. WNP #3	Φ Φ	1,044,598 313,985	85.66% 86.62%	\$	894,807 271,974			\$ 139,70		0.907	0 \$ 10,023
32	9. SYSTEM AUGMENTATION	\$	453,803	85.66%	\$	388,729			\$ 60,7		0.96%	6 \$ 4,354
33	10. BALANCING POWER PURCHASES	\$	159,738	85.66%	\$	136,833			\$ 21,37			6 \$ 1,533
34	11. TOTAL FEDERAL BASE SYSTEM	\$	4,116,660	02.0070		3,538,095		13.3070	\$ 550,8		0.507	\$ 27,753
35		*	.,,		-	-,,			4,-			4 = - ,
36	12. NEW RESOURCES											
37	13. IDAHO FALLS	\$	9,578						\$ 1,28	82		\$ 92
38	14. COWLITZ FALLS	\$	29,659	85.66%	\$	25,406		13.38%	\$ 3,90	68	0.96%	\$ 285
39	15. OTHER NEW RESOURCES PURCHASES	\$	124,886	85.66%	\$	106,978	_	13.38%	\$ 16,7		0.96%	
40	16. TOTAL NEW RESOURCES	\$	164,123		\$	132,384			\$ 21,90	60		\$ 1,575
41	17 DEGIDENTIAL ENGLANCE	Ф	4.012.455	100.0007	Φ.	4.012.455						
42	17. RESIDENTIAL EXCHANGE	\$	4,013,477	100.00%	\$	4,013,477						
43	18. CONSERVATION	\$	379,041	86.62%	¢	220 225		12 200/	\$ 50,7	16		
45	10. CONSERVATION	Ф	319,041	00.0270	\$	328,325		13.36%	φ 3U,/.	10		
46	19. OTHER GENERATION COSTS											
47		\$	280,385	85.66%	\$	240.179		13.38%	\$ 37,5	16	0.96%	s 2,690
_	21. WNP #3 PLANT	\$		22.0070	4	= .0,.77		50/0	¢.		3.237	,070
	22. TOTAL OTHER GENERATION COSTS	\$	280,385		\$	240,179		•	\$ 37,5	16		\$ 2,690
50			·				_					
	23. TOTAL GENERATION COSTS	\$	8,953,685		\$	8,260,664	_	•	\$ 661,00	03		\$ 32,018
52												
	24. TRANSMISSION COSTS:											
	25. TBL TRANSMISSION/ANCILLARY SERV		250,130	100.00%	\$	250,130						
_	26. 3RD PARTY TRANS/ANCILLARY SERVI		2,000	100.00%	\$	2,000						
	27. GENERAL TRANSFER AGREEMENTS	\$	102,030	100.00%	\$	102,030						
_	28. TOTAL TRANSMISSION COSTS		354,160			354,16	U					
58	29. TOTAL PBL REVENUE REQUIREMENT	\$	9,307,845		•	8,614,823	_	•	\$ 693,02	21		
39	23. TOTAL FOL KE VENUE REQUIREMENT	Ф	7,307,843		Þ	0,014,023			\$ 093,02	<b>4</b> 1		

	A		В		С		D	Е
1		Tak	ole 2.3.5				•	
2							C	OSA 09
3	COST O	F SEI	RVICE ANA	LYS	SIS			
4	Functio	nalize	d Revenue C	red	its			
5	Test Period O	ctobe	r 2009 - Sept	eml	per 2011			
6			-					
7								
8			FY 2010		<b>FY 2011</b>		<u>Total</u>	
9								
10		<u>(</u>	<u>\$ 000)</u>					
11								
12	Downstream Benefits & Storage	\$	8,921	\$	8,921	\$	17,842	
13	4(h)(10)(c) Credit	\$	96,689	\$	101,969	\$	198,658	
14	Colville & Spokane Settlements	\$	4,600	\$	4,600	\$	9,200	
15	Network Wind Integration&Shaping	\$	1,953	\$	1,953	\$	3,906	
16	Misc. Revenues	\$	3,420	\$	3,420	\$	6,840	
17	Green Tags	\$	5,040	\$	5,040	\$	10,081	
18	Ancillary Product Revenue	\$	90,176	\$	102,730	\$	192,906	
19	Totals	\$	210,800	\$	228,633	\$	439,432	
20								
21								
22								
23		Tab	ole 2.3.6					
24							COS	SA 09A
25			RVICE ANA					
26	Allocation of EE Re					S		
27	Test Period O	ctobe	r 2009 - Sept	eml	per 2011			
28								
29			EX 2010		EX 2011		T. 4 . 1	
30			FY 2010		<b>FY 2011</b>		<u>Total</u>	
31		4	e 000)					
32		<u>C</u>	<u>\$ 000)</u>					
33 34	Conservation Evnence Defers EE Deverses	¢	196 777	¢	102 264	\$	270 041	
35	Conservation Expense Before EE Revenues Energy Efficiency Revenues	\$ \$	186,777 (20,500)	\$ \$	192,264 (20,500)		379,041 (41,000)	
36	Net Conservation Expense	\$	166,277	\$	171,764	\$	338,041	
37	ret Conservation Expense	Φ	100,477	Φ	1/1,/04	ψ	330,041	
38 39								

Table 2.4.1		A	В	С	D	Е	F G
ALLOCATE 0	1				•		
Second Priority Firm.   Seco						ALI	LOCATE 01
Section   Property Firm   Priority Firm   Pr							
Fy 2010	4	Energy Allocat	tion Fa	ctors with Reside	ential Exchang	e Included	
Total Usage   Priority Firm	5			Average Megawa	atts		
Notal Usage							
9   Total Usage   11,772   11,833   23,605   11   Industrial Firm				<b>FY 2010</b>	<b>FY 2011</b>	<b>Total</b>	
10							
11   Industrial Firm		0		11.750	11.022	22 625	
12   New Resource Firm					•		
13   Surplus Firm Other							
14   Total				ŭ	-	ū	
15   16   Federal Base System   17   Priority Firm		1					-
16   Federal Base System   17   Priority Firm		1 0ta1		12,001	12,912	23,193	
17         Priority Firm.         8,205         8,181         16,387           18         Industrial Firm.         0         0         0           19         New Resource Firm.         0         0         0           20         Surplus Firm Other.         0         0         0           21         Total.         8,205         8,181         16,387           22         Residential Exchange         Total.         8,205         8,181         16,387           22         Residential Exchange         Total.         7,218         16,387           25         Industrial Firm.         3,567         3,652         7,218           26         New Resource Firm.         0         0         0           27         Surplus Firm Other.         629         598         1,227           Total.         4,569         4,621         9,189           29         30         New Resource         New Resource Firm.         0         0         0           31         Priority Firm.         0         0         0         0         0           32         Industrial Firm.         40         41         82         135         135         135<		Federal Rase System					
Industrial Firm				8 205	8 181	16 387	
19		•		_	-		
20         Surplus Firm Other.         0         0         0           21         Total					-	•	
Total				0	0	0	
Residential Exchange		•		8,205	8,181	16,387	<u>-</u>
24       Priority Firm       3,567       3,652       7,218         25       Industrial Firm       373       371       745         26       New Resource Firm       0       0       0         27       Surplus Firm Other       629       598       1,227         28       Total       4,569       4,621       9,189         29       New Resource       9,189         30       New Resource       0       0       0         31       Industrial Firm       40       41       82         33       New Resource Firm       0       0       0         34       Surplus Firm Other       68       67       135         35       Total       108       108       216         36       7       11,833       23,605         39       Industrial Firm       413       413       827         40       New Resource Firm       0       0       0         0       0       0       0	22			•	-	•	
24       Priority Firm       3,567       3,652       7,218         25       Industrial Firm       373       371       745         26       New Resource Firm       0       0       0         27       Surplus Firm Other       629       598       1,227         28       Total       4,569       4,621       9,189         29       New Resource       9,189         30       New Resource       0       0       0         31       Industrial Firm       40       41       82         33       New Resource Firm       0       0       0         34       Surplus Firm Other       68       67       135         35       Total       108       108       216         36       7       11,833       23,605         39       Industrial Firm       413       413       827         40       New Resource Firm       0       0       0         0       0       0       0	23	Residential Exchange					
26       New Resource Firm.       0       0       0         27       Surplus Firm Other.       629       598       1,227         28       Total.       4,569       4,621       9,189         29       30       New Resource         31       Priority Firm.       0       0       0         32       Industrial Firm.       40       41       82         33       New Resource Firm.       0       0       0         34       Surplus Firm Other.       68       67       135         35       Total.       108       108       216         36       7       Conservation       11,772       11,833       23,605         39       Industrial Firm.       413       413       827         40       New Resource Firm.       0       0       0	24	Priority Firm		3,567	3,652	7,218	
Z7       Surplus Firm Other       629       598       1,227         Z8       Total       4,569       4,621       9,189         30       New Resource       8         31       Priority Firm       0       0       0         32       Industrial Firm       40       41       82         33       New Resource Firm       0       0       0         34       Surplus Firm Other       68       67       135         35       Total       108       108       216         36       7       Conservation       11,772       11,833       23,605         39       Industrial Firm       413       413       827         40       New Resource Firm       0       0       0				373	371	745	
Total				ŭ	_	_	
New Resource   Priority Firm		•					<u>=</u>
New Resource           31         Priority Firm.         0         0         0           32         Industrial Firm.         40         41         82           33         New Resource Firm.         0         0         0           34         Surplus Firm Other.         68         67         135           35         Total.         108         108         216           36         37         Conservation         11,772         11,833         23,605           39         Industrial Firm.         413         413         827           40         New Resource Firm.         0         0         0	-	Total		4,569	4,621	9,189	
31       Priority Firm.       0       0       0         32       Industrial Firm.       40       41       82         33       New Resource Firm.       0       0       0         34       Surplus Firm Other.       68       67       135         35       Total.       108       108       216         36       37       Conservation       11,772       11,833       23,605         39       Industrial Firm.       413       413       827         40       New Resource Firm.       0       0       0							
32       Industrial Firm				^	^	^	
33       New Resource Firm.       0       0       0         34       Surplus Firm Other.       68       67       135         35       Total.       108       108       216         36       37       Conservation       11,772       11,833       23,605         39       Industrial Firm.       413       413       827         40       New Resource Firm.       0       0       0				· ·		_	
34       Surplus Firm Other							
35       Total				•	•		
36       37       Conservation         38       Priority Firm		_					=
37         Conservation           38         Priority Firm		1 Utal		108	108	216	
38       Priority Firm.       11,772       11,833       23,605         39       Industrial Firm.       413       413       827         40       New Resource Firm.       0       0       0		Conservation					
39 Industrial Firm				11 772	11 833	23 605	
40 New Resource Firm		•		•		,	
, , , , , , , , , , , , , , , , , , ,				-	-		
42 Total		-					<u>-</u>

	A	В		С		D		Е	F
1		2		<b>Table 2.4.2</b>	2		<u> </u>	<u> </u>	
2				1 11.510 21 11.2					
3								ALLC	OCATE 02
4								71220	, C.111E 02
5		Init	ial I	Rate Pool Cost	<b>A</b> 1	locations			
6				(\$ 000)		iocutions			
7				<u> 10007</u>					
8				FY 2010		FY 2011		<b>Total</b>	
9				112010		112011		10111	
-	CLASSES OF SERVICE:								
11									
12	<b>Priority Firm - Preference</b>								
13	FBS		\$	1,958,270	\$	2,158,390	\$	4,116,660	
14	NR		\$	-	\$	-	\$	-	
15	Exchange		\$	1,526,348	\$	1,626,646	\$	3,152,994	
16	Conservation 1/		\$ \$	151,956	\$	157,410	\$	309,366	
17	BPA programs			290,523	\$	290,181	\$	580,704	-
18	Total		\$	3,927,096	\$	4,232,627	\$	8,159,723	
19									
	Industrial Firm Power								
21	FBS		\$	-	\$	-	\$	-	
22	NR		\$	30,709	\$	31,296	\$	62,005	
23	Exchange		\$	159,768	\$	165,355	\$	325,123	
24	Conservation 1/		\$	5,335	\$	5,499	\$	10,834	
25	BPA programs		\$	10,201	\$	10,136	\$	20,337	
26	Total		\$	206,013	\$	212,286	\$	418,299	
27	N D E								
	New Resources Firm		¢.		¢.		¢.		
29	FBS		\$	-	\$	-	\$	-	
30	NR Evaluação		\$	0.0	\$	0.0	\$	0.0	
31	Exchange Conservation 1/		\$ \$	0.0 0.0	\$ \$	0.0 0.0	\$ \$	0.1 0.0	
33	BPA programs		Φ.				_		
34	Total		<u>\$</u>	0.0 <b>0.1</b>	<u>\$</u>	0.0 <b>0.1</b>	\$ <b>\$</b>	0.0 <b>0.1</b>	_
35	Total		Ф	0.1	Φ	<b>U.1</b>	ψ	<b>U.1</b>	
$\overline{}$	Surplus Firm Power								
37	FBS		\$	_	\$	-	\$	_	
38	NR		\$	51,718	\$	50,400	\$	102,118	
39	Exchange		\$	269,066	\$	266,294	\$	535,360	
40	Conservation 1/		\$	8,985	\$	8,855	\$	17,841	
41	BPA programs		\$	17,179	\$	16,324	\$	33,503	
42	Total		\$	346,948	\$	341,874	\$	688,822	
43	= 2		•		-	,	-	7~	
44	Grand	Total	\$	4,480,058	\$	4,786,787	\$	9,266,845	
45				, ,		•		,	
	1/ Note: Conservation expense	from CC	)SA	06 Tables reduced	d by	EE Revenues in T	able	COSA 09A.	
46									

	A	В	С		D	Е
1	Table 2.5			1		
2	Table 200	·• =				RDS 05
3	RATE DESIGN	STUE	Υ			110000
4	Average Cost of Non			Į.		
5	Test Period October 2009				l	
6	. 223 = 323 2 2 2 2 2 2 2 2 2 2 2 2 2 2 2	I	~			
7	Generation Costs:				<u>(\$ 000)</u>	
8	Federal Base System			\$	4,116,660	
9	New Resources			\$	164,123	
10	Exchange			\$	4,013,477	
11	Conservation and EE			\$	379,041	
12	BPA Programs			\$	280,385	
13	<b>Total Generation Costs</b>			\$	8,953,685	-
14	Transmission Costs For Firm Power			\$	990,747	
15	Transmission Costs For Nonfirm Pwr			\$	250,130	_
	<b>Total Costs</b>			\$	10,194,562	
17						
	Firm Power Sales:				(GWh)	
19	Priority Firm				201,106	
20	Industrial Power/Variable Industrial				7,043	
21	New Resources				0.002	
22	Other Obligations	~ .			22,445	
23	FPS Pre-Sub., Slice Block, Rate Mitigation Contrac	t Sale	S		3,313	_
24	Total Firm				233,908	
25	Projected Trading Flr Sales				39,006	-
26 27	Total Sales				272,914	
	Average Cost of Nonfirm (mills/kwh)				37.35	1
29	Average Cost of Nonthill (Illins/kwil)				31.33	J
30						
31	Table 2.5	3				
32	Table 2.3	). <i>L</i>				RDS 06
33	RATE DESIGN	STIIT	v			KDS 00
34	Bonneville Average Syste			(SC)		
35	Test Period October 2009				İ	
36	Lest Lettor Getorel 2007	≂cρι			-	
	Revenue Requirement:			(S	S Thousands)	
38	Cost of Service Analysis			\$	11,315,957	
39	Applicable Revenue Credits			\$	(283,621)	
	Total			\$	11,032,336	-
41					, ,	
42	Sales:				(GWh)	
43	Firm Power				233,908	
44	Nonfirm Energy				39,006	=
	Total				272,914	
46						,
47	Bonneville Average System Cost (mills/kwh):				40.42	]
48						

	В		С		D		E F	G
1	_	Ţ	Table 2.5.3					
2		-						RDS 11
3	Ī	Rate	e Design Study					1.0011
4	Allocation of Seco			eve	nue Credits			
5			ber 2009 - Septe					
6								
7								
8								
9			<u>(\$ 000)</u>					
10								
11			FY 2010		FY 2011		<u>Total</u>	
12								
13	· ·	\$	703,912		767,646	\$	1,471,558	
14	7b3 Costs Allocated to Secondary Revenues	\$	(186,366)		(187,178)		(373,543)	
15	Secondary Revenues After 7b3 Allocation	\$	517,547	\$	580,468	\$	1,098,015	
16								
17								
18								
19	Allocation of Secondary Revenues Credit	Ф	(517.547)	Ф	(500.460)	Ф	(1,000,015)	
20	Priority Firm	\$	(517,547)		(580,468)		(1,098,015)	
21	Industrial Firm	\$	-	\$	-	\$ \$	-	
22	New Resource Firm	\$	-	\$	-	<b>\$</b>	-	
23	Surplus Firm Other	\$ <b>\$</b>	(517,547)	\$ \$	(580,468)	<u>\$</u>	(1,098,015)	
25	10(a1	Þ	(317,347)	Ф	(380,408)	Þ	(1,070,013)	
26								
27								
28								
29								
30								
31			FY 2010		FY 2011		Total	
32								
33	Total Other Revenue Credits	\$	210,800	\$	228,633	\$	439,432	
34					,		•	
35								
36								
37	Allocation of Other Revenue Credits							
38	Priority Firm	\$	(210,800)	\$	(228,633)	\$	(439,432)	
39	Industrial Firm	\$	-	\$	-	\$	-	
40	New Resource Firm	\$	-	\$	-	\$	-	
41	Surplus Firm Other	\$	-	\$	-	\$		
42	Total	\$	(210,800)	\$	(228,633)	\$	(439,432)	
43								
44								

	В		С		D		Е	F G
1		Гab	le 2.5.4					
2 3 4 5	Rate Calculation of Test Period Octo	FP	` • /					RDS 17
6								
7								
8								
9		<u>(\$</u>	<u> (000)</u>					
10			EV 2040		EV 0044		T-4-1	
	FPS (Surplus)/Shortfall		FY 2010		FY 2011		<u>Total</u>	
12	Costs allocated to FPS contract sales	¢.	246 049	¢.	241 074	<b>o</b>	600 022	
	Expected Revenue from FPS contract sales	\$ \$	346,948 (96,778)	\$ ©	341,874 (88,437)	\$ \$	688,822 (185,216)	
	FPS Pre-Sub Contract Revenue	\$	(37,228)		(34,456)		(71,684)	
16	(Surplus)/Shortfall		212,942	\$	218,981	\$	431,923	
17	(Surprus)/Silortian	Ф	212,742	Φ	210,701	Ф	431,723	
18								
19								
	Secondary Revenues allocated to FPS	\$	_	\$	_	\$	_	
	Revenue Credits allocated to FPS	\$	_	\$	_	\$	_	
22		-		*		*		
	FPS (Surplus)/Shortfall	\$	212,942	\$	218,981	\$	431,923	
24			,		,		,	
25								
26								
27								
28								
29								
30	Rate	De	esign Study					
31	Allocation of I		_	hor	tfall			
32	Test Period Octo	ber	2009 - Septe	mb	er 2011			
33								
34								
35		<u>(\$</u>	<u> (000 )</u>					
36								
	Allocation of FPS (Surplus)/Shortfall		FY 2010		FY 2011		<u>Total</u>	
38								
	Priority Firm	\$	211,902		217,878		429,780	
	Industrial Firm		1,040	\$	1,103		2,143	
	New Resource Firm		0	\$	0	\$	0	
-	Surplus Firm Other		(212,942)		(218,981)		(431,923)	
43	Total	\$	-	\$	-	\$	-	
44								
45								

	В	С	D			Е		F		G	Н
1	·			Ta	ble 2	2.5.5				•	
2											RDS 19
3			1	Rate 1	Desig	n Study					
4		Sur	nmary	of Ir	iitial	Cost Allocatio	ns				
5		Test Pe	eriod C	Octob	er 20	09 - Septembe	r 20	11			
6											
7					<b>(\$ 00</b>	<u>0)</u>					
8											
9						FY 2010		FY 2011		<u>Total</u>	
10											
	Allocation of Revenue Requirement				_				_		
	Priority Firm				\$	3,927,096		4,232,627		8,159,723	
	Industrial Firm				\$	206,013	\$	212,286	\$	418,299	
-	New Resource Firm				\$	0.0512	\$	0.0528	\$	0.1041	
-	Surplus Firm Other			-	\$	346,948	\$	341,874	\$	688,822	
-	Total				\$	4,480,058	\$	4,786,787	\$	9,266,845	
17	AH # 66 1 B C W										
	Allocation of Secondary Revenues Credit				Ф	(517.545)	d.	(500.460)	Ф	(1,000,015)	
	Priority Firm				\$	(517,547)		(580,468)		(1,098,015)	
	Industrial Firm.				\$	-	\$	-	\$	-	
	New Resource Firm				\$	-	\$	-	\$	-	
	Surplus Firm Other			-	\$ \$	(517,547)	\$	(580,468)	<b>\$</b>	(1,000,015)	
23	Total				Þ	(517,547)	Þ	(580,408)	Þ	(1,098,015)	
	Allocation of other Revenues Credits										
	Priority Firm				\$	(210,800)	¢	(228,633)	¢	(439,432)	
	Industrial Firm				\$	(210,800)	Φ Φ	(228,033)	Φ Φ	(439,432)	
	New Resource Firm				\$	-	\$ \$	-	\$	-	
	Surplus Firm Other				\$	_	\$	_	\$	_	
	Total			-	\$	(210,800)	\$	(228,633)	\$	(439,432)	
31	1000				Ψ	(210,000)	Ψ	(220,000)	Ψ	(10),102)	
	Allocation of FPS (Surplus)/Shortfall										
	Priority Firm				\$	211,902	\$	217,878	\$	429,780	
	Industrial Firm				\$	1,040	\$	1,103	\$	2,143	
	New Resource Firm				\$	0.00	\$	0.00	\$	0.00	
	Surplus Firm Other				\$	(212,942)	-	(218,981)		(431,923)	
	Total			-	\$	-	\$	-	\$	-	
38											
39	Low Density Discount Expenses										
	Priority Firm				\$	26,419	\$	26,465	\$	52,884	
41											
	Irrigation Rate Mitigation										
43	Priority Firm				\$	12,036	\$	12,036	\$	24,072	
44		•									
	Initial Allocation to Rate Pools										
	Priority Firm				\$	3,449,107	\$	3,679,905	\$	7,129,012	
	Industrial Firm				\$	207,053	\$	213,389	\$	420,442	
	New Resource Firm.				\$	0.0515	\$	0.0531	\$	0.1046	
	Surplus Firm Other			_	\$	134,007	\$	122,893	\$	256,899	
50	Total				\$	3,790,167	\$	4,016,187	\$	7,806,354	

	A	В	С	D		Е		F	G H
1				<b>Table 2.5.6</b>					
2									RDS 2
3			F	Rate Design Study	y				
4			7(c)	(2) Delta Calcula	tio	n			
5		Test Pe	eriod O	october 2009 - Sej	pte	mber 2011			
6									
7				FY 2010		FY 2011		<u>Total</u>	
8							_		
9	1	IP Allocated Costs	\$	207,053	\$		\$	420,442	
10	2	IP Revenues @ Net Margin	\$	(578)		` /	\$	(1,155)	
11	3	adjustment	\$	(1,047)		(945)		(1,992)	
12		IP Marginal Cost Rate Revenues	\$		\$		\$	303,162	
13	5	PF Allegated Frances Costs	\$	4,458,119			\$	8,942,361	
14		PF Allocated Energy Costs	\$	3,449,107			\$	7,129,012	
15	7	Numerator: 1-2-3-((4/5)*6)	\$	91,404	\$	90,519	\$	181,924	
16 17	8	PF Allocation Factor for Delta		12 140		12 211		24.450	
18		NR Allocation Factor for Delta		12,148 0.0001		12,311 0.0001		24,459 0.0002	
19		Total Allocation Factors for Delta		12,148					
20				12,148		12,311 1.034		24,459 1.034	
21	13	Denominator: $1.0 + ((9/11)*(4/5))$		1.034		1.034		1.034	
22		DELTA: (Numerator / Denominator)	\$	88,399	\$	87,560	\$	175,958	
23	17	DELTA. (Numerator / Denominator)	Ф	00,377	Φ	07,500	Ф	173,730	
24									
25									
26									
27			F	Rate Design Study	v				
28				)(2) Delta allocat	-				
29		Test Pe		october 2009 - Sej					
30				•	•				
31				FY 2010		FY 2011		<u>Total</u>	
32									
33		IP-PF Link Allocations:							$\neg$
34		Priority Firm	\$	88,399	\$	87,560		175,958	
35		Industrial Firm		(88,399)	\$	(87,560)		(175,958)	
36		New Resource Firm	\$	0.0008	\$	0.0008	\$	0.0015	
37		Surplus Firm Other		-	\$	-		-	_
38		Total	\$	(0.000)	\$	(0.000)		(0.000)	
39									
40									
41		Allocation to Rate Pools after Link							
42		Priority Firm Preference		2,164,595	\$		\$	4,460,922	
	i	Priority Firm Exchange	\$	1,372,911	\$		\$	2,844,048	
43		ž –				125 920	\$	244404	1
44		Industrial Firm		118,655	\$			244,484	
44 45		Industrial Firm New Resource Firm	\$	0.0523	\$	0.0538	\$	0.1061	
44 45 46		Industrial Firm New Resource Firm Surplus Firm Other	\$ \$	0.0523 134,007	\$ \$	0.0538 122,893	\$ \$	0.1061 256,899	
44 45		Industrial Firm New Resource Firm	\$	0.0523	\$	0.0538 122,893	\$	0.1061	

	A	В	C D	Е	F	G	Н	I
1			Table 2.	5.7				
2								RDS 23
3			RATE DESIGN	N STUDY				
4		Industrial	Firm Power Flo	or Rate Cal	culation			
5		Test Peri	od October 200	9 - Septembe	r 2011			
6			(\$ Thousa	nds)				
7								
8			A	В	C	D	$\mathbf{E}$	F
9			DEM	AND	ENIE	D.C.V	<b>a</b> ,	7D ( 1)
10 11			DEM		ENE		Channe	Total/
12			Winter (Dec-Apr)	Summer (May Nay)	Winter (Sep-Mar)	Summer (Apr. Aug.)	<u>Charge</u>	<u>Average</u>
13			(Dec-Api)	(May-Nov)	(Sep-Iviai)	(Apr-Aug)		
14	1	IP Billing Determinants <sup>1</sup>	4,020	5,628	4,091	2,952	9,648	7,043
15	2	IP-83 Rates	4,020	2.21	14.70	12.20		7,043
16	3	Revenue	18,572	12,438	60,134	36,018		197,979
17	4	Exchange Adj Clause for OY 1985	10,572	12,.50	00,15	20,010	, 0,010	17,7,77
18		New ASC Effective Jul 1, 1984						
19		Actual Total Exchange Cost (AEC)	938,442					
20	7	Actual Exchange Revenue (AER)	772,029					
21		Forecasted Exchange Cost (FEC)	1,088,690					
22		Forecasted Exchange Revenue (FER)	809,201					
23		Total Under/Over-recovery (TAR)						
24		(TAR=(AEC-AER)-(FEC-FER))	(113,076)					
25		Exchange Cost Percentage for IP (ECP)	0.521					
26		Rebate or Surcharge for IP (CCEA=TAR*ECP)	(58,913)					
27		OY 1985 IP Billing Determinants <sup>2</sup>	24,368					
28		OY 1985 DSI Transmission Costs <sup>3</sup>	92,960					
29	16	Adjustment for Transmission Costs <sup>4</sup>	(3.81)					
30	17	Adjustment for the Exchange (mills/kWh) <sup>5</sup>	(2.42)					
31	18	Adjustment for the Deferral (mills/kWh) <sup>6</sup>	(0.90)					
32	19	IP-83 Average Rate (mills/kWh) <sup>7</sup>	28.11					
33		Floor Rate (mills/kWh) <sup>8</sup>	20.98					
34	-	X ,						
35		Note 1 - Demand billing determinants are the test pe	eriod DSI load ex	pressed in no	ncoincidental	demand MW	/s.	
36		Note 2 - Billing determinants as forecast in the 1983						
37		Note 3 - Transmission Costs as forecast in the 1983 I	Rate Case Final l	Proposal (WP	-83-FS-BPA-	07, p. 80).		
38		Note 4 - Line 15 / Line 14						
39		Note 5 - Rebate or Surcharge for IP divided by OY 1	_	eterminants				
40		Note 6 - 1985 Final Rate Proposal (WP-85-FS-BPA-						
41		Note 7 - Total Revenue Col F, divided by IP Billing			16 . 15	10 - 10		
42		Note 8 - IP-83 Avg Rate adjusted for the effects of the	ne Exchange and	Deterral, Lin	es $16 + 17 + 1$	18 + 19		

	A B	С	D	Е	F	G	Н
1			<b>Table 2.5.8</b>	3	Į.		
2							RDS 24
3		RA	ATE DESIGN S	TUDY			
4		Industrial	Firm Power Fl	loor Rate Test			
5		Test Period	October 2009 -	September 2011			
6			(\$ Thousands	-			
7				,			
8							
9		A	В	C	D	E	$\mathbf{F}$
10							
11		Unbundled		Total			
12		Requirements	Total	Generation	Total		Average
13		<b>Products</b>	<b>Transmission</b>	<b>Demand</b>	<b>Energy</b>	<b>TOTALS</b>	Rate
14							
15							
16	1 IP Billing Determinants				7,043		
17	2 Floor Rate (mills/kWh)				20.98		
18	3 Value of Reserves Credit (mills/kWh)						
19	4 Revenue at Floor Rate Less VOR Credit			4= 0= 0	147,778	147,778	20.98
20	5 IP Revenue Under Proposed Rates	0	0	17,929	225,790	243,719	34.60
21	6 Difference <sup>1</sup>					0	
22							
23	Note 1 - Difference is Line 4 - Line 5.	If difference is i	negative, Floor R	Rate does not trig	ger and differen	nce is set to zero.	
24							

	В С	D		Е		F		G H
1	1-1	Table 2.	5.9					_
2								RDS 30
3		Rate Design	Stud	v				
4	Calculation	_		tion Amount				
5	Test Period	October 2009	9 - Se	ptember 2011				
6				-				
7								
8	Section	17(b)(2) Rate	Test	Trigger		8.17		
9				•				
10				FY 2010		FY 2011		<u>Total</u>
11								
	Total PF Preference Load (GWH)			61370		61447		122816
13								
_	PF Preference Protection Amount		\$	501,392	\$	502,018	\$	1,003,410
15								
16								
17 18								
19		Table 2.5	. 0. 4					
20		Table 2.5	.9A					DDC 21
21		Data Dasign	Stud	l=7				RDS 31
22	Calculation of 7	Rate Design		•	ition			
23				eptember 2011				
24	rest remou	October 200.	- 50	ptember 2011				
25				FY 2010		FY 2011		Total
26					•			
27	7b2 Protection Allocation							
28	Priority Firm Preference		\$	(501,392)	\$	(502,018)	\$	(1,003,410)
29	Priority Firm Exchange		\$	288,890	\$	288,989	\$	577,879
	Industrial Firm		\$	26,136	\$	25,852	\$	51,988
	New Resource Firm		\$	0.0065	\$	0.0064	\$	0.0129
	Surplus Firm Other		\$	-	\$	-	\$	-
	Reduction in Secondary Revenue Credit 1/		\$	186,366	\$	187,178	\$	373,543
34	Total		\$	-	\$	-	\$	-
35								
36	Allocation to Rate Pools after 7b2							
			\$	1,663,202	\$	1,794,309	\$	3,457,511
	Priority Firm Preference Priority Firm Exchange		\$ \$	1,661,801	\$ \$	1,760,126	\$ \$	3,421,927
	Industrial Firm		\$	1,001,801	\$	151,682	\$	296,472
	New Resource Firm		\$	0.0588	\$	0.0603	\$	0.1191
	Surplus Firm Other		\$	134,007	\$	122,893	\$	256,899
43	Total		\$	3,603,801	\$	3,829,009	\$	7,432,810
44			~	-,,	~	-,,	~	.,,
45	1/ See Table 2.5.3							
46								

	В	D	Е	F	G HII.
_	В			F	G H I .
1		Table 2	.5.10		DDC 22
2		D . D .	6. 1		RDS 33
3	T(1)(2): 1	Rate Desig	•		
4			7(c)(2) Delta Calcu		
5	Test Perio	a October 20	09 - September 201	ı	
7			FY 2010	FY 2011	Total
8			1 1 2010	112011	<u>rotar</u>
9	1 IP Allocated Costs after 7c2 adjustment	\$	118,655	125,830	\$ 244,484
10	2 IP share of 7b2 adjustment	\$	26,136	,	\$ 51,988
11	3 Total IP revenue requirement	\$	144.791 \$		\$ 296,472
12	4	-	,	- ,	
13	5 IP revenues at PF preference rate	\$	91,272 \$	98,267	\$ 189,539
14	6 IP Revenues @ Net Margin	\$	(578) \$	(578)	\$ (1,155)
15	7 IP share of 7b2 adjustment	\$	26,136 \$	25,852	\$ 51,988
16	8 Total IP revenue requirement	\$	116,830 \$	123,541	\$ 240,372
17					
18	DELTA: (3 - 8)	\$	27,961 \$	28,140	\$ 56,101
19					
20					
21					
22			FY 2010	FY 2011	<u>Total</u>
23	ID DELL A AB C				
24	IP-PF Linc 2 Allocation	¢	¢	,	
26	Priority Firm Preference	\$ \$	27,961 \$	28,140	\$ 56,101
27	Priority Firm ExchangeIndustrial Firm	\$ \$	(27,961) \$	,	
28	New Resource Firm.	\$ \$	0.0006	. , ,	\$ (30,101)
29	Surplus Firm Other	\$	0.0000 1	0.0000	\$ 0.0013
30	Total	\$	(0) \$	5 (0)	*
31	10001	Ψ	(0) 4	, (0)	Ψ (0)
32	Allocation to Rate Pools after IP-PF Linc 2				
33	Priority Firm Preference	\$	1,663,202 \$	1,794,309	\$ 3,457,511
34	Priority Firm Exchange	\$	1,689,762	, ,	\$ 3,478,028
35	Industrial Firm	\$	116,830 \$		\$ 240,372
36	New Resource Firm	\$	0.0594	0.0609	\$ 0.1203
37	Surplus Firm Other	\$	134,007 \$	122,893	\$ 256,899
38	Total	\$	3,603,801	3,829,009	\$ 7,432,810

E	С	D		Е		F		G	Н	I	ŢJ
1	<u> </u>	ble 2.6.1	1		_	-		Ü		<u> </u>	
2	1 a	2.U.					SLI	CESEP 01			
3	Rata I	Design St	ndv				JLIV	CLULI UI			
4	Slice PF Pr	_		ntion							
5	Test Period Octobe										
6	rest retion Octobe		~~P								
7				FY 2010		FY 2011		<u>Total</u>			
8								<u> </u>			
9	Slice Revenue requirement		\$	566,071	\$	605,258	\$	1,171,329			
10	Slice Revenue Credits		\$	(50,756)	\$	(54,791)	\$	(105,546)			
11	Net Slice PF Product Revenue Requirement		\$	515,316	\$	550,467	\$	1,065,783			
12											
13	Slice Implementation Expenses		\$	2,830	\$	2,830	\$	5,660			
14											
15	Amount to Allocate		\$	515,316	\$	550,467	\$	1,065,783			
16											
17											
18											
19	All de COP D								_		
20	Allocation of Slice Revenues										
21	Drianity Cima Drofanana		¢.	(515.210)	¢	(550.467)	e	(1.065.792)			
23	Priority Firm Preference		\$ \$	(515,316)	\$	(550,467)	\$	(1,065,783)			
24	Priority Firm Exchange Industrial Firm		\$	-	\$	-	\$	-			
25	New Resource Firm.		\$	_	\$	-	\$	-			
26	Surplus Firm Other		\$	-	\$	-	\$	-			
27	Total		-\$	(515,316)	4"	(550,467)		(1,065,783)			
28			4	(515,510)	4	(550, .07)	Ψ.	(1,000,700)			
29									_		
30											
31											
32											
33	Slice Secondary Revenue Credit Adjustment		\$	159,280	\$	173,701	\$	332,981			
34											
35	Priority Firm Preference		\$	159,280	\$	173,701		332,981			
36	Priority Firm Exchange		\$	-	\$	-	\$	-			
37	Industrial Firm		\$	-	\$	-	\$	-			
38	New Resource Firm.		\$	-	\$	-	\$	-			
39	Surplus Firm Other		\$	150 200	\$	172 701	\$	222.001			
40	Total		\$	159,280	\$	173,701	\$	332,981			
41											
42 54											
55				FY 2010		FY 2011		Total	7		
56	Allocation to Rate Pools after Slice Separation Step			1 1 2010		. I <u>2VII</u>		IOIAI			
57	Priority Firm Preference		\$	1,307,167	¢	1,417,543	\$	2,724,709			
58	Priority Firm Exchange		\$	1,689,762		1,788,266		3,478,028			
59	Industrial Firm.		\$	116,830		123,541		240,372			
60	New Resource Firm		\$	0.0594		0.0609		0.1203			
61	Surplus Firm Other		\$	134,007	\$	122,893		256,899			
62	Total		\$	3,247,765	\$	3,452,243	\$	6,700,009			
63			-	-,,	-	-,,0	•	-,,/			
64									_		

	A	В	С	D		Е		F	G	Н	I
1				Table	2.6	.2					
2									SLIC	CESEP 02	
3				Rate Design	Stu	ıdy					
4		After	Slice	Separation 7(c)			on				
5				od October 2009							
6						•					
7				FY 2010		FY 2011		<u>Total</u>			
8											
9	1	IP Allocated Costs	\$	207,053	\$	213,389	\$	420,442			
10	2	IP Revenues @ Net Margin	\$	25,552	\$	29,369	\$	54,922			
11	3	adjustment	\$	25,216	\$	16,217	\$	41,433			
12	4	IP Marginal Cost Rate Revenues	\$	151,581	\$	151,581	\$	303,162			
13		PF Marginal Cost Rate Revenues	\$	1,252,800	\$	1,266,362	\$	2,519,162			
14		PF Allocated Energy Costs	\$	1,307,167	\$	1,417,543	\$	2,724,709			
15		Numerator: 1-2-3-((4/5)*6)		(1,873)		(1,875)		(3,810)	)		
16	8			, ,		,		/			
17	9	PF Allocation Factor for Delta		5,523		5,578		11,101			
18	10	NR Allocation Factor for Delta		0.0001		0.0001		0.0002			
19	11	Total Allocation Factors for Delta		5,523		5,578		11,101			
20	12	Denominator: $1.0 + ((9/11)*(4/5))$		1.1210		1.1197		1.1203			
21	13										
22	14	DELTA: (Numerator / Denominator)		(1,671)		(1,674)		(3,346)	)		
23											
24											
25				Rate Design	Stu	ıdy					
26		After	Slice	Separation 7(c	)(2)	Delta allocatio	n				
27		Test	Peri	od October 2009	9 - 8	September 201	1				
28											
29				FY 2010		FY 2011		<u>Total</u>			
30											
31		IP-PF Link 3 Allocations:									
32		Priority Firm	\$	(1,671)	\$	(1,674)	\$	(3,346)	)		
33		Industrial Firm	\$	1,671	\$	1,674	\$	3,346			
34		New Resource Firm	\$	-	\$	-	\$	-			
35		Surplus Firm Other	\$	-	\$	-	\$	-	_		
36		Total	\$	-	\$	-	\$	-			
37											
38											
39		Allocation to Rate Pools after Link 3									
40		Priority Firm Preference	\$	1,305,495		1,415,868	\$	2,721,364			
41		Priority Firm Exchange	\$	1,689,762		1,788,266	\$	3,478,028			
42		Industrial Firm	\$	118,502		125,216	\$	243,717			
43		New Resource Firm	\$	0.0594	\$	0.0609	\$	0.1203			
44		Surplus Firm Other	\$	134,007	\$	122,893	\$	256,899	_		
45		Total	\$	3,247,765	\$	3,452,243	\$	6,700,009			
46											

A	В	С	D	Е	F	G	Н	I	J	K	L	M	N	O P	Q	R
1							T	able 2.7								
2							D 4	<b>D</b> • G( )							P	F 2010-11
3						~ 1 . 1		Design Study	D							
5					•			rm Preferenc		onents						
5						I est I	eriod Octob	er 2009 - Sep	tember 2011							
7	PF PREFERENCE RATE	SHAPE														
8	TT TREFERENCE RATE	Oct	Nov	Dec	<u>Jan</u>	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep			
9	Energy Mills/kwh	<u> </u>	1101	<u> 200</u>	<u>oun</u>	100	<u>iviui</u>	<u> 1461</u>	<u> </u>	<u>oun</u>	<u></u>	rug	<u>00p</u>			
9	HLH	29.21	31.15	32.51	27.60	28.19	26.15	24.54	20.50	18.55	22.85	26.76	27.62			
11	LLH	21.40	22.72	23.85	19.96	20.16	19.17	17.64	14.17	9.85	16.73	19.85	22.17			
12	MONTHLY DEMAND	1.91	2.04	2.14	1.82	1.85	1.72	1.62	1.34	1.23	1.50	1.76	1.82			
13	_														-	
14													LV Rate	0.46		
15	PF billing determinants (G	,											_			
16		Oct	<u>Nov</u>	<u>Dec</u>	<u>Jan</u>	<u>Feb</u>	<u>Mar</u>	<u>Apr</u>	<u>May</u>	<u>Jun</u>	<u>Jul</u>	<u>Aug</u>	<u>Sep</u>	Total Energy		
17	HLH	4,307	4,775	5,488	5,452	4,943	4,926	4,377	4,158	4,244	4,421	4,619	4,193	94582	31527	3599
18 19	LLH Demand	2,843 12,523	3,474 13,929	3,936 15,274	4,016 15,721	3,345 15,239	3,242 13,714	2,923	3,055 10,973	2,757	3,199	2,955	2,935			
20	Demand	12,323	13,929	13,274	13,721	13,239	13,/14	12,216	10,973	10,836	12,176	11,677	11,375 Determinant	69605257		
21												L v Dilling	Determinant	09003237		
22	Revenue At Marginal Rates													Maginal	Allocated	Rate
22		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Revenues	Costs	Factor
24 25	HLH		\$ 148,755	\$ 178,409			\$ 128,826				\$ 101,020	\$ 123,611		\$ 2,226,016	\$ 2,393,789	107.53%
25	LLH	\$ 60,830	\$ 78,929	\$ 93,870	\$ 80,157	\$ 67,427	\$ 62,143	\$ 51,560	\$ 43,296	\$ 27,153	\$ 53,520	\$ 58,663	\$ 65,076			
26	Demand	\$ 23,919	\$ 28,415	\$ 32,687	\$ 28,612	\$ 28,192	\$ 23,588	\$ 19,791	\$ 14,703	\$ 13,329	\$ 18,264				\$ 293,145	107.53%
27													LV Revenue		\$ 34,429	107.53%
28														\$ 2,530,788	\$ 2,721,364	107.53%
29														_		
30	PF rates	Oot	Nov	Doo	lan	Eab	Mor	Ann	Mov	lun	11	Aua	Son			
32	HLH	Oct 31.41	Nov 33.50	<u>Dec</u> 34.96	<u>Jan</u> 29.68	<u>Feb</u> 30.31	<u>Mar</u> 28.12	<u>Apr</u> 26.39	<u>May</u> 22.04	<u>Jun</u> 19.95	<u>Jul</u> 24.57	Aug 28.78	Sep 29.70			
33	LLH	23.01	24.43		21.46	21.68			15.24	10.59						
34	Demand	2.05			1.96	1.99			1.44	1.32						
35												LV Rate	0.490			
36																
37	Revenues at Proposed Rate	s														
38 39		<u>Oct</u>	Nov	<u>Dec</u>	<u>Jan</u>	<u>Feb</u>	<u>Mar</u>	<u>Apr</u>	<u>May</u>	<u>Jun</u>	<u>Jul</u>	<u>Aug</u>	<u>Sep</u>	<u>Totals</u>		
39	HLH		\$ 159,978	. ,							\$ 108,624	\$ 132,942	\$ 124,523	\$ 2,393,689		
40	LLH			\$ 100,955				\$ 55,447		\$ 29,193	\$ 57,551	\$ 63,067	\$ 69,978			
41	Demand	\$ 25,672	\$ 30,504	\$ 35,131	\$ 30,813	\$ 30,325	\$ 25,371	\$ 21,257	\$ 15,801	\$ 14,304	\$ 19,603	\$ 22,070	\$ 22,295	\$ 293,145		
42													LV Revenue	\$ 34,107	-	
44														\$ 2,720,941		
45		Non-Slice PF Av	erage Rate													
46	1	on once if Av	cruge mate													
47	Energy Costs	\$ 2,393,789		25.31												
48	Demand Costs			3.10												
49	Unbundled Cost	\$ 34,429	_	0.36												
50	Total	\$ 2,721,364		28.77												
51																
52	Billing Determinants	94582														
53																

I	АВ	C	D	Е	F	G	Н	I	J	K	L	M	N	O P	Q	R
1							Tabl	e 2.8								
2															Base PF	x 2010-11
3					,			ign Study	D . C							
5					(	Calculation of U	nbiturcated P			onents						
6						1est re	riou October 2	2009 - Septen	iber 2011							
7	LEVELIZED SHAPE OF POWER															
8		Oct	Nov	Dec	<u>Jan</u>	Feb	<u>Mar</u>	<u>Apr</u>	May	<u>Jun</u>	<u>Jul</u>	Aug	Sep			
9	Energy Mills/kwh	· <u></u>	·								_			_		
10	HLH	40.32	42.10	44.52	48.58	47.65	45.40	40.71	40.03	39.39	42.11	47.13	46.09			
11	LLH	34.12	37.37	39.33	40.73	40.08	37.99	34.05	28.16	29.42	36.21	39.66	40.76			
12	MONTHLY DEMAND	2.05	2.19	2.30	1.96	1.99	1.85	1.74	1.44	1.32	1.61	1.89	1.96			
13	Unbifurcated PF billing deteri	ninants (CWI	Ie)													
15	Chonui Cateu i i bining deteri	Oct	Nov	Dec	<u>Jan</u>	Feb	Mar	<u>Apr</u>	May	Jun	Jul	Aug	Sep	Total Energy		
16	HLH	9,268	10,365	12,243	12,738	11,623	11,325	9,952	8,834	8,195	8,345	9,437	9,516			
17	LLH	5,921	6,921	7,970	8,920	7,637	7,179	6,205	6,161	5,054	5,643	5,578	6,079			
18	Demand	28,434	30,943	35,448	38,138	36,580	30,163	27,393	23,806	21,658	24,419	25,280	26,758	3		
19																_
20	Revenue At Marginal Rates	0-4	Na	Dan	la	Fab.	Man	A	Mari	l	11	A	C	Maginal	Allocated	Rate
21	Energy \$	Oct	Nov \$ 694,999 \$	Dec 858,590 S	<u>Jan</u> § 982,083 5	Feb 859,890 \$	Mar 786 020	<u>Apr</u>	May \$ 527 122	<u>Jun</u> \$ 471,513	<u>Jul</u> \$ 555.721	<u>Aug</u>	Sep \$ 686.361	Revenues \$ 8,281,358	Costs \$ 6,643,967	Factor 80.23%
23	Energy 5	3/3,/1/	\$ 09 <del>4</del> ,999 \$	858,590	902,003	p 659,690 q	780,920	\$ 010,437	\$ 321,133	\$ 4/1,515	\$ 555,721	\$ 005,995	\$ 000,501	\$ 0,201,330	\$ 0,043,907	80.2370
24	Demand \$	58,289	\$ 67,766 \$	81,530	3 74,750	\$ 72,794 \$	55,801	\$ 47,664	\$ 34,281	\$ 28,589	\$ 39,315	\$ 47,778	\$ 52,446	\$ 661,003	\$ 661,003	100.00%
25																
26												Trans	mission Costs	S	\$ - \$ 7,304,970	
27	T. 1.0													\$ 8,942,361	\$ 7,304,970	
28	Unbifurcated PF	Oct	Nov	Doo	Jan	Feb	Mar	Anr	May	Jun	Jul	Aug	Sep			
30	Energy	30.41	32.26	Dec 34.08	36.38	35.82	34.12	<u>Apr</u> 30.61	28.20		31.87	Aug 35.59		1		
31												-				
32	Demand	2.05	2.19	2.30	1.96	1.99	1.85	1.74	1.44	1.32	1.61	1.89	1.9	6		
33																
34																
35	Revenues at Proposed Rates	0-4	Na	Dan	la	Fab.	Man	A	Mari	l	11	A	C	Tatala		
36	Energy \$	Oct 461 886	Nov \$ 557,584 \$	Dec 688,830 S	<b>Jan</b> § 787,905 5	<u>Feb</u> § 689,873 §	Mar 631 330	<u>Apr</u>	May \$ 422,000	<u>Jun</u> \$ 378,286	<u>Jul</u> \$ 445.844	<u>Aug</u>	Sep \$ 550.65/	Totals \$ 6,643,967		
38	Energy 5	401,000	ф 557,564 ф	000,050	767,705	002,075	, 051,550 .	p +7-1,555	J 422,707	\$ 376,260	\$ 445,644	\$ 554,515	\$ 550,05-	\$ 0,043,707		
20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40 41	Demand \$	58,289	\$ 67,766 \$	81,530	74,750	\$ 72,794 \$	55,801	\$ 47,664	\$ 34,281	\$ 28,589	\$ 39,315	\$ 47,778	\$ 52,446	\$ 661,003		
40												Trans	mission Cost	s \$ -		
41				•										\$ 7,304,970		
42 43 44					_											
43	Unbif	urcated PF Ra	ite			*1	nbifurcated P	E	26.22							
44	Energy Costs \$	6,643,967		33.04		U		ssion Costs	36.32 4.26							
46	Demand Costs \$			33.04		D	ransmi elivered Unbif		4.20							
47	Unbundled Cost \$			0.00		D		1 1	10.50							
47 48	Transmission Costs \$			0.00	<u> </u>					ı						
49 50 51 52	Total \$	7,304,970		36.32												
50																
51	Billing Determinants \$	201,106														
	1															

	В	1	С		D	Е		F	G		Н	Ĭ	I		K		L		M
2	В				В	L	1	1	Table 2.9	1	11			-				i .	141
3									Tubic 2.5										
4								Rate	Design Study										
5					Ca	lculation of U	tilit	ty Specific Priori		nge R	ates and Ne	t REP Benef	fits						REP 1
6								Test Period Octo											
7									•										
8																			
9			A		В	C		D	E		F	G	Н		I		J		K
10																			
11																			
12			Utility										Load Weighte	1		Load	Weighted		
13 14		Load	l Weighted			Rate Period		Preliminary	Rate Period	7b	3 and 7c2		Average				Average		Utility
14			Average		Delivered	Exchange		Benefits at	Percent of		llocation	Exchange	Rate Period		Delivered		ity Specific		Specific
15		Ra	ate Period	U	nbifurcated	Load		Unbifurcated	Preliminary		ng Percent	Load	Supplemental		nbifurcated	PF	Exchange		Exchange
16			ASCs		PF Rate	GWH		PF Rate	Benefits	of	Benefits	GWH	7b3 Charge		PF Rate		Rate		Benefits
17								(A - B) * C					F/G				H + I	( <i>P</i>	A - J) * C
18			45.40	Φ.	40.50	0000	•	54.500	4.50/	•	20.600	0000			40.50		44.20		25.024
	Avista	\$	47.40		40.58	8020	\$	54,700	4.7%	\$	29,688	8020	\$ 3.70			\$	44.28	\$	25,024
	Idaho Power	\$	35.65	\$	40.58	0	\$	21 100	0.0%	\$	- 11 401	0	\$ -	\$	40.58	\$	40.58	\$	- 0.720
	Northwestern Energy PNWR	\$ \$	57.57	\$	40.58	1248 19170	•	21,198	1.8%	\$	11,481	1248 19170	\$ 9.20		40.58	\$	49.78	\$	9,720
	Pacificorp Portland General	9	56.54 56.89	\$ \$	40.58 40.58	17588	\$	305,949 286,854	26.2% 24.6%	\$ \$	165,741 156,109	17588	\$ 8.65 \$ 8.88		40.58 40.58	\$	49.23 49.46	\$ \$	140,131 130,676
		\$ \$	59.32	\$	40.58	23972	Φ	449,234	38.5%	\$	244,907	23972	\$ 10.22		40.58	\$	50.80	\$	204,241
25	Puget Sound Energy Franklin	\$ \$	49.28	\$	40.58	714	\$	6,216	0.5%	\$ \$	3,367	714	\$ 10.22		40.58	¢ ¢	45.29	\$	2,851
	Snohomish	\$	46.12	\$	40.58	7578	\$	41,982	3.6%	\$	22,687	7578	\$ 2.99		40.58	\$	43.29		19,324
27	SHOHOHHISH	ψ	70.12	ψ	40.36	7376	Ф	41,962	5.070	Ψ	22,007	1310	φ 2.95	Ф	40.36	Ψ	73.37	Ψ	17,324
28																			
28 29	Total/Average	a					\$	1,166,133	100%	\$	633,980					\$	48.68	\$	531,966
30	10ttil Average	-					Ψ	1,100,133	10070	Ψ	055,700					Ψ	70.00	Ψ	331,700
31		Note	· Values in	this	table are load	weighted valu	ies f	for the rate period.	The individua	LFY ?	2010 and FY	2011 utility	specific PF Excl	าลทฐค	rates are fo	und ir	the rate so	hedu	les

A	. В	C	D	E	F	G	Н	I	J	K	L	M	N	O P	Q	R
1							Table	2.9A								
3							Rate Desi	on Study							Average Pl	Fx 2010-11
4					Calcı	lation of Avera			e Rate Com	ponents						
5							od October 2			•						
6																
8	LEVELIZED SHAPE OF POWER	Ont	Nov	Doo	lon	Eab	Mor	A	May	lum	ll	A	Con			
9	Energy Mills/kwh	<u>Oct</u>	<u>Nov</u>	<u>Dec</u>	<u>Jan</u>	<u>Feb</u>	<u>Mar</u>	<u>Apr</u>	<u>May</u>	<u>Jun</u>	<u>Jul</u>	<u>Aug</u>	<u>Sep</u>			
10	HLH	40.32	42.10	44.52	48.58	47.65	45.40	40.71	40.03	39.39	42.11	47.13	46.09			
11	LLH	34.12	37.37	39.33	40.73	40.08	37.99	34.05	28.16	29.42	36.21	39.66	40.76			
12	MONTHLY DEMAND	2.05	2.19	2.30	1.96	1.99	1.85	1.74	1.44	1.32	1.61	1.89	1.96			
14	PFx billing determinants (GWH	Is)														
15	11 x suming determinants (G v 1	Oct	Nov	Dec	<u>Jan</u>	<u>Feb</u>	Mar	Apr	May	<u>Jun</u>	<u>Jul</u>	Aug	Sep	Total Ener	gy	
16	HLH	3,580	4,069	5,237	5,776	5,420	5,067	4,611	3,068	2,569	2,501	3,311	4,050		0	
17	LLH	2,167	2,341	2,945	3,792	3,439	3,061	2,638	1,925	1,399	1,414	1,658	2,252			
18 19	Demand	11,893	12,580	15,948	18,062	17,456	12,743	12,484	8,593	7,293	8,325	9,794	11,929	,		
20	Revenue At Marginal Rates													Maginal	Allocated	Rate
21	g	<u>Oct</u>	Nov	<u>Dec</u>	<u>Jan</u>	<u>Feb</u>	<u>Mar</u>	<u>Apr</u>	<u>May</u>	<u>Jun</u>	<u>Jul</u>	<u>Aug</u>	<u>Sep</u>	Revenues		Factor
22	Energy \$	218,275	\$ 258,782 \$	349,019 \$	435,019 \$	396,115 \$	346,363 \$	277,517	\$ 177,020	\$ 142,356 \$	156,510	\$ 221,837	\$ 278,465	\$ 3,257,27	7 \$ 3,196,685	98.14%
24	Demand \$	24,381	\$ 27,551 \$	36,680 \$	35,402 \$	34,738 \$	23,575 \$	21,722	\$ 12,373	\$ 9,627 \$	13,403	\$ 18,510	\$ 23,38	\$ 281.34	3 \$ 281,343	100.00%
25	Demand \$	24,501	p 27,331 p	50,000 \$	33,402 \$	J-1,750 \$	25,575 \$	21,722	12,575	\$ 7,027 \$	13,403	\$ 10,510	\$ 25,56	\$ 201,54	J # 201,545	100.0070
26												Trans	mission Cost		5 \$ 333,515	100.00%
27														\$ 3,872,13	5 \$ 3,811,543	
28	PF exchange rates	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep			
20 21 22 23 24 25 26 27 28 29 30 31	Energy	37.27	39.62	41.86	44.62	43.88	41.82	37.57	34.80	35.21	39.24	43.81		6		
31																
32	Demand	2.05	2.19	2.30	1.96	1.99	1.85	1.74	1.44	1.32	1.61	1.89	1.9	6		
32 33 34 35 36 37 38														_		
35	Revenues at Proposed Rates															
36		Oct	Nov	<u>Dec</u>	<u>Jan</u>	Feb	Mar	<u>Apr</u>	May	<u>Jun</u>	<u>Jul</u>	Aug	Sep	Totals	_	
37	Energy \$	214,215	\$ 253,968 \$	342,527 \$	426,927 \$	388,746 \$	339,920 \$	272,355	\$ 173,727	\$ 139,708 \$	153,598	\$ 217,711	\$ 273,285	\$ 3,196,68	5	
39	Demand \$	24.381	\$ 27,551 \$	36,680 \$	35,402 \$	34,738 \$	23.575 \$	21,722	\$ 12,373	\$ 9.627 \$	13,403	\$ 18,510	\$ 23,38	\$ 281,34	3	
39 40		- ', '	,	,	, +	- 1,1-0	,	,	,	,	,		mission Cost			
41														\$ 3,811,54	3	
42	DE Euch	4	D.4.													
42 43 44	rr Excna	nge Average l	rate													
45 46	Energy Costs \$	3,196,685		40.83												
46	Demand Costs \$	281,343		3.59												
47	Unbundled Cost \$	- 222 515		0.00												
48	Transmission Costs \$	333,515 3,811,543	_	4.26 48.68												
47 48 49 50 51	Total 5	ر <del>د</del> ر,11,0,0		70.00												
51	Billing Determinants	78,290														
51	Diffing Determinants	70,270		J												

1	В		C	D	Е	F	G	Н	I	J	K	L	M	N	O P	Q	R
1								Tabl	e 2.10								
2								D / D	. 6. 1								IP 2010-11
3						(	Calculation of		sign Study irm Power I	Pata Campan	onte						
5						`		iod October		•	ents						
6							1036161	iou october	2005 Septe	mber 2011							
7	LEVELIZED SHAPE OF	POWER															
8			<u>Oct</u>	<u>Nov</u>	<u>Dec</u>	<u>Jan</u>	<u>Feb</u>	<u>Mar</u>	<u>Apr</u>	<u>May</u>	<u>Jun</u>	<u>Jul</u>	<u>Aug</u>	<u>Sep</u>			
9	Energy Mills/kwh														7		
10		HLH	40.32	42.10	44.52	48.58	47.65	45.40	40.71	40.03	39.39	42.11	47.13	46.09	-		
12	MONTHLY DEMAND	LLH	34.12 2.05	37.37 2.19	39.33 2.30	40.73 1.96	40.08 1.99	37.99 1.85	34.05 1.74	28.16 1.44	29.42 1.32	36.21 1.61	39.66 1.89	40.76 1.96	-		
13	MONTHLI DEMAND		2.03	2.19	2.30	1.90	1.55	1.00	1.74	1.44	1.32	1.01	1.09	1.90	_		
14	IP billing determinan	ts (GWHs)															
15	0		<u>Oct</u>	Nov	Dec	<u>Jan</u>	<u>Feb</u>	<u>Mar</u>	<u>Apr</u>	<u>May</u>	<u>Jun</u>	<u>Jul</u>	<u>Aug</u>	Sep	Total Energy		
16		HLH	340.90	315.17	334.46	321.60	308.74	347.33	334.46	321.60	334.46	328.03	340.90	321.60	,		
17		LLH	257.28	264.52	263.71	276.58	231.55	250.04	244.42	276.58	244.42	270.14	257.28	257.28			
18		Demand	804.00	804.00	804.00	804.00	804.00	804.00	804.00	804.00	804.00	804.00	804.00	804.00			
19 20	Revenue At Marginal	Dates													Maginal	Allocated	Rate
21	Revenue At Margina	Rates	Oct	Nov	Dec	<u>Jan</u>	<u>Feb</u>	Mar	Apr	<u>May</u>	Jun	<u>Jul</u>	Aug	Sep	Revenues	Costs	Factor
22		HLH \$	13,744												\$ 285,233		
23		LLH \$	8,778	\$ 9,885	\$ 10,372	\$ 11,264	\$ 9,281	9,500	\$ 8,323	\$ 7,788	\$ 7,191	\$ 9,782	\$ 10,204	\$ 10,486	ŕ	ŕ	
24		Demand \$	1,648	\$ 1,761	\$ 1,849	\$ 1,576	\$ 1,600	\$ 1,487	\$ 1,399	\$ 1,158	\$ 1,061	\$ 1,294	\$ 1,520	\$ 1,576			
22 23 24 25 26															\$ 303,162	\$ 243,717	'
26															<del></del>		
27 28	IP rates		Oct	Nov	Dec	<u>Jan</u>	<u>Feb</u>	<u>Mar</u>	<u>Apr</u>	May	<u>Jun</u>	<u>Jul</u>	Aug	Sep			
29	11 Tates	HLH	31.92	33.33	35.24	38.46	37.72	35.94	32.23			33.33	37.31		,		
30		LLH	27.01	29.58	31.13	32.24	31.73	30.08	26.95			28.66	31.40				
31		Demand	2.05	2.19	2.30	1.96	1.99	1.85	1.74			1.61	1.89				
32																	
33																	
34	Revenues at Proposed	l Rates	Oot	May	Doo	lan	Fah	Mor	A	May	lum	ll	A	Con	Totala		
35 36		HLH \$	Oct 10,881	Nov \$ 10,505	<u>Dec</u> \$ 11,787	<b>Jan</b> \$ 12,369	Feb \$ 11,646	Mar 12,483	<b>Apr</b> \$ 10,780	May \$ 10,192	<u>Jun</u> \$ 10,429	<b>Jul</b> \$ 10,933	Aug \$ 12.710	Sep \$ 11,735	Totals \$ 225,790		
37		LLH \$				\$ 8,917				\$ 6,165			\$ 8,079	\$ 8,300			
38		Demand \$	1,648			\$ 1,576											
39															\$ 243,719	•	
40	_																
41																	
42		IP Ave	rage Rate														
44	E	nergy Costs \$	225 788 0		32.06												
45		mand Costs \$			2.55												
46		ndled Costs \$			0.00												
47			243,717.2		34.60												
48																	
49	Non-Slice Billing De	eterminants \$	7,043.0														
50																	

	.	1									1	T T			-1	_	1
	A B	C		D	Е	F	G	Н	I	J	K	L	M	N	O P	Q	R
1								Tabl	e 2.11								
2																N	R 2010-11
3									ign Study								
4								on of New Re		•	ts						
5							Test Pe	riod October	2009 - Sept	ember 2011							
6	LEVELIZED SHAPE OF POWER	₹															
7																	
8		<u>Oct</u>		<u>Nov</u>	<u>Dec</u>	<u>Jan</u>	<u>Feb</u>	<u>Mar</u>	<u>Apr</u>	<u>May</u>	<u>Jun</u>	<u>Jul</u>	<u>Aug</u>	<u>Sep</u>			
9	Energy Mills/kwh								-								
10	HLH	40.32		42.10	44.52	48.58	47.65	45.40	40.71	40.03	39.39	42.11	47.13	46.09			
11	LLH	34.12		37.37	39.33	40.73	40.08	37.99	34.05	28.16	29.42	36.21	39.66	40.76			
12	MONTHLY DEMAND	2.05		2.19	2.30	1.96	1.99	1.85	1.74	1.44	1.32	1.61	1.89	1.96			
13																	
14	NR billing determinants (GV	,			_				_				_	_	- · · · -		
15		Oct		Nov	<u>Dec</u>	<u>Jan</u>	<u>Feb</u>	<u>Mar</u>	<u>Apr</u>	<u>May</u>	<u>Jun</u>	<u>Jul</u>	<u>Aug</u>	<u>Sep</u>	Total Energy		
16		LH 0.000		80000.0	0.00008	0.00008	0.00008	0.00009	0.00008	0.00008	0.00008	0.00008	0.00008	0.00008	0.002		
17		LH 0.000		0.00007	0.00007	0.00007	0.00006	0.00006	0.00006	0.00007	0.00006	0.00007	0.00006	0.00006			
18	Dem	and 0.000	20 (	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020	0.00020			
19	B 4/35 1 1B /																ъ.
20	Revenue At Marginal Rates				_				_				_	_	Maginal	Allocated	Rate
21		Oct		Nov	<u>Dec</u>	<u>Jan</u>	Feb	Mar	Apr	May	<u>Jun</u>	<u>Jul</u>	Aug	Sep	Revenues	Costs	Factor
22		LH \$ 0.0		0.003				\$ 0.004		\$ 0.003	\$ 0.003			\$ 0.004	\$ 0.071	\$ 0.116	163.27%
23		LH \$ 0.0		0.002				\$ 0.002		\$ 0.002	\$ 0.002			\$ 0.003		n 0.004	100.000/
24	Dem	<b>and</b> \$ 0.0	00 \$	0.000	\$ 0.000	\$ 0.000	\$ 0.000	\$ 0.000	0.000	\$ 0.000	\$ 0.000	\$ 0.000	\$ 0.000	\$ 0.000	\$ 0.004 \$ 0.075	\$ 0.004	100.00%
25															\$ 0.075	\$ 0.120	
26															_		
27	ND (	0-4		N	D		F. I.		A					0			
28	NR rates	Oct		Nov (0.74	<u>Dec</u>	<u>Jan</u>	Feb	<u>Mar</u>	Apr	May (5.26	<u>Jun</u>	<u>Jul</u>	Aug 76.05	<u>Sep</u>			
29			5.83	68.74	72.70	79.32	77.80	74.13	66.47	65.36			76.95	75.26			
30			5.71	61.02	64.22	66.49	65.44	62.03	55.60	45.98		59.12	64.76	66.54			
31	Dem	and 2	2.05	2.19	2.30	1.96	1.99	1.85	1.74	1.44	1.32	1.61	1.89	1.96			
32																	
33	D (D 1D)																
34	Revenues at Proposed Rates	Oct		Mari	Daa	lan	Fab	Mon	A	May	lum	11	A	Com	Totala		
36	***	Oct		Nov 0.005	<u>Dec</u>	<u>Jan</u>	<u>Feb</u>	Mar \$ 0.006	<u>Apr</u>	May	<u>Jun</u>	<u>Jul</u> \$ 0.006	<u>Aug</u>	<b>Sep</b> \$ 0.006	Totals \$ 0.116		
36		LH \$ 0.0 LH \$ 0.0		0.005			\$ 0.006 \$ 0.004	\$ 0.006 \$ 0.004		\$ 0.005 \$ 0.003	\$ 0.005 \$ 0.003			\$ 0.006 \$ 0.004	\$ 0.116		
38			00 \$	0.004										\$ 0.004	\$ 0.004		
39	Deni	and 5 0.0	00 \$	0.000	\$ 0.000	\$ 0.000	\$ 0.000	\$ 0.000	0.000	\$ 0.000	\$ 0.000	\$ 0.000	\$ 0.000	\$ 0.000	\$ 0.004 \$ 0.120	•	
40															э U.12U		
41	NII	R Average Ra	nto														
42	INI	Average Ka	iie														
43	Energy C	osts \$ 0.1	16		66.12												
44	Demand C				2.55												
45	Unbundled C				0.00												
46		otal \$ 0.1		_	68.67												
47	1	otal p U.I	20		08.07												
48	Non-Slice Billing Determin	ants \$ 0.0	02														
49	Non-Since Binning Determini	ants \$ 0.0	02														
50	L																
30																	

	D. I	C	D	Б	Б	C	11	т	т Т	17	l r		NT I	0	D
A	В	С	D	Е	F	G	H	1 1	J	K	L	M	N	О	P
1							Table 2	2.12						T21 .	DE <b>2</b> 010 11
2								G						Flat	PF 2010-11
3					<b>~</b>		ate Design	•							
2 3 4 5 6						ation of Fl	•			e					
5					Tes	st Period O	ctober 200	19 - Septem	ber 2011						
6															
7 8	DED 6 D														
9	PF Preference Rate		Marr	Daa	la.a	F.h	M	<b>A</b>	Marr	l	11	A	0		
10	нін	<u>Oct</u>	<u>Nov</u>	<u>Dec</u>	Jan 20 (0	<u>Feb</u>	<u>Mar</u> 28.12	<u>Apr</u>	<u>May</u>	<u>Jun</u>	<u>Jul</u>	<u>Aug</u>	<u>Sep</u>		
11	HLH LLH	31.41 23.01	33.50 24.43	34.96	29.68 21.46	30.31 21.68	28.12	26.39 18.97	22.04 15.24	19.95			29.70 23.84		
12	Demand	23.01	24.43	25.65 2.30	1.96	1.99	1.85	18.97	15.24	10.59 1.32		1.89	1.96		
13	Demand	2.05	2.19	2.30	1.90	1.99	1.85	1./4	1.44	1.32	1.01	1.89	1.90		
14															
15															
16															
17	Flat Load FY2010-1	11													
18	riat Loau r 12010-1	Oct	Nov	Dec	<u>Jan</u>	Feb	<u>Mar</u>	<u>Apr</u>	May	<u>Jun</u>	<u>Jul</u>	Aug	Sep		<u>Total</u>
19	HLH	340.9	315.2	334.5	321.6	308.7	347.3	334.5	321.6	334.5			<u>зер</u> 321.6		7043.0
20	LLH	257.3	264.5	263.7	276.6	231.6	250.0	244.4	276.6	244.4		257.3	257.3		7043.0
21	Demand	804.0	804.0	804.0	804.0	804.0	804.0	804.0	804.0	804.0			804.0		
	Demand	001.0	001.0	001.0	001.0	001.0	001.0	001.0	001.0	001.0	001.0	001.0	001.0		
23															
24															
22 23 24 25															
26	Revenues at Propos	ed Rates													
27		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep		Total
28	HLH	\$ 10,708	\$ 10,558			\$ 9,358	\$ 9,767	\$ 8,827	\$ 7,088	\$ 6,673	\$ 8,060	\$ 9,811	\$ 9,552		\$ 174,817
29		\$ 5,920	\$ 6,462				\$ 5,153	\$ 4,637	\$ 4,215	\$ 2,588	\$ 4,860	\$ 5,490	\$ 6,134		,
30	Demand		\$ 1,761				\$ 1,487	\$ 1,399	\$ 1,158	\$ 1,061	\$ 1,294		\$ 1,576		\$ 17,929
31		•	•	•	•	,	,	•	•	,	•	,	,		\$ 192,746
32															
33	-														
34									ſ						
32 33 34 35 36											Flat PF P	reference R	ate FY200	7-09	\$ 27.37
36															

Table 2.13.1 (1 of 2)  Silice Costing Table  Ty 2018 forecast  PY		Α	В	С	F	G	Н
1   Operating Expenses		Л		C	I.	J	11
1   Operating Expenses	2		Table 2.13.1 (1 of 2)				
1	3		Slice Costing Table				
	4		•				
Operating Expenses	5						
Operating Expenses					EV.0040.5		EV 0044 5
1		1	Operating Evpanses		FY 2010 forecast		FY 2011 forecast
To							
1	9		Operating Generation				
1							
13   7							
Total	13				\$ 30,455	\$	30,767
To					\$ 566,644	\$	644,192
1					\$ 21.328	\$	21 754
TROIN DECOMMISSIONING	17						
14	18				• • • • • • • • • • • • • • • • • • • •	•	0.000
15   Sub-Total	20						
14   B	21						
14   B	22						
22   Augmentation Promer Purchases (centrol - Calculated below)	23						2 620
22   Augmentation Promer Purchases (centrol - Calculated below)	25				\$ 2,042	φ	2,020
22   Augmentation Promer Purchases (centrol - Calculated below)	26	20	Sub-Total		\$ 2,042	\$	2,620
10   24	27						
10   24	28						
1	30						
14   28	31	25	Sub-Total		\$ -	\$	-
14   28	32				¢ 12.101	0	10.016
35   29	34						
37   31   Renewable Generation	35	29					
Section   Sect	36				\$ 266,871	\$	268,683
33	38				\$ 6 174	\$	6 133
A	39						
12  36   Generation Conservation   GENERATION CONSERVATION R&D   GENERATION CONSERVATION ACQUISITION   \$ 14,000 \$ 14,000 \$ 5		-			\$ 30,374		
37   GENERATION CONSERVATION RAD	41				\$ 40,548	\$	39,598
TATE   38	43						
161   40	44						-
TT	45						
HE   42							
43							
ST	49				\$ 14,500		
SQ   CONSERVATION RATE CREDIT   \$ 28,000 \$ 29,500					\$ 55,988	\$	55,622
CONSERVATION AND RENEWABLE DISCOUNT   \$ 28,000 \$ 29,500	52				\$ 28.000	\$	29.500
Section   Power System Generation Sub-Total   Section	53	47	CONSERVATION AND RENEWABLE DISCOUNT				,
Formation   Power Services Transmission Acquisition and Ancillary Services   Transmission Acquisition and Ancillary Services   Transmission Acquisition and Ancillary Services   Transmission Acquisition and Ancillary Services   Transmission Acquisition and Ancillary Services   Transmission Acquisition and Ancillary Services   Transmission Acquisition and Ancillary Services   Services   Transmission Acquisition and Ancillary Services	54						
Transmission Acquisition and Ancillary Services   S	~ /		·		\$ 984,039	\$	1,064,697
TRANSMISSION & ANCILLARY SERVICES   \$ 27,000 \$ 27,000	57						
Fig. 2	58						
STATESTIC   STAT	59						
Section   Sect						\$	
Tellemetre   Final State   F	62	56	3RD PARTY TRANS & ANCILLARY SVCS				
Formal							
Form							
Formal   F	66				, 00,0-10	Ψ	33,130
G9	67						
To   64					¢	•	
TT							
Total   Figure   Total   Tot	71		INFORMATION TECHNOLOGY		\$ 6,318	\$	6,282
74         68         Sub-Total         \$ 13,608         \$ 13,824           75         69         Scheduling         \$ 13,608         \$ 13,824           76         70         SCHEDULING R&D         \$ 9,317         \$ 9,564           77         71         OPERATIONS SCHEDULING         \$ 5,808         \$ 5,874           78         72         OPERATIONS PLANNING         \$ 15,125         \$ 15,438           80         74         Marketing and Business Support         * 16,699         \$ 17,885           81         75         SALES & SUPPORT         \$ 16,699         \$ 17,885           82         76         Contractual exclusion         \$ (5,360)         \$ (5,360)           83         77         Implementation Expense Exclusions - Add back         * PUBLIC COMMUNICATION & TRIBAL LIAISON           85         79         STRATEGY, FINANCE & RISK MGMT         \$ 16,870         \$ 17,343           86         80         EXECUTIVE AND ADMINISTRATIVE SERVICES         \$ 2,546         \$ 2,727           87         81         CONSERVATION SUPPORT (EE staff costs)         \$ 11,356         \$ 12,003           88         82         Sub-Total         \$ 42,111         \$ 44,558	72				\$ 7,290	\$	7,542
Total   Scheduling	74				\$ 13.608	•	13 824
76         70         SCHEDULING R&D           77         71         OPERATIONS SCHEDULING         \$ 9,317         \$ 9,564           78         72         OPERATIONS PLANNING         \$ 5,808         \$ 5,874           79         73         Sub-Total         \$ 15,125         \$ 15,438           80         74         Marketing and Business Support         \$ 16,699         \$ 17,885           82         76         Contractual exclusion         \$ (5,360)         \$ (5,360)           83         77         Implementation Expense Exclusions - Add back         PUBLIC COMMUNICATION & TRIBAL LIAISON           85         79         STRATEGY, FINANCE & RISK MGMT         \$ 16,870         \$ 17,343           86         80         EXECUTIVE AND ADMINISTRATIVE SERVICES         \$ 2,546         \$ 2,727           87         81         CONSERVATION SUPPORT (EE staff costs)         \$ 11,356         \$ 12,003           88         82         Sub-Total         \$ 42,111         \$ 44,598	75				Ψ 10,000	•	10,024
78         72         OPERATIONS PLANNING         \$ 5,808         \$ 5,874           79         73         Sub-Total         \$ 15,125         \$ 15,438           80         74         Marketing and Business Support         \$ 16,699         \$ 17,885           81         75         SALES & SUPPORT         \$ (5,360)         \$ (5,360)           82         76         Contractual exclusion         \$ (5,360)         \$ (5,360)           83         77         Implementation Expense Exclusions - Add back         PUBLIC COMMUNICATION & TRIBAL LIAISON           85         79         STRATEGY, FINANCE & RISK MGMT         \$ 16,870         \$ 17,343           86         80         EXECUTIVE AND ADMINISTRATIVE SERVICES         \$ 2,546         \$ 2,727           87         81         CONSERVATION SUPPORT (EE staff costs)         \$ 11,336         \$ 12,003           88         82         Sub-Total         \$ 42,111         \$ 44,598	76		SCHEDULING R&D				
79   73   Sub-Total   \$ 15,125   \$ 15,438     80   74   Marketing and Business Support   \$ 16,699   \$ 17,885     81   75   SALES & SUPPORT   \$ 16,699   \$ 17,885     82   76   Contractual exclusion   \$ (5,360)   \$ (5,360)     83   77   Implementation Expense Exclusions - Add back     84   78   PUBLIC COMMUNICATION & TRIBAL LIAISON   \$ 16,870   \$ 17,343     85   79   STRATEGY, FINANCE & RISK MGMT   \$ 16,870   \$ 17,343     86   80   EXECUTIVE AND ADMINISTRATIVE SERVICES   \$ 2,546   \$ 2,727     87   81   CONSERVATION SUPPORT (EE staff costs)   \$ 11,356   \$ 12,003     88   82   Sub-Total   \$ 42,111   \$ 44,598     89   Sub-Total   \$ 42,111   \$ 44,598     80   SUB-Total   \$ 42,111   \$ 44,598     80   SUB-Total   \$ 42,111   \$ 44,598     81   SUB-Total   \$ 42,111   \$ 44,598     81   SUB-Total   \$ 42,111   \$ 44,598     82   SUB-Total   \$ 42,111   \$ 44,598     83   SUB-Total   \$ 42,111   \$ 44,598     84   SUB-Total   \$ 42,111   \$ 44,598     85   SUB-Total   \$ 42,111   \$ 44,598     86   SUB-Total   \$ 42,111   \$ 44,598     87   SUB-Total   \$ 42,111   \$ 44,598     88   SUB-Total   \$ 42,111   \$ 44,598     89   SUB-Total   \$ 42,111   \$ 44,598     80   SUB-Total   \$ 42,111   \$ 44,5							
80         74         Marketing and Business Support         \$ 16,699         \$ 17,885           81         75         SALES & SUPPORT         \$ 16,699         \$ 17,885           82         76         Contractual exclusion         \$ (5,360)         \$ (5,360)           83         77         Implementation Expense Exclusions - Add back         PUBLIC COMMUNICATION & TRIBAL LIAISON           85         79         STRATEGY, FINANCE & RISK MGMT         \$ 16,870         \$ 17,343           86         80         EXECUTIVE AND ADMINISTRATIVE SERVICES         \$ 2,546         \$ 2,727           87         81         CONSERVATION SUPPORT (EE staff costs)         \$ 11,356         \$ 12,003           88         82         Sub-Total         \$ 42,111         \$ 44,598							
82         76         Contractual exclusion         \$ (5,360)         \$ (5,360)           83         77         Implementation Expense Exclusions - Add back           84         78         PUBLIC COMMUNICATION & TRIBAL LIAISON           85         79         STRATEGY, FINANCE & RISK MGMT         \$ 16,870         \$ 17,343           86         80         EXECUTIVE AND ADMINISTRATIVE SERVICES         \$ 2,546         \$ 2,727           87         81         CONSERVATION SUPPORT (EE staff costs)         \$ 11,356         \$ 12,003           88         82         Sub-Total         \$ 42,111         \$ 44,598	80	74	Marketing and Business Support		10,120	Ψ	10,430
83         77         Implementation Expense Exclusions - Add back           84         78         PUBLIC COMMUNICATION & TRIBAL LIAISON           85         79         STRATEGY, FINANCE & RISK MGMT         \$ 16,870         \$ 17,343           86         80         EXECUTIVE AND ADMINISTRATIVE SERVICES         \$ 2,546         \$ 2,727           87         81         CONSERVATION SUPPORT (EE staff costs)         \$ 11,336         \$ 12,003           88         82         Sub-Total         \$ 42,111         \$ 44,598						\$	
84         78         PUBLIC COMMUNICATION & TRIBAL LIAISON           85         79         STRATEGY, FINANCE & RISK MGMT         \$ 16,870         \$ 17,343           86         80         EXECUTIVE AND ADMINISTRATIVE SERVICES         \$ 2,546         \$ 2,727           87         81         CONSERVATION SUPPORT (EE staff costs)         \$ 11,356         \$ 12,003           88         82         Sub-Total         \$ 42,111         \$ 44,598					\$ (5,360)	\$	(5,360)
85         79         STRATEGY, FINANCE & RISK MGMT         \$ 16,870         \$ 17,343           86         80         EXECUTIVE AND ADMINISTRATIVE SERVICES         \$ 2,546         \$ 2,727           87         81         CONSERVATION SUPPORT (EE staff costs)         \$ 11,336         \$ 12,003           88         82         Sub-Total         \$ 42,111         \$ 44,598							
87         81         CONSERVATION SUPPORT (EE staff costs)         \$ 11,356         \$ 12,003           88         82         Sub-Total         \$ 42,111         \$ 44,598	85	79	STRATEGY, FINANCE & RISK MGMT				
88 82 Sub-Total \$ 42,111 \$ 44,598	86						
67 65 Fower Non-Generation Operations Sub-Total	89	83	Power Non-Generation Operations Sub-Total		\$ 42,111 \$ 70,844	\$	

	A	В С	F	G	Н	I	J
1		Table 2.13.1 (2 of 2)	•				
2		Slice Costing Table					
		Since Obsting rable					
3	84	Fish and Wildlife/USF&W/Planning Council/Environmental Req	FY 2010 forecast		FY 2011 forecast		
5	85	BPA Fish and Wildlife (includes F&W Shared Services)					
7	86 87	FISH & WILDLIFE Sub-Total	\$ 215,000 \$ 215,000		\$ 236,000 \$ 236,000		
8	88 89	USF&W Lower Snake Hatcheries USF&W LOWER SNAKE HATCHERIES	\$ 23,600	)	\$ 24,480		
10	90 91	Planning Council					
11	92	PLANNING COUNCIL Environmental Requirements	,		,		
13	93 94	ENVIRONMENTAL REQUIREMENTS Fish and Wildlife/USF&W/Planning Council Sub-Total	\$ 300 \$ 248,583		\$ 300 <b>\$ 270,714</b>		
15 16	95 96	General and Administrative/Shared Services Additional Post-Retirement Contribution					
17	97 98	ADDITIONAL POST-RETIREMENT CONTRIBUTION	\$ 15,447		\$ 15,579		
18 19	99	BPA Internal Support - G&A and Shared Srv. (excludes direct project support)  AGENCY SERVICES G&A	\$ 49,961		\$ 50,064		
20	100 101	Sub-Total BPA Internal Support Services Supply Chain - Shared Services	\$ 49,961		\$ 50,064		
22	102 103	General and Administrative/Shared Services Sub-Total Bad Debt Expense	\$ 65,408 \$		\$ 65,643 \$ -		
24 25	104	Other Income, Expenses, Adjustments	\$ -		\$ -		
26	105 106	Non-Federal Debt Service Energy Northwest Debt Service					
26 27 28 29	107 108	COLUMBIA GENERATING STATION DEBT SVC WNP-1 DEBT SVC	\$ 235,736 \$ 166,013		\$ 226,169 \$ 167,549		
29	109	WNP-3 DEBT SVC EN RETIRED DEBT	\$ 144,892		\$ 169,093		
31	111	EN LIBOR INTEREST RATE SWAP					
32	112 113	Sub-Total Non-EN Debt Service	\$ 546,641		\$ 562,811		
34	114 115	COWLITZ FALLS DEBT SVC N. WASCO DEBT SVC	\$ 11,566 \$ 2,200		\$ 11,563 \$ 2,196		
36	116	TROJAN DEBT SVC	\$ -		\$ -		
37 38 39	117 118	CONSERVATION DEBT SVC Sub-Total	\$ 5,079 \$ 18,845	i :	\$ 4,924 \$ 18,683		
39 40	119 120	Non-Federal Debt Service Sub-Total  Depreciation (excludes TMS)	\$ 565,486 \$ 120,111		<b>581,494</b> 121,235		
41	121 122	Amortization (excludes ConAug amortization) Total Operating Expenses	\$ 64,392 \$ 2,204,403		\$ 72,363 <b>\$ 2,336,196</b>		
43	123		\$ 2,204,403		ş 2,336,196		
44	124 125	Other Expenses Net Interest Expense	\$ 167,119	,	\$ 173,301		
46 47	126 127	LDD Irrigation Rate Mitigation Costs	\$ 26,419 \$ 12,036		\$ 26,465 \$ 12,036		
48	128 129	Sub-Total Sub-Total	\$ 205,574		\$ 211,802		
50	130	Total Expenses	\$ 2,409,977		\$ 2,547,998		
50 51 52	131 132	Revenue Credits Ancillary and Reserve Service Revs. Total	\$ 90,176		\$ 102,730		
53 54	133 134	Downstream Benefits and Pumping Power 4(h)(10)(c)	\$ 8,921 \$ 96,689		\$ 8,921 \$ 101,969		
55	135	Colville and Spokane Settlements	\$ 4,600		\$ 4,600		
56 57	136 137	FCCF Energy Efficiency Revenues	\$ 20,500		\$ 20,500		
58 59	138 139	Miscellaneous  Green Tag revenue associated with Klondike III	\$ 3,420 \$		\$ 3,420 \$ -		
60	140	Ad Hoc revenue credit adjustment					
61	141 142	Total Revenue Credits Augmentation Costs (not subject to True-Up)	\$ 224,306		\$ 242,140		
64	143 144	Non-Slice Net Augmentation Costs Gross Augmentation cost (72.7 aMW, 274.7 aMW)	\$ 26,023		\$ 108,365		
65	145	Minus revenues 70.7 aMW, 267.1 aMW @ PF rate	\$ (17,818	i)	\$ (67,316)		
66	146 147	DSI Net Augmentation Costs	\$ 8,205		\$ 41,049		
68 69	148 149	Gross Augmentation cost (413 aMW, 413 aMW) Minus revenues 402 aMW, 402 aMW @ IP rate	\$ 154,746 \$ (121,852		\$ 164,668 \$ (121,852)		
70 71	150 151		\$ 32,895		\$ 42,815		
72	152	Total Net Cost of Augmentation	\$ 41,100		\$ 83,864	Ш	
73 74	153 154						
75 76	155 156		\$ 202,673		\$ 204,163		
77	157	Irrigation assistance	\$ -		\$ -		
78 79	158 159	Amortization	\$ 120,111 \$ 77,728	3	\$ 121,235 \$ 85,699		
80 81	160 161	Capitalization Adjustment Bond Premium Amortization	\$ (45,937 \$ 185		\$ (45,937) \$ 185		
82	162	Principal Payment of Fed Debt exceeds non cash expenses	\$ 50,586	:	\$ 42,981		
83 84	163 164	Minimum Required Net Revenues	\$ 50,586		\$ 42,981		Year Total Rev
85 86	165 166	Annual Slice Revenue Requirement (Amounts for each FY)	\$ 2,277,356		\$ 2,432,703	\$	4,710,060
87	167 168	SLICE TRUE-UP ADJUSTMENT CALCULATION					
89	169	FY 2010-2011 Average Slice Revenue Requirement determined in WP-10 rate case					
89 90 91 92	170 171	TRUE UP AMOUNT (Diff. between actual Slice Rev Reqt and forecast average Slice Rev Reqt)  AMOUNT BILLED (22.6278 percent)					
93	172 173	Slice Implementation Expenses (not incl. in base rate)  TRUE UP ADJUSTMENT					
94	174 175						
96	176						400.070.17
97 98	177 178	Monthly Slice Revenue Requirement (2-Year total divided by 24 months)  One Percent of Monthly Requirement (Slice Rate per percent Slice - Monthly Slice Rev. Req't. divided by 100	0)			\$ \$	196,252,498 1,962,525
99 100	179 180	ANNUAL BASE SLICE REVENUES				\$	532,891,473
101	181	Annual Slice Implementation Expenses				\$	2,830,000
102	182	TOTAL ANNUAL SLICE REVENUES				Þ	535,721,473

## D Table 2.13.2 3 4 5 FINAL PROPOSAL WITH/WITHOUT 7B3 ALLOCATION TO SECONDARY Final Proposal Rate and Benefit Summary Final Proposal with No 7b3 Allocation to FPS/Secondary Summary 2010-11 2010-11 7 2010-11 7b2 Trigger 2010-11 7b2 Trigger 36.32 8.17 Unbifurcated PF 34.53 6.82 Unbifurcated PF \$ 9 PF Preference (average non-Slice) 28.77 6.95% PF Preference (average non-Slice) \$ 28.32 5.28% 10 7b3 7b3 PF Exchange (w/ Transmission) 48.68 PF Exchange (w/ Transmission) 49.20 11 7.380 9.810 34.60 36.61 12 NR 68.67 NR 71.05 13 **IOU Net Exchange Benefits** IOU Net Exchange Benefits FY 2010 FY 2011 FY 2010 FY 2011 15 Avista 12,517 \$ 12,425 Avista 13.075 12.869 16 Idaho Power Idaho Power \$ 17 4,668 \$ Northwestern Energy PNWR 5,164 \$ 4,545 Northwestern Energy PNWR 18 19 20 21 Pacificorp 74,394 \$ 65,786 Pacificorp 67.623 \$ 60.682 Portland General 64,314 \$ 66,368 Portland General 58.889 \$ 60.713 Puget Sound Energy 95,959 \$ 108,102 Puget Sound Energy 86,900 \$ 97,256 252,349 \$ 257,227 \$ 254,788 231,155 \$ 235,687 \$ 233,421 22 Slice Slice 23 24 Net Public Exchange 12,101 \$ 10,016 \$ 535,723 Net Public Exchange 12,828 \$ 10,971 529,628 2010-11 Net Augmentation Costs \$ 124,979 2010-11 Net Augmentation Costs \$ 112,154 25 26 7B3 Allocations and Revenues From Requirements Sales 7B3 Allocations and Revenues From Requirements Sales 27 Total 7b3 protection amount 1,003,410 Total 7b3 protection amount 837,608 \$ 28 7b3 allocted to PFx \$ 577,879 7b3 allocted to PFx \$ 768,474 29 7b3 allocted to IP 51,988 7b3 allocted to IP \$ 69,134 30 373.543 7b3 allocated to secondary 7b3 allocated to secondary 31 32 \$ 1,071,446 \$ 1,059,255 slice rate revenues slice rate revenues 33 non-slice revenues 2,965,078 non-slice revenues 2,936,609 34 \$ 4,036,524 \$ 3,995,864 35 36 37 PROOF THAT REQUIREMENT SALES REVENUE MINUS NET REP BENEFITS IS THE SAME WITH/WITHOUT THE ALLOCATION OF 7B3 AMOUNTS TO SECONDARY 38 delta 39 40 41 42 43 44 Total PF&IP Revenue minus net REP \$ 3,504,831 Total PF&IP Revenue minus net REP \$ 3,505,223 \$ 392 0.019 PROOF THAT SLICE IS ALLOCATED THE PROPER COSTS 45 46 47 48 49 50 WHEN 7B3 PROTECTION AMOUNTS ARE ALLOCATED TO SECONDARY Change in REP Net Benefits Due to 7b3 to Secondary 41,052 Allocating 7b3 protection amounts to secondary has multiple effects: 2 Slice percent 0.226278 3 Slice Share of Change in REP Net Benefit Costs 9,289 1. The secondary revenue credit to the unbifurcated PF rate is reduced, raising that rate. 2. The 7b3 amount allocated to the PF Exchange rate is reduced. 51 5 Net Augmentation Costs with 7b3 to Secondary 124,979 3. The effect of 1 and 2 above is to reduce the PF Exchange rate. 52 6 Net Augmentation Costs without 7b3 to Secondary 112.154 4. The reduced PF Exchange rate produces increased REP benefits. 53 54 7 decrease in Net Augmentation Due to 7b3 to Secondary 12,825 8 Slice percent 0.226278 5. The 7b3 amount allocated to the IP rate is reduced and the IP rate is lowered. 55 56 57 58 9 Slice Share of Change in Net Augmentation 2,902 6. The lower IP rate has the effect of increasing the cost of net augmentation. 11 Expected Change in Slice Cost (In 3 plus In 9) 12,191 7. As can be seen in the box to the left, Slice costs are increase to cover the slice percentage of the increased REP benefits and the increase in the net cost of augmentation. 59 60 61 14 Observed Slice Revenue with 7b3 to Secondary 1.071.446 15 Observed Slice Revenue with no 7b3 to Secondary 1,059,255 62 16 Observed Change in Slice Costs 12,191 63

	В	С	D	E
1	Tab	le 2.14.1		
2				RDS 60A
3	RATE DE	ESIGN STUDY		
4	Allocated Co	sts and Unit Cost	S	
5	Priority F	irm Power (PF)		
6	•	housands)		
7	Test Period Octobe		er 2011	
8		-		
9		$\mathbf{A}$	В	C
10		ALLOCATED	UNIT	PERCENT
11		<b>COSTS</b>	<b>COSTS</b>	<b>CONTRIBUTION</b>
12	GENERATION ENERGY	(\$ Thousands)	(Mills/KwH)	(Percent)
13			· ·	, , , ,
14	Federal Base System			
15	Hydro	1,234,212	6.137	16.90%
16	Fish & Wildlife	571,415	2.841	7.82%
17	Trojan	4,500	0.022	0.06%
18	WNP #1	334,408	1.663	4.58%
19	WNP #2	1,044,598	5.194	14.30%
20	WNP #3	313,985	1.561	4.30%
21	System Augmentation	453,803	2.257	6.21%
22	Balancing Power Purchases	159,738	0.794	2.19%
23	Total Federal Base System	4,116,660	20.470	56.35%
24	New Resources			
25	Gross Residential Exchange	3,152,994	15.678	43.16%
26	Conservation	309,366	1.538	4.24%
28	BPA Programs	580,704	2.888	7.95%
29	TOTAL COSA ALLOCATIONS	8,159,723	40.574	109.17%
30				
31				
32	Nonfirm Excess Revenue Credit	(1,098,015)	-5.460	-15.03%
33	Low Density Discount Expense	52,884	0.263	0.72%
34	Other Revenue Credits	(439,432)	-2.185	-6.02%
35	Irrigation Rate Mitigation Expense	24,072	0.120	0.33%
36	SP Revenue Surplus/Dfct Adj.	429,780	2.137	5.88%
37	7(c)(2) Delta Adjustment	175,958	0.875	2.41%
38	7(c)(2) Floor Rate Adjustment			
39	TOTAL RATE DESIGN ADJUSTMENTS	(854,754)	-4.250	-11.70%
40				
41	Total Generation	7,304,970	36.32	100.00%
56		-		-
57	Billing Determinants With LDD Discount	201,106		
58				

	Α	В	С	D	E
3		Table 2	2.14.2		
4					RDS 60B
5		RATE DESIG	GN STUDY		
6		Allocated Costs a	and Unit Costs		
7		Priority Firm Powe	r (PF) Bifurcated		
8		(\$ Thous	sands)		
9		Test Period October 20	08 - September 20	009	
10					
11			$\mathbf{A}$	В	$\mathbf{C}$
12			ALLOCATED	UNIT	PERCENT
13			<b>COSTS</b>	<u>COSTS</u>	<b>CONTRIBUTION</b>
14					
15		Rate Design Step PF Rate	(\$ Thousands)	(Mills/KwH)	(Percent)
16					
17		PRIORITY FIRM PREFERENCE	4 471 173	26.224	100.0007
18		Revenue Reqmt @ PF Combined Rate	4,461,173	36.324	129.02%
19		7(b)(2) Credit	(1,003,410)	-8.170	-29.02%
20		Subtotal	3,457,763	28.154	100.00%
21		Floor Rate Adjustment TOTAL	2 457 762	20 154	100.00%
22		Billing Determinants:	3,457,763	28.154	100.0076
24		Total PF Preference Forecasted Sales	122,816	28.154	100.00%
25		Total IT Treference Porceasted Sales	122,610	20.134	100.0070
26					
27					
28		Slice Separation Step			
29		Revenue Reqmt @ Rate Design Step PF Pref.	3,457,763		
30		Slice PF Product Revenues	(1,065,783)		
31		Slice Secondary Revenue Credit Adjustment	332,981		
32		Slice Separation 7c2 Adjustement	(3,346)		
33		Revenue Reqmt @ Non-Slice PF Pref.	2,721,615		
34					
35		Non-Slice PF Preference Forecasted Sales	94,582	28.775	
36					
37		PRIORITY FIRM EXCHANGE			
38		Revenue Reqmt @ PF Combined Rate	2,843,797	36.324	74.62%
39		7(b)(2) Adjustment	577,879	7.381	15.16%
40		7(b)(2) Industrial Adjustment	56,101	0.717	1.47%
41		Subtotal	3,477,776	44.422	91.25%
42		Floor Rate Adjustment			
43		Total Energy	3,477,776	44.422	91.25%
44					
45		m . 1m	222 515	4.2.0	0.550
46		Total Transmission	333,515	4.260	8.75%
47		TOTAL Pilling Determinants	3,811,292	48.682	100.00%
48		Billing Determinants:	70.200	40.702	100.000/
49		Forecasted Exchange Loads	78,290	48.682	100.00%
50					

	A B I	С	D	E
1		able 2.14.3	В	
2	1.	ubic 2.14.5		RDS 61
3	RATE	DESIGN STUDY	7	KDS 01
4		Costs and Unit C		
5		Firm Power Rate		
6	(\$ Thousands/Unit Cos	sts in Mills/KwH,	or as Indicated)	
7	Test Period Octo			
8				
9		A	В	C
10		ALLOCATED	UNIT	PERCENT
11		<b>COSTS</b>	<b>COSTS</b>	<b>CONTRIBUTION</b>
12	GENERATION ENERGY	(\$ Thousands)	(Mills/KwH)	(Percent)
13				
14	Federal Base System			
15	Hydro			
16	Fish & Wildlife			
17	Trojan WNP #1			
18 19	WNP #1 WNP #2			
20	WNP #3			
21	System Augmentation			
22	Balancing Power Purchases			
23	Total Federal Base System			
24	New Resources	62,005	8.804	25.44%
25	Gross Residential Exchange	325,123	46.162	133.40%
26	Conservation	10,834	1.538	4.45%
27	BPA Programs	20,337	2.888	8.34%
28	TOTAL COSA ALLOCATIONS	418,299	59.392	171.63%
29				
30	Nonfirm Excess Revenue Credit			
31				
32	Other Revenue Credits			
33	SD Davanua Sumulua/Dfat A di	2 142	0.204	0.88%
34	SP Revenue Surplus/Dfct Adj. 7(c)(2) Delta Adjustment	2,143 (175,958)	0.304 -24.983	-72.20%
35 36	7(c)(2) Floor Rate Adjustment	(175,956)	-24.703	-/2.20/0
37	TOTAL RATE DESIGN ADJSTMTS	(173,815)	-24.679	-71.32%
38	Total Generation	244,484	34.713	100.31%
39			2 10	
50				
51	Total Allocated & Adjusted Costs	244,484	34.713	100.31%
52	-			
53	7(b)(2) Adjustments			
54	7(b)(2) Amount	51,988	7.381	21.33%
55	7(b)(2) Industrial Adj.	(56,101)	-7.965	-23.02%
56		240,372	34.129	98.63%
57				
58	Slice Separation Step Adjustment	2 246	0.475	1 270/
59	7(c)(2) Slice Separation Amount	3,346	0.475	1.37%
60	Total With 7(b)(2) Adjustments	243,717	34.604	100.00%
61	Billing Determinants:			
62	Energy (GwH)	7,043		
63	Energy (Owit)	7,043		

	A B	С	D	E						
1		<b>Table 2.14</b>	1.4							
2				<b>RDS 62</b>						
3	RATE	DESIGN STUDY	7							
4	Allocated	<b>Costs and Unit C</b>	osts							
5	New Resources Firm Power (NR)									
6	(\$ Thousands/Unit Co	sts in Mills/KwH,	or as Indicated)							
7	Test Period Octo	ober 2008 - Septe	mber 2009							
8										
9		$\mathbf{A}$	В	C						
10		ALLOCATED	UNIT	<b>PERCENT</b>						
11		<b>COSTS</b>	<b>COSTS</b>	<b>CONTRIBUTION</b>						
12	GENERATION ENERGY	(\$ Thousands)	(Mills/KwH)	(Percent)						
13										
14	Federal Base System									
15	Hydro									
16	Fish & Wildlife									
17	Trojan									
18	WNP #1									
19	WNP #2									
20	WNP #3									
21	System Augmentation									
22	Balancing Power Purchases									
23	Total Federal Base System									
24	New Resources	0.0154	8.804							
25	Gross Residential Exchange	0.0809	46.162	67.22%						
26	Conservation	0.0027	1.538							
27	BPA Programs	0.0051	2.888							
28	TOTAL COSA ALLOCATIONS	0.1041	59.392	86.49%						
29										
30	Nonfirm Excess Revenue Credit									
31				0.4407						
34	SP Revenue Surplus/Dfct Adj.	0.0005	0.304							
35	7(c)(2) Delta Adjustment	0.0015	0.875	1.27%						
36	7(c)(2) Floor Rate Adjustment	0.0001	1.150	1.500/						
37	TOTAL RATE DESIGN ADJSTMTS	0.0021	1.179							
38	Total Generation Energy	0.1061	60.571	88.21%						
47	T . 1 A 11 1 0 A 11 1 C	0.1071	(0.551	00.010/						
49	Total Allocated & Adjusted Costs	0.1061	60.571	88.21%						
50	7(b)(2) Adjustments	0.0120	7.201	10.750/						
51	7(b)(2) Amount	0.0129	7.381	10.75%						
52	7(b)(2) Industrial Adj.	0.0013	0.717	1.04%						
53	7(b(2)Exchange Cost Adjustment	0.1202	(0.65	100 000/						
54	Total With 7(b)(2) Adjustments	0.1203	68.67	100.00%						
55	Dilling Determinent / Firem (CVII)	0.0010								
56	Billing Determinant / Energy (GWh)	0.0018								

	А	В	С	D	E F	G	Н	1	J
1				<b>Table 2.14.5</b>					
2									RDS63
3									
4									
5									
6									
		A	В	$\mathbf{C}$	D	E	F	G	Н
7		11	D	C	D	L	•	3	
8		ATT	OCATED GENER	ATION COSTS			PERCENT	ACEC	
9		ALL	CATED GENER	ATION COSTS			FERCENT	AGES	
10		FBS	Exchange	New		FBS	Exchange	New	
12		Resources	Resources	Resources	Total	Resources	Resources	Resources	Total
13		Resources	Resources	Resources	<u>10tai</u>	Resources	Resources	Resources	<u>10tai</u>
	CLASSES OF SERVICE:								
15	CERUSES OF SERVICE.								
	Power Rates								
17	Priority Firm - Preference	2,514,060	1,925,545		4,439,605	56.63%	43.37%		100.00%
18	Priority Firm - Exchange	1,602,600	1,227,448		2,830,048	56.63%	43.37%		100.00%
19	Priority Firm Power - Total	4,116,660	3,152,994		7,269,653	56.63%	43.37%		100.00%
20	Industrial Firm Power	, ,	325,123	62,005	387,128		83.98%	16.02%	100.00%
21	New Resources Firm		0.081	0.015	0.096		83.98%	16.02%	100.00%
22	Firm Power Products and Services		535,360	102,118	637,478		83.98%	16.02%	100.00%
23									
24									
25	TOTALS	4,116,660	4,013,477	164,123	8,294,260	49.63%	48.39%	1.98%	100.00%
26									
27					233,908				
28									
29			Average C	ost of Resources	35.46				

CHAPTER 3:	SLICE TRUE-UP	ADJUSTMENT CH	ARGE FORECAST T	ABLES



 Table 3.1

 Slice True-Up Adjustment Charge Forecast after \$42M Shift in Generation Amortization Payments to the US Treasury (\$000s)

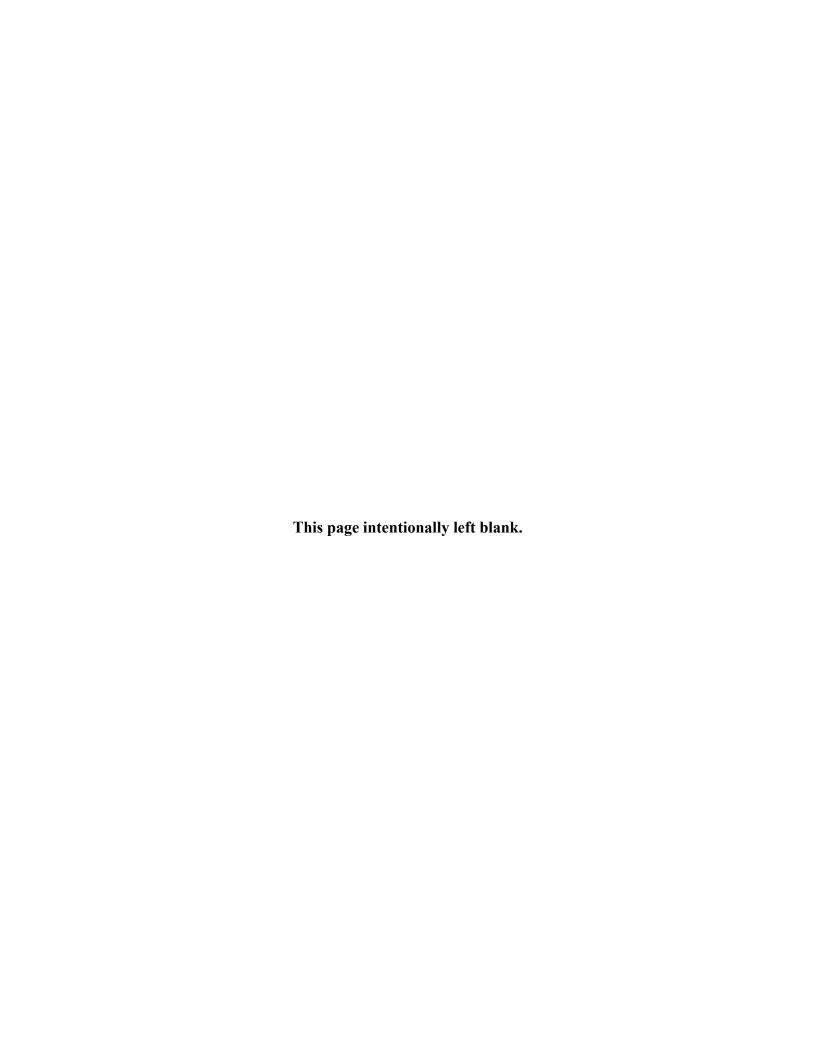
		(\$000s)					
	Α	В С		D	Е	F	G H
1		Audited Actual Date	a F	2010 forecast		FY 2011 forecast	
2	1	Operating Expenses					
3	2	Power System Generation Resources					
4	3	Operating Generation					
5	4	COLUMBIA GENERATING STATION (WNP-2)	\$	257,811		\$ 324,882	
6	5	BUREAU OF RECLAMATION	\$	87,318		\$ 96,110	
7	6	CORPS OF ENGINEERS	\$	191,060		\$ 192,433	
8	7	LONG-TERM CONTRACT GENERATING PROJECTS	\$	30,455		\$ 30,767	
9	8	Sub-Total	\$	566,644		\$ 644,192	
			Þ	300,044		\$ 644,192	
10	9	Operating Generation Settlement Payment		04.000		0 04 754	
11	10	COLVILLE GENERATION SETTLEMENT	\$	21,328		\$ 21,754	
12	11	Sub-Total	\$	21,328		\$ 21,754	
13	12	Non-Operating Generation					
14	13	TROJAN DECOMMISSIONING	\$	2,200		\$ 2,300	
15	14	WNP-1&3 DECOMMISSIONING	\$	418		\$ 428	
16	15	Sub-Total	\$	2,618		\$ 2,728	
17	16	Contracted Power Purchases					
18	17	HEDGING/MITIGATION (omit except for those assoc. with inventory solution)	\$	-		\$ -	
19	18	PNCA HEADWATER BENEFITS	\$	2,042		\$ 2,620	
20	19	GROSS OTHER POWER PURCHASES (short term - omit)					
21	20	Sub-Total	\$	2,042		\$ 2,620	
22	21	Bookout Adjustment to Power Purchases (omit)		**		, , , ,	
22 23	22	Augmentation Power Purchases (omit - calculated below)					
24	23	AUGMENTATION POWER PURCHASES (omit)					
25	23	CONSERVATION AUGMENTATION (omit)					
25 26	25	Sub-Total	\$			e	
20			э	•		\$ -	
27	26	Exchanges and Settlements		10.101		e 10.075	ļ
28	27	PUBLIC RESIDENTIAL EXCHANGE	\$	12,101		\$ 10,016	ļ
29	28	IOU RESIDENTIAL EXCHANGE	\$	254,770		\$ 258,667	
30	29	OTHER SETTLEMENTS	\$	-		\$ -	
31	30	Sub-Total	\$	266,871		\$ 268,683	
32 33	31	Renewable Generation					
33	32	RENEWABLES R&D	\$	6,174		\$ 6,133	
34	33	RENEWABLES CONSERVATION RATE CREDIT	\$	4,000		\$ 2,500	
35	34	RENEWABLES (excludes expenses from reinvested revenues)	\$	30,374		\$ 30,965	
35 36	35	Sub-Total	\$	40,548		\$ 39,598	-
37	36	Generation Conservation		,		,	
38	37	GENERATION CONSERVATION R&D					
39	38	DSM TECHNOLOGIES	s			\$ -	
40	39		\$	14,000			
		CONSERVATION ACQUISITION				\$ 14,000	
41	40	LOW INCOME WEATHERIZATION & TRIBAL	\$	5,000		\$ 5,000	
42	41	ENERGY EFFICIENCY DEVELOPMENT	\$	20,500		\$ 20,500	
43	42	LEGACY	\$	1,988		\$ 1,622	
44	43	MARKET TRANSFORMATION	\$	14,500		\$ 14,500	
45	44	Sub-Total	\$	55,988		\$ 55,622	
46	45	Conservation and Renewable Discount (C&RD)					
47	46	CONSERVATION RATE CREDIT	\$	28,000		\$ 29,500	
48	47	CONSERVATION AND RENEWABLE DISCOUNT					
49	48	Sub-Total	\$	28,000		\$ 29,500	
50	49	Power System Generation Sub-Total	\$	984,039		\$ 1,064,697	
51	50	Power Services Transmission Acquisition and Ancillary Services					
52	51	Transmission Acquisition and Ancillary Services					
53	52	TRANSMISSION & ANCILLARY SERVICES					
54	53	Canadian Entitlement Agreement Transmission Expenses	\$	27,000		\$ 27,000	
55	54	PNCA & NTS Transmission and System Obligaton Expenses	\$	1,000		\$ 1,000	
	55		\$				
56		3RD PARTY GTA WHEELING	Ф	50,690		\$ 51,340	
57	56	3RD PARTY TRANS & ANCILLARY SVCS		0.000		e 0.000	
58	57	GENERATION INTEGRATION	\$	6,800		\$ 6,800	
59	58	TELEMETERING/EQUIP REPLACEMT	\$	50		\$ 50	
60	59	Power Services Trans Acquisition and Ancillary Serv Sub-Total	\$	85,540		\$ 86,190	
61	60						
62	61	Power Non-Generation Operations					
63	62	System Operations					ļ
64	63	SYSTEM OPERATIONS R&D	\$	-		\$ -	
65	64	EFFICIENCIES PROGRAM (excludes TMS expenses)	\$	-		\$ -	
66	65	INFORMATION TECHNOLOGY	\$	6,318		\$ 6,282	ļ
67	66	GENERATION PROJECT COORDINATION	\$	7,290		\$ 7,542	
68	67	SLICE IMPLEMENTATION (omit - calculated separately)					
69	68	Sub-Total	\$	13,608		\$ 13,824	<del></del>
70	69	Scheduling		,		,	
71	70	SCHEDULING R&D					
72	71	OPERATIONS SCHEDULING	\$	9,317		\$ 9,564	ļ
73	72	OPERATIONS SCHEDOLING OPERATIONS PLANNING	\$	5,808		\$ 5,874	ļ
74	73	Sub-Total	\$	15,125		\$ 15,438	<del></del>
75	73 74	Marketing and Business Support	Ф	15,125		ψ 10,438	
76			•	16.600		¢ 17.005	ļ
	75 76	SALES & SUPPORT	\$	16,699		\$ 17,885	ļ
77	76	Contractual exclusion	\$	(5,360)		\$ (5,360)	
78	77	Implementation Expense Exclusions - Add back					
79	78	PUBLIC COMMUNICATION & TRIBAL LIAISON					ļ
80	79	STRATEGY, FINANCE & RISK MGMT	\$	16,870		\$ 17,343	
81	80	EXECUTIVE AND ADMINISTRATIVE SERVICES	\$	2,546		\$ 2,727	
82	81	CONSERVATION SUPPORT (EE staff costs)	\$	11,356		\$ 12,003	
83	82	Sub-Total	\$	42,111		\$ 44,598	<u> </u>
84	83	Power Non-Generation Operations Sub-Total	\$	70,844		\$ 73,860	
85	84	Fish and Wildlife/USF&W/Planning Council/Environmental Req					
86	85	BPA Fish and Wildlife (includes F&W Shared Services)					
87	86	FISH & WILDLIFE	\$	215,000		\$ 236,000	
88	87	Sub-Total	\$	215,000		\$ 236,000	
		· · · · · · · · · · · · · · · · · · ·	_	,			

 Table 3.1

 Slice True-Up Adjustment Charge Forecast after \$42M Shift in Generation Amortization Payments to the US Treasury (\$000s)

		(\$000s)					
	Α	В С	D	Е	F	G	Н
89	88	USF&W Lower Snake Hatcheries	FY 2010 forecast		FY 2011 forecast		
90	89	USF&W LOWER SNAKE HATCHERIES	\$ 23,600	\$	24,480		
91	90	Planning Council	20,000	Ť	21,100		
92	91	PLANNING COUNCIL	\$ 9,683	\$	9,934		
93	92	Environmental Requirements					
94	93	ENVIRONMENTAL REQUIREMENTS	\$ 300	\$			
95 96	94 95	Fish and Wildlife/USF&W/Planning Council Sub-Total General and Administrative/Shared Services	\$ 248,583	\$	270,714		
97	96	Additional Post-Retirement Contribution					
98	97	ADDITIONAL POST-RETIREMENT CONTRIBUTION	\$ 15,447	\$	15,579		
99	98	BPA Internal Support - G&A and Shared Srv. (excludes direct project support)					
100	99	AGENCY SERVICES G&A	\$ 49,961	\$	50,064		
101	100	Sub-Total BPA Internal Support Services	\$ 49,961	\$	50,064		
102	101	Supply Chain - Shared Services	A 07.400		05.040		
103 104	102 103	General and Administrative/Shared Services Sub-Total Bad Debt Expense	\$ 65,408 \$ -	<b>\$</b> \$	65,643		
105	103	Other Income, Expenses, Adjustments	\$ -	\$			
106	105	Non-Federal Debt Service	•	Ť			
107	106	Energy Northwest Debt Service					
108	107	COLUMBIA GENERATING STATION DEBT SVC	\$ 235,736	\$	226,169		
109	108	WNP-1 DEBT SVC	\$ 166,013	\$	167,549		
110	109	WNP-3 DEBT SVC	\$ 144,892	\$	169,093		
111	110	EN RETIRED DEBT					
112 113	111 112	EN LIBOR INTEREST RATE SWAP Sub-Total	\$ 546,641	\$	562,811		
114	113	Non-EN Debt Service	J40,041	•	302,011		
115	114	COWLITZ FALLS DEBT SVC	\$ 11,566	\$	11,563		
116	115	N. WASCO DEBT SVC	\$ 2,200	\$	2,196		
117	116	TROJAN DEBT SVC	\$ -	\$	-		
118	117	CONSERVATION DEBT SVC	\$ 5,079	\$	4,924		
119	118	Sub-Total	\$ 18,845				
120 121	119 120	Non-Federal Debt Service Sub-Total Depreciation (excludes TMS)	\$ 565,486 \$ 120,111				
121	121	Amortization (excludes 1 MS) Amortization (excludes ConAug amortization)	\$ 64,392	\$			
123	122	Total Operating Expenses	\$ 2,204,403	\$			
124	123	· · · · · · · · · · · · · · · · · · ·	-,,	ľ	_,,		
125	124	Other Expenses					
126	125	Net Interest Expense	\$ 167,119				
127	126	LDD	\$ 26,419	\$			
128	127	Irrigation Rate Mitigation Costs	\$ 12,036	\$			
129 130	128 129	Sub-Total Total Expenses	\$ 205,574 \$ 2,409,977	\$			
131	130	Total Expenses	\$ 2,409,977	3	2,547,990		
132	131	Revenue Credits					
133	132	Ancillary and Reserve Service Revs. Total	\$ 90,176	\$	102,730		
134	133	Downstream Benefits and Pumping Power	\$ 8,921	\$	8,921		
135	134	4(h)(10)(c)	\$ 96,689	\$			
136	135	Colville and Spokane Settlements	\$ 4,600	\$	4,600		
137	136	FCCF	e 00.500		20.500		
138 139	137 138	Energy Efficiency Revenues Miscellaneous	\$ 20,500 \$ 3,420	\$			
140	139	Green Tag revenue associated with Klondike III	\$ -	\$			
141	140	Ad Hoc revenue credit adjustment	·				
142	141	Total Revenue Credits	\$ 224,306	\$	242,140		
143	142	Augmentation Costs (not subject to True-Up)					
144	143	Non-DSI Net Augmentation Costs	e 00.040		400.075		
145 146	144 145	Gross Augmentation cost (72.7 aMW, 274.7 aMW) Minus revenues 70.7 aMW, 267.1 aMW @ PF rate	\$ 26,019 \$ (17,815				
147	146	Willius Teverides 70.7 alwivv, 207.1 alvivv @ FF Tate	\$ 8,204	\$			
148	147	DSI Net Augmentation Costs	* -,	· ·	,		
149	148	Gross Augmentation cost (413 aMW, 413 aMW)	\$ 154,746	\$	164,668		
150	149	Minus revenues 402 aMW, 402 aMW @ IP rate	\$ (121,852)				
151	150		\$ 32,895	\$	42,815	]	
152	151	Total Not Cost of Augmentation	e 44.000		92.005		
153 154	152 153	Total Net Cost of Augmentation	\$ 41,099	\$	83,865		
155	154						
156	155	Minimum Required Net Revenue calculation					
157	156	Principal Payment of Fed Debt for Power	\$ 202,673	\$	204,163		
158	156a	Shift in principal payment	\$ 42,000	\$	(42,000)		
159	157	Irrigation assistance	\$ -	\$			
160	158	Depreciation	\$ 120,111				
161 162	159	Amortization Controlization Adjustment	\$ 77,728 \$ (45,937				
162	160 161	Capitalization Adjustment Bond Premium Amortization	\$ (45,937 \$ 185				
164	162	Principal Payment of Fed Debt exceeds non cash expenses	\$ 92,586				
165	163	Minimum Required Net Revenues	\$ 92,586				
166	164	·					2-Year Total Rev
167	165	Annual Slice Revenue Requirement (Amounts for each FY)	\$ 2,319,356	\$	2,390,704		\$ 4,710,060
168	166	CLICE TRUE LID AD HISTMENT CALCULATION					
169 170	167 168	SLICE TRUE-UP ADJUSTMENT CALCULATION					
171		FY 2010-2011 Average Slice Revenue Requirement determined in WP-10 rate case	\$ 2,355,030				
172	170	TRUE UP AMOUNT (Diff. between actual Slice Rev Reqt and forecast average Slice Rev Reqt)	\$ (35,674	) \$	35,674		
173	171	AMOUNT BILLED (22.6278 percent)	\$ (8,072				
174	172	Slice Implementation Expenses (not incl. in base rate)	\$ 2,790	\$	2,870		
175	173	TRUE UP ADJUSTMENT	\$ (5,282	FY 2010 \$	10,942	FY 2011	
176	174	CLICE DATE CALCULATION (C)		True-Up		True-Up	
177 178	175 176	SLICE RATE CALCULATION (\$) Monthly Slice Revenue Requirement (2-Year total divided by 24 months)					\$ 196,252,520
178	176	One Percent of Monthly Requirement (Slice Rate per percent Slice - Monthly Slice Rev. Reg't. divided	by 100)				\$ 196,252,520 \$ 1,962,525
180	178	, , , , , , , , , , , , , , , , , , ,					,,
181	179	ANNUAL BASE SLICE REVENUES					\$ 532,891,534
182	180	Annual Slice Implementation Expenses					\$ 2,830,000
183	181	TOTAL ANNUAL SLICE REVENUES					\$ 535,721,534

**CHAPTER 4: REVENUE FORECAST** 



	А	В	С	D	Е	F
1			Table 4.5: 4l	h10C Credits		
2						
3			4h10C Credi	its (\$ Million)		
4						
5	Fiscal Year	Purch. Cost	BPA Exp.	BPA Cap.	<u>Total</u>	Credit @ 22.3%
6						
7	FY 2010	146.8	216.8	70.0	433.6	96.7
8						
9	FY 2011	159.5	237.8	60.0	457.3	102.0

**Table 4.6.1 Summary of Revenues at Current Rates** 

	A	В	С	D	Е	F	G
1							
2		FY 200	9	FY 201	10	FY 201	1
3		(\$000)	aMW	(\$000)	aMW	(\$000)	aMW
4	Revenues						
5	PF Preference	\$1,228,242	5,299	\$1,212,059	5,211	\$1,229,472	5,284
6	Lookback Adjustment	(\$70,769)	0	\$0	0	\$0	0
7	PF Slice	\$502,645	1,680	\$508,173	2,082	\$523,821	2,067
8	Pre-sub/Hungry Horse	\$37,626	210	\$45,156	199	\$45,695	201
9	Irrigation Mitigation	\$20,212	196	\$22,022	191	\$21,953	190
10	Industrial Power	\$0	0	\$122,619	402	\$122,619	402
11	Long-Term Obligations	\$91,498	624	\$85,694	655	\$78,483	609
12	Generation Inputs/Reserve Services	\$80,897	24	\$101,590	14	\$101,590	14
13	Slice True-Up	\$5,370	0	(\$5,282)	0	\$10,942	0
14	Network Wind Integration & Shaping	\$1,989	0	\$1,953	0	\$1,953	0
15	4h10C credits	\$78,578	0	\$96,689	0	\$101,969	0
16	Colville credits	\$4,600	0	\$4,600	0	\$4,600	0
17	Downstream Benefits/Storage	\$9,646	175	\$8,921	175	\$8,921	175
18	Energy Efficiency	\$14,500	0	\$20,500	0	\$20,500	0
19	Green Tags/Green Premiums	\$3,644	0	\$5,040	0	\$5,040	0
20	Misc Generation	\$3,927	0	\$3,420	0	\$3,420	0
21	Secondary Sales	\$327,742	1,164	\$544,632	1,694	\$593,944	1,751
22	Bookouts	(\$24,059)	-59	\$0	0	\$0	0
23	Ad hoc Gen Input adjustment						
24	Total Revenue	\$2,316,288	9,312	\$2,777,787	10,623	\$2,874,922	10,693
25	Purchases						
26	Augmentation Purchases	\$3,134	13	\$180,622	486	\$272,955	688
27	Secondary Purchases	\$211,930	553	\$84,566	195	\$70,692	149

П	A	В	С	D	Е	F	G	Н	I	J	K	L	M	N	0	P	Q
1		Jul 17, 2009 @ 12:19			s at Curren												
3				Reven	ue (\$ Thousa FY2009	inds)											
4					1 12003												
5														Г	Fiscal V	'ear 200	19
7		Western HUB	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Total	aMW	
8		West Hub PF Billing Determinants PF Full Service	\$2.670	\$2.477	\$4.026	\$2.904	\$3.151	\$2.697	\$2.262	\$1.458	\$1.285	\$1.611	\$1.830	\$1.869	\$28.241		
10		LLH Energy Flat	275.595	328,586	414.396	\$2,904 401.655	336,365	326.384	301.624	289.916	252,472	266.250	254,797	263,424	3.711.464	424	3711
11		HLH Energy Flat	461,962	452,386	622,642	597,386	521,181	525,558	477,297	430,813	420,450	411,867	430,484	409,319	5,761,345	658	5761
12		PF Flat LLH Energy Rate PF Flat HLH Energy Rate	\$21.40 \$29.21	\$22.72 \$31.15	\$23.85 \$32.51	\$19.96 \$27.60	\$20.16 \$28.19	\$19.17 \$26.15	\$17.63 \$24.54	\$14.17 \$20.50	\$9.85 \$18.55	\$16.73 \$22.85	\$19.85 \$26.76	\$22.17 \$27.62			
14 15		LLH Energy Revenue Flat Revenue = 11*13/1000	\$5,343	\$7,465	\$9,883	\$8,017	\$6,781	\$6,257	\$5,318	\$4,108	\$2,487	\$4,454	\$5,058	\$5,840	\$71,012		
15 16		HLH Energy Revenue Flat Revenue= 12*14/1000 Demand	\$12,694 1,398	\$14,092 1,214	\$20,242 1,881	\$16,488 1,596	\$14,692 1,703	\$13,743 1,568	\$11,713 1,396	\$8,832 1,088	\$7,799 1,045	\$9,411 1,074	\$11,520 1,040	\$11,305 1,027	\$152,532 16,030		
17		PF GSP Demand Rate	\$1.91	\$2.04	\$2.14	\$1.82	\$1.85	\$1.72	\$1.62	\$1.34	\$1.23	\$1.50	\$1.76	\$1.82			
18		Demand Revenue = 17*18	\$2,563	\$2,477	\$4,026	\$2,904	\$3,151	\$2,697	\$2,262	\$1,458	\$1,285	\$1,611	\$1,830	\$1,869	\$28,134		
19 20		Load Variance PF I d Variance Rate	750,216 \$0.46	793,646 \$0.46	1,051,953 \$0.46	1,013,764 \$0.46	869,157 \$0.46	909,632 \$0.46	836,154 \$0.46	782,813 \$0.46	732,274 \$0.46	737,461 \$0.46	743,680 \$0.46	725,315 \$0.46	9,946,064	1135	9946
21		Load Variance Revenue = 20*21/1000	\$315	\$365	\$484	\$466	\$400	\$418	\$385	\$360	\$337	\$339	\$342	\$334	\$4,545		
22		Low Density Discount Percent =30/(15+16+21+22+25+28)	-1.66%	-1.84%	-1.95%	-1.95%	-1.94%	-2.38%	-2.38%	-2.44%	-2.40%	-2.28%	-2.26%	-2.26%			
23 24	4 000 646	Low Density Discount	-\$348 -\$1.009	-\$449 -\$1.009	-\$675 -\$1.009	-\$543 -\$1.009	-\$486 -\$1.009	-\$550 -\$1.009	-\$468 -\$1.009	-\$360 -\$1.009	-\$286 -\$1,009	-\$361 -\$1.009	-\$425 -\$1.009	-\$438 -\$1.009	-\$5,388 -\$12.103		
25	- 1,000,018	B LBCRAC True-up/Lookback Adjust PF Other Energy	0	-\$1,009 0	-\$1,009 0	-\$1,009 0	-\$1,009 0	-φ1,009	900,1 و-	-φ1,UU9	-\$1,UU9	900,1 و-	900,1 و-	-φ1,009	-p 1∠, 1U3		
25 26 27		PF Other revenues	\$4	\$0	\$0	\$0	\$0	ec 070	85.050	65.040	20.000	64.055	er 700	80 450	\$4		
28		PF Partial Service	\$6,680 \$14,538	\$7,889 \$13,817	\$9,843 \$18,750	\$7,950 \$15,450	\$6,833 \$13,924	\$6,270 \$15,162	\$5,250 \$13,621	\$5,048 \$11,657	\$2,636 \$9,097	\$4,855 \$11,913	\$5,766 \$14,511	\$6,458 \$14,291	\$75,479 \$166,728		
28 29		LLH Energy Flat	312,148	347,212	412,690	398,298	338,926	327,080	297,780	356,279	267,650	290,224	290,497	291,308	3,930,093	449	3,930
30		HLH Energy Flat LLH Energy Revenue Flat (30*13)/1000	497,690 \$6,681	443,562 \$7,889	576,742 \$9,843	559,797 \$7,950	493,919 \$6,833	579,795 \$6,270	555,036 \$5,250	568,611 \$5,048	490,382 \$2,636	521,350 \$4,855	542,248 \$5,766	517,406 \$6,458	6,346,539 \$75,480	724	6,347
32		HLH Energy Revenue Flat (31*14)/1000	\$14,535	\$13,817	\$18,750	\$15,450	\$13,924	\$15,162	\$13,621	\$11,657	\$9,097	\$11,913	\$14,511	\$14,291	\$166,726		
33		GSP Demand Demand Revenue (34*18)	1,454 \$2,777	1,321 \$2,695	1,951 \$4 175	1,672 \$3,043	1,676 \$3,100	1,468 \$2,525	1,425 \$2,308	1,359 \$1,822	1,168 \$1,437	1,252 \$1,878	1,262 \$2,221	1,265 \$2,303	17,273 \$30,283		
34 35		Load Variance	1,038,945	1,019,974	1,238,664	1,211,281	1,063,890	1,144,954	1,087,995	1,052,352	1,007,251	1,042,228	1,053,565	1,021,789	12,982,888	1482	12983
36	4 422 000	Load Variance Revenue (36*21)/1000 D LBCRAC True-up/Lookback Adjust	\$478 -\$1.134	\$469 -\$1,134	\$570 -\$1.134	\$557 -\$1.134	\$489 -\$1,134	\$527 -\$1,134	\$500 -\$1,134	\$484 -\$1,134	\$463 -\$1,134	\$479 -\$1,134	\$485 -\$1,134	\$470 -\$1,134	\$5,972 -\$13,608		
38	-1,133,960	PF Other Energy	-\$1,134	-\$1,134 0	-\$1,134	-\$1,134 0	-\$1,134 1	-\$1,134	-\$1,134	-\$1,134	-\$1,134	-\$1,134	-\$1,134	-\$1,134	-\$13,008		
39		PF Other revenues	\$0	\$23	\$0	\$0	\$0								\$23		
40		PF Block Service	\$16,430	\$20,167	\$25.574	\$21.827	\$20.124	\$18,720	\$13.534	\$8.416	\$7,202	\$9,998	\$12.887	\$15.465	\$190.343		
42		LLH Energy Flat	392,808	521,676	578,264	588,104	510,624	562,702	403,016	363,494	291,791	357,555	390,748	447,947	5,408,729	617	5,409
44		HLH Energy Flat LLH Energy Revenue Flat (43*13)/1000	562,464 \$8,406	647,424 \$11,852	786,656 \$13,792	790,816 \$11,739	713,856 \$10,294	715,854 \$10,787	551,495 \$7,105	410,513 \$5,151	388,255 \$2,874	437,536 \$5,982	481,595 \$7,756	559,934 \$9,931	7,046,398 \$105,669	804	7,046
45		LLH Energy Revenue Stepped (56*19)/1000	\$0,400		\$13,792	\$11,739			\$1,105	\$5,151	\$2,074	\$3,862	\$1,150	\$9,931	\$105,009		
46 47		HLH Energy Revenue Flat (44*14)/1000 HLH Energy Revenue Stepped (57*20)/1000	\$16,430	\$20,167	\$25,574	\$21,827	\$20,124	\$18,720	\$13,534	\$8,416	\$7,202	\$9,998	\$12,887	\$15,465	\$190,343 \$0		
48		GSP Demand	1,408	1,812	2,006	2,059	1,992	1,721	1,326	1,137	1,088	1,225	1,308	1,400	18,482		
49 50	4 000 000	Demand Revenue (49*24)	\$2,689	\$3,696	\$4,293	\$3,747	\$3,685	\$2,960	\$2,148	\$1,523	\$1,338	\$1,838	\$2,303	\$2,548	\$32,769		
51	-1,309,822	2 LBCRAC True-up/Lookback Adjust PF SUMY	-\$1,310 \$0	-\$1,310 \$0	-\$1,310 \$0	-\$1,310 \$0	-\$1,310 \$0	-\$1,310 \$0	-\$1,310 \$0	-\$1,310 \$0	-\$1,310 \$0	-\$1,310 \$0	-\$1,310 \$0	-\$1,310 \$0	-\$15,718 \$0		
52 53		Low Density Discount Percent = 70/(59+60+61+62+64)	-0.89%	-0.79%	-0.80%	-0.81%	-0.79%	-0.75%	-1.00%	-0.94%	-0.87%	-0.78%	-0.71%	-0.95%			
53		Low-Density Discount PF Other Energy	-\$246	-\$282	-\$351	-\$304	-\$271	-\$244	-\$228	-\$143	-\$99	-\$140	-\$162	-\$266	-\$2,735 0		
55		PF Block Other Revenues													\$0		
56 57		Irrigation Mitigation LLH	0	0	0	0	0	\$0 0	\$0 0	\$1,334 28.360	\$1,603 39,538	\$2,428 44.975	\$2,494 39,179	0	\$7,859 152.052	17	152
58		Irrigation Mitigation HLH	0	0	0	0	0	0	0	45,493	65,398	73,313	64,136	0	248,340	28	248
59 60		Irrigation Mitigation Revenues	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$710	\$721	\$1,383	\$1,568	\$0	\$4,382		
61		Pt Townsend LLH	5,124	5,972	3,984	5,629	5,721	5,559	5,168	5,848	5,168	5,576	5,576	5,440	64,765	7	65
62		Pt Townsend HLH Pt Townsend Demand	6,871 18	6,774 19	5,551 19	7,230 17	7,429 17	7,072 17	7,072 17	6,800 17	7,072 17	7,072	7,072 17	6,800 17	82,815 210	9	83
63 64		Pt Townsend Demand Pt Townsend Revenues	18 \$359	19 \$401	19 \$328	17 \$357	17 \$371	17 \$328	17 \$299	17 \$252	17 \$210	17 \$288	17 \$337	17 \$346	\$3,876		
65		PF SLICE															
66 67		PER SLICE Percent of SLICE	18.5108%	18.5108%	18.5108%	18.5108%	18.5108%	18.5108%	18.5108%	18.5108%	18.5108%	18.5108%	18.5108%	18.5108%	18.51%	1331	
68		Slice rate	\$1,873	\$1,873	\$1,873	\$1,873	\$1,873	\$1,873	\$1,873	\$1,873	\$1,873	\$1,873	\$1,873	\$1,873			
69 70		Slice Charges (\$000) = 69*70*100 Monetary Benefits to IOUs (\$000)	\$34,660 \$0	\$34,660 \$0	\$34,660 \$0	\$34,660 \$0	\$34,660 \$0	\$34,663 \$0	\$34,663 \$0	\$34,663 \$0	\$34,663 \$0	\$34,663 \$0	\$34,663 \$0	\$34,663 \$0	\$415,936 \$0		
71	-1,091,516	B LBCRAC True-up/Lookback Adjust	-\$1,092	-\$1,092	-\$1,092	-\$1,092	-\$1,092	-\$1,092	-\$1,092	-\$1,092	-\$1,092	-\$1,092	-\$1,092	-\$1,092	-\$13,098		
72		LDD Percentage Low-Density Discount	-1.08% -373	-1.08% -373	-1.08% -373	-1.08% -373	-1.08% -373	-1.12% -\$389	-1.12% -\$389	-1.12% -\$389	-1.12% -\$389	-1.12% -\$389	-1.12% -\$389	-1.12% -\$389	-\$4,588		
73 74		Slice Other	-3/3 \$0	-3/3 \$0	-\$1,033	-373 \$52	-3/3 \$0	-9369	-4069	-0069	-\$369	-0009	-\$369	-9369	-\$4,588 -\$981		
75 76		West Hub FPS (Pre-Subscription) Sales	4.040	4.040	4.040	4 040	4.450	0.00=		7.00	0.00	0.000	0.000	0.700	E0 70-	_	
77		LLH Energy Full Service LLH Energy Revenue	1,248 \$27	1,348 \$27	1,312 \$26	1,312 \$26	1,152 \$23	6,867 \$27	6,384 \$25	7,224 \$29	6,384 \$25	6,888 \$27	6,888 \$27	6,720 \$27	53,727 \$315	6	54
78		HLH Energy Full Service	1,728	1,536	1,664	1,664	1,536	8,736	8,736	8,400	8,736	8,736	8,736	8,400	68,608	8	69
79 80		HLH Energy Revenue GSP Demand	\$34 4	\$30 4	\$33 4	\$33 4	\$30 4	\$35 21	\$35 21	\$33 21	\$35 21	\$35 21	\$35 21	\$33 21	\$400 167		
81		Demand Revenue	-\$4	-\$4	-\$4	-\$4	-\$4								-\$20		
82 83		Load Variance Load Variance Revenue	0 \$0	0 \$0	0 \$0	0 \$0	0 \$0	15,603 \$7	15,120 \$7	15,624 \$7	15,120 \$7	15,624 \$7	15,624 \$7	15,120 \$7	107,835 \$50	12	108
84		Low-Density Discount	40	30	\$0	30	40	9/	91	ş/	31	9/	31	31	\$0		
85 86		LT SURPLUS FB CRAC Netrwork Wind Integration Service													\$0		
87		Other Pre-Subscription revenues	\$10	\$10	\$14	\$13	\$10								\$57		
88		Total	\$102,491	\$114,484	\$140,744	\$121,509	\$112,891	\$109,398	\$93,542	\$79,115	\$67,298	\$83,727	\$95,796	\$100,253	\$1,263,672		

	A	В	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF
1		Jul 17, 2009 @ 12:19			s at Curren												
3				kevenu	ie (\$ Thous FY2010	arius)											
5																	
6														Г	Fiscal \	rear 201	0
7		Western HUB	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	<u>Jun-10</u>	<u>Jul-10</u>	Aug-10	Sep-10	Total	aMW	GWh
8		West Hub PF Billing Determinants PF Full Service	\$2.783	\$3.211	\$3.632	\$3,225	\$3.175	\$2.664	\$2.237	\$1,430	\$1.280	\$1.619	\$1.806	\$1.855	\$28.916		
10		LLH Energy Flat	275,385	349,641	387,390	385,617	328,467	312,183	291,681	277,240	243,958	270,676	249,430	259,424	3,631,092	415	3631
11 12		HLH Energy Flat PF Flat LLH Energy Rate	458,093 \$21.40	523,708 \$22.72	582,651 \$23.85	581,666 \$19.96	525,031 \$20.16	508,570 \$19.17	464,840 \$17.63	417,011 \$14.17	407,021 \$9.85	389,772 \$16.73	420,595 \$19.85	403,621 \$22.17	5,682,579	649	5683
13		PF Flat HLH Energy Rate	\$29.21	\$31.15	\$32.51	\$27.60	\$28.19	\$26.15	\$24.54	\$20.50	\$18.55	\$22.85	\$26.76	\$27.62			
14		LLH Energy Revenue Flat Revenue = 11*13/1000	\$5,893	\$7,944	\$9,239	\$7,697	\$6,622	\$5,985	\$5,142	\$3,928	\$2,403	\$4,528	\$4,951	\$5,751	\$70,085		
15 16		HLH Energy Revenue Flat Revenue= 12*14/1000 Demand	\$13,381 1,457	\$16,314 1,574	\$18,942 1,697	\$16,054 1,772	\$14,801 1,716	\$13,299 1,549	\$11,407 1,381	\$8,549 1,067	\$7,550 1,041	\$8,906 1,079	\$11,255 1,026	\$11,148 1,019	\$151,606 16,378		
17		PF GSP Demand Rate	\$1.91	\$2.04	\$2.14	\$1.82	\$1.85	\$1.72	\$1.62	\$1.34	\$1.23	\$1.50	\$1.76	\$1.82			
18 19		Demand Revenue = 17*18 Load Variance	\$2,783 754.019	\$3,211 895.929	\$3,632 995.586	\$3,225 991.790	\$3,175 875.886	\$2,664 843.421	\$2,237 781.180	\$1,430 721.793	\$1,280 677.495	\$1,619 685.878	\$1,806 694,615	\$1,855 682.762	\$28,916	1096	9600
20		PF Ld Variance	754,019 \$0.46	\$0.46	\$0.46	\$0.46	\$0.46	\$0.46	\$0.46	\$0.46	\$0.46	\$0.46	\$0.46	\$0.46	9,600,354	1096	9600
21		Load Variance Revenue = 20*21/1000	\$347	\$412	\$458	\$456	\$403	\$388	\$359	\$332	\$312	\$316	\$320	\$314	\$4,416		
22		Low Density Discount Percent =30/(15+16+21+22+25+28)	-2.02%	-2.09%	-2.13%	-2.13%	-2.13%	-2.08%	-2.10%	-2.08%	-2.06%	-1.99%	-1.97%	-1.98%			
23 24		Low Density Discount	-\$452	-\$582	-\$688	-\$583	-\$532	-\$464	-\$401	-\$296	-\$238	-\$306	-\$362	-\$378	-\$5,283 \$0		
25	- 1,000,019	LBCRAC True-up/Lookback Adjust PF Other Energy													\$0		
26 27		PF Other revenues				****									\$0		
27		PF Partial Service	\$6,266 \$13,670	\$8,556 \$15,745	\$9,722 \$18,319	\$8,015 \$14,934	\$6,748 \$14,105	\$6,226 \$13,073	\$5,690 \$11,938	\$4,927 \$9,218	\$2,866 \$8,251	\$5,142 \$9,965	\$5,838 \$12,840	\$6,583 \$11,987	\$76,579 \$154,045		
29		LLH Energy Flat	292,812	376,569	407,646	401,531	334,706	324,762	322,760	347,741	290,928	307,350	294,113	296,931	3,997,849	456	3,998
30		HLH Energy Flat	468,002 \$6,266	505,457 \$8,556	563,482 \$9,722	541,076 \$8,015	500,348 \$6,748	499,916 \$6,226	486,488 \$5,690	449,661 \$4,927	444,801 \$2,866	436,120 \$5,142	479,809 \$5,838	434,003 \$6,583	5,809,163 \$76,579	663	5,809
31 32		LLH Energy Revenue Flat (30*13)/1000 HLH Energy Revenue Flat (31*14)/1000	\$6,266 \$13,670	\$8,556 \$15,745	\$9,722 \$18,319	\$8,015 \$14,934	\$6,748 \$14,105	\$6,226	\$5,690 \$11,938	\$4,927	\$2,866	\$5,142 \$9,965	\$5,838 \$12,840	\$6,583 \$11,987	\$76,579 \$154,045		
33		GSP Demand	1,453	1,654	1,693	1,685	1,662	1,525	1,448	1,307	1,236	1,380	1,315	1,278	17,636		
34 35		Demand Revenue (34*18) Load Variance	\$2,775 1,010,835	\$3,374 1,134,069	\$3,623 1,251,375	\$3,067 1,220,046	\$3,075 1,087,221	\$2,623 1,090,317	\$2,346 1,060,987	\$1,751 1,049,283	\$1,520 988,300	\$2,070 987,361	\$2,314 1,011,512	\$2,326 961,639	\$30,865 12,852,945	1467	12853
36		Load Variance Revenue (36*21)/1000	\$465	\$522	\$576	\$561	\$500	\$502	\$488	\$483	\$455	\$454	\$465	\$442	\$5,912	1407	12000
37 38		LBCRAC True-up/Lookback Adjust PF Other Energy	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
39		PF Other Energy PF Other revenues													\$0		
40		DE DIVIL OVER THE															
41 42		PF Block Service LLH Energy Flat	\$16,393 391,915	\$20,107 520,023	\$25,542 577.456	\$21,232 609.659	\$20,268 514.460	\$19,607 520.497	\$13,447 381.897	\$8,826 340.167	\$7,328 281.881	\$10,341 339.246	\$13,192 376,183	\$15,825 428.295	\$192,108 5.281.679	603	5.282
42 43		HLH Energy Flat	561,229	645,484	785,676	769,284	718,962	749,781	547,958	430,537	395,060	452,541	492,986	572,946	7,122,444	813	7,122
44 45		LLH Energy Revenue Flat (43*13)/1000 LLH Energy Revenue Stepped (56*19)/1000	\$8,387	\$11,815	\$13,772	\$12,169	\$10,372	\$9,978	\$6,733	\$4,820	\$2,777	\$5,676	\$7,467	\$9,495	\$103,460 \$0		
46		HLH Energy Revenue Flat (44*14)/1000	\$16,393	\$20,107	\$25,542	\$21,232	\$20,268	\$19,607	\$13,447	\$8,826	\$7,328	\$10,341	\$13,192	\$15,825	\$192,108		
47		HLH Energy Revenue Stepped (57*20)/1000													\$0		
48 49		GSP Demand Demand Revenue (49*24)	1,405 \$2.684	1,787 \$3.645	1,982 \$4,241	2,038 \$3,709	2,005 \$3.709	1,889 \$3,249	1,407 \$2,279	1,283 \$1,719	1,148 \$1.412	1,279 \$1,919	1,367 \$2.406	1,470 \$2.675	19,060 \$33,648		
50	-1,309,822	LBCRAC True-up/Lookback Adjust													\$0		
51 52		PF SUMY Low Density Discount Percent = 70/(59+60+61+62+64)	\$0 -0.90%	\$0 -0.79%	\$0 -0.81%	\$0 -0.81%	\$0 -0.79%	\$0 -0.73%	\$0 -0.99%	\$0 -0.90%	\$0 -0.83%	\$0 -0.75%	\$0 -0.68%	\$0 -0.93%	\$0		
53		Low-Density Discount	-\$246	-\$282	-\$351	-\$302	-\$273	-\$240	-\$223	-\$138	-\$96	-\$135	-\$156	-\$260	-\$2,703		
54		PF Other Energy													0		
55 56		PF Block Other Revenues								\$1,333	\$1,601	\$2,424	\$2,491		\$7,849		
57		Irrigation Mitigation LLH	0	0	0	0	0	0	0	28,360	39,538	44,975	39,179	0	152,052	17	152
58 59		Irrigation Mitigation HLH Irrigation Mitigation Revenues	0 \$0	0 \$0	0 \$0	0 \$0	0 \$0	0 \$0	0 \$0	45,414 \$805	65,334 \$836	73,164 \$1,557	64,012 \$1,746	0 \$0	247,924 \$4,944	28	248
60			φU	40	φU	U	40	Ψ	40	4003	9000	\$1,00 <i>1</i>	¥1,740	φU	¥4,044		
61 62		Pt Townsend LLH Pt Townsend HLH															
63		Pt Townsend HLH Pt Townsend Demand															
64		Pt Townsend Revenues															
65 66		PF SLICE															
67		Percent of SLICE	18.5108%	18.5108%	18.5108%	18.5108%	18.5108%	18.5108%	18.5108%	18.5108%	18.5108%	18.5108%	18.5108%	18.5108%	18.51%	1703	
68 69		Slice rate Slice Charges (\$000) = 69*70*100	\$1,873 \$34.664	\$1,873 \$34,664	\$1,873 \$34.664	\$1,873 \$34.664	\$1,873 \$34.664	\$1,873 \$34.664	\$1,873 \$34.664	\$1,873 \$34,664	\$1,873 \$34,664	\$1,873 \$34.664	\$1,873 \$34,664	\$1,873 \$34.664	\$415,969		
70		Monetary Benefits to IOUs (\$000)	\$34,004	\$34,004	\$34,664	\$34,004	\$34,004	\$34,004	\$34,004	\$34,004	\$34,004	\$34,004	\$34,004	\$34,664	\$0		
71		LBCRAC True-up/Lookback Adjust													\$0		
72 73		LDD Percentage Low-Density Discount	-1.15% -\$400	-1.15% -\$400	-1.15% -\$400	-1.15% -\$400	-1.15% -\$400	-1.15% -\$400	-1.15% -\$400	-1.15% -\$400	-1.15% -\$400	-1.15% -\$400	-1.15% -\$400	-1.15% -\$400	-\$4,799		
74 75		Slice Other					4.20		4.20		4	Ţu			,. 20		
75 76		West Hub FPS (Pre-Subscription) Sales LLH Energy Full Service	1,248	1,352	1,312	1,376	1,152	1,240	1,216	1,376	1,216	1,312	1,312	1,280	15,392	2	15
77		LLH Energy Revenue	\$27	\$31	\$31	\$27	\$23	\$24	\$21	\$19	\$12	\$22	\$26	\$28	\$292		
78		HLH Energy Full Service	1,728	1,536	1,664	1,600	1,536	1,728	1,664	1,600	1,664	1,664	1,664	1,600	19,648	2	20
79 80		HLH Energy Revenue GSP Demand	\$50 4	\$48 4	\$54 4	\$44 4	\$43 4	\$45 4	\$41 8	\$33 4	\$31 4	\$38 4	\$45 8	\$44 4	\$516 56		
81		Demand Revenue													\$0		
82 83		Load Variance Load Variance Revenue	2,976 \$1	2,888 \$1	2,976 \$1	2,976 \$1	2,688 \$1	2,968 \$1	2,880 \$1	2,976 \$1	2,880 \$1	2,976 \$1	2,976 \$1	2,880 \$1	35040 \$16	4	35
84		Low-Density Discount	\$1	φI	\$1	φï	\$1	φT	\$1	φT	\$1	\$1	\$1	φT	\$10		
85		LT SURPLUS FB CRAC													-		
86 87		Netrwork Wind Integration Service Other Pre-Subscription revenues													\$0 \$0		
88		Total	\$106,689	\$125,124	\$141,378	\$124,570	\$117,303	\$111,224	\$95,771	\$80,672	\$70,964	\$86,376	\$98,419	\$102,102	\$1,260,592		

	Α	В	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AO	AR	AS	AT	AU
1		Jul 17, 2009 @ 12:19	7.0	Revenue	s at Curren		7110		7.0.11		710			7410			-110
2				Revenu	ie (\$ Thous FY2011	ands)											
3 4 5					112011												
6														Г	Fiscal \	rear 201	1
7		Western HUB	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Total	aMW	
8		West Hub PF Billing Determinants PF Full Service	\$2 834	\$3 268	\$3 689	\$3 272	\$3 221	\$2.707	\$2 274	\$1 458	\$1 306	\$1 652	\$1.843	\$1.891	\$29 416		
10		LLH Energy Flat	283,578	354,922	394,600	390,289	330,326	317,074	296,897	282,531	248,811	267,121	253,314	264,571	3,684,034	421	3684
11		HLH Energy Flat	465,668	536,072	592,983	588,814	528,514	516,024	472,333	424,229	414,610	410,079	431,338	411,221	5,791,885	661	5792
12 13		PF Flat LLH Energy Rate PF Flat HLH Energy Rate	\$21.40 \$29.21	\$22.72 \$31.15	\$23.85 \$32.51	\$19.96 \$27.60	\$20.16 \$28.19	\$19.17 \$26.15	\$17.63 \$24.54	\$14.17 \$20.50	\$9.85 \$18.55	\$16.73 \$22.85	\$19.85 \$26.76	\$22.17 \$27.62			
14		LLH Energy Revenue Flat Revenue = 11*13/1000	\$6,069	\$8,064	\$9,411	\$7,790	\$6,659	\$6,078	\$5,234	\$4,003	\$2,451	\$4,469	\$5,028	\$5,866	\$71,123		
15 16		HLH Energy Revenue Flat Revenue= 12*14/1000 Demand	\$13,602 1.484	\$16,699 1,602	\$19,278 1.724	\$16,251 1.798	\$14,899 1,741	\$13,494 1,574	\$11,591 1.404	\$8,697 1.088	\$7,691 1,062	\$9,370 1,101	\$11,543 1.047	\$11,358 1,039	\$154,472 16.664		
17		PF GSP Demand Rate	\$1.91	\$2.04	\$2.14	\$1.82	\$1.85	\$1.72	\$1.62	\$1.34	\$1.23	\$1.50	\$1.76	\$1.82			
18		Demand Revenue = 17*18 Load Variance	\$2,834 769.662	\$3,268 913.492	\$3,689 1.013.058	\$3,272 1,003,535	\$3,221 881.143	\$2,707 855.669	\$2,274 793,774	\$1,458 734,170	\$1,306 689,789	\$1,652 702.458	\$1,843 709.091	\$1,891 695,357	\$29,416 9,761,198	1114	9761
20		PF Ld Variance Rate	\$0.46	\$0.46	\$0.46	\$0.46	\$0.46	\$0.46	\$0.46	\$0.46	\$0.46	\$0.46	\$0.46	\$0.46	0,701,100		0.01
21		Load Variance Revenue = 20*21/1000	\$354	\$420	\$466	\$462	\$405	\$394	\$365	\$338	\$317	\$323	\$326	\$320	\$4,490		
22		Low Density Discount Percent =30/(15+16+21+22+25+28) Low Density Discount	-2.02% -\$462	-2.08% -\$593	-2.13% -\$698	-2.13% -\$593	-2.15% -\$541	-2.08% -\$471	-2.09% -\$408	-2.08% -\$301	-2.07% -\$243	-2.00% -\$316	-1.98% -\$371	-1.99% -\$386	-\$5,382		
24		) LBCRAC True-up/Lookback Adjust	-\$402	-\$383	-\$090	-\$080	-\$341	-5471	-\$400	-\$301	-9243	-\$310	-\$371	-\$300	-\$5,362 \$0		
25		PF Other Energy															
26 27		PF Other revenues	\$6,643	\$8,460	\$9,810	\$8,157	\$6,883	\$6,352	\$5,808	\$5,016	\$2,923	\$5,312	\$5,764	\$6,717	\$0 \$77,846		
28 29		PF Partial Service	\$13,758	\$16,372	\$18,498	\$15,223	\$14,404	\$13,355	\$12,198	\$9,408	\$8,430	\$10,146	\$13,355	\$12,248	\$157,393		
30		LLH Energy Flat HLH Energy Flat	310,434 471.002	372,366 525.588	411,304 568,988	408,670 551,562	341,401 510.967	331,376 510.691	329,438 497.054	354,011 458,917	296,778 454.435	317,507 444,014	290,391 499,065	302,982 443.432	4,066,658 5,935,715	464 678	4,067 5.936
31		LLH Energy Revenue Flat (30*13)/1000	\$6,643	\$8,460	\$9,810	\$8,157	\$6,883	\$6,352	\$5,808	\$5,016	\$2,923	\$5,312	\$5,764	\$6,717	\$77,846	0,0	0,000
32		HLH Energy Revenue Flat (31*14)/1000 GSP Demand	\$13,758 1.481	\$16,372 1.710	\$18,498 1.733	\$15,223 1.725	\$14,404 1.705	\$13,355 1.565	\$12,198 1.488	\$9,408 1,346	\$8,430 1.276	\$10,146 1.396	\$13,355 1.366	\$12,248 1.319	\$157,393 18.110		
34 35		Demand Revenue (34*18)	\$2,829	\$3,488	\$3,709	\$3,140	\$3,154	\$2,692	\$2,411	\$1,804	\$1,569	\$2,094	\$2,404	\$2,401	\$31,694		
35		Load Variance Load Variance Revenue (36*21)/1000	1,031,458 \$474	1,150,010 \$529	1,260,540 \$580	1,237,670 \$569	1,104,535 \$508	1,107,706 \$510	1,078,232 \$496	1,064,810 \$490	1,003,784 \$462	1,005,411 \$462	1,027,047 \$472	977,119 \$449	13,048,322 \$6,002	1490	13048
37	-1,133,980	LBCRAC True-up/Lookback Adjust	\$474	\$529 \$0	\$580	\$009	\$008	\$510	\$496	\$490 \$0	\$462	\$462	\$472	\$449	\$6,002		
38		PF Other Energy															
39 40		PF Other revenues													\$0		Į.
41		PF Block Service	\$15,948	\$20,704	\$25,542	\$21,232	\$20,268	\$19,607	\$13,447	\$8,826	\$7,328	\$10,084	\$13,552	\$15,825	\$192,363		
42		LLH Energy Flat HLH Energy Flat	407,170 545,974	501,586 664.641	577,456 785.676	609,659 769,284	514,460 718.962	520,497 749.781	381,897 547.958	340,167 430.537	281,881 395.060	353,957 441,310	359,890 506,444	428,295 572,946	5,276,915 7,128,573	602 814	5,277 7,129
44		LLH Energy Revenue Flat (43*13)/1000	\$8,713	\$11,396	\$13,772	\$12,169	\$10,372	\$9,978	\$6,733	\$4,820	\$2,777	\$5,922	\$7,144	\$9,495	\$103,290		.,
45 46		LLH Energy Revenue Stepped (56*19)/1000 HLH Energy Revenue Flat (44*14)/1000	\$15.948	\$20.704	\$25.542	\$21.232	\$20.268	\$19.607	\$13.447	\$8.826	\$7.328	\$10.084	\$13,552	\$15.825	\$0 \$192.363		
47		HLH Energy Revenue Stepped (57*20)/1000				. , .									\$0		
48		GSP Demand Demand Revenue (49*24)	1,419 \$2,710	1,769 \$3.609	1,982 \$4,241	2,038 \$3,709	2,005 \$3,709	1,889 \$3,249	1,408 \$2,281	1,283 \$1,719	1,148 \$1,412	1,297 \$1.946	1,355 \$2.385	1,470 \$2.675	19,063 \$33.646		
50	-1,309,822	P LBCRAC True-up/Lookback Adjust	\$2,710	\$3,009	\$4,241	\$3,709	\$3,709	\$3,249	\$2,201	\$1,719	\$1,412	\$1,940	\$2,365	\$2,075	\$33,046		
51		PF SUMY	\$0 -0.89%	\$0 -0.79%	\$0 -0.81%	\$0 -0.81%	\$0 -0.79%	\$0 -0.73%	\$0 -0.99%	\$0 -0.90%	\$0 -0.83%	\$0 -0.77%	\$0 -0.67%	\$0 -0.93%	\$0		
52 53		Low Density Discount Percent = 70/(59+60+61+62+64) Low-Density Discount	-0.89% -\$245	-0.79% -\$284	-0.81%	-0.81%	-0.79%	-0.73% -\$240	-0.99% -\$223	-0.90% -\$138	-0.83% -\$96	-0.77%	-0.67%	-0.93% -\$260	-\$2,704		
54 55		PF Other Energy PF Block Other Revenues													0		
56		PF Block Other Revenues															
57		Irrigation Mitigation LLH	0	0	0	0	0	0	0	28,360	39,538	44,977	39,178	0	152,053	17	152
58 59		Irrigation Mitigation HLH Irrigation Mitigation Revenues	0 \$0	0 \$0	0 \$0	0 \$0	0 \$0	0 \$0	0 \$0	45,414 \$805	65,334 \$836	71,988 \$1.541	64,939 \$1.762	0 \$0	247,675 \$4.944	28	248
60		•	•	40	••	•	•••	•••	•	<b>\$</b>	4000	<b>\$1,041</b>	01,702	Ψ0	<b>44,044</b>		
62		Pt Townsend LLH Pt Townsend HLH															
63		Pt Townsend Demand															
64 65		Pt Townsend Revenues															
66		PF SLICE															
67 68		Percent of SLICE Slice rate	18.511% \$1.873	18.511% \$1.873	18.511% \$1.873	18.511% \$1.873	18.511% \$1.873	18.511% \$1.873	18.511% \$1.873	18.511% \$1.873	18.511% \$1.873	18.511% \$1.873	18.511% \$1.873	18.511% \$1.873	18.51%	1690	
69		Slice Charges (\$000) = 69*70*100	\$1,873 \$36,326	\$1,873 \$36,326	\$1,873 \$36,326	\$1,873 \$36,326	\$1,873 \$36,326	\$1,873 \$36,326	\$1,873 \$36,326	\$1,873 \$36,326	\$1,873 \$36,326	\$1,873 \$36,326	\$1,873 \$36,326	\$1,873 \$36,326	\$435,916		
70		Monetary Benefits to IOUs (\$000)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
71 72		B LBCRAC True-up/Lookback Adjust LDD Percentage	-1.07%	-1.07%	-1.07%	-1.07%	-1.07%	-1.07%	-1.07%	-1.07%	-1.07%	-1.07%	-1.07%	-1.07%	\$0		
73 74		Low-Density Discount	-\$389	-\$389	-\$389	-\$389	-\$389	-\$389	-\$389	-\$389	-\$389	-\$389	-\$389	-\$389	-\$4,663		
74 75		Slice Other West Hub FPS (Pre-Subscription) Sales															
76		LLH Energy Full Service	1,312	1,288	1,312	1,376	1,152	1,240	1,216	1,376	1,216	1,376	0	0	12,864	1	13
77 78		LLH Energy Revenue HLH Energy Full Service	\$27 1,664	\$27 1,600	\$27 1,664	\$29 1,600	\$24 1,536	\$26 1,728	\$25 1,664	\$29 1 600	\$25 1 664	\$29 1 600	\$0 0	\$0 0	\$267 16.320	2	16
79		HLH Energy Revenue	\$35	\$33	\$35	\$33	\$32	\$36	\$35	\$33	\$35	\$33	\$0	\$0	\$339	-	10
80 81		GSP Demand Demand Revenue	4	4	4	4	4	4	8	4	4	4	0	0	44 \$0		
82		Load Variance	2,976	2,888	2,976	2,976	2,688	2,968	2,880	2,976	2,880	2,976	0	0	29184	3	29
83		Load Variance Revenue	\$1	\$1	\$1	\$1	\$1	\$1	\$1	\$1	\$1	\$1	\$0	\$0	\$13		
84 85		Low-Density Discount LT SURPLUS FB CRAC													\$0		
86		Netrwork Wind Integration Service													\$0		
87 88		Other Pre-Subscription revenues Total	\$109 230	\$128.131	\$143 948	\$127.080	\$119.663	\$113 706	\$98.206	\$82.945	\$73.162	\$88.867	\$100 991	\$104 536	\$0 \$1,290,466		
		was	₩.JJ,2JU	ψ120, IOI	♥1-10,0 <del>11</del> 0	ψ . L . ,000	÷,003	\$1.10,700	400,200	ψυ <u>ε</u> ,σ <del>η</del> υ	ψ. J, 10Z	400,007	₩100,001	\$ 10-7,000	₩.,EJU,4U0		

B	С	D	E	F	G	Н	I	J	K	L	M	N	0	P	Q
1 Jul 20, 2009 @ 10:19			s at Currer ue (\$ Thous												
3		rtoron	FY2009	u.i.uu)											
4															
5												T.	Fiscal	Year 200	19
7 Eastern HUB	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Total	aMW	GWh
8	\$5,368	\$6,506	\$8,885	\$7,108	\$5,906	\$5,239	\$4,567	\$3,496	\$2,146	\$4,493	\$4,870	\$6,311	\$64,894		
9 East Hub PF Billing Determinants	\$11,917	\$11,762	\$17,209	\$14,011	\$12,160	\$11,143	\$10,015	\$7,231	\$6,659	\$9,099	\$10,793	\$11,749	\$133,748		
10 PF Full Service 11 LLH Energy Flat	\$2,227 250,844	\$2,235 286,353	\$3,639 372,533	\$2,596 356,091	\$2,579 292,954	\$2,093 273,287	\$1,874 259,029	\$1,489 246,688	\$1,396 217.862	\$2,351 268,559	\$2,409 245,333	\$2,324 284,685	\$27,212 3.354,218	383	3,354
12 HLH Energy Flat	407,981	377,601	529,332	507,651	431,350	426,128	408,092	352,756	358,976	398,206	403,309	425,382	5,026,764	574	5,027
13 PF Flat LLH Energy Rate	\$21.40 \$29.21	\$22.72 \$31.15	\$23.85 \$32.51	\$19.96 \$27.60	\$20.16 \$28.19	\$19.17 \$26.15	\$17.63 \$24.54	\$14.17 \$20.50	\$9.85 \$18.55	\$16.73 \$22.85	\$19.85 \$26.76	\$22.17 \$27.62			
14 PF Flat HLH Energy Rate 15 LLH Energy Revenue Flat= (11*13)/100	\$29.21 \$5,368	\$31.15 \$6.506	\$32.51 \$8.884	\$27.60	\$28.19 \$5,906	\$26.15 \$5.239	\$24.54 \$4,567	\$3,496	\$18.55	\$22.85 \$4 493	\$4,870	\$6,311	\$64,893		
16 HLH Energy Revenue Flat= (12*14)/100	\$11,917	\$11,762	\$17,200	\$14,011	\$12,160	\$11,143	\$10,015	\$7,231	\$6,659	\$9,099	\$10,793	\$11,749	\$133,739		
17 GSP Demand	1,166	1,095	1,701	1,426	1,394	1,217	1,157	1,111	1,135	1,567	1,369	1,277	15,615	2	16
18 PF GSP Demand Rate 19 Demand Revenue= (18*17	\$1.91 \$2.227	\$2.04 \$2.235	\$2.14 \$3.638	\$1.82 \$2.596	\$1.85 \$2.579	\$1.72 \$2.093	\$1.62 \$1.875	\$1.34 \$1.488	\$1.23 \$1,396	\$1.50 \$2.350	\$1.76 \$2.410	\$1.82 \$2.325	\$27 213		
20 PF Ld Variance	666,394	672,419	910,999	872,428	729,881	702,637	671,689	756,946	799,339	918,757	865,138	712,436	9,279,063	1,059	9,279
21 PF Ld Variance Rate	\$0.46	\$0.46	\$0.46 \$419	\$0.46 \$401	\$0.46	\$0.46 \$323	\$0.46	\$0.46	\$0.46	\$0.46	\$0.46	\$0.46 \$327			
22 Load Variance= (20*21)/100( 23 Low Density Discount Percent=28/(15+16+2	\$307 -3.83%	\$309 -3.66%	-3.75%	-3.73%	\$336 -3.67%	-3.70%	\$309 -3.98%	\$307 -3.71%	\$308 -3.52%	\$360 -3.55%	\$343 -3.55%	-4.07%	\$4,049		
24 Low Density Discount	-\$758	-\$761	-\$1,131	-\$900	-\$770	-\$696	-\$667	-\$465	-\$370	-\$578	-\$653	-\$842	-\$8,591		
25 LBCRAC True-up/Lookback Adjust	-\$603	-\$603	-\$603	-\$603	-\$603	-\$603	-\$603	-\$603	-\$603	-\$603	-\$603	-\$603	-\$7,235		_
26 PF Other Energy 27 PF Other Revenues	-\$169	0 \$0	0 \$0	0 \$0	0 \$0								-\$169	0	0
28	\$1,709	\$2,063	\$2,680	\$2,153	\$1,822	\$1,761	\$1,425	\$1,126	\$745	\$1,549	\$1,638	\$1,903	\$20,575		
29 PF Partial Service	\$3,724	\$3,683	\$5,158	\$4,195	\$3,754	\$3,627	\$2,931	\$2,248	\$2,248	\$3,000	\$3,534	\$3,374	\$41,475	400	4 070
30 LLH Energy Flat 31 HLH Energy Flat	79,872 127,480	90,795 118,245	112,377 158.653	107,878 151.997	90,396 133,163	91,865 138,684	80,822 119,422	79,443 109.656	75,667 121,177	92,580 131,293	82,528 132.068	85,852 122,171	1,070,075	122 179	1,070 1,564
32 LLH Energy Revenue Flat = 30*13/100	\$1,709	\$2,063	\$2,680	\$2,153	\$1,822	\$1,761	\$1,425	\$1,126	\$745	\$1,549	\$1,638	\$1,903	\$20,575		.,
33 HLH Energy Revenue Flat = 31*14/100	\$3,724	\$3,683	\$5,158	\$4,195	\$3,754	\$3,627	\$2,931	\$2,248	\$2,248	\$3,000	\$3,534	\$3,374	\$41,475		
34 GSP Demand 35 Demand Revenue = 34*1;	342 \$654	328 \$669	481 \$1 030	440 \$801	406 \$752	355 \$611	331 \$536	269 \$360	290 \$357	337 \$506	325 \$572	297 \$541	4,202 \$7,388		
36 Load Variance	214,856	216,324	270,370	259,854	222,876	218,741	193,179	184,753	196,567	223,003	209,678	194,364	2,604,565	297	2,605
37 Load Variance = 36*21/1000	\$99	\$100	\$128	\$123	\$103	\$101	\$89	\$85	\$90	\$103	\$96	\$89	\$1,205		
38 LBCRAC True-up/Lookback Adjus 39 Low Density Discount Percent= 56/(42+43+4	-\$188 -2.69%	-\$188 -2 65%	-\$188 -2.36%	-\$188 -2.37%	-\$188 -2.51%	-\$188 -2 34%	-\$188 -2.35%	-\$188 -2.31%	-\$188 -2.43%	-\$188 -2.41%	-\$188 -2.46%	-\$188 -2.66%	-\$2,252		
40 Low Density Discount	-\$167	-\$173	-\$212	-\$172	-\$161	-\$143	-\$117	-\$88	-\$84	-\$124	-\$144	-\$157	-\$1,742		
41 PF Other Energy	0	0	0	0	0								0	0	0
42 PF Other Revenue	\$0 \$2,450	\$0 \$2,894	\$3 \$3,207	\$3 \$2,724	\$2 \$2,380	\$2,158	\$2,208	\$1,801	\$1,052	\$1,838	\$1,923	\$2,618	\$8 \$27,255		
44 PF Block Service	\$4,719	\$4,605	\$5,640	\$4,857	\$4,514	\$3,737	\$4,202	\$2,682	\$2,441	\$2,709	\$2,860	\$4,070	\$47,036		
45 LLH Energy Flat	114,504	127,386 147,840	134,480 173,472	136,448 175,968	118,080 160 128	112,587	125,243 171 239	127,087 130,828	106,824	109,867	96,891	118,103 147,340	1,427,500	163 202	1,428
46 HLH Energy Flat 47 LLH Energy Revenue Flat=(45*13)/100	161,568 \$2,450	147,840 \$2.894	\$3,207	\$2,724	\$2,380	142,900 \$2,158	\$2,208	130,828 \$1.801	131,616 \$1.052	118,569 \$1.838	106,867 \$1,923	\$2,618	1,768,335 \$27,255	202	1,768
48 HLH Energy Revenue Flat=(46*14)/100	\$4,719	\$4,605	\$5,640	\$4,857	\$4,514	\$3,737	\$4,202	\$2,682	\$2,441	\$2,709	\$2,860	\$4,070	\$47,036		
49 GSP Demand	374	385	417	423	417	341	403	457	500	495	413	368	4,993		
50 Demand Revenue=(49*24 51 LBCRAC True-up/Lookback Adjus	\$714 -\$320	\$785 -\$320	\$892 -\$320	\$770 -\$320	\$771 -\$320	\$587 -\$320	\$653 -\$320	\$613 -\$320	\$614 -\$320	\$742 -\$320	\$727 -\$320	\$669 -\$320	\$8,539 -\$3,840		
52 Low-Density Discoun	\$0	\$0	\$0	\$0	\$0								\$0		
53 PF Other Energy	0 \$0	0 \$0	0 \$0	0 \$0	0 \$0								0	0	0
54 PF Block Other Revenue	\$0	\$0	\$0	\$0	\$0										
56 PF SLICE	\$7,714	\$7,714	\$7,714	\$7,714	\$7,714	\$7,714	\$7,714	\$7,714	\$7,714	\$7,714	\$7,714	\$7,714	\$92,568		
57 Percent of SLICE 58 Slice Rate	4.1193% \$1.873	4.1193% \$1.873	4.1193% \$1.873	4.1193% \$1.873	4.1193% \$1.873	4.1193% \$1.873	4.1193% \$1.873	4.1193% \$1.873	4.1193% \$1.873	4.1193% \$1.873	4.1193% \$1.873	4.1193% \$1.873	4.1193%	349	
59 Slice Rate 59 Slice Charges = 57*58*100	\$1,873	\$1,873	\$1,873	\$1,873 \$7,714	\$1,873	\$1,873	\$1,873	\$1,873	\$1,873	\$1,873	\$1,873	\$1,873	\$92,564		
60 LBCRAC True-up/Lookback Adjust	-\$243	-\$243	-\$243	-\$243	-\$243	-\$243	-\$243	-\$243	-\$243	-\$243	-\$243	-\$243	-\$2,915		
61 Slice Other Revenues 62	\$0	\$0	-\$286	\$0	\$0								-\$285		
63 East Hub FPS (Pre-Subscription) Sales															
64 LLH Energy Pre-Sub	36,570	45,106	64,189	60,054	47,683	55,768	48,804	50,954	48,701	61,609	52,733	48,484	620,655	71	621
65 LLH Energy Revenue 66 HLH Energy Pre-Sub	\$819 60,392	\$1,013 60,156	\$1,444 90,776	\$1,355 85,239	\$1,077 71,334	\$1,162 87,630	\$902 74,790	\$524 75,799	\$448 83,085	\$780 91,980	\$903 92,307	\$1,019 72,031	\$11,447 945,519	108	946
67 HLH Energy Revenue	\$1,485	\$1,478	\$2,236	\$2,095	\$1,758	\$2,012	\$1,542	75,799 \$953	\$985	\$1,403	\$1,877	\$1,667	\$19,491	100	340
68 GSP Demand	176	182	308	262	223	234	214	186	192	245	229	200	2,651		
69 Demand Revenue 70 Load Variance	\$169 78,157	\$170 80,377	\$280 114,002	\$230 105,127	\$199 86,046	\$241 137,710	\$213 119,954	\$176 121,940	\$176 123,478	\$241 149,025	\$235 140,209	\$204 117,755	\$2,535 1,373,780	157	1,374
71 Load Variance Revenu	78,157 \$45	\$47	\$66	\$61	\$50	\$78	\$68	\$70	\$70	\$85	\$80	\$67	\$787	101	1,374
72 Low Density Discount Percen	-2.77%	-2.84%	-2.60%	-2.79%	-2.82%	-5.00%	-4.93%	-4.57%	-4.74%	-4.73%	-4.83%	-4.97%	****		
73 Low Density Discount 74 Wind Integration Service	-\$70	-\$77	-\$105	-\$104	-\$87	-\$175	-\$134	-\$79	-\$80	-\$119	-\$150	-\$147	-\$1,325 \$0		
75 Other Presubscription revenue:	\$2	\$2	\$3	\$3	\$2								\$13		
76 Irrigation Mitigation						\$0	\$0	\$4,336	\$5,308	\$8,144	\$7,986		\$25,775		
77 Irrigation Mitigation LLH	0	0	0	0	0	0	0	92,652 147 478	128,555 217,906	154,155 243,565	123,083 207,128	0	498,445 816,077	57 93	498 816
78 Irrigation Mitigation HLH 79 Irrigation Mitigation Flat Revenues	\$0	\$0	\$0	\$0	-\$3	\$0	\$0	\$1,259	\$1,411	\$2,649	\$2,875	\$0	\$8,191	93	010
80 Irrigation Mitigation Stepped Revenues	\$0	\$0	\$0	\$0	-\$5	\$0	\$0	\$1,293	\$1,325	\$2,497	\$2,529	\$0	\$7,639		
81 Total	\$41,605	\$43,673	\$57,535	\$48,671	\$43,500	\$40,219	\$36,975	\$31,441	\$28,300	\$39,943	\$43,679	\$42,149	\$497,689		

	В	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF
1	Jul 20, 2009 @ 10:19			s at Currer									•			
2			Revenu	e (\$ Thous FY2010	sands)											
3																
5													T.	Elec al 1	Year 201	10
7	Eastern HUB	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Total	aMW	GWh
8		\$5,498	\$6,817	\$8,708	\$7,382	\$5,959	\$5,192	\$4,646	\$3,511	\$2,178	\$4,842	\$4,904	\$6,382	\$66,019		
9	East Hub PF Billing Determinants PF Full Service	\$11,974	\$13,291 \$2,444	\$16,631 \$3,007	\$14,494 \$2,706	\$12,582 \$2.579	\$11,121 \$1.973	\$9,907	\$7,374 \$1,395	\$6,552 \$1.396	\$8,656 \$2,183	\$10,777 \$2,369	\$11,739 \$2,188	\$135,098 \$26,245		
	LLH Energy Flat	\$2,273 256,926	300.030	365.105	369,853	295.572	270.818	\$1,733 263,535	247.807	221,089	289,424	247,039	287.876	3.415.074	390	3.415
12	HLH Energy Flat	409,926	426,668	511,562	525,154	446,340	425,282	403,695	359,686	353,216	378,836	402,715	425,019	5,068,099	579	5,068
13	PF Flat LLH Energy Rate PF Flat HLH Energy Rate	\$21.40 \$29.21	\$22.72 \$31.15	\$23.85 \$32.51	\$19.96 \$27.60	\$20.16 \$28.19	\$19.17 \$26.15	\$17.63 \$24.54	\$14.17 \$20.50	\$9.85 \$18.55	\$16.73 \$22.85	\$19.85 \$26.76	\$22.17 \$27.62			
15	LLH Energy Revenue Flat= (11*13)/100	\$5,498	\$6,817	\$8,708	\$7,382	\$5,959	\$5,192	\$4,646	\$3,511	\$2,178	\$4,842	\$4,904	\$6,382	\$66,019		
16	HLH Energy Revenue Flat= (12*14)/100	\$11,974	\$13,291	\$16,631	\$14,494	\$12,582	\$11,121	\$9,907	\$7,374	\$6,552	\$8,656	\$10,777	\$11,739	\$135,098		
	GSP Demand PF GSP Demand Rate	1,190 \$1.91	1,198 \$2.04	1,405 \$2 14	1,487 \$1.82	1,394 \$1.85	1,147 \$1.72	1,070 \$1.62	1,041 \$1.34	1,135 \$1.23	1,455 \$1.50	1,346 \$1.76	1,202 \$1.82	15,070		
19	Demand Revenue= (18*17	\$2,273	\$2,444	\$3,007	\$2,706	\$2,579	\$1,973	\$1,733	\$1,395	\$1,396	\$2,183	\$2,369	\$2,188	\$26,245		
	PF Ld Variance PF Ld Variance Rate	669,814 \$0.46	730,157 \$0.46	878,853 \$0.46	895,914 \$0.46	743,124 \$0.46	698,937 \$0.46	671,474 \$0.46	764,764 \$0.46	796,577 \$0.46	919,892 \$0.46	865,875 \$0.46	714,885 \$0.46	9,350,266	1,067	9,350
	Load Variance= (20*21)/1000	\$328	\$357	\$430	\$439	\$364	\$342	\$329	\$331	\$327	\$384	\$366	\$350	\$4,347		
	Low Density Discount Percent=28/(15+16+2	-3.86%	-3.70%	-3.73%	-3.71%	-3.70%	-3.73%	-3.96%	-3.73%	-3.54%	-3.55%	-3.54%	-4.09%			
24	Low Density Discount LBCRAC True-up/Lookback Adjust	-\$775	-\$847	-\$1,073	-\$929	-\$794	-\$694	-\$658	-\$471	-\$371	-\$570	-\$653	-\$846	-\$8,679 \$0		
26	PF Other Energy													0	0	0
27 28	PF Other Revenues	\$1.739	\$2.180	\$2.606	\$2.246	\$1.843	\$1.679	\$1.376	\$1.051	\$721	\$1.518	\$1.556	\$1.766	\$20.281		
	PF Partial Service	\$3,698	\$4,124	\$4,746	\$4,313	\$3,814	\$3,455	\$2,821	\$2,140	\$2,135	\$2,808	\$3,297	\$3,155	\$40,505		
30	LLH Energy Flat	81,285	95,941	109,282	112,511	91,394	87,582	78,065	74,172	73,207	90,707	78,372	79,662	1,052,180	120	1,052
	HLH Energy Flat LLH Energy Revenue Flat = 30*13/100i	126,584 \$1,739	132,407 \$2,180	145,989 \$2.606	156,269 \$2,246	135,279 \$1,843	132,110 \$1,679	114,972 \$1,376	104,371 \$1,051	115,090 \$721	122,891 \$1,518	123,207 \$1,556	114,213 \$1,766	1,523,382 \$20,281	174	1,523
33	HLH Energy Revenue Flat = 31*14/100	\$3,698	\$4,124	\$4,746	\$4,313	\$3,814	\$3,455	\$2,821	\$2,140	\$2,135	\$2,808	\$3,297	\$3,155	\$40,505		
	GSP Demand	365	358	432	445 \$810	406	355	348 \$564	285	313	355	322 \$567	303	4,287		
	Demand Revenue = 34*1; Load Variance	\$697 214.933	\$730 234.662	\$924 262.188	\$810 272.047	\$751 231.849	\$611 225.819	\$564 199,704	\$382 190,292	\$385 201.838	\$533 229,265	216,449	\$551 200.638	\$7,505 2,679,684	306	2,680
37	Load Variance = 36*21/1000	\$99	\$108	\$121	\$125	\$107	\$104	\$92	\$88	\$93	\$105	\$100	\$92	\$1,233		_,
38	LBCRAC True-up/Lookback Adjust Low Density Discount Percent= 56/(42+43+4	-2 62%	-2 50%	-2 45%	-2 38%	-2 42%	-2 41%	-2 46%	-2.37%	-2 55%	-2 52%	-2 52%	-2 67%	\$0		
40	Low Density Discount	-\$163	-\$178	-\$206	-\$178	-\$158	-\$141	-\$119	-\$87	-\$85	-\$125	-\$139	-\$149	-\$1,727		
41	PF Other Energy					****		****						0	0	0
43	PF Other Revenue	-\$107 \$2,272	-\$117 \$2,642	-\$131 \$2,931	-\$136 \$2,616	-\$116 \$2,218	-\$113 \$2,051	-\$100 \$2,208	-\$95 \$1,779	-\$101 \$1,048	-\$115 \$1,838	-\$108 \$1,928	-\$100 \$2,618	-\$1,340 \$26,150		
44	PF Block Service	\$4,288	\$4,114	\$5,057	\$4,192	\$4,127	\$3,884	\$4,202	\$2,681	\$2,441	\$2,709	\$2,871	\$4,070	\$44,636		
45	LLH Energy Flat HLH Energy Flat	106,189 146,812	116,270 132,060	122,909 155 543	131,065 151,870	110,031	106,978 148,510	125,243 171 239	125,535 130,786	106,388 131,616	109,867 118 569	97,150 107,283	118,103 147,340	1,375,728	157 193	1,376 1,688
47	LLH Energy Revenue Flat=(45*13)/100	\$2,272	\$2,642	\$2,931	\$2,616	\$2,218	\$2,051	\$2,208	\$1,779	\$1,048	\$1,838	\$1,928	\$2,618	\$26,150	100	1,000
	HLH Energy Revenue Flat=(46*14)/100	\$4,288 338	\$4,114 342	\$5,057	\$4,192 377	\$4,127 379	\$3,884 341	\$4,202 403	\$2,681 457	\$2,441 500	\$2,709	\$2,871	\$4,070	\$44,636		
50	GSP Demand Demand Revenue=(49*24	\$646	\$698	372 \$796	\$686	\$701	\$587	\$653	\$612	\$615	495 \$743	414 \$729	368 \$670	4,786 \$8.134		
51	LBCRAC True-up/Lookback Adjus	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
	Low-Density Discount PF Other Energy													\$0 0	0	0
54	PF Block Other Revenue														,	J
55	PF SLICE															
57	Percent of SLICE	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	379	
	Slice Rate	\$1,873	\$1,873	\$1,873 \$8,084	\$1,873 \$8,084	\$1,873 \$8,084	\$1,873 \$8,084	\$1,873 \$8,084	\$1,873	\$1,873 \$8,084	\$1,873 \$8,084	\$1,873	\$1,873 \$8,084	. 20 502		
59 60	Slice Charges = 57*58*100 LBCRAC True-up/Lookback Adjus	\$8,084 \$0	\$8,084 \$0	\$8,084 \$0	\$8,084 \$0	\$8,084 \$0	\$8,084 \$0	\$8,084 \$0	\$8,084 \$0	\$8,084 \$0	\$8,084 \$0	\$8,084 \$0	\$8,084 \$0	\$97,004 \$0		
61	Slice Other Revenues			20		20	,,,	50	20	50	20	20	30	30		
62	East Hub FPS (Pre-Subscription) Sales															
64	LLH Energy Pre-Sub	48,311	59,076	71,350	71,090	59,268	57,319	50,063	50,774	48,422	64,168	53,122	48,854	681,817	78	682
65	LLH Energy Revenue	\$1,034	\$1,342	\$1,702	\$1,419	\$1,195	\$1,099	\$883	\$719	\$477	\$1,074	\$1,054	\$1,083	\$13,080		4.000
	HLH Energy Pre-Sub HLH Energy Revenue	76,790 \$2,243	85,495 \$2,663	100,471 \$3,266	102,743 \$2,836	89,919 \$2,535	89,482 \$2,340	75,692 \$1,857	76,506 \$1,568	81,603 \$1,514	87,731 \$2,005	91,807 \$2,457	72,242 \$1,995	1,030,481 \$27,279	118	1,030
68	GSP Demand	229	239	289	307	281	241	221	191	207	253	235	201	2,894		
	Demand Revenue	\$437 122.499	\$488 138.070	\$618 166 468	\$559 168.993	\$520 142.704	\$415 141.213	\$358 124 113	\$256 124 263	\$255 125.985	\$380 148.512	\$414 141,713	\$366 119.780	\$5,064 1 664 313	190	1,664
71	Load Variance Revenue	\$56	\$64	\$77	\$78	\$66	\$65	\$57	\$57	\$58	\$68	\$65	\$55	\$766	100	1,004
	Low Density Discount Percen	-4.00%	-3.89%	-3.79%	-4.56%	-4.42%	-4.60%	-4.45%	-3.09%	-3.56%	-3.35%	-3.79%	-4.26%	61 050		
74	Low Density Discount Wind Integration Service	-\$151	-\$177	-\$214	-\$223	-\$191	-\$180	-\$140	-\$80	-\$82	-\$118	-\$151	-\$149	-\$1,858 \$0		
75	Other Presubscription revenue:													\$0		
76	Irrigation Mitigation Irrigation Mitigation LLH	0	0	0	0	0	\$0 0	\$0 0	\$4,203 90,110	\$5,137 124,006	\$7,860 147,923	\$7,739 118,453	0	\$24,939 480,492	55	480
	Irrigation Mitigation LLH Irrigation Mitigation HLH	0	0	0	0	0	0	0	142,759	211,084	235,661	201,328	0	790,832	90	791
79	Irrigation Mitigation Flat Revenues	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$1,321	\$1,500	\$2,737	\$2,979	\$0	\$8,537		
	Irrigation Mitigation Stepped Revenues	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$1,451	\$1,509	\$2,783	\$2,797	\$0	\$8,540		
81	Total	\$44,170	\$48,825	\$58,080	\$51,518	\$46,184	\$41,871	\$38,752	\$34,068	\$30,649	\$42,521	\$46,260	\$43,920	\$526,819		

В	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT	AU
1 Jul 20, 2009 @ 10:19			s at Currer												
2 3		Revenu	e (\$ Thous FY2011	sands)											
4															
5												г	Flacul V	001	
7 Eastern HUB	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Total	ear 201	GWh
8	\$5,679	\$6,916	\$8,897	\$7,530	\$6,093	\$5,313	\$4,753	\$3,605	\$2,237	\$4,763	\$4,970	\$6,523	\$67,279	<u></u>	<u> </u>
9 East Hub PF Billing Determinants	\$12,160	\$13,667	\$16,970	\$14,772	\$12,857	\$11,375	\$10,129	\$7,571	\$6,733	\$9,208	\$11,157	\$11,995	\$138,593		
10 PF Full Service 11 LLH Energy Flat	\$2,323 265.363	\$2,499 304,387	\$3,073 373.047	\$2,761 377,242	\$2,638 302.236	\$2,018 277,167	\$1,772 269.587	\$1,424 254,440	\$1,423 227,103	\$2,219 284,701	\$2,415 250.391	\$2,233 294.218	\$26,797 3 479 882	397	3 480
12 HLH Energy Flat	416,290	438,749	521,990	535,221	456,078	435,003	412,742	369,302	362,987	402,968	416,923	434,274	5,202,527	594	5,203
13 PF Flat LLH Energy Rate	\$21.40 \$29.21	\$22.72 \$31.15	\$23.85 \$32.51	\$19.96 \$27.60	\$20.16 \$28.19	\$19.17 \$26.15	\$17.63 \$24.54	\$14.17 \$20.50	\$9.85 \$18.55	\$16.73 \$22.85	\$19.85 \$26.76	\$22.17 \$27.62			
14 PF Flat HLH Energy Rate 15 LLH Energy Revenue Flat= (11*13)/100	\$5.679	\$6,916	\$8.897	\$7.530	\$6.093	\$5.313	\$4,753	\$20.50	\$2.237	\$4.763	\$4.970	\$6.523	\$67,279		
16 HLH Energy Revenue Flat= (12*14)/100	\$12,160	\$13,667	\$16,970	\$14,772	\$12,857	\$11,375	\$10,129	\$7,571	\$6,733	\$9,208	\$11,157	\$11,995	\$138,593		
17 GSP Demand 18 PF GSP Demand Rate	1,216 \$1.91	1,225 \$2.04	1,436 \$2.14	1,517 \$1.82	1,426 \$1.85	1,173 \$1.72	1,094 \$1.62	1,063 \$1.34	1,157 \$1.23	1,479 \$1.50	1,372 \$1.76	1,227 \$1.82	15,385		
19 Demand Revenue= (18*17	\$2,323	\$2,499	\$3,073	\$2,761	\$2,638	\$2,018	\$1,772	\$1,424	\$1,423	\$2,219	\$2,415	\$2,233	\$26,797		
20 PF Ld Variance	684,415	746,400	897,023	913,370	759,525	715,007	686,764	781,073	812,604	939,584	883,433	730,482	9,549,680	1,090	9,550
21 PF Ld Variance Rate 22 Load Variance= (20*21)/1000	\$0.46 \$335	\$0.46 \$365	\$0.46 \$439	\$0.46 \$447	\$0.46 \$372	\$0.46 \$350	\$0.46 \$336	\$0.46 \$339	\$0.46 \$335	\$0.46 \$394	\$0.46 \$374	\$0.46 \$358	\$4,444		
23 Low Density Discount Percent=28/(15+16+2	-3.86%	-3.70%	-3.73%	-3.72%	-3.70%	-3.73%	-3.96%	-3.74%	-3.56%	-3.56%	-3.56%	-4.09%	<b>\$1,111</b>		
24 Low Density Discount	-\$792	-\$869	-\$1,097	-\$948	-\$813	-\$710	-\$673	-\$484	-\$382	-\$591	-\$673	-\$863	-\$8,894		
25 LBCRAC True-up/Lookback Adjust 26 PF Other Energy													\$0 0	0	0
27 PF Other Revenues													\$0		Ĭ
28 29 PF Partial Service	\$1,825 \$3,779	\$2,215 \$4,304	\$2,689 \$4,898	\$2,315 \$4,452	\$1,901 \$3,939	\$1,733 \$3,569	\$1,423 \$2,919	\$1,083 \$2,208	\$741 \$2,196	\$1,534 \$2,947	\$1,579 \$3,450	\$1,823 \$3,260	\$20,861 \$41,920		
30 LLH Energy Flat	\$5,779 85,264	97,487	112,736	115,966	94,307	90,408	80,720	76,449	75,245	91,685	79,545	82,221	1,082,033	124	1,082
31 HLH Energy Flat	129,384	138,166	150,669	161,287	139,722	136,475	118,944	107,717	118,399	128,953	128,908	118,022	1,576,646	180	1,577
32 LLH Energy Revenue Flat = 30*13/100 33 HLH Energy Revenue Flat = 31*14/100	\$1,825 \$3,779	\$2,215 \$4,304	\$2,689 \$4.898	\$2,315 \$4,452	\$1,901 \$3,939	\$1,733 \$3.569	\$1,423 \$2,919	\$1,083 \$2,208	\$741 \$2 196	\$1,534 \$2,947	\$1,579 \$3,450	\$1,823 \$3,260	\$20,861 \$41,920		
34 GSP Demand	377	369	446	459	419	367	360	294	322	366	333	313	4,425		
35 Demand Revenue = 34*17	\$720	\$753	\$954	\$835	\$775	\$631	\$583	\$394	\$396	\$549	\$586	\$570	\$7,747		
36 Load Variance 37 Load Variance = 36*21/1000	221,712 \$102	241,968 \$111	270,323 \$124	280,520 \$129	239,205 \$110	233,009 \$107	206,330 \$95	195,915 \$90	207,185	236,306 \$109	223,324 \$103	207,006 \$95	2,762,803 \$1,271	315	2,763
38 LBCRAC True-up/Lookback Adjust							***	***	***				\$0		
39 Low Density Discount Percent= 56/(42+43+4	-2.57% -\$165	-2.46% -\$182	-2.41% -\$209	-2.34% -\$181	-2.38% -\$160	-2.37% -\$143	-2.42% -\$121	-2.34% -\$88	-2.52% -\$87	-2.47% -\$127	-2.48% -\$142	-2.63% -\$151	-\$1,757		
41 PF Other Energy	-\$100	-\$182	-\$209	-\$181	-\$160	-\$143	-\$121	-\$60	-\$87	-\$127	-\$142	-\$151	-\$1,757 0	0	0
42 PF Other Revenu€	-\$111	-\$121	-\$135	-\$140	-\$120	-\$117	-\$103	-\$98	-\$104	-\$118	-\$112	-\$104	-\$1,381	-	-
44 PF Block Service	\$2,390 \$4,128	\$2,514 \$4,288	\$2,931 \$5.057	\$2,616 \$4 192	\$2,218 \$4 127	\$2,051 \$3.884	\$2,208 \$4,202	\$1,779 \$2,681	\$1,048 \$2,441	\$1,967 \$2.554	\$1,799 \$3.045	\$2,618 \$4.070	\$26,140 \$44.668		
45 LLH Energy Flai	111,697	110,670	122,909	131,065	110,031	106,978	125,243	125,535	106,388	117,561	90,638	118,103	1,376,818	157	1,377
46 HLH Energy Flat	141,305	137,660	155,543	151,870	146,410	148,510	171,239	130,786	131,616	111,758	113,795	147,340	1,687,832	193	1,688
47 LLH Energy Revenue Flat=(45*13)/100i 48 HLH Energy Revenue Flat=(46*14)/100i	\$2,390 \$4,128	\$2,514 \$4,288	\$2,931 \$5,057	\$2,616 \$4 192	\$2,218 \$4 127	\$2,051 \$3,884	\$2,208 \$4,202	\$1,779 \$2,681	\$1,048 \$2,441	\$1,967 \$2,554	\$1,799 \$3,045	\$2,618 \$4,070	\$26,140 \$44,668		
49 GSP Demand	338	342	372	377	379	341	403	457	500	495	414	368	4,786		
50 Demand Revenue=(49*24	\$646 \$0	\$698 \$0	\$796 \$0	\$686 \$0	\$701 \$0	\$587 \$0	\$653 \$0	\$612 \$0	\$615 \$0	\$743 \$0	\$729 \$0	\$670 \$0	\$8,134		
51 LBCRAC True-up/Lookback Adjust 52 Low-Density Discount	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0 \$0		
53 PF Other Energy													0	0	0
54 PF Block Other Revenue															
56 PF SLICE															
57 Percent of SLICE	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	376	
58 Slice Rate 59 Slice Charges = 57*58*100	\$1,873 \$7,714	\$1,873 \$7,714	\$1,873 \$7,714	\$1,873 \$7,714	\$1,873 \$7,714	\$1,873 \$7,714	\$1,873 \$7,714	\$1,873 \$7,714	\$1,873 \$7,714	\$1,873 \$7,714	\$1,873 \$7,714	\$1,873 \$7,714	\$92.568		
60 LBCRAC True-up/Lookback Adjust	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
61 Slice Other Revenues															
63 East Hub FPS (Pre-Subscription) Sales	-3.52%	-3.46%	-3.39%	-4.05%	-3.93%	-4.13%	-3.93%	-2.78%	-3.19%	-2.96%	-3.30%	-3.75%			
64 LLH Energy Pre-Sut	48,808	59,694	71,524	71,208	59,272	57,502	50,596	51,333	48,917	62,298	54,173	49,844	685,169	78	685
65 LLH Energy Revenue 66 HLH Energy Pre-Sub	\$1,044 77.645	\$1,356 86,476	\$1,706 100.821	\$1,421 103,157	\$1,195 91.001	\$1,102 90.468	\$892 76.547	\$727 77.373	\$482 82.498	\$1,042 92,686	\$1,075 93,889	\$1,105 73.661	\$13,149 1.046.222	119	1.046
67 HLH Energy Revenue	\$2,268	\$2,694	\$3,278	\$2,847	\$2,565	\$2,366	\$1,878	\$1,586	\$1,530	\$2,118	\$2,512	\$2,035	\$27,677	119	1,040
68 GSP Demand	232	243	293	311	285	246	225	194	210	256	238	204	2,937		
69 Demand Revenue	\$443 124 612	\$496 140.485	\$627 169.313	\$566 171,850	\$527 145.233	\$423 143.629	\$365 126.284	\$260 126 466	\$258 128,173	\$384 151.230	\$419 144.127	\$371 121.860	\$5,139 1 693 262	193	1.693
71 Load Variance Revenue	\$57	\$65	\$78	\$79	\$67	\$66	\$58	\$58	\$59	\$70	\$66	\$56	\$779		1,000
72 Low Density Discount Percen	-3.52%	-3.46%	-3.39%	-4.05%	-3.93%	-4.13%	-3.93%	-2.78%	-3.19%	-2.96%	-3.30%	-3.75%	61 600		
73 Low Density Discount 74 Wind Integration Service	-\$134	-\$160	-\$193	-\$199	-\$171	-\$163	-\$126	-\$73	-\$74	-\$107	-\$135	-\$134	-\$1,669 \$0		
75 Other Presubscription revenues													\$0		
76 Irrigation Mitigation 77 Irrigation Mitigation LLH	0	0	0	0	0	0	0	90,110	124,006	148,154	117,248	0	479 518	55	480
77 Irrigation Mitigation LLH 78 Irrigation Mitigation HLH	0	0	0	0	0	0	0	142,759	211,084	234,548	199,640	0	479,518 788,031	90	788
79 Irrigation Mitigation Flat Revenues	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$1,321	\$1,500	\$2,737	\$2,924	\$0	\$8,482		
80 Irrigation Mitigation Stepped Revenues	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$1,451	\$1,509	\$2,769	\$2,797	\$0	\$8,527		
81 Total	\$44,410	\$49,323	\$58,598	\$51,893	\$46,537	\$42,155	\$38,957	\$34,163	\$30,668	\$42,875	\$46,652	\$44,242	\$530,475		

	В	С	D	Е	F	G	Н	I	J	K	L	M	N	0	P	Q
1	Jul 17, 2009 @ 12:20	I I	Revenue	es at Curren	t Rates											``
2			Reven	ue (\$ Thous	ands)											
3				FY2009									-			
4		744	721	744	744	672	743	720	744	720	744	744	720	Fiscal Y	ear 200	9
5		432 312	384 337	416 328	416 328	384 288	416 327	416 304	400 344	416 304	416 328	416 328	400 320			
7	Bulk HUB	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Total	aMW	GWh
8	Investor-Owned Utilities Residential Exchange	00.00	1101 00	200 00	0411 00	. 02 00	<u> 00</u>	<del>л.р. 00</del>	may oo	0411.00	<u> </u>	rug co	<u>000 00</u>	<u> </u>		<u> </u>
9	Residential Exchange Rate	(46.46)	(46.46)	(46.46)	(47.22)	(\$47.45)	(47.45)	(47.56)	(47.56)	(47.67)	(47.67)	(48.00)	(48.00)	(49.46)		
10	Energy (MWhr)	2,357,543	2,669,837	3,476,522	4,317,495	3,368,129	3,127,975	2,701,817	2,484,845	2,481,228	2,644,717	2,528,174	2,314,738	34,473,020	3,935	34,473
11	Residential Exchange Revenue (\$000) = (12+13)*14	-\$113,539	-\$129,016	-\$167,543	-\$213,478	-\$168,287	-\$156,379	-\$135,368	-\$123,944	-\$123,530	-\$130,913	-\$126,651	-\$116,493	-\$1,705,142		
	Direct-Service Industries (IP-02 & FPS)  IP LBCRAC True-up (MWH)															
	IP LBCRAC True-up (MWH) IP LBCRAC True-up Revenue (\$000)															
	PAC capacity, WNP-3 and other L-T contracts															
	Demand (MW)	751	863	770	770	870	940	788	1,003	808	959	978	796	10,296		
17		171,719	239,003	224,011	217,419	187,526	143,338	108,238	180,235	96,442	134,718	158,477	79,495	1,940,621	222	
	LLH Energy (MWhr)	-129,870	-42,585	-78,946	-90,293	-74,210	-146,665	-44,319	9,357	-19,103	21,631	-5,171	-92,823	-692,997	-79	-693
19	Energy (aMW)	56	272	195 \$10.768	171	169	-4	89	255	107	210	206	-19	1,707	142	1,248
20		\$3,951	\$10,923	\$10,768	\$10,811	\$10,175	\$7,503	\$7,331	\$7,536	\$4,027	\$6,514	\$7,981	\$3,980	\$91,498		
22																
23		1,245	1,245	1,245	1,245	1,245	1,245	1,245	1,245	1,245	1,245	1,273	1,273	14,996		
	HLH Energy (MWhr)	346,350	334,728	345,886	345,886	312,413	345,886	334,263	345,886	334,728	345,886	421,922	408,312	4,222,146	482	4,222
25	LLH Energy (MWhr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26		465	465	465	465	465	465	465	465	465	465	567	567	5,783	482	
27	Revenue (\$ Thousand)	0	0	0	0	0	0	0	0	0	0	0	0	\$0		
29	Monthly Trading Floor Committed Sales (MWH)	357.945	445,952	403,914	829,746	136,700	796,138	502,329	613,200	616,800	72,800	41,600	40,000	4,857,124	554	4,857
30		\$19,669	\$21.826	\$22,239	\$33,118	\$4.668	\$22,333	\$18.584	\$24,159	\$24.990	\$4.878	\$2,174	\$2.090	\$200.727	554	4,007
31	Monthly Trading Floor Balancing Sales (MWH)						. ,	791,866	1,347,854	1,885,286	1,060,593	47,628	205,501	5,338,728	609	5,339
32								\$20,412	\$28,616	\$40,960	\$29,549	\$1,449	\$6,029	\$127,015		
33																
34	Other Monthly Sales (\$000) FPS Bookouts	-98.215	-122.762	-143.872	-1.904	-29.136	-121.373							-517.262	-59	-517
36	Revenue reversals (\$000)	-96,215	-\$5,930	-143,672	-1,904	-29,136	-\$3,450							-\$24,059	-59	-517
37	revenue reversus (4000)	-40,100	-40,550	-00,411	ΨΟ	-ψ1,000	-90,400							-924,000		
	Power Purchases															
	ERE Augmentation Power purchases	8,959	9,661	10,726	9,685	9,002	8,595	7,511	10,295	11,286	11,468	11,239	8,959	117,384	13	117
40		\$261	\$299	\$337	\$272	\$269	\$238	\$206	\$221	\$215	\$260	\$291	\$264	\$3,134		
41		34.311	34.324	41.382	47.002	21.638	38.693	28.678	26.230	27.059	28.177	24.661	24.297	376.451	43	376
42	Renewable LLH (MWH)	6.519	6,070	9,789	9,829	8,209	28,514	23,689	24,297	26,321	25,352	22,458	19,996	211,044	43 24	211
44		\$2,017	\$2,071	\$2,587	\$2,933	\$1,681	\$3,394	\$2,694	\$2,669	\$2,727	\$2,744	\$2,437	\$2,317	\$30,273		
45																
46	Power Purchases Bookouts (MWH)	-98,215	-122,762	-143,872	-1,904	-29,136	-121,373	0	0	0	0	0	0	-517,262	-59	-517
47		-\$5,185	-\$5,930	-\$8,411	\$0	-\$1,083	-\$3,450	\$0	\$0	\$0	\$0	\$0	\$0	-\$24,059		
48														0	0	0
50														\$0	U	U
51														<b>40</b>		
52	Other Committed Power Purchases (MWH)	5,669	6,860	3,092	1,773	9,682	9,801	15,033	24,268	44,612	27,856	15,507	5,796	169,950	19	170
53								420	17,608	-	10,895	435,023	207,637	671,584	77	672
54		502,816	612,716	937,212	138,711	642,173	626,970	118,824	-		131,200	291,000	168,000	4,169,622	476	4,170
55 56		\$660	\$564	\$793	\$687	\$390	\$726	\$952	\$991	\$1,118	\$1,640	\$330	\$513	\$9,365		
	Balancing Purchase Power Expense (\$000) Trading Floor Purchase Power Expense (\$000)	\$24,625	\$30,061	\$61,783	\$4,924	\$26,086	\$18,938	\$11 <b>\$3,245</b>	\$451 <b>\$0</b>	\$0 <b>\$0</b>	\$319 <b>\$3,850</b>	\$14,700 <b>\$10,646</b>	\$6,656 <b>\$5,636</b>	\$22,136 \$189,793		
58		Ψ24,020	ψ55,061	ψ01,703	ψ4,524	Ψ20,000	ψ10,330	<b>43,24</b> 5	ŞU.	ŞU.	<b>\$3,000</b>	ψ10,040	<b>#3,030</b>	Ψ105,753		
59		\$4,665	\$5,750	\$7,102	\$7,986	\$6,592	\$6,178	\$5,357	\$4,969	\$5,019	\$6,075	\$5,774	\$5,303	\$70,768		
60		2,357,543	2,669,837	3,476,522	4,317,495	3,368,129	3,127,975	2,701,817	2,484,845	2,481,228	2,644,717	2,528,174	2,314,738	34,473,020	3,935	34,473
61	Residential Exchange cost	\$129,830	\$147,028	\$191,452	\$237,764	\$185,483	\$172,258	\$148,789	\$136,840	\$136,641	\$145,645	\$139,227	\$127,473	\$1,898,429		

В	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF
Jul 17, 2009 @ 12:20			es at Curren												
2 3		Reven	ue (\$ Thous	ands)											
3			FY2010									-			
4	744	721	744	744	672	743	720	744	720	744	744	720	Fiscal Y	'ear 201	0
5	432	384	416	416	384	416	416	400	416	416	416	400			
6	312	337	328	328	288	327	304	344	304	328	328	320			
7 Bulk HUB	Oct-09	Nov-09	Dec-09	<u>Jan-10</u>	Feb-10	Mar-10	Apr-10	May-10	<u>Jun-10</u>	<u>Jul-10</u>	Aug-10	Sep-10	Total	aMW	GWI
8 Investor-Owned Utilities Residential Exchange															
9 Residential Exchange Rate	(47.67)	(47.67)	(47.67)	(47.67)	(47.67)	(47.67)	(47.67)	(47.67)	(47.67)	(47.67)	(47.67)	(47.67)	(47.67)		
10 Energy (MWhr)	2,649,207	2,942,305	3,728,537		4,007,690	3,704,316	3,386,118	2,215,354	1,840,532	1,833,428	2,299,252	2,861,130	35,792,280		
11 Residential Exchange Revenue (\$000) = (12+13)*14	-\$126,298	-\$140,271	-\$177,753	-\$206,161	-\$191,062	-\$176,599	-\$161,429	-\$105,614	-\$87,745	-\$87,406	-\$109,614	-\$136,401	-\$1,706,352		
Direct-Service Industries (IP-02 & FPS)	000 000	000 040	299 088	000 000	270.144	298 686	289 440	299 088	289 440	000 000	000 000	289 440	0.504.500	400	0.500
13 IP LBCRAC True-up (MWH)	299,088 \$11.671	289,842 \$11.908	\$12,927	299,088 \$10.920	\$10,144	\$10.382	\$9,440 \$9,450	299,088 \$7.928	\$6,548	299,088 \$9.077	299,088 \$10.679	\$10.986	3,521,520 \$122,619	402	3,522
14 IP LBCRAC True-up Revenue (\$000) 15 PAC capacity, WNP-3 and other L-T contracts	\$11,671	\$11,908	\$12,927	\$10,920	\$10,142	\$10,382	\$9,450	\$7,928	\$6,548	\$9,077	\$10,679	\$10,986	\$122,619		
	851	963	870	870	870	788	788	988	770	785	938	758	10.239		
Demand (MW)	54.962	98.624	142.515	159.523	125.172	94.802	100.158	178.576	89.776	67.322	145.400	74.435		152	1.33
17 HLH Energy (MWhr) 18 LLH Energy (MWhr)	-129,189	-50,621	-16,121	-34,115	-13,973	-47,213	-40,587	9,357	-47,376	-38,354	-3,129	-87,730	1,331,265 -499,051	-57	-499
18 LLH Energy (MWNr) 19 Energy (aMW)	-129,189	-50,621 67	170	-34,115 169	-13,973	-47,213 64	-40,587 83	9,357	-47,376 59	-38,354 39	-3,129 191	-87,730 -18	1,141	-57 95	
20 Revenue (\$ Thousand)	\$3.982	\$10.285	\$10.455	\$10,444	\$9.903	\$7.266	\$7.165	\$7.536	\$4.027	\$4.023	\$6.629	\$3.980	1,141 \$85.694	95	034
20 Revenue (\$ Triousanu)	\$3,962	\$10,265	\$10,455	\$10,444	\$9,903	\$7,200	\$7,100	\$7,536	\$4,027	\$4,023	\$0,029	\$3,960	\$65,094		
22 Contractual Obligations (CER)															
23 Demand (MW)	1.273	1.273	1.273	1.273	1.273	1.273	1.273	1.273	1.273	1.273	1.240	1.240	15.210		
24 HLH Energy (MWhr)	422.490	408.312	421.922	421.922	381.091	421.922	407.745	421.922	408.312	421.922	392.088	379,440	4.909.088	560	4.909
25 LLH Energy (MWhr)	422,430	100,512	121,322	721,322	001,001	121,322	0 ,745	721,322	100,012	0	032,000	0 0 0	4,505,000	0	7,500
26 Energy (aMW)	567	567	567	567	567	567	567	567	567	567	527	527	6,725	560	,
27 Revenue (\$ Thousand)	0	0	0	0	007	0	0	007	0	0	0	027	\$0	300	
28	0	U	U	U	U	U	U	U	U	U	U	U	90		
29 Monthly Trading Floor Committed Sales (MWH)															
30 Monthly Trading Floor Committed Sales (\$000)															
31 Monthly Trading Floor Balancing Sales (MWH)	264.582	441.458	619.865	1.297.484	1.051.699	1.335.168	1.823.398	3.066.531	2.349.974	1.750.318	566.422	272.940	14.839.839	1 694	14.840
32 Monthly Trading Floor Balancing Sales (\$000)	\$8.514	\$15,446	\$23,222	\$55,912	\$42.798	\$52,434	\$63,709	\$102,412	\$78,428	\$66,440	\$24.115	\$11,201	\$544,632	1,001	,.
33 Other Monthly Sales (MWH)	ψ0,011	ψ10,110	QLO,LLL	400,012	ψ. <u>Σ,</u> ,,οο	φο <u>υ</u> , ιο ι	400,700	\$10E,11E	ψ10,120	400,110	ψ2 1,1 10	ψ,20.	φ0 1 1,00 <u>2</u>		
34 Other Monthly Sales (\$000)															
35 FPS Bookouts															
36 Revenue reversals (\$000)															
37															
Nower Purchases															
39 ERE Augmentation Power purchases	6.986	7.280	8.274	7.504	6.647	6.555	5.396	7.924	9,304	8.467	9.108	6.783	90.228	10	90
40 ERE Augmentation Purchase Expense	\$215	\$233	\$271	\$216	\$202	\$185	\$147	\$184	\$197	\$211	\$256	\$204	\$2,522		
41															
42 Renewable HLH (MWH)	26,590	26,485	24,292	24,063	20,328	38,693	28,677	31,104	27,057	28,175	24,658	24,297	324,419	37	324
43 Renewable LLH (MWH)	19,733	19,210	19,295	16,522	17,589	28,515	23,690	24,298	26,321	25,353	22,460	19,997	262,982	30	
44 Renewable Expense (\$000) (included in Program Expense Forecast)	\$2,431	\$2,444	\$2,371	\$2,250	\$2,149	\$3,453	\$2,750	\$2,869	\$2,760	\$2,764	\$2,435	\$2,318	\$30,994		
45															
46 Power Purchases Bookouts (MWH)															
47 Power Purchases Reversals (\$000)															
48															
49 Augmentation Power Purchases (MWH)	353,933	342,992	353,933	353,933	319,681	353,457	342,516	353,933	342,516	353,933	353,933	342,516	4,167,276	476	4,167
50 Augmentation Power Purchases (\$000)	\$15,126	\$14,659	\$15,126	\$15,126	\$13,662	\$15,106	\$14,638	\$15,126	\$14,638	\$15,126	\$15,126	\$14,638	\$178,100		
51															
52 Other Committed Power Purchases (MWH)	3,406	3,515	3,034	4,884	5,546	6,251	9,672	11,172	9,842	5,660	5,912	4,596	73,489	8	73
53 Balancing Power Purchases (MWH)	67,363	242,691	276,916	331,699	250,469	151,184	151,073	2,469	7,222	23,487	131,834	71,560	1,707,967	195	1,708
54 NLS Power Purchases (MWH) 79506, 79507, 79510, 79671, 79590		-													
55 Other Committed Purchase Power Expense (\$000)	\$384	\$390	\$370	\$439	\$473	\$145	\$124	\$175	\$162	\$117	\$167	\$118	\$3,065		
56 Balancing Purchase Power Expense (\$000)	\$2,038	\$11,378	\$13,579	\$16,913	\$13,112	\$8,763	\$8,621	\$85	\$301	\$899	\$5,785	\$3,091	\$84,566		
57 Trading Floor Purchase Power Expense (\$000)			,	,	, .=	,	,				,	,	,		
58															
59 Lookback adjustment															
60 Residential Exchange Power Purchase	2,649,207	2,942,305	3,728,537	4,324,412	4,007,690	3,704,316	3,386,118	2,215,354	1,840,532	1,833,428	2,299,252	2,861,130	35,792,280	4,086	35,792

_	В	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT	AU
1	Jul 17, 2009 @ 12:20			es at Curren												
3			Reven	ue (\$ Thous	ands)											
3				FY2011												
4		744	721	744	744	672	743	720	744	720	744	744	720	Fiscal Y	ear 201	1
5		432	384	416	416	384	416	416	400	416	416	416	400			
6		312	337	328	328	288	327	304	344	304	328	328	320	T-1-1	- 84847	014/1
	lulk HUB	Oct-10	Nov-10	Dec-10	<u>Jan-11</u>	Feb-11	<u>Mar-11</u>	Apr-11	May-11	<u>Jun-11</u>	<u>Jul-11</u>	Aug-11	Sep-11	Total	<u>aMW</u>	GW
	nvestor-Owned Utilities Residential Exchange tesidential Exchange Rate	(47.56)	(47.56)	(47.56)	(47.56)	(47.56)	(47.56)	(47.56)	(47.56)	(47.56)	(47.56)	(47.56)	(47.56)	(47.56)		
	nergy (MWhr)	2.601.476	2.958.308	3.739.296	4.324.875	4.004.777	3.683.861	3.309.864	2.372.017	1.934.557	1.919.477		2.950.443	36.196.069		
	tesidential Exchange Revenue (\$000) = (12+13)*14	-\$123,728	-\$140,700	-\$177,844	-\$205,695	-\$190,470	-\$175,207	-\$157,420	-\$112,815	-\$92,009	-\$91,292	-\$114,009	-\$140,325	(\$1,721,514)		
	hirect-Service Industries (IP-02 & FPS)	-9123,720	-\$ 140,700	-9177,044	-\$205,055	-\$150,470	-φ175,207	-\$157,420	-φ112,013	-952,005	-951,252	-\$114,009	-9140,323	(\$1,721,514)		
	PLBCRAC True-up (MWH)	299 088	289.842	299 088	299.088	270.144	298.686	289,440	299.088	289 440	299.088	299.088	289 440	3.521.520	402	3.522
	P LBCRAC True-up Revenue (\$000)	11.671	11.908	12.927	10.920	10.142	10.382	9,450	7.928	6.548	9.077	10.679	10.986	\$122.619	702	0,022
	AC capacity, WNP-3 and other L-T contracts	11,071	11,500	12,321	10,320	10,142	10,002	3,430	7,320	0,040	3,011	10,073	10,300	Ψ122,013		
	Demand (MW)	828	947	854	854	854	772	772	965	770	800	784	183	9.383		
	ILH Energy (MWhr)	49.873	97.242	139.155	155.843	121.972	91.281	96.708	173.826	89.776	67.498	78.083	-6.696	1.154.561	132	1.155
	LH Energy (MWhr)	-119,795	-44,396	-7,954	-26,149	-7,244	-39,709	-35,127	13,899	-47,376	-38,596	-61,515	-6,599	-420,561	-48	
	nergy (aMW)	-94	73	176	174	171	69	86	252	59	39	22	-18	1,010	84	
	tevenue (\$ Thousand)	\$3,982	\$10,146	\$10,316	\$10,305	\$9,764	\$7,127	\$7,026	\$7,336	\$4,027	\$4,024	\$4,372	\$59	\$78,483		
21																
22 (	Contractual Obligations (CER)															
23 E	emand (MW)	1,240	1,240	1,240	1,240	1,240	1,240	1,240	1,240	1,240	1,240	1,240	1,240	14,880		
24 H	ILH Energy (MWhr)	392,615	379,440	392,088	392,088	354,144	392,088	378,913	392,088	379,440	392,088	384,648	372,240	4,601,880	525	4,602
25 L	LH Energy (MWhr)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(
	nergy (aMW)	524	524	524	524	524	524	524	524	524	524	524	524	6,288	525	
	tevenue (\$ Thousand)	0	0	0	0	0	0	0	0	0	0	0	0	\$0		
28																
	fonthly Trading Floor Committed Sales (MWH)															
	fonthly Trading Floor Committed Sales (\$000)															
	fonthly Trading Floor Balancing Sales (MWH)	533,732	499,896	706,318	1,486,068	1,142,705					1,810,013	727,604	355,182	15,339,720	1,751	15,340
	fonthly Trading Floor Balancing Sales (\$000)	\$22,235	\$21,049	\$30,042	\$64,900	\$48,333	\$61,709	\$60,252	\$93,306	\$73,618	\$71,649	\$31,736	\$15,114	\$593,944		
33	Other Monthly Sales (MWH)															
34	Other Monthly Sales (\$000)															
	PS Bookouts															
	tevenue reversals (\$000)															
37																
	ower Purchases	5.044	F F00	0.004	5 700	5.050	4.000	4.400	5 500	0.005	0.004	0.005	5 400	07.044		0-
	RE Augmentation Power purchases RE Augmentation Purchase Expense	5,311 \$166	5,533 \$180	6,284 \$208	5,702 \$166	5,056 \$156	4,986 \$142	4,106 \$114	5,532 \$131	6,225 \$134	6,264 \$159	6,885 \$197	5,129 \$157	67,014 \$1,909	8	67
40 E	RE Augmentation Purchase Expense	\$100	\$180	\$208	\$100	\$156	\$142	\$114	\$131	\$134	\$159	\$197	\$157	\$1,909		
	tenewable HLH (MWH)	26.590	26,485	24.292	24.063	20.328	38.693	28.677	31.104	27.057	28.175	24 659	24.297	324.420	37	324
	tenewable hth (MWH)	19,733	19,210	19,295	16,522	17,589	28,515	23,690	24,298	26,321	25,353	22,459	19,997	262,981	30	
	tenewable Expense (\$000) (included in Program Expense Forecast)	\$2,452	\$2,470	\$2,391	\$2,280	\$2,175	\$3,506	\$2,788	\$2,907	\$2,798	\$2,801	\$2,459	\$2,349	\$31,384	30	203
44 1	tonowabic Expense (4000) (included in Frogram Expense Forecast)	φ <b>∠,<del>4</del>5</b> Ζ	φ2,470	φ <u>2</u> ,331	φ <b>∠</b> , <b>∠</b> 00	φ2,1/5	φυ,υυσ	φ2,100	92,507	92,130	φ2,00 l	φ2, <del>4</del> 07	φ <u>2</u> ,349	φυ1,00 <del>4</del>		
	ower Purchases Bookouts (MWH)															
	ower Purchases Reversals (\$000)															
48	(4000)															
	ugmentation Power Purchases (MWH)	506.186	490.537	506.186	506.186	457.200	505.505	489.857	506.186	489.857	506.186	506.186	489.857	5.959.928	680	5.960
	ugmentation Power Purchases (\$000)	\$23.020	\$22.309	\$23.020	\$23.020	\$20,793	\$22,989	\$22,278	\$23,020	\$22,278	\$23.020	\$23.020	\$22,278	\$271.045		2,200
51		,		*,	*,	,	*,	*	*,	·,	*,	,	<b>4</b> ,			
	Other Committed Power Purchases (MWH)	3,406	3,515	3,034	4,884	5,546	6,251	9,672	11,172	9,842	5,660	5,912	4,596	73,489	8	73
	alancing Power Purchases (MWH)	4,402	156,897	208,567	283,867	214,360	131,400	175,784	16,417	25,379	4,283	51,699	34,874	1,307,928	149	
	ILS Power Purchases (MWH) 79506, 79507, 79510, 79671, 79590		,	,	,	,	,	, -	,	,	,	,	,-			
	Other Committed Purchase Power Expense (\$000)	\$54	\$60	\$40	\$109	\$143	\$145	\$124	\$175	\$162	\$117	\$167	\$118	\$1,415		
	alancing Purchase Power Expense (\$000)	\$198	\$8,811	\$11,273	\$15,047	\$11,674	\$7,919	\$9,710	\$642	\$1,107	\$173	\$2,588	\$1,548	\$70,692		
	rading Floor Purchase Power Expense (\$000)															
58																
59 L	ookback adjustment															
	Residential Exchange Power Purchase	2.601.476	2.958.308	3.739.296	4.324.875	4.004.777	3.683.861	3.309.864	2.372.017	1.934.557	1.919.477	2.397.118	2.050.442	00 400 000	4 132	36.196
	Residential Exchange cost			0,700,200	4,324,073	4,004,777	3,003,001	3,309,004	2,312,011	1,934,557	1,919,477	2,397,110	2,950,445	36,196,069	7,102	

	В	С	D	E	F	G	Н	I	J	K	L	M	N	0	P	Q
1	Jul 17, 2009 @ 12:20		Revenue	s at Curren	t Rates											
3			Reveni	ue (\$ Thousa	ands)											
3				FY2009												
4																
5																
6														Fiscal \	ear 200	•
4 5 6 7		Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Total	aMW	GWh
8 9 10	GEN INPUTS:															
9	Redispatch	\$8	\$165	\$129	\$0	\$0	\$125	\$125	\$125	\$125	\$125	\$125	\$125	\$1,178		
10	Energy Imbalance	\$452	\$683	\$790	\$650	\$265	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$2,840		
11	Federal RAS for Generation Dropping	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$396		
11 12 13	Synchronous Condensing	\$341	\$341	\$341	\$341	\$341	\$341	\$341	\$341	\$341	\$341	\$341	\$341	\$4,091	0	0
13	Station Service	\$174	\$174	\$174	\$174	\$174	\$174	\$174	\$174	\$174	\$174	\$174	\$174	\$2,089	24	212750
14 15 16	Regulating Reserves	\$1,097	\$1,097	\$1,097	\$1,097	\$1,097	\$1,097	\$1,097	\$1,097	\$1,097	\$1,097	\$1,097	\$1,097	\$13,158		
15	Operating Reserves - Spinning & Supplemental	\$2,395	\$2,254	\$2,624	\$2,786	\$2,442	\$2,742	\$2,742	\$2,742	\$2,742	\$2,742	\$2,742	\$2,742	\$31,694		
16	COE/BOR Network/Delivery Facilities Segmentation	\$616	\$616	\$616	\$616	\$616	\$616	\$616	\$616	\$616	\$616	\$616	\$616	\$7,397		
17	Within-Hour Balancing Service for Wind Integration	\$738	\$738	\$738	\$840	\$911	\$1,028	\$1,201	\$1,201	\$1,492	\$1,492	\$2,120	\$2,120	\$14,617		
18	Total Interbusiness Line	\$5,854	\$6,101	\$6,542	\$6,538	\$5,878	\$6,156	\$6,329	\$6,329	\$6,619	\$6,619	\$7,247	\$7,247	\$77,460	24	
19																
20	RESERVE SERVICES:															
21	External	\$158	\$198	\$359	\$303	\$303	\$303	\$303	\$303	\$303	\$303	\$303	\$303	\$3,438		
22	Total Reserve Services	\$158	\$198	\$359	\$303	\$303	\$303	\$303	\$303	\$303	\$303	\$303	\$303	\$3,438		
19 20 21 22 23 24 25 26 27	TOTAL Ancillary and Reserves	\$6,012	\$6,300	\$6.901	\$6.840	\$6.181	\$6,459	\$6,631	\$6,631	\$6.922	\$6.922	\$7.550	\$7,550	\$80,897	24	
25	TOTAL Allomary and Reserves	ψ0,012	40,000	ψ0,501	<b>40,040</b>	ψ0,101	ψο, του	ψ0,001	ψ0,001	ψ0,522	<b>40,522</b>	ψ1,000	ψ1,000	400,007		
26	OTHER REVENUES															
27	Downstream Benefits and Storage (MWh)	70,190	10,264	23,245	52,260	53,085	152.833	174,525	215.620	206,324	230.778	187.731	157.687	1,534,543	175	1,535
28	Downstream Benefits and Pumping Power \$\$\$	\$882	\$848	\$864	\$858	\$845	\$714	\$733	\$762	\$782	\$800	\$792	\$765	\$9,646		.,
28 29 30 31 32 33	Slice True-Up (and Implementation costs)						4	4.00	4			4	\$5.370	\$5,370		
30	Misc. Generation	\$288	\$328	\$395	\$614	\$308	\$285	\$285	\$285	\$285	\$285	\$285	\$285	\$3,927		
31	Energy Efficiency Rev's	\$2,431	\$639	\$1,111	\$931	\$780	\$605	\$801	\$901	\$1,000	\$1,000	\$1,500	\$2,800	\$14,500		
32	Green Tags and Green Premiums Bulk	\$56	\$162	\$325	\$5	\$198	\$90	\$90	\$90	\$90	\$90	\$90	\$147	\$1,434		
33	Green Premium West	\$150	\$145	\$147	\$147	\$133	\$24	\$23	\$24	\$23	\$24	\$24	\$23	\$886		
34 35 36	Green Premium East	\$111	\$108	\$111	\$111	\$100	\$113	\$110	\$113	\$110	\$113	\$113	\$110	\$1,323		
35	4(h)(10)c credit	\$7,547	\$6,954	\$7,088	\$7,029	\$7,894	\$6,009	\$6,009	\$6,009	\$6,009	\$6,009	\$6,009	\$6,009	\$78,578		
36	Network Wind Integration&Shaping	\$170	\$170	\$170	\$170	\$170	\$163	\$163	\$163	\$163	\$163	\$163	\$163	\$1,989		
37	Colville and Spokane Settlements	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$4,600		
38	LB CRAC True-up															
38 39 40	Aluminum Hedging															
40	TOTAL OTHER REVENUES	\$12,018	\$9,737	\$10,594	\$10,249	\$10,813	\$8,387	\$8,598	\$8,731	\$8,845	\$8,868	\$9,360	\$16,055	\$122,254		
41																
42	Trading Floor Transmission	\$5,849	\$6,004	\$6,004	\$6,004	\$6,004	\$6,004	\$6,004	\$5,804	\$5,804	\$5,804	\$5,641	\$5,641	\$70,564		
43	Other Transmission Expenses	\$2,216	\$2,061	\$2,061	\$2,061	\$2,061	\$2,061	\$2,061	\$2,260	\$2,260	\$2,260	\$2,424	\$2,424	\$26,211		

	В	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE AF
1	Jul 17, 2009 @ 12:20		Revenue	s at Curren	nt Rates										
2			Revenu	e (\$ Thous	ands)										
3				FY2010	,										
4															
5															
4 5 6 7														Fiscal Y	'ear 2010
7		Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Total	aMW GWh
8	GEN INPUTS:														
	Redispatch	\$125	\$125	\$125	\$125	\$125	\$125	\$125	\$125	\$125	\$125	\$125	\$125	\$1,500	
10	Energy Imbalance	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
11	Federal RAS for Generation Dropping	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$396	
12	Synchronous Condensing	\$122	\$122	\$122	\$122	\$122	\$122	\$122	\$122	\$122	\$122	\$122	\$122	\$1,466	0 0
13	Station Service	\$158	\$158	\$158	\$158	\$158	\$158	\$158	\$158	\$158	\$158	\$158	\$158	\$1,891	14 1E+05
14 15 16	Regulating Reserves	\$607	\$607	\$607	\$607	\$607	\$607	\$607	\$607	\$607	\$607	\$607	\$607	\$7,281	l
15	Operating Reserves - Spinning & Supplemental	\$2,213	\$2,213	\$2,213	\$2,213	\$2,213	\$2,213	\$2,213	\$2,213	\$2,213	\$2,213	\$2,213	\$2,213	\$26,551	
16	COE/BOR Network/Delivery Facilities Segmentation	\$616	\$616	\$616	\$616	\$616	\$616	\$616	\$616	\$616	\$616	\$616	\$616	\$7,397	
17	Within-Hour Balancing Service for Wind Integration	\$4,592	\$4,592	\$4,592	\$4,592	\$4,592	\$4,592	\$4,592	\$4,592	\$4,592	\$4,592	\$4,592	\$4,592	\$55,107	
18	Total Interbusiness Line	\$8,341	\$8,466	\$8,466	\$8,466	\$8,466	\$8,466	\$8,466	\$8,466	\$8,466	\$8,466	\$8,466	\$8,466	\$101,590	14
19	DECEDIE CEDITORO														
20	RESERVE SERVICES:  External	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
22	Total Reserve Services	\$0 \$0													
23	10141.11000.10 00111000	ų,	Ų.	ΨÜ	40	Ų.	ų.	Ų.							
20 21 22 23 24 25 26 27	TOTAL Ancillary and Reserves	\$8,341	\$8,466	\$8,466	\$8,466	\$8,466	\$8,466	\$8,466	\$8,466	\$8,466	\$8,466	\$8,466	\$8,466	\$101,590	14
25															
26	OTHER REVENUES														
27	Downstream Benefits and Storage (MWh)	70,190	10,264	23,245	52,260	53,085	152,833	174,525	215,620	206,324	230,778	187,731	157,687	1,534,543	175 1,535
28	Downstream Benefits and Pumping Power \$\$\$	\$731	\$710	\$710	\$710	\$711	\$714	\$733	\$762	\$782	\$800	\$792	\$765	\$8,921	
29 30 31	Slice True-Up (and Implementation costs)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	(\$5,282)	(\$5,282)	
30	Misc. Generation	\$285	\$285	\$285	\$285	\$285	\$285	\$285	\$285	\$285	\$285	\$285	\$285	\$3,420	
31	Energy Efficiency Rev's	\$1,367	\$1,367	\$1,367	\$1,367	\$1,367	\$1,367	\$1,367	\$1,367	\$1,367	\$2,733	\$2,733	\$2,733	\$20,500	l
32	Green Tags and Green Premiums Bulk	\$404	\$378	\$357	\$320	\$296	\$589	\$446	\$489	\$467	\$477	\$423	\$394	\$5,040	l
33	Green Premium West	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
34 35 36	Green Premium East	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
35	4(h)(10)c credit	\$8,057	\$8,057	\$8,057	\$8,057	\$8,057	\$8,057	\$8,057	\$8,057	\$8,057	\$8,057	\$8,057	\$8,057	\$96,689	
36	Network Wind Integration&Shaping	\$163	\$163	\$163	\$163	\$163	\$163	\$163	\$163	\$163	\$163	\$163	\$163	\$1,953	
37	Colville and Spokane Settlements	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$4,600	l
38	LB CRAC True-up														
40	Aluminum Hedging TOTAL OTHER REVENUES	644 200	644 242	644 222	¢44.006	644.000	\$44 EE0	644 425	644 506	¢44 E04	642.000	640.027	67 400	6425.042	
41	IUIAL UIHER REVENUES	\$11,390	\$11,343	\$11,323	\$11,286	\$11,262	\$11,558	\$11,435	\$11,506	\$11,504	\$12,899	\$12,837	\$7,498	\$135,842	
42	Trading Floor Transmission	\$7,418	\$7 A40	\$7.440	¢7 440	\$7.449	\$7.440	\$7.440	\$7 A10	¢7 440	\$7.440	¢7 440	\$7 A10	¢00 040	l
43	Other Transmission Expenses	\$7,418 \$2,513	\$89,018 \$30,159	l											
43	Other Transmission Expenses	<b>⊅∠,513</b>	<b>⊅∠,513</b>	<b>⊅∠,513</b>	<b>⊅∠,513</b>	<b>⊅</b> ∠,513	<b>⊅</b> ∠,513	<b>⊅∠,513</b>	<b>⊅∠,513</b>	<b>⊅</b> ∠,513	<b>⊅</b> 2,513	<b>⊅∠,513</b>	<b>⊅∠,513</b>	<b>\$30,159</b>	

	В	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT	ΑU
1	Jul 17, 2009 @ 12:20		Revenue	s at Curren	t Rates											
2			Revenu	e (\$ Thous	ands)											
3				FY2011												
1																
5																
6														Fiscal \	ear 2011	
5 6 7		Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Total	aMW	GWI
8	GEN INPUTS:															
9	Redispatch	\$125	\$125	\$125	\$125	\$125	\$125	\$125	\$125	\$125	\$125	\$125	\$125	\$1,500		
10	Energy Imbalance	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
1	Federal RAS for Generation Dropping	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$396		
12	Synchronous Condensing	\$122	\$122	\$122	\$122	\$122	\$122	\$122	\$122	\$122	\$122	\$122	\$122	\$1,466	0	(
13	Station Service	\$158	\$158	\$158	\$158	\$158	\$158	\$158	\$158	\$158	\$158	\$158	\$158	\$1,891	14 ##	#####
4	Regulating Reserves	\$607	\$607	\$607	\$607	\$607	\$607	\$607	\$607	\$607	\$607	\$607	\$607	\$7,281		
15	Operating Reserves - Spinning & Supplemental	\$2,213	\$2,213	\$2,213	\$2,213	\$2,213	\$2,213	\$2,213	\$2,213	\$2,213	\$2,213	\$2,213	\$2,213	\$26,551		
16	COE/BOR Network/Delivery Facilities Segmentation	\$616	\$616	\$616	\$616	\$616	\$616	\$616	\$616	\$616	\$616	\$616	\$616	\$7,397		
17	Within-Hour Balancing Service for Wind Integration	\$4,592	\$4,592	\$4,592	\$4,592	\$4,592	\$4,592	\$4,592	\$4,592	\$4,592	\$4,592	\$4,592	\$4,592	\$55,107		
18	Total Interbusiness Line	\$8,466	\$8,466	\$8,466	\$8,466	\$8,466	\$8,466	\$8,466	\$8,466	\$8,466	\$8,466	\$8,466	\$8,466	\$101,590	14	
19																
20	RESERVE SERVICES:															
21	External	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
22	Total Reserve Services	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
.3	TOTAL Ancillary and Reserves	\$8,466	\$8,466	\$8,466	\$8,466	\$8,466	\$8,466	\$8.466	\$8.466	\$8,466	\$8,466	\$8,466	\$8,466	\$101,590	14	
5	TOTAL Anomary and Reserves	ψ0,400	ψ0,400	ψ0,400	ψο,-του	<b>40,400</b>	ψ0,400	ψο, του	ψο,400	ψ0,400	ψ0,400	ψο, του	ψ0,400	ψ101,000	1-7	
26	OTHER REVENUES															
20 21 22 23 24 25 26 27	Downstream Benefits and Storage (MWh)	70,190	10.264	23.245	52,260	53,085	152.833	174,525	215.620	206,324	230.778	187.731	157.687	1,534,543	175	1,535
28	Downstream Benefits and Pumping Power \$\$\$	\$731	\$710	\$710	\$710	\$711	\$714	\$733	\$762	\$782	\$800	\$792	\$765	\$8,921		.,
29	Slice True-Up (and Implementation costs)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$10,942	\$10,942		
30	Misc. Generation	\$285	\$285	\$285	\$285	\$285	\$285	\$285	\$285	\$285	\$285	\$285	\$285	\$3,420		
28 29 30 31 32	Energy Efficiency Rev's	\$1,367	\$1,367	\$1,367	\$1,367	\$1,367	\$1,367	\$1,367	\$1,367	\$1,367	\$2,733	\$2,733	\$2,733	\$20,500		
32	Green Tags and Green Premiums Bulk	\$404	\$378	\$357	\$320	\$296	\$589	\$446	\$489	\$467	\$477	\$423	\$394	\$5,040		
33	Green Premium West	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
34	Green Premium East	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
35	4(h)(10)c credit	\$8,497	\$8,497	\$8,497	\$8,497	\$8,497	\$8,497	\$8,497	\$8,497	\$8,497	\$8,497	\$8,497	\$8,497	\$101,969		
33 34 35 36 37 38 39	Network Wind Integration&Shaping	\$163	\$163	\$163	\$163	\$163	\$163	\$163	\$163	\$163	\$163	\$163	\$163	\$1,953		
37	Colville and Spokane Settlements	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$4,600		
38	LB CRAC True-up															
39	Aluminum Hedging															
40 41	TOTAL OTHER REVENUES	\$11,830	\$11,783	\$11,763	\$11,726	\$11,702	\$11,998	\$11,875	\$11,946	\$11,944	\$13,339	\$13,277	\$24,162	\$157,345		
<b>+</b> 1																
42	Trading Floor Transmission	\$7,363	\$7,363	\$7,363	\$7,363	\$7,363	\$7,363	\$7,363	\$7,363	\$7,363	\$7,363	\$7,363	\$7,363	\$88,352		
43	Other Transmission Expenses	\$2,421	\$2,421	\$2,421	\$2,421	\$2,421	\$2,421	\$2,421	\$2,421	\$2,421	\$2,421	\$2,421	\$2,421	\$29,049		

**Table 4.6.2 Summary of Revenues at Proposed Rates** 

	A	В	С	D	Е	F	G
1		B	C	D		-	
2		FY 200	9	FY 201	10	FY 201	1
3		(\$000)	aMW	(\$000)	aMW	(\$000)	aMW
4	Revenues						
5	PF Preference	\$1,228,242	5,299	\$1,302,923	5,211	\$1,321,640	5,284
6	Lookback Adjustment	(\$70,769)	0	\$0	0	\$0	0
7	PF Slice	\$502,645	1,680	\$528,120	2,082	\$528,264	2,067
8	Pre-sub/Hungry Horse	\$37,624	210	\$37,235	199	\$34,462	201
9	Irrigation Mitigation	\$20,212	196	\$22,022	191	\$21,953	190
10	Industrial Power	\$0	0	\$121,852	403	\$121,852	403
11	Long-Term Obligations	\$91,498	624	\$96,778	655	\$88,437	609
12	Generation Inputs/Reserve Services	\$80,897	24	\$90,171	14	\$102,735	14
13	Slice True-Up	\$5,370	0	(\$5,282)	0	\$10,942	0
14	Network Wind Integration & Shaping	\$1,989	0	\$1,953	0	\$1,953	0
15	4h10C credits	\$78,578	0	\$96,689	0	\$101,969	0
16	Colville credits	\$4,600	0	\$4,600	0	\$4,600	0
17	Downstream Benefits/Storage	\$9,646	175	\$8,921	175	\$8,921	175
18	Energy Efficiency	\$14,500	0	\$20,500	0	\$20,500	0
19	Green Tags/Green Premiums	\$3,644	0	\$5,040	0	\$5,040	0
20	Misc Generation	\$3,927	0	\$3,420	0	\$3,420	0
21	Secondary Sales	\$327,742	1,164	\$544,632	1,694	\$593,944	1,751
22	Bookouts	(\$24,059)	-59	\$0	0	\$0	0
23	Ad hoc Gen Input adjustment						
24	Total Revenue	\$2,316,286	9,312	\$2,879,575	10,624	\$2,970,633	10,694
25	Purchases						
26	Augmentation Purchases	\$3,134	13	\$180,766	486	\$273,043	688
27	Secondary Purchases	\$211,930	553	\$84,566	195	\$70,692	149

	A	В	С	D	Е	F	G	Н	I	J	K	L	М	N	0	P	0
1		Jul 22, 2009 @ 15:58		*	•	•		enues at P								,	
2							-	Revenue (\$		)							
3								Fiscal Y	ear 2009								
5			\$26.81	\$2.03													
6			\$20.01	\$2.03										Г	Fiscal Y	'ear 200	19
7		Western HUB	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Total	aMW	GWh
9		East Hub PF Billing Determinants													_		
9		PF Full Service															
10		LLH Energy Flat	275,595 461,962	328,586 452,386	414,396 622 642	401,655 597,386	336,365 521 181	326,384 525,558	301,624 477,297	289,916 430,813	252,472 420,450	266,250 411.867	254,797 430 484	263,424 409,319	3,711,464	424 658	3711 5761
11		HLH Energy Flat PF Flat LLH Energy Rate	461,962 \$21.40	452,386 \$22.72	\$23,85	\$19.96	521,181 \$20.16	\$19.17	\$17.63	430,813 \$14.17	420,450 \$9.85	411,867 \$16.73	430,484 \$19.85	409,319 \$22.17	5,761,345	658	5/61
13		PF Flat HLH Energy Rate	\$29.21	\$31.15	\$32.51	\$27.60	\$28.19	\$26.15	\$24.54	\$20.50	\$18.55	\$22.85	\$26.76	\$27.62			
14		LLH Energy Revenue Flat Revenue = 11*13/1000	\$5,343	\$7,465	\$9,883	\$8,017	\$6,781	\$6,257	\$5,318	\$4,108	\$2,487	\$4,454	\$5,058	\$5,840	\$71,012		
15 16		HLH Energy Revenue Flat Revenue= 12*14/1000 Demand	\$12,694 1.398	\$14,092 1,214	\$20,242	\$16,488 1,596	\$14,692 1,703	\$13,743 1.568	\$11,713 1,396	\$8,832	\$7,799 1,045	\$9,411	\$11,520 1,040	\$11,305 1,027	\$152,532 16,030		
17		PF GSP Demand Rate	\$1.91	\$2.04	\$2.14	\$1.82	\$1.85	\$1.72	\$1.62	\$1.34	\$1.23	\$1.50	\$1.76	\$1.82	10,000		
18		Demand Revenue = 17*18	\$2,563	\$2,477	\$4,026	\$2,904	\$3,151	\$2,697	\$2,262	\$1,458	\$1,285	\$1,611	\$1,830	\$1,869	\$28,134		
19		Load Variance	750,216	793,646	1,051,953	1,013,764	869,157	909,632	836,154	782,813	732,274	737,461	743,680	725,315	9,946,064	1135	9946
20 21 22		PF Ld Variance Rate Load Variance Revenue = 20*21/1000	\$0.46 \$315	\$0.46 \$365	\$0.46 \$484	\$0.46 \$466	\$0.46	\$0.46 \$418	\$0.46 \$385	\$0.46 \$360	\$0.46 \$337	\$0.46 \$339	\$0.46 \$342	\$0.46 \$334	\$4.545		
22		Low Density Discount Percent = 30/(15+16+21+22+25+28)	-1.66%	-1.84%	-1.95%	-1.95%	-1.94%	-2.38%	-2.38%	-2.44%	-2.40%	-2.28%	-2.26%	-2.26%	\$4,545		
23		Low Density Discount	-\$348	-\$449	-\$675	-\$543	-\$486	-\$550	-\$468	-\$360	-\$286	-\$361	-\$425	-\$438	-\$5,388		
24	-1,008,619	LBCRAC True-up/Lookback Adjust	-\$1,009	-\$1,009	-\$1,009	-\$1,009	-\$1,009	-\$1,009	-\$1,009	-\$1,009	-\$1,009	-\$1,009	-\$1,009	-\$1,009	-\$12,103		
25		PF Other Energy	0	0	0	0 \$0	0										
25		PF Other revenues	\$4	\$0	\$0	\$0	\$0								\$4		
24 25 26 27 28 29		PF Partial Service															
29		LLH Energy Flat	312,148 497 690	347,212 443,562	412,690 576,742	398,298	338,926 493,919	327,080	297,780 555,036	356,279 568 611	267,650 490,382	290,224 521.350	290,497 542 248	291,308	3,930,093 6,346,539	449 724	3,930
30 31		HLH Energy Flat LLH Energy Revenue Flat (30*13)/1000	497,690 \$6,681	443,562 \$7.889	576,742 \$9,843	559,797 \$7,950	493,919 \$6.833	579,795 \$6.270	555,036 \$5,250	568,611 \$5,048	490,382 \$2.636	521,350 \$4.855	542,248 \$5,766	517,406 \$6,458	6,346,539 \$75,480	/24	6,347
32		HLH Energy Revenue Flat (31*14)/1000	\$14,535	\$13,817	\$18,750	\$15,450	\$13,924	\$15,162	\$13,621	\$11,657	\$9,097	\$11,913	\$14,511	\$14,291	\$166,726		
33		GSP Demand	1,454	1,321	1,951	1,672	1,676	1,468	1,425	1,359	1,168	1,252	1,262	1,265	17,273		
34 35		Demand Revenue (34*18) Load Variance	\$2,777	\$2,695 1,019,974	\$4,175 1.238.664	\$3,043 1,211,281	\$3,100 1.063.890	\$2,525 1,144,954	\$2,308 1.087.995	\$1,822 1.052.352	\$1,437 1,007,251	\$1,878 1.042.228	\$2,221 1.053.565	\$2,303 1,021,789	\$30,283 12.982.888	1482	12983
36		Load Variance Revenue (36*21)/1000	\$478	\$469	\$570	\$557	\$489	\$527	\$500	\$484	\$463	\$479	\$485	\$470	\$5,972	1402	12503
37	-1,133,980	LBCRAC True-up/Lookback Adjust	-\$1,134	-\$1,134	-\$1,134	-\$1,134	-\$1,134	-\$1,134	-\$1,134	-\$1,134	-\$1,134	-\$1,134	-\$1,134	-\$1,134	-\$13,608		
38		PF Other Energy PF Other revenues	0 \$0	0 \$23	0 \$0	0 \$0	1 \$0								\$23		
39 40 41		PF Other revenues	\$0	\$23	\$0	\$0	\$0								\$23		
41		PF Block Service															
42 43		LLH Energy Flat	392,808 562 464	521,676 647,424	578,264 786,656	588,104 790,816	510,624 713,856	562,702 715,854	403,016 551 495	363,494 410,513	291,791 388 255	357,555 437,536	390,748 481 595	447,947 559 934	5,408,729 7,046,398	617 804	5,409 7,046
44		HLH Energy Flat LLH Energy Revenue Flat (43*13)/1000	\$8,406	\$11.852	786,656 \$13,792	790,816 \$11.739	713,856 \$10.294	715,854 \$10,787	\$7 105	\$5 151	388,255 \$2,874	437,536 \$5,982	481,595 \$7,756	559,934 \$9,931	7,046,398 \$105,669	804	7,046
45		LLH Energy Revenue Stepped (56*19)/1000		,	****		,	****	***,****	**,	42,0	******	******	***	\$0		
46		HLH Energy Revenue Flat (44*14)/1000	\$16,430	\$20,167	\$25,574	\$21,827	\$20,124	\$18,720	\$13,534	\$8,416	\$7,202	\$9,998	\$12,887	\$15,465	\$190,343		
47 48		HLH Energy Revenue Stepped (57*20)/1000 GSP Demand	1,408	1.812	2 006	2 059	1 992	1.721	1 326	1.137	1 088	1 225	1 308	1 400	\$0 18 482		
49		Demand Revenue (49*24)	\$2,689	\$3,696	\$4,293	\$3,747	\$3,685	\$2,960	\$2,148	\$1,523	\$1,338	\$1,838	\$2,303	\$2,548	\$32,769		
50	-1,309,822	LBCRAC True-up/Lookback Adjust	-\$1,310	-\$1,310	-\$1,310	-\$1,310	-\$1,310	-\$1,310	-\$1,310	-\$1,310	-\$1,310	-\$1,310	-\$1,310	-\$1,310	-\$15,718		
51		PF SUMY Low Density Discount Percent = 70/(59+60+61+62+64)	\$0 -0.89%	\$0 -0.79%	\$0 -0.80%	\$0 -0.81%	\$0 -0.79%	\$0 -0.75%	\$0 -1.00%	\$0 -0.94%	\$0 -0.87%	\$0 -0.78%	\$0 -0.71%	\$0 -0.95%	\$0		
53		Low-Density Discount Percent = 70/(59+60+61+62+64) Low-Density Discount	-0.89% -\$246	-0.79%	-0.80%	-0.81% -\$304	-0.79% -\$271	-0.75% -\$244	-1.00% -\$228	-0.94% -\$143	-0.87%	-0.78% -\$140	-0.71%	-0.95% -\$266	-\$2,735		
54		PF Other Energy													0		
51 52 53 54 55 56		PF Block Other Revenues													\$0		
57		Irrigation Mitigation LLH	0	0	0	0	0	0	0	28.360	39.538	44.975	39.179	0	152.052	17	152
58		Irrigation Mitigation HLH	0	0	0	0	0	0	0	45,493	65,398	73,313	64,136	0	248,340	28	248
57 58 59 60		Irrigation Mitigation Revenues	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$710	\$721	\$1,383	\$1,568	\$0	\$4,382		
61		Pt Townsend LLH	5.124	5.972	3.984	5.629	5.721	5.559	5.168	5.848	5.168	5.576	5.576	5,440	64.765	7	65
61		Pt Townsend HLH	6,871	6,774	5,551	7,230	7,429	7,072	7,072	6,800	7,072	7,072	7,072	6,800	82,815	9	83
63		Pt Townsend Demand	18	19	19	17	17	17	17 \$299	17	17	17	17	17	210		
64		Pt Townsend Revenues	\$359	\$401	\$328	\$357	\$371	\$328	\$299	\$252	\$210	\$288	\$337	\$346	\$3,876		
66 67		PF Slice															
67		Percent of SLICE	18.5108%	18.5108%	18.5108%	18.5108%	18.5108%	18.5108%	18.5108%	18.5108%	18.5108%	18.5108%	18.5108%	18.5108%	18.51%	1331	
68 69		Slice rate Slice Charges (\$000) = 69*70*100	\$1,873 \$34,660	\$1,873 \$34,660	\$1,873 \$34,660	\$1,873 \$34,660	\$1,873 \$34,660	\$1,873 \$34,663	\$415.936								
70		Monetary Benefits to IOUs (\$000)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
71 72	-1,091,516	LBCRAC True-up/Lookback Adjust	-\$1,092	-\$1,092	-\$1,092	-\$1,092	-\$1,092	-\$1,092	-\$1,092	-\$1,092	-\$1,092	-\$1,092	-\$1,092	-\$1,092	-\$13,098		
72		LDD Percentage Low-Density Discount	-1.08% -373	-1.08% -373	-1.08% -373	-1.08% -373	-1.08% -373	-1.12% -\$389	-\$4.588								
74		Slice Other	-3/3 \$0	-3/3 \$0	-\$1,033	\$52	-3/3 \$0	-9309	-6009	-4009	-0008	-4009	-9309	-4109	-\$4,566 -\$981		
75		West Hub FPS (Pre-Subscription) Sales															
76 77		LLH Energy Full Service LLH Energy Revenue	1,248 \$25	1,348 \$27	1,312 \$26	1,312 \$26	1,152 \$23	6,867 \$27	6,384 \$25	7,224 \$29	6,384 \$25	6,888 \$27	6,888 \$27	6,720 \$27	53,727 \$313	6	54
78		HLH Energy Full Service	\$25 1.728	1.536	\$26 1.664	\$26 1.664	\$23 1.536	\$27 8.736	\$25 8.736	\$29 8.400	\$25 8.736	\$27 8.736	\$27 8.736	\$27 8.400	\$313 68.608	8	69
79 80 81		HLH Energy Revenue	\$34	\$30	\$33	\$33	\$30	\$35	\$35	\$33	\$35	\$35	\$35	\$33	\$400	-	
80		GSP Demand	4	4	4	4	4	21	21	21	21	21	21	21	167		
81		Demand Revenue Load Variance	-\$4 0	-\$4 0	-\$4 0	-\$4 0	-\$4 0	15.603	15.120	15.624	15.120	15.624	15.624	15.120	-\$20 107.835	12	108
82 83		Load Variance Load Variance Revenue	\$0	\$0	\$0	\$0	\$0	15,603	15,120	15,624	15,120	15,624	15,624	15,120	107,835	12	106
84 85		Low-Density Discount	-	,-	,-	,-	-	,		-	,				\$0		
85 86		LT SURPLUS FB CRAC Netrwork Wind Integration Service													so		
87		Other Pre-Subscription revenues	\$10	\$10	\$14	\$13	\$10								\$0 \$57		
88		Total	\$102,489	\$114,484	\$140,744	\$121,509	\$112,891	\$109,398	\$93,542	\$79,115	\$67,298	\$83,727	\$95,796	\$100,253	\$1,263,670		

	A	В	R	S	T	U	v	W	X	Y	Z	AA	AB	AC	AD	AE	AF
1	J	ul 22, 2009 @ 15:58		•	•	•			roposed		•						
3							R		Thousand	ls)							
4								riscui i	edi 2010								
5														_			
7		Vestern HUB	Oct-09	Nov-09	Dec-09	Jan-10	E-1- 10	M 10	A 10	May-10	Jun-10	h.l. 10	A 10	S== 10	Fiscal Y Total	ear 201 aMW	0 GWh
8		estern HUB est Hub PF Billing Determinants	<u>OC1-09</u>	NOV-UY	Dec-03	Jan-10	Feb-10	Mar-10	Apr-10	<u>may-10</u>	JUN-10	JUI- 10	Aug-10	Sep-10	Iotal	<u>aww</u>	GWn
9	P	F Full Service															
10		LH Energy Flat	275,385 458.093	349,641 523,708	387,390 582,651	385,617 581.666	328,467 525.031	312,183 508.570	291,681 464,840	277,240 417,011	243,958 407.021	270,676 389,772	249,430 420,595	259,424 403.621	3,631,092 5,682,579	415 649	3631 5683
11	P	ILH Energy Flat 'F Flat LLH Energy Rate	\$23.01	\$24.43	\$25.65	\$21.46	\$21.68	\$20.61	\$18.97	\$15.24	\$10.59	\$17.99	\$21.34	\$23.84	5,002,579	049	2003
13 14	P	F Flat HLH Energy Rate	\$31.41	\$33.49 \$8.542	\$34.96	\$29.68 \$8.275	\$30.31 \$7.121	\$28.12	\$26.39	\$22.04 \$4.225	\$19.95 \$2.584	\$24.57	\$28.77 \$5.323	\$29.70 \$6.185			
15		LH Energy Revenue Flat Revenue = 11*13/1000 ILH Energy Revenue Flat Revenue= 12*14/1000	\$6,337 \$14,389	\$8,542 \$17.539	\$9,937 \$20,369	\$8,275	\$7,121	\$6,434 \$14,301	\$5,533 \$12,267	\$4,225	\$2,584 \$8,120	\$4,869 \$9.577	\$5,323 \$12,101	\$6,185 \$11.988	\$75,364 \$163.019		
16	D	emand	1,457	1,574	1,697	1,772	1,716	1,549	1,381	1,067	1,041	1,079	1,026	1,019	16,378		
17		F GSP Demand Rate Demand Revenue = 17*18	\$2.05 \$2.986	\$2.19 \$3.446	\$2.30 \$3.902	\$1.96 \$3.473	\$1.99 \$3.414	\$1.85 \$2.866	\$1.74 \$2.403	\$1.44 \$1.537	\$1.32 \$1.374	\$1.61 \$1.736	\$1.89 \$1.940	\$1.96 \$1.98	\$31,076		
19		oad Variance	754,019	895,929	995,586	991,790	875,886	843,421	781,180	721,793	677,495	685,878	694,615	682,762	9,600,354	1096	9600
20		F Ld Variance Rate	\$0.49	\$0.49	\$0.49	\$0.49	\$0.49	\$0.49	\$0.49	\$0.49	\$0.49	\$0.49	\$0.49	\$0.49			
21		oad Variance Revenue = 20*21/1000 ow Density Discount Percent =30/(15+16+21+22+25+28)	\$369 -2 02%	\$439 -2.09%	\$488 -2 13%	\$486 -2 13%	\$429 -2 13%	\$413 -2.08%	\$383 -2.10%	\$354 -2.08%	\$332 -2.06%	\$336 -1 99%	\$340 -1.97%	\$335 -1 98%	\$4,704		
23		ow Density Discount	-\$486	-\$626	-\$740	-\$627	-\$571	-\$498	-\$432	-\$318	-\$256	-\$329	-\$389	-\$406	-\$5.679		
24	-1,008,619 L	BCRAC True-up/Lookback Adjust													\$0		
25		PF Other Energy PF Other revenues													\$0		
26 27															ψU		
28 29		F Partial Service	292.812	376.569	407.646	401.531	334.706	324.762	322.760	347.741	290.928	307.350	294.113	296.931	3.997.849	456	3.998
30	H	LH Energy Flat ILH Energy Flat	468,002	505,457	563,482	401,531 541,076	500,348	499,916	322,760 486,488	347,741 449,661	290,928 444,801	436,120	294,113 479,809	434,003	5,809,163	663	5,809
31	L	LH Energy Revenue Flat (30*13)/1000	\$6,738	\$9,200	\$10,456	\$8,617	\$7,256	\$6,693	\$6,123	\$5,300	\$3,081	\$5,529	\$6,276	\$7,079	\$82,348		
32	H	ILH Energy Revenue Flat (31*14)/1000 SSP Demand	\$14,700 1.453	\$16,928 1.654	\$19,699 1,693	\$16,059 1,685	\$15,166 1.662	\$14,058 1,525	\$12,838 1,448	\$9,911 1,307	\$8,874 1.236	\$10,715 1,380	\$13,804 1,315	\$12,890 1,278	\$165,641 17,636		
34		Pernand Revenue (34*18)	\$2,979	\$3,622	\$3,894	\$3,303	\$3,308	\$2,821	\$2,520	\$1,882	\$1,632	\$2,221	\$2,485	\$2,506	\$33,174		
35 36		oad Variance oad Variance Revenue (36*21)/1000	1,010,835 \$495	1,134,069 \$556	1,251,375 \$613	1,220,046 \$598	1,087,221 \$533	1,090,317 \$534	1,060,987 \$520	1,049,283 \$514	988,300 \$484	987,361 \$484	1,011,512 \$496	961,639 \$471	12,852,945 \$6,298	1467	12853
37	-1,133,980 L	BCRAC True-up/Lookback Adjust	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
38 39		F Other Energy F Other revenues													\$0		
40	-	r Otter revenues													\$0		
41		F Block Service	391.915		577.456		514.460		381.897	340.167	281.881	339.246	376.183	428.295	5.281.679	603	
43		LH Energy Flat ILH Energy Flat	391,915 561,229	520,023 645,484	785.676	609,659 769,284	718,962	520,497 749,781	381,897 547,958	430,537	281,881	452,541	376,183 492,986	428,295 572,946	7.122.444	813	5,282 7,122
44	L	LH Energy Revenue Flat (43*13)/1000	\$9,018	\$12,704	\$14,812	\$13,083	\$11,153	\$10,727	\$7,245	\$5,184	\$2,985	\$6,103	\$8,028	\$10,211	\$111,253		
45 46	L	LH Energy Revenue Stepped (56*19)/1000 ILH Energy Revenue Flat (44*14)/1000	\$17.628	\$21.617	\$27.467	\$22.832	\$21.792	\$21.084	\$14,461	\$9,489	\$7.881	\$11,119	\$14.183	\$17.016	\$0 \$206,570		
47	Н	ILH Energy Revenue Stepped (57*20)/1000													\$0		
48 49		SSP Demand Demand Revenue (49*24)	1,405 \$2,880	1,787 \$3,912	1,982 \$4,559	2,038 \$3,995	2,005 \$3,991	1,889 \$3,494	1,407 \$2,449	1,283 \$1,848	1,148 \$1,515	1,279 \$2,059	1,367 \$2,584	1,470 \$2,880	19,060 \$36,167		
50	-1,309,822 L	BCRAC True-up/Lookback Adjust	32,000	93,512	94,005	43,553	40,001	93,454	\$2,445	\$1,040	\$1,010	92,005	92,004	\$2,000	\$30,107		
51 52 53 54 55	P	F SUMY	\$0 -0.90%	\$0 -0.79%	\$0 -0.81%	\$0 -0.81%	\$0 -0.79%	\$0 -0.73%	\$0 -0.99%	\$0 -0.90%	\$0 -0.83%	\$0 -0.75%	\$0 -0.68%	\$0 -0.93%	\$0		
53	Ĺ	ow Density Discount Percent = 70/(59+60+61+62+64) ow-Density Discount	-0.90%	-0.79% -\$303	-0.81%	-0.81% -\$325	-0.79% -\$294	-0.73% -\$258	-0.99%	-0.90% -\$149	-0.83%	-0.75% -\$145	-0.68%	-0.93% -\$280	-\$2,907		
54	P	F Other Energy													0		
56	Р	F Block Other Revenues															
57	I	rrigation Mitigation LLH	0	0	0	0	0	0	0	28,360	39,538	44,975	39,179	0	152,052	17	152
58 59		rrigation Mitigation HLH rigation Mitigation Revenues	0 \$0	45,414 \$805	65,334 \$836	73,164 \$1.557	64,012 \$1,746	0 \$0	247,924 \$4,944	28	248						
60				-	**	**	-	*-		****	*****	**,***	*-,	**	* 1,0		
61		t Townsend LLH t Townsend HLH															
63	P	t Townsend Demand															
64 65	P	t Townsend Revenues															
66		*F Slice															
67 68		ercent of SLICE	18.5108% \$1.963	18.51%	1703												
69		lice rate lice Charges (\$000) = 69*70*100	\$1,963 \$36,326	\$435,916													
70	N	fonetary Benefits to IOUs (\$000)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
71	-1,091,516 L	BCRAC True-up/Lookback Adjust DD Percentage	-1.10%	-1.10%	-1.10%	-1.10%	-1.10%	-1.10%	-1.10%	-1.10%	-1.10%	-1.10%	-1.10%	-1.10%	\$0		
72 73 74	L	ow-Density Discount	-\$400	-\$400	-\$400	-\$400	-\$400	-\$400	-\$400	-\$400	-\$400	-\$400	-\$400	-\$400	-\$4,799		
74		lice Other Vest Hub FPS (Pre-Subscription) Sales															
76	L	LH Energy Full Service	1,248	1,352	1,312	1,376	1,152	1,240	1,216	1,376	1,216	1,312	1,312	1,280	15,392	2	15
77 78		LH Energy Revenue ILH Energy Full Service	\$26 1.728	\$28 1.536	\$27 1.664	\$29 1.600	\$24 1.536	\$26 1.728	\$25 1.664	\$29 1,600	\$25 1.664	\$27 1.664	\$27 1.664	\$27 1.600	\$320 19.648	2	20
79	H	ILH Energy Revenue	1,728	1,536	1,664	1,600	1,536	1,728	1,664	1,600	1,664	1,664	1,664 \$35	1,600	\$408	2	20
80		SSP Demand Demand Revenue	4	4	4	4	4	4	8	4	4	4	8	4	56 \$0		
81 82	L	oad Variance	2,976	2,888	2,976	2,976	2,688	2,968	2,880	2,976	2,880	2,976	2,976	2,880	35040	4	35
83	L	oad Variance Revenue	\$1	\$1	\$1	\$1	\$1	\$1	\$1	\$1	\$1	\$1	\$1	\$1	\$17		
84 85		ow-Density Discount T SURPLUS FB CRAC													\$0		
86	N	letrwork Wind Integration Service													\$0		
87 88		Other Pre-Subscription revenues	\$113.758	\$133,564	\$151.069	\$133 024	\$125 196	\$118 659	\$102.058	\$85.762	\$75.326	\$91.821	\$104.739	\$108.859	\$0 \$1.343.834		
0.0		vui	J110,700	#100,004	#101,00B	y100,024	J120,100	\$1.00,00d	#102,000	900,102	ψ, J,J20	₩U1,02 I	2104,108	\$100,00d	÷1,0+0,004		

П	A	В	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT	AU
1		Jul 22, 2009 @ 15:58							oposed R								
2							Re	venue (\$ 1 Fiscal Ye	(housands)								
3 4 5 6 7 8 9								niscui re	ui 2011								
5														_			
6		Western HUB	Oct-10	Nov-10	Doc-10	Jan-11	Ech. 11	Mar-11	Apr. 11	May-11	Jun-11	lul-11	Aug-11	Sep-11		ear 201 aMW	GWh
8		East Hub PF Billing Determinants	001-10	1404-10	Dec-10	Juli-11	ieb-ii	Mul-11	Apr-11	MGY-11	3011-11	301-11	Aug-11	3ep-11	ioidi	<u>univi</u>	GWII
9		PF Full Service															
11		LLH Energy Flat HLH Energy Flat	283,578 465,668	354,922 536,072	394,600 592,983	390,289 588.814	330,326 528,514	317,074 516.024	296,897 472,333	282,531 424,229	248,811 414,610	267,121 410,079	253,314 431,338	264,571 411,221	3,684,034 5,791,885	421 661	3684 5792
12		PF Flat LLH Energy Rate	\$23.01	\$24.43	\$25.65	\$21.46	\$21.68	\$20.61	\$18.97	\$15.24	\$10.59	\$17.99	\$21.34	\$23.84	0,707,000	001	0702
13 14		PF Flat HLH Energy Rate LLH Energy Revenue Flat Revenue = 11*13/1000	\$31.41 \$6.525	\$33.49 \$8.671	\$34.96 \$10.121	\$29.68 \$8.376	\$30.31 \$7.161	\$28.12 \$6.535	\$26.39 \$5.632	\$22.04 \$4.306	\$19.95 \$2.635	\$24.57 \$4.806	\$28.77 \$5.406	\$29.70 \$6.307	\$76.481		
15		HLH Energy Revenue Flat Revenue= 12*14/1000	\$14,627	\$17,953	\$20,731	\$17,476	\$16,019	\$14,511	\$12,465	\$9,350	\$8,271	\$10,076	\$12,410	\$12,213	\$166,101		
16 17		Demand PF GSP Demand Rate	1,484 \$2.05	1,602 \$2,19	1,724 \$2.30	1,798 \$1.96	1,741 \$1.99	1,574 \$1.85	1,404 \$1,74	1,088 \$1.44	1,062 \$1.32	1,101 \$1.61	1,047 \$1.89	1,039 \$1.96	16,664		
18		Demand Revenue = 17*18	\$3,042	\$3,508	\$3,965	\$3,524	\$3,465	\$2,912	\$2,443	\$1,567	\$1,402	\$1,773	\$1,979	\$2,036	\$31,616		
19		Load Variance	769,662	913,492		1,003,535	881,143	855,669	793,774	734,170	689,789	702,458	709,091	695,357	9,761,198	1114	9761
20 21		PF Ld Variance Rate Load Variance Revenue = 20*21/1000	\$0.49 \$377	\$0.49 \$448	\$0.49 \$496	\$0.49 \$492	\$0.49 \$432	\$0.49 \$419	\$0.49 \$389	\$0.49 \$360	\$0.49 \$338	\$0.49 \$344	\$0.49 \$347	\$0.49 \$341	\$4,783		
22		Low Density Discount Percent =30/(15+16+21+22+25+28)	-2.02%	-2.08%	-2.13%	-2.13%	-2.15%	-2.08%	-2.09%	-2.08%	-2.07%	-2.00%	-1.98%	-1.99%	\$4,763		
23		Low Density Discount	-\$496	-\$637	-\$751	-\$638	-\$582	-\$506	-\$438	-\$324	-\$262	-\$340	-\$399	-\$415	-\$5,786		
24 25	-1,008,619	LBCRAC True-up/Lookback Adjust													\$0		
26		PF Other Energy PF Other revenues													\$0		
26 27 28		DE Dantiel Comice															
28 29 30		PF Partial Service LLH Energy Flat	310,434	372,366	411,304	408,670	341,401	331,376	329,438	354,011	296,778	317,507	290,391	302,982	4,066,658	464	4,067
30		HLH Energy Flat	471,002	525,588	568,988	551,562	510,967	510,691	497,054	458,917	454,435	444,014	499,065	443,432	5,935,715	678	5,936
31 32		LLH Energy Revenue Flat (30*13)/1000 HLH Energy Revenue Flat (31*14)/1000	\$7,143 \$14,794	\$9,097 \$17,602	\$10,550 \$19,892	\$8,770 \$16,370	\$7,402 \$15,487	\$6,830 \$14,361	\$6,249 \$13,117	\$5,395 \$10,115	\$3,143 \$9,066	\$5,712 \$10,909	\$6,197 \$14,358	\$7,223 \$13,170	\$83,711 \$169,242		
33		GSP Demand	1,481	1,710	1,733	1,725	1,705	1,565	1,488	1,346	1,276	1,396	1,366	1,319	18,110		
34 35		Demand Revenue (34*18) Load Variance	\$3,036 1.031.458	\$3,745 1 150 010	\$3,986 1 260 540	\$3,381 1,237,670	\$3,393 1 104 535	\$2,895 1 107 706	\$2,589 1.078.232	\$1,938	\$1,684 1,003,784	\$2,248	\$2,582	\$2,585 977.119	\$34,062 13,048,322	1490	13048
36		Load Variance Revenue (36*21)/1000	\$505	\$564	\$618	\$606	\$541	\$543	\$528	\$522	\$492	\$493	\$503	\$479	\$6,394	1400	10040
37 38	-1,133,980	LBCRAC True-up/Lookback Adjust PF Other Energy	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
39		PF Other revenues													\$0		
40		PF Block Service															
42		LLH Energy Flat	407,170	501,586	577,456	609,659	514,460	520,497	381,897	340,167	281,881	353,957	359,890	428,295	5,276,915	602	5,277
43		HLH Energy Flat	545,974 \$9.369	664,641 \$12,254	785,676 \$14.812	769,284 \$13.083	718,962 \$11,153	749,781 \$10,727	547,958 \$7,245	430,537 \$5,184	395,060 \$2,985	441,310 \$6,368	506,444 \$7.680	572,946 \$10.211	7,128,573 \$111.071	814	7,129
44		LLH Energy Revenue Flat (43*13)/1000 LLH Energy Revenue Stepped (56*19)/1000	\$9,309	\$12,254	\$14,012	\$13,063	\$11,153	\$10,727	\$1,245	\$5,104	\$2,900	\$0,300	\$7,000	\$10,211	\$111,071		
46 47		HLH Energy Revenue Flat (44*14)/1000	\$17,149	\$22,259	\$27,467	\$22,832	\$21,792	\$21,084	\$14,461	\$9,489	\$7,881	\$10,843	\$14,570	\$17,016	\$206,844		
48		HLH Energy Revenue Stepped (57*20)/1000 GSP Demand	1.419	1.769	1.982	2.038	2.005	1.889	1.408	1.283	1.148	1.297	1.355	1,470	\$0 19.063		
49		Demand Revenue (49*24)	\$2,909	\$3,874	\$4,559	\$3,994	\$3,990	\$3,495	\$2,450	\$1,848	\$1,515	\$2,088	\$2,561	\$2,881	\$36,164		
50	-1,309,822	LBCRAC True-up/Lookback Adjust PE SUMY	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0 \$0		
52		Low Density Discount Percent = 70/(59+60+61+62+64)	-0.89%	-0.79%	-0.81%	-0.81%	-0.79%	-0.73%	-0.99%	-0.90%	-0.83%	-0.77%	-0.67%	-0.93%			
53		Low-Density Discount PF Other Energy	-\$263	-\$305	-\$378	-\$325	-\$294	-\$258	-\$240	-\$149	-\$103	-\$148	-\$165	-\$280	-\$2,908 0		
55		PF Block Other Revenues													-		
51 52 53 54 55 56 57		Irrigation Mitigation LLH	0	0	0	0	0	0	0	28.360	39.538	44,977	39,178	0	152.053	17	152
58 59		Irrigation Mitigation HLH	0	0	0	0	0	0	0	45,414	65,334	71,988	64,939	0	247,675	28	248
59 60		Irrigation Mitigation Revenues	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$805	\$836	\$1,541	\$1,762	\$0	\$4,944		
61		Pt Townsend LLH															
62		Pt Townsend HLH Pt Townsend Demand															
64		Pt Townsend Revenues															
65		PF Slice															
66 67		Percent of SLICE	18.511%	18.511%	18.511%	18.511%	18.511%	18.511%	18.511%	18.511%	18.511%	18.511%	18.511%	18.511%	18.51%	1690	
68 69		Slice rate Slice Charges (\$000) = 69*70*100	\$1,963 \$36,326	\$1,963 \$36.326	\$1,963 \$36.326	\$1,963 \$36,326	\$1,963 \$36,326	\$1,963 \$36,326	\$1,963 \$36,326	\$1,963 \$36.326	\$1,963 \$36,326	\$1,963 \$36,326	\$1,963 \$36.326	\$1,963 \$36.326	\$435.916		
70		Monetary Benefits to IOUs (\$000)	\$36,326	\$36,326	\$36,326	\$36,326	\$36,326	\$36,326	\$36,326	\$36,326	\$36,326	\$36,326	\$36,326	\$36,326	\$435,916		
71	-1,091,516	LBCRAC True-up/Lookback Adjust	-1 07%	4.0701	4.0701	4.0701	4.070	4.070	4.070	-1 07%	4.0701	4.07**	-1 07%	-1 07%	\$0		
72 73		LDD Percentage Low-Density Discount	-1.07% -\$389	-1.07% -\$389	-1.07% -\$389	-1.07% -\$389	-1.07% -\$389	-1.07% -\$389	-1.07% -\$389	-1.07% -\$389	-1.07% -\$389	-1.07% -\$389	-1.07% -\$389	-1.07% -\$389	-\$4,663		
74		Slice Other															
75 76		West Hub FPS (Pre-Subscription) Sales LLH Energy Full Service	1,312	1,288	1,312	1,376	1,152	1,240	1,216	1,376	1,216	1,376	0	0	12,864	1	13
77		LLH Energy Revenue	\$27	\$27	\$27	\$29	\$24	\$26	\$25	\$29	\$25	\$29	\$0	\$0	\$267		
78 79		HLH Energy Full Service HLH Energy Revenue	1,664 \$35	1,600 \$33	1,664 \$35	1,600 \$33	1,536 \$32	1,728 \$36	1,664 \$35	1,600 \$33	1,664 \$35	1,600 \$33	0 \$0	0 \$0	16,320 \$339	2	16
80		GSP Demand	4	4	4	4	4	4	8	4	4	4	0	0	44		
81 82		Demand Revenue Load Variance	2.976	2.888	2.976	2.976	2.688	2.968	2.880	2.976	2.880	2.976	0	0	\$0 29184	3	29
83		Load Variance Revenue	\$1	\$1	\$1	\$1	\$1	\$1	\$1	\$1	\$1	\$1	\$0	\$0	\$14	-	
84 85		Low-Density Discount LT SURPLUS FB CRAC													\$0		
86		Netrwork Wind Integration Service													\$0		
87 88		Other Pre-Subscription revenues Total	\$114 710	\$135.031	\$152.000	\$133.944	\$125.955	\$110.549	\$102.889	\$86.406	\$75.883	\$02.712	\$105.728	\$100 704	\$0 \$1.354.591		
00		r Otto	Ç117,110	2100,001	+102,000	2100,044	J.EU,000	+110,040	J102,000	¥00,700	2,0,000	ψυ <b>ε</b> , 112	+100,720	2100,700	+.,004,031		

Secretary   Proposed Rates   Proposed	_	R	С	D	E	F	G	н	1 1	1	К	I.	M	N	0	P	0
Fig.	1	Jul 17, 2009 @ 12:18						nues at Pro	oposed R	ates						-	~
Fig.   Section   Fig.   Section   Fig.   Section   Sec							Re										
The state of NUB   Section   Nor-city   No								Fiscal Ye	ar 2009								
Fig.   Eastern HUB   Plant	4																
Fig.   Beach No.   P.   Beach															Elegal	V = = x 20	00
The part of the		Eastern HIIB	Oct-08	Nov-08	Dec-08	Ian-09	Fab-09	Mar-09	Apr-09	May-09	lun-00	Iul-09	Aug-09	San-09			
The Part Hill Service			001-00	1404-00	Dec-00	3411-07	160-07	Mai-07	Api-07	May-07	3011-07	301-07	Aug-u/	<u>360-07</u>	ioidi	<u>untiti</u>	<u>GWIII</u>
		PF Full Service															
Image: Comparison of the Com															5,026,764	5/4	5,027
	14	LLH Energy Revenue Flat= (11*13)/100															
The Property Revenue File   1977   51.91   52.04   52.14   51.82   51.82   51.72   51.02   51.03   51.02   51.03   51.02   51.03   51.02   51.03   51.02   51.03   5	15	HLH Energy Revenue Flat= (12*14)/100														2	16
															15,015	2	10
			\$2,227				\$2,579			\$1,488	\$1,396	\$2,350	\$2,410	\$2,325			
															9,279,063	1,059	9,279
Descript Discount Frenene-20(15161942   3.85%   3.69%   3.75%   3.67%   3.75%   3.67%   3.50%   3.67%   3.50%   3.67%   3.55%   3.65%   3.55%   3.65%   3.60															64.040		
Demand Policocurr   S756   S761   S1131   S900   S770   S606   S607   S406   S370   S570   S603   S403   S400   S770   S605   S761   S500   S770   S605   S762   S603   S760															\$4,04 <i>0</i>		
The Property of the Penergy   10	23	Low Density Discount	-\$758	-\$761	-\$1,131	-\$900	-\$770			-\$465	-\$370	-\$578	-\$653	-\$842			
The Princip Provide   1,314   51,515   51,516   52,516								-\$603	-\$603	-\$603	-\$603	-\$603	-\$603	-\$603		^	_
Practical Service																U	U
The Energy File   19   179, 72   20,705   112,377   107,708   20,308   18,057   31,061   31,061   31,061   31,061   31,061   31,061   31,061   31,061   31,061   31,061   31,061   31,061   31,061   31,061   31,061   31,061   31,061   32,061   31,061   32,061   31,061   32,061   31,061   32,061   31,061   32,061   32,071   31,061   31,061   32,061   32,071   31,061   31,061   32,061   32,071   31,061   31,061   32,061   32,071   31,061   31,061   32,061   32,071   31,061   31,061   32,061   32,071   31,061   31,061   32,061   32,071   31,061   31,061   32,061   32,071   31,061   31,061   32,061   32,071   31,061   31,061   32,061   32,071   31,061   31,061   32,061   32,071   31,061   31,061   32,061   32,071   31,061   31,061   32,061   32,071   31,061   31,061   32,061   32,071   31,061   31,061   32,061   32,071   31,061   31,061   32,061   32,071   31,061   31,061   32,061   32,071   31,061   31,061   32,061   32,071   31,061   31,061   32,061   32,071   31,061   31			Ų.J3	<b>\$</b> 0	<b>4</b> 0	<b>4</b> 0	<b>\$</b> 0								ψ.55		
		I I H Energy Revenue Flat = 30*13/100														179	1,304
Standard	32	HLH Energy Revenue Flat = 31*14/100	\$3,724														
State   Stat																	
Standar   1967   1970   1989   1980																207	2 605
37   EPROCRAC True-upf.cokback Adjus																231	2,000
39   Low Density Discount		LBCRAC True-up/Lookback Adjus	-\$188	-\$188	-\$188	-\$188	-\$188	-\$188		-\$188	-\$188	-\$188	-\$188	-\$188			
1   PC Other Revenue								-\$143	-\$11/	-\$88	-\$84	-\$124	-\$144	-\$157		0	0
13   PR Block Service																	ŭ
Hell Henery Fiel																	
15																400	4 400
The Henergy Revenue Flate-(46*13)/100  \$2,450 \$2,804 \$3,207 \$2,724 \$2,300 \$2,181 \$3,203 \$2,181 \$3,003 \$2,450 \$2,841 \$2,009 \$2,860 \$4,070 \$4,700 \$4,																	
B   SP   Demand   ST   SP   SP   SP   SP   SP   SP   SP	46	LLH Energy Revenue Flat=(45*13)/1000	\$2,450	\$2,894	\$3,207	\$2,724		\$2,158	\$2,208		\$1,052						.,
To   IncRAC True-upl. Lookback Adjus   \$320																	
Sign																	
Sign		Low-Density Discount															
Section   Sect															0	0	0
Second   S		PF Block Other Revenue	\$0	\$0	\$0	\$0	\$0										
Stock   Stoc		PF SLICE	\$7,714	\$7,714	\$7,714	\$7,714	\$7,714	\$7,714	\$7,714	\$7,714	\$7,714	\$7,714	\$7,714	\$7,714	\$92,568		
State   Stat															4.1193%	349	
Second National Content															\$92 564		
The Control Revenue   So   So   So   So   So   So   So   S																	
State   Stat	60		\$0		-\$286		\$0								-\$285		
163   LH Energy Pre-Sult   36,570   45,106   64,189   60,054   47,683   55,788   48,804   50,954   48,701   61,609   52,733   48,484   620,655   71   621		Fort High EDG (Dec Cube colorles) C :															
Hel-Henergy Revenut			36 570	45 106	64 180	60.054	47 683	55 768	48 804	50 954	48 701	61 600	52 733	48 484	620 655	71	621
65   H.H. Finergy Pre-Sult   60,392   60,156   90,776   85,239   71,334   87,830   74,790   75,799   83,085   91,980   92,307   72,031   945,519   108   946																- ' '	321
Figure   F	65	HLH Energy Pre-Sub	60,392	60,156	90,776	85,239	71,334	87,630	74,790	75,799	83,085	91,980	92,307	72,031	945,519	108	946
Separate																	
To   Low Density Discount  Percen   \$45   \$47   \$66   \$61   \$50   \$78   \$68   \$81   \$70   \$70   \$85   \$80   \$67   \$787   \$71   Low Density Discount  Percen   \$2.77%   \$2.94%   \$2.60%   \$2.27%   \$2.28%   \$2.02%   \$2.02%   \$2.02%   \$4.39%   \$4.57%   \$4.74%   \$4.73%   \$4.83%   \$4.87%   \$4.83%   \$4.97%   \$72   Low Density Discount    \$70   \$510	69				114,002	105,127	86,046	137,710	119,954	121,940	123,478	149,025	140,209	117,755		157	1,374
To   Density Discount   \$70				\$47											\$787		
73   Wind Integration Service															-\$1 32E		
T4 Other Presubscirigition revenues   \$2			-\$1U	-p//	-\$105	-p104	-90/	-\$1/5	-p134	-919	-#00	-9119	-p130	-p147	-φ1,325 \$0		
To   Irrigation Mitigation LLH	74	Other Presubscription revenues	\$2	\$2	\$3	\$3	\$2								\$13		
To   Irrigation Mitigation H1.H   0 0 0 0 0 0 0 147,478 217,906 243,565 207,128 0 816,077 93 816							_										400
78 Irrigation Mitigation Flat Revenues         \$0         \$0         \$0         \$3         \$0         \$1.259         \$1.411         \$2.649         \$2.875         \$0         \$8.191           79 Irrigation Mitigation Stepped Revenues         \$0         \$0         \$0         \$5         \$0         \$1.293         \$1.325         \$2.497         \$2.529         \$0         \$7.639			-				-										
79 Irrigation Mitigation Stepped Revenues \$0 \$0 \$0 \$0 -\$5 \$0 \$0 \$1,293 \$1,325 \$2,497 \$2,529 \$0 \$7,639			-	-	-	-	-	-	-	,				-		93	010
80 Total \$41,605 \$43,673 \$57,535 \$48,671 \$43,500 \$40,219 \$36,975 \$31,441 \$28,300 \$39,943 \$43,679 \$42,149 \$497,689																	
	80	Total															

R	R	s	т	U	v	w	Y	v	7	ΔΔ	AB	AC	AD	AE	AF
1 Jul 17, 2009 @ 12:18			• 1	Ü	Reve	nues at Pr	oposed F	Rates		7.0.1	7115	710	7112	711.	/11
2						evenue (\$									
3						Fiscal Ye	ar 2010								
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6	0-4-00	N 00	D 00	I 10	F-1- 10	10	4 10	10	l 10	1.1.10	4 10	C 10		Year 20	
7 Eastern HUB 8 East Hub PF Billing Determinants	Oct-09	Nov-09	Dec-09	<u>Jan-10</u>	Feb-10	<u>Mar-10</u>	Apr-10	<u>May-10</u>	Jun-10	<u>Jul-10</u>	Aug-10	Sep-10	<u>Total</u>	aMW	GWh
9 PF Full Service	\$2,440	\$2,624	\$3,232	\$2.915	\$2,774	\$2,122	\$1.862	\$1,499	\$1.498	\$2,343	\$2,544	\$2,356	\$28.207		
10 LLH Energy Flat	256,926	300,030	365,105	369,853	295,572	270,818	263,535	247,807	221,089	289,424	247,039	287,876		390	3,415
11 HLH Energy Flat	409,926	426,668	511,562	525,154	446,340	425,282	403,695	359,686	353,216	378,836	402,715		5,068,099	579	5,068
12 PF Flat LLH Energy Rate 13 PF Flat HLH Energy Rate	\$23.01 \$31.41	\$24.43 \$33.49	\$25.65 \$34.96	\$21.46 \$29.68	\$21.68 \$30.31	\$20.61 \$28.12	\$18.97 \$26.39	\$15.24 \$22.04	\$10.59 \$19.95	\$17.99 \$24.57	\$21.34 \$28.77	\$23.84 \$29.70			
14 LLH Energy Revenue Flat= (11*13)/100	\$5.912	\$7,330	\$9.365	\$7.937	\$6.408	\$5.582	\$4.999	\$3,777	\$2.341	\$5.207	\$5.272	\$6.863	\$70,992		
15 HLH Energy Revenue Flat= (12*14)/100	\$12,876	\$14,289	\$17,884	\$15,587	\$13,529	\$11,959	\$10,654	\$7,927	\$7,047	\$9,308	\$11,586	\$12,623	\$145,268		
16 GSP Demand	1,190	1,198	1,405	1,487	1,394	1,147	1,070	1,041	1,135	1,455	1,346	1,202	15,070		
17 PF GSP Demand Rate 18 Demand Revenue= (18*17	\$2.05 \$2.440	\$2.19 \$2.624	\$2.30 \$3.232	\$1.96 \$2.915	\$1.99 \$2.774	\$1.85 \$2.121	\$1.74 \$1.862	\$1.44 \$1.500	\$1.32 \$1.499	\$1.61 \$2.343	\$1.89 \$2.544	\$1.96 \$2.356	\$28,210		
19 PF Ld Variance	669.814	730.157	878.853	895.914	743.124	698.937	671,474	764.764	796.577	919.892	865.875	714.885	9,350,266	1,067	9.350
20 PF Ld Variance Rate	\$0.49	\$0.49	\$0.49	\$0.49	\$0.49	\$0.49	\$0.49	\$0.49	\$0.49	\$0.49	\$0.49	\$0.49		.,	-,
21 Load Variance= (20*21)/1000	\$328	\$357	\$430	\$439	\$364	\$342	\$329	\$331	\$327	\$384	\$366	\$350	\$4,347		
22 Low Density Discount Percent=28/(15+16+2 23 Low Density Discount	-3.86% -\$832	-3.70% -\$909	-3.73% -\$1,152	-3.71% -\$998	-3.70% -\$853	-3.73% -\$745	-3.96% -\$707	-3.73% -\$505	-3.54% -\$398	-3.55% -\$612	-3.54% -\$701	-4.09% -\$908	-\$9,319		
24 LBCRAC True-up/Lookback Adjus	-9032	-\$308	-\$1,102	-\$250	-9003	-9140	-9/0/	-0005	- 4086	-9012	-p/U1	-Ф908	-\$9,319 \$0		
25 PF Other Energy													0	0	0
26 PF Other Revenues															
27 28 PF Partial Service	\$3.976	\$4,434	\$5.104	\$4.638	\$4,100	\$3.715	\$3.034	\$2,300	\$2.296	\$3.019	\$3.545	\$3.392	\$43,554		
29 LLH Energy Flat	81,285	95,941	109,282	112,511	91,394	87.582	78,065	74.172	73,207	90.707	78,372		1,052,180	120	1.052
30 HLH Energy Flat	126,584	132,407	145,989	156,269	135,279	132,110	114,972	104,371	115,090	122,891	123,207			174	1,523
31 LLH Energy Revenue Flat = 30*13/100	\$1,870	\$2,344	\$2,803	\$2,414	\$1,981	\$1,805	\$1,481	\$1,130	\$775	\$1,632	\$1,672	\$1,899	\$21,808		
32 HLH Energy Revenue Flat = 31*14/100	\$3,976 365	\$4,434 358	\$5,104 432	\$4,638 445	\$4,100 406	\$3,715 355	\$3,034 348	\$2,300 285	\$2,296 313	\$3,019 355	\$3,545 322	\$3,392 303	\$43,554 4.287		
34 Demand Revenue = 34*17	\$748	\$783	\$993	\$872	\$808	\$656	\$605	\$410	\$413	\$571	\$609	\$594	\$8,064		
35 Load Variance	214,933	234,662	262,188	272,047	231,849	225,819	199,704	190,292	201,838	229,265	216,449			306	2,680
36 Load Variance = 36*21/1000	\$105	\$115	\$128	\$133	\$114	\$111	\$98	\$93	\$98	\$111	\$105	\$98	\$1,310		
37 LBCRAC True-up/Lookback Adjus		-2 50%	-2 45%	-2 38%		-2 41%				-2 52%	-2 52%		\$0		
38 Low Density Discount Percent= 56/(42+43+4 39 Low Density Discount	-2.62% -\$175	-2.50% -\$192	-2.45% -\$221	-2.38% -\$192	-2.42% -\$169	-2.41% -\$151	-2.46% -\$128	-2.37% -\$93	-2.55% -\$91	-2.52% -\$134	-2.52% -\$149	-2.67% -\$160	-\$1,857		
40 PF Other Energy	-9175	-9102	-9221	-9102	-ψ103	-\$151	-\$120	-400	-401	-0104	-9140	-φ100	0	0	0
41 PF Other Revenue	-\$107	-\$117	-\$131	-\$136	-\$116	-\$113	-\$100	-\$95	-\$101	-\$115	-\$108	-\$100	-\$1,340		
42															
43 PF Block Service 44 LLH Energy Flat	\$4,611 106,189	\$4,423 116,270	\$5,438 122,909	\$4,508 131.065	\$4,438 110.031	\$4,176 106,978	\$4,519 125,243	\$2,883 125,535	\$2,626 106.388	\$2,913 109.867	\$3,087 97,150	\$4,376 118,103	\$47,996 1.375,728	157	1 376
45 HLH Energy Flat	146 812	132,060	155 543	151,870	146,410	148 510	171,239	130 786	131,616	118 569	107,283	147 340	1 688 038	193	1,370
46 LLH Energy Revenue Flat=(45*13)/100	\$2,443	\$2,840	\$3,153	\$2,813	\$2,385	\$2,205	\$2,376	\$1,913	\$1,127	\$1,977	\$2,073	\$2,816	\$28,120		.,
47 HLH Energy Revenue Flat=(46*14)/100	\$4,611	\$4,423	\$5,438	\$4,508	\$4,438	\$4,176	\$4,519	\$2,883	\$2,626	\$2,913	\$3,087	\$4,376	\$47,996		
48 GSP Demand 49 Demand Revenue=(49*24	338 \$692	342 \$749	372 \$855	377 \$740	379 \$755	341 \$631	403 \$702	457 \$659	500 \$659	495 \$797	414 \$782	368 \$720	4,786 \$8,741		
50 LBCRAC True-up/Lookback Adjus	\$032	\$0	\$0	\$0	\$0	\$0	\$0	\$055	\$000	\$0	\$7.02	\$720	\$0,741		
51 Low-Density Discount													\$0		
52 PF Other Energy													0	0	0
53 PF Block Other Revenue															
55 PF SLICE															
56 Percent of SLICE	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	379	
57 Slice Rate	\$1,963	\$1,963	\$1,963	\$1,963	\$1,963	\$1,963	\$1,963	\$1,963	\$1,963	\$1,963	\$1,963	\$1,963	607.00		
58 Slice Charges = 57*58*100 59 LBCRAC True-up/Lookback Adjus	\$8,084 \$0	\$8,084 \$0	\$8,084 \$0	\$8,084 \$0	\$8,084 \$0	\$8,084 \$0	\$97,004 \$0								
60 Slice Other Revenues	φυ	Ų0	<b>4</b> 0	φ0	ψU	φ0	<b>4</b> 0	φυ	<b>4</b> 0	<b>4</b> 0	Ų0	φ0	\$0		
61															
62 East Hub FPS (Pre-Subscription) Sales	40.041	FO 070	74.050	74.000	F0.000	F7 040	F0.000	50.77	40.400	04.400	F0 400	40.05	004.047	70	
63 LLH Energy Pre-Sub 64 LLH Energy Revenue	48,311 \$1,031	59,076 \$1,274	71,350 \$1,559	71,090 \$1,519	59,268 \$1,267	57,319 \$1,213	50,063 \$957	50,774 \$541	48,422 \$467	64,168 \$828	53,122 \$926	48,854 \$1,047	681,817 \$12,629	78	682
65 HLH Energy Pre-Sub	76,790	85,495	100,471	102,743	89,919	89,482	75,692	76,506	81,603	87,731	91,807	72,242		118	1,030
66 HLH Energy Revenue	\$1,855	\$2,089	\$2,486	\$2,468	\$2,167	\$2,092	\$1,615	\$994	\$1,021	\$1,363	\$1,898	\$1,705	\$21,753	-	,
67 GSP Demand	229	239	289	307	281	241	221	191	207	253	235	201	2,894		
68 Demand Revenue	\$245 122,499	\$268 138.070	\$318 166 468	\$320 168 993	\$300 142 704	\$255 141,213	\$225 124,113	\$183 124,263	\$187 125.985	\$251 148.512	\$245 141,713	\$208 119 780	\$3,005 1 664 313	190	1 664
70 Load Variance Revenue	122,499 \$71	\$80	\$96	\$98	\$82	141,213 \$81	124,113 \$71	124,263 \$72	\$73	148,512 \$86	\$82	\$69	\$961	190	1,004
71 Low Density Discount Percen	-4.71%	-4.77%	-4.81%	-5.07%	-5.00%	-4.95%	-4.90%	-4.50%	-4.69%	-4.67%	-4.80%	-4.93%	****		
72 Low Density Discount	-\$151	-\$177	-\$214	-\$223	-\$191	-\$180	-\$140	-\$80	-\$82	-\$118	-\$151	-\$149	-\$1,858		
73 Wind Integration Service 74 Other Presubscription revenues													\$0 \$0		
75 Irrigation Mitigation													φ0		
76 Irrigation Mitigation LLH	0	0	0	0	0	0	0	90,110	124,006	147,923	118,453	0	480,492	55	480
77 Irrigation Mitigation HLH	0	0	0	0	0	0	0	142,759	211,084	235,661	201,328	0	790,832	90	791
78 Irrigation Mitigation Flat Revenues	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$1,321	\$1,500	\$2,737	\$2,979	\$0	\$8,537		
79 Irrigation Mitigation Stepped Revenues 80 Total	\$0 \$46.022	\$0 \$50,688	\$0 \$60.209	\$0 \$53.935	\$0 \$48.228	\$0 \$43.839	\$0 \$40.535	\$1,451 \$34,796	\$1,509 \$31,378	\$2,783 \$43,415	\$2,797 \$47.541	\$0 \$45.882	\$8,540 \$546.466		
ou Total	φ40,022	400,008	900,209	400,935	φ40,228	φ40,039	φ <del>4</del> υ,υ33	φ34,190	φυ1,υ/6	ψ <del>4</del> υ,415	140,140	φ <del>4</del> υ,062	9040,400		

В	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT	AU
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2					Re	evenue (\$ 1		)							
3						Fiscal Ye	ar 2011								
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6												F	Fiscal Y	ear 201	
7 Eastern HUB	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Total	aMW	- GWh
8 East Hub PF Billing Determinants															
9 PF Full Service	\$2,493	\$2,683	\$3,303	\$2,973	\$2,838	\$2,170	\$1,904	\$1,531	\$1,527	\$2,381	\$2,593	\$2,405	\$28,800		
10 LLH Energy Flat 11 HLH Energy Flat	265,363 416,290	304,387 438,749	373,047 521,990	377,242 535,221	302,236 456,078	277,167 435.003	269,587 412,742	254,440 369,302	227,103 362,987	284,701 402,968	250,391 416,923	294,218 434,274	3,479,882 5,202,527	397 594	3,480 5,203
12 PF Flat LLH Energy Rate	\$23.01	\$24.43	\$25.65	\$21.46	\$21.68	\$20.61	\$18.97	\$15.24	\$10.59	\$17.99	\$21.34	\$23.84	3,202,327	394	3,203
13 PF Flat HLH Energy Rate	\$31.41	\$33.49	\$34.96	\$29.68	\$30.31	\$28.12	\$26.39	\$22.04	\$19.95	\$24.57	\$28.77	\$29.70			
14 LLH Energy Revenue Flat= (11*13)/100/ 15 HLH Energy Revenue Flat= (12*14)/100/	\$6,106	\$7,436	\$9,569	\$8,096	\$6,552	\$5,712	\$5,114	\$3,878	\$2,405	\$5,122	\$5,343	\$7,014	\$72,347		
15 HLH Energy Revenue Flat= (12*14)/100 16 GSP Demand	\$13,076 1,216	\$14,694 1,225	\$18,249 1.436	\$15,885 1.517	\$13,824 1,426	\$12,232 1 173	\$10,892 1 094	\$8,139 1.063	\$7,242 1 157	\$9,901 1.479	\$11,995 1.372	\$12,898 1.227	\$149,027 15.385		
17 PF GSP Demand Rate	\$2.05	\$2.19	\$2.30	\$1.96	\$1.99	\$1.85	\$1.74	\$1.44	\$1.32	\$1.61	\$1.89	\$1.96			
18 Demand Revenue= (18*17	\$2,494	\$2,683	\$3,302	\$2,974	\$2,837	\$2,170	\$1,904	\$1,530	\$1,527	\$2,382	\$2,593	\$2,405	\$28,801		
19 PF Ld Variance 20 PF Ld Variance Rate	684,415 \$0.49	746,400 \$0.49	897,023 \$0.49	913,370 \$0.49	759,525 \$0.49	715,007 \$0.49	686,764 \$0.49	781,073 \$0.49	812,604 \$0.49	939,584 \$0.49	883,433 \$0.49	730,482 \$0.49	9,549,680	1,090	9,550
21 Load Variance= (20*21)/1000	\$335	\$365	\$439	\$447	\$372	\$350	\$336	\$339	\$335	\$394	\$374	\$358	\$4,444		
22 Low Density Discount Percent=28/(15+16+2	-3.86%	-3.70%	-3.73%	-3.72%	-3.70%	-3.73%	-3.96%	-3.74%	-3.56%	-3.56%	-3.56%	-4.09%			
23 Low Density Discount	-\$850	-\$933	-\$1,178	-\$1,018	-\$873	-\$763	-\$723	-\$519	-\$410	-\$634	-\$723	-\$927	-\$9,551		
24 LBCRAC True-up/Lookback Adjust 25 PF Other Energy													\$0 0	0	0
26 PF Other Revenues													\$0		Ĭ
27															
28 PF Partial Service 29 LLH Energy Flat	\$4,064 85,264	\$4,627 97 487	\$5,267 112,736	\$4,787 115,966	\$4,235 94,307	\$3,838 90,408	\$3,139 80,720	\$2,374 76,449	\$2,362 75,245	\$3,168 91 685	\$3,709 79,545	\$3,505 82 221	\$45,076 1 082 033	124	1 082
30 HLH Energy Flat	129,384	138,166	150,669	161,287	139,722	136,475	118,944	107,717	118,399	128,953	128,908	118,022	1,576,646	180	1,577
31 LLH Energy Revenue Flat = 30*13/100	\$1,962	\$2,382	\$2,892	\$2,489	\$2,045	\$1,863	\$1,531	\$1,165	\$797	\$1,649	\$1,697	\$1,960	\$22,432		
32 HLH Energy Revenue Flat = 31*14/100 33 GSP Demand	\$4,064 377	\$4,627 369	\$5,267 446	\$4,787 459	\$4,235 419	\$3,838 367	\$3,139 360	\$2,374 294	\$2,362 322	\$3,168 366	\$3,709 333	\$3,505 313	\$45,076 4 425		
34 Demand Revenue = 34*1;	\$773	\$809	\$1,026	\$900	\$835	\$678	\$627	\$423	\$425	\$589	\$629	\$614	\$8,329		
35 Load Variance	221,712	241,968	270,323	280,520	239,205	233,009	206,330	195,915	207,185	236,306	223,324	207,006	2,762,803	315	2,763
36 Load Variance = 36*21/1000	\$109	\$119	\$132	\$137	\$117	\$114	\$101	\$96	\$101	\$115	\$108	\$101	\$1,350		
37 LBCRAC True-up/Lookback Adjust 38 Low Density Discount Percent= 56/(42+43+4	-2.57%	-2.46%	-2 41%	-2.34%	-2 38%	-2.37%	-2.42%	-2 34%	-2.52%	-2 47%	-2 48%	-2.63%	\$0		
39 Low Density Discount	-\$178	-\$195	-\$225	-\$195	-\$172	-\$154	-\$130	-\$95	-\$93	-\$137	-\$153	-\$163	-\$1,889		
40 PF Other Energy													0	0	0
41 PF Other Revenue	-\$111	-\$121	-\$135	-\$140	-\$120	-\$117	-\$103	-\$98	-\$104	-\$118	-\$112	-\$104	-\$1,381		
43 PF Block Service	\$4,438	\$4,610	\$5,438	\$4,508	\$4,438	\$4,176	\$4,519	\$2,883	\$2,626	\$2,746	\$3,274	\$4,376	\$48,031		
44 LLH Energy Flai	111,697	110,670	122,909	131,065	110,031	106,978	125,243	125,535	106,388	117,561	90,638	118,103	1,376,818	157	1,377
45 HLH Energy Flat	141,305	137,660	155,543	151,870	146,410	148,510	171,239	130,786	131,616	111,758	113,795	147,340	1,687,832	193	1,688
46 LLH Energy Revenue Flat=(45*13)/100i 47 HLH Energy Revenue Flat=(46*14)/100i	\$2,570 \$4,438	\$2,704 \$4,610	\$3,153 \$5,438	\$2,813 \$4,508	\$2,385 \$4,438	\$2,205 \$4,176	\$2,376 \$4,519	\$1,913 \$2,883	\$1,127 \$2,626	\$2,115 \$2,746	\$1,934 \$3,274	\$2,816 \$4,376	\$28,110 \$48,031		
48 GSP Demand	338	342	372	377	379	341	403	457	500	495	414	368	4,786		
49 Demand Revenue=(49*24	\$692	\$749	\$855	\$740	\$755	\$631	\$702	\$659	\$659	\$797	\$782	\$720	\$8,741		
50 LBCRAC True-up/Lookback Adjust 51 Low-Density Discount	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0 \$0		
52 PF Other Energy													0	0	0
53 PF Block Other Revenue													-	-	-
54															
55 PF SLICE 56 Percent of SLICE	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	4.1193%	376	
57 Slice Rate	\$1,963	\$1,963	\$1,963	\$1,963	\$1,963	\$1,963	\$1,963	\$1,963	\$1,963	\$1,963	\$1,963	\$1,963		0.0	
58 Slice Charges = 57*58*100	\$8,084	\$8,084	\$8,084	\$8,084	\$8,084	\$8,084	\$8,084	\$8,084	\$8,084	\$8,084	\$8,084	\$8,084	\$97,011		
59 LBCRAC True-up/Lookback Adjust 60 Slice Other Revenues	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
61															
62 East Hub FPS (Pre-Subscription) Sales	-4.55%	-4.63%	-4.71%	-4.96%	-4.87%	-4.83%	-4.75%	-4.36%	-4.56%	-4.48%	-4.57%	-4.73%		_	
63 LLH Energy Pre-Sut 64 LLH Energy Revenus	48,808 \$1,041	59,694 \$1,286	71,524 \$1,559	71,208 \$1,522	59,272 \$1,267	57,502 \$1,218	50,596 \$967	51,333 \$545	48,917 \$472	62,298 \$805	54,173 \$945	49,844 \$1,069	685,169 \$12,697	78	685
65 HLH Energy Pre-Sub	\$1,041 77,645	\$1,286 86,476	\$1,559 100,821	\$1,522 103,157	91,001	\$1,218 90,468	\$967 76,547	77,373	\$472 82,498	92,686	93,889	73,661	1,046,222	119	1,046
66 HLH Energy Revenu€	\$1,591	\$1,810	\$2,109	\$2,064	\$1,854	\$1,825	\$1,379	\$872	\$895	\$1,245	\$1,666	\$1,478	\$18,789	-	,
67 GSP Demand 68 Demand Revenue	232 \$248	243 \$272	293	311	285	246 \$258	225 \$228	194 \$186	210	256 \$254	238	204	2,937 \$3.047		
68 Demand Revenue	\$248 124 612	\$272 140,485	\$323 169 313	\$324 171,850	\$304 145,233	\$258 143.629	\$228 126.284	\$186 126 466	\$190 128 173	\$254 151,230	\$248 144 127	\$211 121,860	\$3,047 1 693 262	193	1 693
70 Load Variance Revenue	\$72	\$81	\$98	\$99	\$84	\$83	\$73	\$73	\$74	\$88	\$83	\$70	\$978	100	1,000
71 Low Density Discount Percen	-4.55%	-4.63%	-4.71%	-4.96%	-4.87%	-4.83%	-4.75%	-4.36%	-4.56%	-4.48%	-4.57%	-4.73%			
72 Low Density Discount 73 Wind Integration Service	-\$134	-\$160	-\$193	-\$199	-\$171	-\$163	-\$126	-\$73	-\$74	-\$107	-\$135	-\$134	-\$1,669 \$0		
74 Other Presubscription revenues													\$0 \$0		
75 Irrigation Mitigation															
76 Irrigation Mitigation LLH	0	0	0	0	0	0	0	90,110	124,006	148,154	117,248	0	479,518	55	480
77 Irrigation Mitigation HLH	0	0 \$0	0 \$0	0 \$0	0 \$0	0 \$0	0 \$0	142,759	211,084	234,548	199,640 \$2,924	0	788,031 \$8,482	90	788
78 Irrigation Mitigation Flat Revenues 79 Irrigation Mitigation Stepped Revenues	\$0 \$0	\$1,321 \$1,451	\$1,500 \$1,509	\$2,737 \$2,769	\$2,924 \$2,797	\$0 \$0	\$8,482 \$8,527								
80 Total	\$46,383	\$51,301	\$60,765	\$54,316	\$48,652	\$44,241	\$40,890	\$35,147	\$1,509	\$43,965	\$48,065	\$46,353	\$551,728		
	,.,.														

	В	С	D	E	Е	G	Н	1 1	1 1	v	т Т	M	N	0	р	0
1	Jul 17, 2009 @ 12:18		D	Е	r		venues at Pr	nnosed Rate	PS .	Λ.	L	ivi	IN I	0	г	Ų
2	301 11, 2000 @ 12.10						Revenue (\$									
3							Fiscal Ye									
3		744	721	744	744	672	743	720	744	720	744	744	720	Fiscal Y	ear 200	9
5		432	384	416	416	384	416	416	400	416	416	416	400	1100011		•
6		312	337	328	328	288	327	304	344	304	328	328	320			
	Bulk HUB	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Total	aMW	GWh
8	Investor-Owned Utilities Residential Exchange															
9	Residential Exchange Rate	(46.46)	(46.46)	(46.46)	(47.22)	(47.45)	(47.45)	(47.56)	(47.56)	(47.67)	(47.67)	(48.00)	(48.00)	(49.46)		
10	Energy (MWhr)	2,357,543	2,669,837	3,476,522	4,317,495	3,368,129	3,127,975	2,701,817	2,484,845	2,481,228	2,644,717	2,528,174	2,314,738	34,473,020	3,935	34,473
11	Residential Exchange Revenue (\$000) = (12+13)*14	-\$113,539	-\$129,016	-\$167,543	-\$213,478	-\$168,287	-\$156,379	-\$135,368	-\$123,944	-\$123,530	-\$130,913	-\$126,651	-\$116,493	-\$1,705,142		
	Direct-Service Industries (IP-02 & FPS)															
	IP LBCRAC True-up (MWH)															
	IP LBCRAC True-up Revenue (\$000)															
	PAC capacity, WNP-3 and other L-T contracts															
	Demand (MW)	751	863	770	770	870	940	788	1,003	808	959	978	796	10,296		
	HLH Energy (MWhr)	171,719	239,003	224,011	217,419	187,526	143,338	108,238	180,235	96,442	134,718	158,477	79,495	1,940,621	222	
	LLH Energy (MWhr)	-129,870	-42,585	-78,946	-90,293	-74,210	-146,665	-44,319	9,357	-19,103	21,631	-5,171	-92,823	-692,997	-79	-693
	Energy (aMW)	56	272	195	171	169	-4	89	255	107	210	206	-19	1,707	142	1,248
20	Revenue (\$ Thousand)	\$3,951	\$10,923	\$10,768	\$10,811	\$10,175	\$7,503	\$7,331	\$7,536	\$4,027	\$6,514	\$7,981	\$3,980	\$91,498		
	Contractual Obligations (CER)															
	Demand (MW)	1.245	1.245	1.245	1.245	1.245	1.245	1.245	1.245	1.245	1.245	1.273	1.273	14.996		
	HLH Energy (MWhr)	346.350	334.728	345.886	345.886	312.413	345.886	334.263	345.886	334.728	345.886	421.922	408.312	4.222.146	482	4,222
	LLH Energy (MWhr)	0,000	0 0	0-0,000	0-0,000	0 0	0 0 0 0	0.04,200	0,000	0.04,720	0,000	0	0 0,512	4,222,140	-02	7,222
	Energy (aMW)	465	465	465	465	465	465	465	465	465	465	567	567	5,783	482	ŭ
	Revenue (\$ Thousand)	0	0	0	0	0	0	0	0	0	0	0	0	\$0		
28																
29	Monthly Trading Floor Committed Sales (MWH)	357.945	445.952	403.914	829,746	136.700	796.138	502.329	613.200	616.800	72.800	41.600	40.000	4,857,124	554	4,857
	Monthly Trading Floor Committed Sales (\$000)	\$19,669	\$21,826	\$22,239	\$33,118	\$4,668	\$22,333	\$18,584	\$24,159	\$24,990	\$4,878	\$2,174	\$2,090	\$200,727		,
31	Monthly Trading Floor Balancing Sales (MWH)							791,866	1,347,854	1,885,286	1,060,593	47,628	205,501	5,338,728	609	5,339
32	Monthly Trading Floor Balancing Sales (\$000)							\$20,412	\$28,616	\$40,960	\$29,549	\$1,449	\$6,029	\$127,015		
33	Other Monthly Sales (MWH)															
34	Other Monthly Sales (\$000)															
	FPS Bookouts	-98,215	-122,762	-143,872	-1,904	-29,136	-121,373							-517,262	-59	-517
	Revenue reversals (\$000)	-\$5,185	-\$5,930	-\$8,411	\$0	-\$1,083	-\$3,450							-\$24,059		
37																
	Power Purchases															
	ERE Augmentation Power purchases	8,959	9,661	10,726	9,685	9,002	8,595	7,511	10,295	11,286	11,468	11,239	8,959	117,384	13	117
	ERE Augmentation Purchase Expense	\$261	\$299	\$337	\$272	\$269	\$238	\$206	\$221	\$215	\$260	\$291	\$264	\$3,134		
42	IOU Power Buyback/Deferred LB CRAC expense															
	Renewable HLH (MWH)	34.311	34.324	41.382	47.002	21.638	38.693	28.678	26.230	27.059	28.177	24.661	24.297	376.451	43	376
	Renewable LLH (MWH)	6.519	6.070	9,789	9.829	8,209	28.514	23,689	24,297	26,321	25,352	22,458	19.996	211.044	24	211
	Renewable Expense (\$000) (included in Program Expense Forecast)	\$2.017	\$2.071	\$2.587	\$2,933	\$1.681	\$3,394	\$2,694	\$2,669	\$2,727	\$2,744	\$2,437	\$2,317	\$30,273	24	211
46	(molade Expense (4000) (moladed in Frogram Expense Forecast)	92,017	Ψ2,071	Ψ2,507	Ψ2,000	ψ1,001	ψυ,υσ4	Ψ2,034	92,009	42,121	42,144	ψ <u>2</u> , <del>1</del> 31	Ψ2,511	ψ50,275		
	Power Purchases Bookouts (MWH)	-98.215	-122.762	-143.872	-1.904	-29.136	-121.373	0	0	0	0	0	0	-517.262	-59	-517
	Power Purchases Reversals (\$000)	-\$5,185	-\$5,930	-\$8,411	\$0	-\$1,083	-\$3,450	\$0	\$0	\$0	\$0	\$0	\$0	-\$24,059		
49		,	,	,		. ,	,	,-	**	**	-			. ,		
	Augmentation Power Purchases (MWH)													0	0	0
51	Augmentation Power Purchases (\$000)													\$0		
52																
	Other Committed Power Purchases (MWH)	5,669	6,860	3,092	1,773	9,682	9,801	15,033	24,268	44,612	27,856	15,507	5,796	169,950	19	170
54	Balancing Power Purchases (MWH)							420	17,608	-	10,895	435,023	207,637	671,584	77	672
55	NLS Power Purchases (MWH) 79506, 79507, 79510, 79671, 79590	502,816	612,716	937,212	138,711	642,173	626,970	118,824			131,200	291,000	168,000	4,169,622	476	4,170
	Other Committed Purchase Power Expense (\$000)	\$660	\$564	\$793	\$687	\$390	\$726	\$952	\$991	\$1,118	\$1,640	\$330	\$513	\$9,365		
	Balancing Purchase Power Expense (\$000)							\$11	\$451	\$0	\$319	\$14,700	\$6,656	\$22,136		
	Trading Floor Purchase Power Expense (\$000)	\$24,625	\$30,061	\$61,783	\$4,924	\$26,086	\$18,938	\$3,245	\$0	\$0	\$3,850	\$10,646	\$5,636	\$189,793		
59	I and the nation of the contract of	64.00=	05.750	67.400	67.000	ec rcc	00.470	65.057	64.000	65.040	60.075	05.774	er 000	670 700		
	Lookback adjustment	\$4,665	\$5,750	\$7,102	\$7,986	\$6,592 3.368.129	\$6,178	\$5,357	\$4,969	\$5,019	\$6,075	\$5,774	\$5,303	\$70,768	2 025	04.470
61	Residential Exchange Power Purchase Residential Exchange cost	2,357,543 \$129.830	2,669,837 \$147,028	3,476,522 \$191,452			3,127,975		2,484,845	2,481,228	2,644,717 \$145,645		2,314,738 \$127,473	34,473,020 \$1.898.429	3,935	34,473
0.2	residential Excitative cost	g 129,03U	φ1+1,U20	φισ1,452	φεσ/,/04	φ100,463	φ112,200	φ1 <del>4</del> 0,769	ş 130,64U	\$130,041	\$140,040	\$139,22 <i>1</i>	φ121,413	φ1,090,429		

	В	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF
2	Jul 17, 2009 @ 12:18	-1					venues at Pi Revenue (\$	roposed Rate	is .							
3		-1					Fiscal Ye									
4		744	721	744	744	672	743	720	744	720	744	744	720	Fiscal Y	ear 201	0
5		432	384	416	416	384	416	416	400	416	416	416	400			
6	Bulk HUB	312	337	328	328	288	327	304	344	304	328	328	320	T-4-1	- 84147	CIATI
	Bulk HUB Investor-Owned Utilities Residential Exchange	Oct-09	Nov-09	Dec-09	<u>Jan-10</u>	Feb-10	Mar-10	Apr-10	May-10	<u>Jun-10</u>	<u>Jul-10</u>	Aug-10	Sep-10	Total	aMW	GWh
	Residential Exchange Rate	(47.67)	(47.67)	(47.67)	(47.67)	(47.67)	(47.67)	(47.67)	(47.67)	(47.67)	(47.67)	(47.67)	(47.67)	(47.67)		
10	Energy (MWhr)	2,864,806	3,197,882	4,085,457	4,784,898	4,429,309	4,062,639	3,595,448	2,466,659	1,948,191	1,918,756	2,449,230	3,121,073	38,924,348		
	Residential Exchange Revenue (\$000) = (12+13)*14	-\$136,569	-\$152,448	-\$194,760	-\$228,103	-\$211,152	-\$193,672	-\$171,400	-\$117,589	-\$92,873	-\$91,470	-\$116,758	-\$148,786	-\$1,855,580		
	Direct-Service Industries (IP-02 & FPS)	000 100		000 100	000 100	070 540		000 040	000 400	000 040	000 100	000 100	000 010	0.500.011		0.500
	IP LBCRAC True-up (MWH) IP LBCRAC True-up Revenue (\$000)	299,490 \$9.753	290,244 \$10,033	299,490 \$10,923	299,490 \$11,429	270,546 \$10,296	299,088 \$10,745	289,842 \$9,381	299,490 \$8,757	289,842 \$8,591	299,490 \$10,000	299,490 \$11,138	289,842 \$10,805	3,526,344 \$121,852	403	3,526
	PAC capacity, WNP-3 and other L-T contracts	90,100	ψ10,000	ψ10,323	ψ11, <del>4</del> 23	ψ10,230	\$10,745	ψ3,301	ψ0,737	ψ0,551	\$10,000	\$11,150	\$10,000	ψ121,032		
16	Demand (MW)	851	963	870	870	870	788	788	988	770	785	938	758	10,239		
	HLH Energy (MWhr)	54,962	98,624	142,515	159,523	125,172	94,802	100,158	178,576	89,776	67,322	145,400	74,435	1,331,265	152	1,331
	LLH Energy (MWhr)	-129,189	-50,621	-16,121	-34,115	-13,973	-47,213	-40,587	9,357	-47,376	-38,354	-3,129	-87,730	-499,051	-57 95	-499
	Energy (aMW) Revenue (\$ Thousand)	-100 \$4,862	67 \$11,176	170 \$11,346	169 \$11,335	165 \$10,793	64 \$8,156	83 \$8,055	253 \$8,681	59 \$4,907	39 \$4,903	191 \$7,705	-18 \$4,860	1,141 \$96,778	95	832
21	Revenue (\$ 1110usanu)	94,002	\$11,170	φ11,3 <del>4</del> 0	\$11,333	\$10,793	φο, 130	φ0,000	φο,υο ι	φ4,907	φ4,903	\$1,103	\$4,000	\$90,776		
	Contractual Obligations (CER)															
	Demand (MW)	1,273	1,273	1,273	1,273	1,273	1,273	1,273	1,273	1,273	1,273	1,240	1,240	15,210		
	HLH Energy (MWhr)	422,490	408,312	421,922	421,922	381,091	421,922	407,745	421,922	408,312	421,922	392,088	379,440	4,909,088	560	4,909
	LLH Energy (MWhr)	0	0	0	0	0	0 567	0	0	0	0	0	0	0	560	0
	Energy (aMW) Revenue (\$ Thousand)	567 0	567 0	567 0	567 0	567 0	567	567 0	567 0	567 0	567 0	527 0	527 0	6,725 \$0	560	
28	Revenue (\$ 1110usanu)	·	U	U	U	U	U	U	U	U	·	U	U	φU		
	Monthly Trading Floor Committed Sales (MWH)															
	Monthly Trading Floor Committed Sales (\$000)															
	Monthly Trading Floor Balancing Sales (MWH)	264,582	441,458				1,335,168			2,349,974		566,422	272,940	14,839,839	1,694	14,840
	Monthly Trading Floor Balancing Sales (\$000)	\$8,514	\$15,446	\$23,222	\$55,912	\$42,798	\$52,434	\$63,709	\$102,412	\$78,428	\$66,440	\$24,115	\$11,201	\$544,632		
33	Other Monthly Sales (MWH) Other Monthly Sales (\$000)															
35	FPS Bookouts															
	Revenue reversals (\$000)															
37	(4444)															
38	Power Purchases															
	ERE Augmentation Power purchases	6,986	7,280	8,274	7,504	6,647	6,555	5,396	7,924	9,304	8,467	9,108	6,783	90,228	10	90
	ERE Augmentation Purchase Expense	\$228	\$247	\$287	\$230	\$214	\$196	\$156	\$193	\$207	\$222	\$270	\$216	\$2,665		
42	IOU Power Buyback/Deferred LB CRAC expense															
	Renewable HLH (MWH)	26.590	26.485	24.292	24.063	20.328	38.693	28.677	31,104	27.057	28.175	24.658	24,297	324,419	37	324
	Renewable LLH (MWH)	19,733	19,210	19,295	16,522	17,589	28,515	23,690	24,298	26,321	25,353	22,460	19,997	262,982	30	263
45	Renewable Expense (\$000) (included in Program Expense Forecast)	\$2,431	\$2,444	\$2,371	\$2,250	\$2,149	\$3,453	\$2,750	\$2,869	\$2,760	\$2,764	\$2,435	\$2,318	\$30,994		
46																
47	Power Purchases Bookouts (MWH) Power Purchases Reversals (\$000)															
49	Fowel Fulchases Reversals (\$000)															
	Augmentation Power Purchases (MWH)	353.933	342,992	353.933	353.933	319.681	353.457	342.516	353.933	342.516	353,933	353.933	342.516	4.167.276	476	4.167
	Augmentation Power Purchases (\$000)	\$15,126	\$14,659	\$15,126	\$15,126	\$13,662	\$15,106	\$14,638	\$15,126	\$14,638	\$15,126	\$15,126	\$14,638	\$178,100		.,
52																
	Other Committed Power Purchases (MWH)	3,406	3,515	3,034	4,884	5,546	6,251	9,672	11,172	9,842	5,660	5,912	4,596	73,489	8	73
	Balancing Power Purchases (MWH) NLS Power Purchases (MWH) 79506, 79507, 79510, 79671, 79590	67,363	242,691	276,916	331,699	250,469	151,184	151,073	2,469	7,222	23,487	131,834	71,560	1,707,967	195	1,708
	Other Committed Purchase Power Expense (\$000)	\$384	\$390	\$370	\$439	\$473	\$145	\$124	\$175	\$162	\$117	\$167	\$118	\$3.065		
	Balancing Purchase Power Expense (\$000)	\$2.038	\$11.378	\$13.579	\$16.913	\$13.112	\$8.763	\$8.621	\$85	\$301	\$899	\$5.785	\$3.091	\$84.566		
58	Trading Floor Purchase Power Expense (\$000)	,	,	,,	,	,	72,.30	,	+30			,. 50	,	,		
59																
	Lookback adjustment															
61	Residential Exchange Power Purchase			4,085,457								2,449,230		38,924,348	4,443	38,924
62	Residential Exchange cost	\$155,931	\$174,061	\$222,371	\$260,442	\$241,087	\$221,129	\$195,700	\$134,260	\$106,040	\$104,438	\$133,312	\$169,880	\$2,118,652		

	В	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT	AU
2	Jul 17, 2009 @ 12:18						venues at Pi Revenue (\$	roposed Rate	es							
3							Fiscal Ye									
4		744	721	744	744	672	743	720	744	720	744	744	720	Fiscal Y	ear 201	1
5		432	384	416	416	384	416	416	400	416	416	416	400			
6	Bulk HUB	312	337	328	328	288	327	304	344	304	328	328	320	T-4-1	- 84147	CIATI
	Bulk HUB Investor-Owned Utilities Residential Exchange	Oct-10	Nov-10	Dec-10	<u>Jan-11</u>	Feb-11	Mar-11	Apr-11	May-11	<u>Jun-11</u>	<u>Jul-11</u>	Aug-11	Sep-11	Total	aMW	GWh
	Residential Exchange Rate	(49.69)	(49.69)	(49.69)	(49.69)	(49.69)	(49.69)	(49.69)	(49.69)	(49.69)	(49.69)	(49.69)	(49.69)	(49.69)		
10	Energy (MWhr)	2,882,173	3,211,722	4,096,937	4,782,810	4,430,300	4,065,369	3,653,017	2,526,085	2,019,769	1,996,001	2,520,392	3,181,028	39,365,605		
	Residential Exchange Revenue (\$000) = (12+13)*14	-\$143,207	-\$159,581	-\$203,565	-\$237,644	-\$220,129	-\$201,997	-\$181,508	-\$125,514	-\$100,357	-\$99,176	-\$125,231	-\$158,056	(\$1,955,964)		
	Direct-Service Industries (IP-02 & FPS)	000 100		000 100	000 100	070 540		000 040	000 100	000 010	000 100		000 040	0.500.011		0.500
	IP LBCRAC True-up (MWH) IP LBCRAC True-up Revenue (\$000)	299,490 \$9.722	290,244 \$10,057	299,490 \$10,923	299,490 \$11,429	270,546 \$10,296	299,088 \$10,745	289,842 \$9.381	299,490 \$8,757	289,842 \$8,591	299,490 \$9,970	299,490 \$11,176	289,842 \$10.805	3,526,344 \$121,852	403	3,526
	PAC capacity, WNP-3 and other L-T contracts	90,122	ψ10,031	ψ10,323	ψ11, <del>4</del> 23	\$10,230	ψ10,743	ψ3,301	ψ0,737	ψ0,551	\$3,310	\$11,170	\$10,000	Ψ121,032		
16	Demand (MW)	828	947	854	854	854	772	772	965	770	800	784	183	9,383		
	HLH Energy (MWhr)	49,873	97,242	139,155	155,843	121,972	91,281	96,708	173,826	89,776	67,498	78,083	-6,696	1,154,561	132	1,155
	LLH Energy (MWhr)	-119,795	-44,396	-7,954	-26,149	-7,244	-39,709	-35,127	13,899	-47,376	-38,596	-61,515	-6,599	-420,561	-48	-421
	Energy (aMW) Revenue (\$ Thousand)	-94 \$4,862	73 \$11,026	176 \$11,196	174 \$11,185	171 \$10,644	69 \$8,006	86 \$7,905	252 \$8,465	59 \$4,907	39 \$4,903	22 \$5,280	-18 \$59	1,010 \$88,437	84	734
21	revenue (# 11100aanu)	ψ4,00Z	ψ11,020	ψ11,190	ψ11,100	ψ10,044	ψ3,000	ψε,900	ψ0,400	φ+,907	ψ+,903	φ3,200	\$39	ψ00,431		
	Contractual Obligations (CER)															
23	Demand (MW)	1,240	1,240	1,240	1,240	1,240	1,240	1,240	1,240	1,240	1,240	1,240	1,240	14,880		
	HLH Energy (MWhr)	392,615	379,440	392,088	392,088	354,144	392,088	378,913	392,088	379,440	392,088	384,648	372,240	4,601,880	525	4,602
	LLH Energy (MWhr)	0 524	0 524	0 524	0 524	0 524	0 524	0 524	0 524	0 524	0 524	0	0 524	0	0 525	0
	Energy (aMW) Revenue (\$ Thousand)	0	0.0	0	0	0.0	0	0	0	524 0	524 0	524 0	0	6,288 \$0	525	
28	revenue (# mousand)	٠	·	·	·	·	U	U	U	·	·	·	U	40		
	Monthly Trading Floor Committed Sales (MWH)															
30	Monthly Trading Floor Committed Sales (\$000)															
	Monthly Trading Floor Balancing Sales (MWH)	533,732	499,896				1,506,518			2,172,688	1,810,013	727,604	355,182	15,339,720	1,751	15,340
	Monthly Trading Floor Balancing Sales (\$000)	\$22,235	\$21,049	\$30,042	\$64,900	\$48,333	\$61,709	\$60,252	\$93,306	\$73,618	\$71,649	\$31,736	\$15,114	\$593,944		
33	Other Monthly Sales (MWH) Other Monthly Sales (\$000)															
35	FPS Bookouts															
	Revenue reversals (\$000)															
37																
38	Power Purchases															
	ERE Augmentation Power purchases	5,311	5,533	6,284	5,702	5,056	4,986	4,106	5,532	6,225	6,264	6,885	5,129	67,014	8	67
	ERE Augmentation Purchase Expense IOU Power Buyback/Deferred LB CRAC expense	\$174	\$189	\$219	\$175	\$164	\$150	\$119	\$136	\$139	\$165	\$205	\$164	\$1,998		
42	IOU Power Buyback/Deferred LB CRAC expense															
	Renewable HLH (MWH)	26,590	26,485	24,292	24,063	20,328	38,693	28,677	31,104	27,057	28,175	24,659	24,297	324,420	37	324
44	Renewable LLH (MWH)	19,733	19,210	19,295	16,522	17,589	28,515	23,690	24,298	26,321	25,353	22,459	19,997	262,981	30	263
	Renewable Expense (\$000) (included in Program Expense Forecast)	\$2,452	\$2,470	\$2,391	\$2,280	\$2,175	\$3,506	\$2,788	\$2,907	\$2,798	\$2,801	\$2,467	\$2,349	\$31,384		
46 47	Power Purchases Bookouts (MWH)															
	Power Purchases Reversals (\$000)															
49	ower i dichases iteversals (4000)															
50	Augmentation Power Purchases (MWH)	506,186	490,537	506,186	506,186	457,200	505,505	489,857	506,186	489,857	506,186	506,186	489,857	5,959,928	680	5,960
51	Augmentation Power Purchases (\$000)	\$23,020	\$22,309	\$23,020	\$23,020	\$20,793	\$22,989	\$22,278	\$23,020	\$22,278	\$23,020	\$23,020	\$22,278	\$271,045		
52																
	Other Committed Power Purchases (MWH)	3,406	3,515	3,034	4,884	5,546	6,251	9,672	11,172	9,842	5,660	5,912	4,596	73,489	8	73
	Balancing Power Purchases (MWH) NLS Power Purchases (MWH) 79506, 79507, 79510, 79671, 79590	4,402	156,897	208,567	283,867	214,360	131,400	175,784	16,417	25,379	4,283	51,699	34,874	1,307,928	149	1,308
	Other Committed Purchase Power Expense (\$000)	\$54	\$60	\$40	\$109	\$143	\$145	\$124	\$175	\$162	\$117	\$167	\$118	\$1,415		
	Balancing Purchase Power Expense (\$000)	\$198	\$8,811	\$11,273	\$15,047	\$11,674	\$7,919	\$9,710	\$642	\$1,107	\$173	\$2,588	\$1,548	\$70,692		
58	Trading Floor Purchase Power Expense (\$000)								•	. ,		. ,	. ,-			
59																
	Lookback adjustment															
	Residential Exchange Power Purchase Residential Exchange cost				4,782,810			3,653,017				2,520,392		39,365,605	4,494	39,366
62	Residential Exchange Cost	\$162,872	\$181,494	\$231,518	\$270,277	\$25U,356	\$229,734	\$20b,432	\$14Z,/49	\$114,137	\$112,794	\$142,427	\$179,760	\$2,224,550		

	В	С	D	Е	F	G	Н	I	J	K	L	M	N	0	P	Q
1 Ju	I 17, 2009 @ 12:18	•	•	•	•	R	evenues at P	roposed Rates	s	•	•	•	•	•		
2							Revenue (\$	Thousands)								
3							Fiscal Ye	ear 2009								
4																
5																
5													Г	Fiscal `	Year 200	9
7		Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Total	aMW	GWh
8	GEN INPUTS:											-				
9	Redispatch	\$8	\$165	\$129	\$0	\$0	\$125	\$125	\$125	\$125	\$125	\$125	\$125	\$1,178		
10	Energy Imbalance	\$452	\$683	\$790	\$650	\$265	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$2,840		
11	Federal RAS for Generation Dropping	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$396		
12	Synchronous Condensing	\$341	\$341	\$341	\$341	\$341	\$341	\$341	\$341	\$341	\$341	\$341	\$341	\$4,091	16	136337
13	Station Service	\$174	\$174	\$174	\$174	\$174	\$174	\$174	\$174	\$174	\$174	\$174	\$174	\$2,089	9	76421
12 13 14 15 16	Regulating Reserves	\$1,097	\$1,097	\$1,097	\$1,097	\$1,097	\$1,097	\$1,097	\$1,097	\$1,097	\$1,097	\$1,097	\$1,097	\$13,158		
15	Operating Reserves - Spinning & Supplemental	\$2,395	\$2,254	\$2,624	\$2,786	\$2,442	\$2,742	\$2,742	\$2,742	\$2,742	\$2,742	\$2,742	\$2,742	\$31,694		
16	COE/BOR Network/Delivery Facilities Segmentation	\$616	\$616	\$616	\$616	\$616	\$616	\$616	\$616	\$616	\$616	\$616	\$616	\$7,397		
17	Within-Hour Balancing Service for Wind Integration	\$738	\$738	\$738	\$840	\$911	\$1,028	\$1,201	\$1,201	\$1,492	\$1,492	\$2,120	\$2,120	\$14,617		
18	Total Interbusiness Line	\$5,854	\$6,101	\$6,542	\$6,538	\$5,878	\$6,156	\$6,329	\$6,329	\$6,619	\$6,619	\$7,247	\$7,247	\$77,460	24	
19																
20	RESERVE SERVICES:															
21	External	\$158	\$198	\$359	\$303	\$303	\$303	\$303	\$303	\$303	\$303	\$303	\$303	\$3,438		
22	Total Reserve Services	\$158	\$198	\$359	\$303	\$303	\$303	\$303	\$303	\$303	\$303	\$303	\$303	\$3,438		
23																
24	TOTAL Ancillary and Reserves	\$6,012	\$6,300	\$6,901	\$6,840	\$6,181	\$6,459	\$6,631	\$6,631	\$6,922	\$6,922	\$7,550	\$7,550	\$80,897	24	
25																
26	OTHER REVENUES															
27	Downstream Benefits and Storage (MWh)	70,190	10,264	23,245	52,260	53,085	152,833	174,525	215,620	206,324	230,778	187,731	157,687	1,534,543	175	1,535
28	Downstream Benefits and Pumping Power \$\$\$	\$882	\$848	\$864	\$858	\$845	\$714	\$733	\$762	\$782	\$800	\$792	\$765	\$9,646		
29	Slice True-Up (and Implementation costs)												\$5,370	\$5,370		
30	Misc. Generation	\$288	\$328	\$395	\$614	\$308	\$285	\$285	\$285	\$285	\$285	\$285	\$285	\$3,927		
31	Energy Efficiency Rev's	\$2,431	\$639	\$1,111	\$931	\$780	\$605	\$801	\$901	\$1,000	\$1,000	\$1,500	\$2,800	\$14,500		
32	Green Tags and Green Premiums Bulk	\$56	\$162	\$325	\$5	\$198	\$90	\$90	\$90	\$90	\$90	\$90	\$147	\$1,434		
33	Green Premium West	\$150	\$145	\$147	\$147	\$133	\$24	\$23	\$24	\$23	\$24	\$24	\$23	\$886		
34	Green Premium East	\$111	\$108	\$111	\$111	\$100	\$113	\$110	\$113	\$110	\$113	\$113	\$110	\$1,323		
35	4(h)(10)c credit	\$7,547	\$6,954	\$7,088	\$7,029	\$7,894	\$6,009	\$6,009	\$6,009	\$6,009	\$6,009	\$6,009	\$6,009	\$78,578		
36	Network Wind Integration&Shaping	\$170	\$170	\$170	\$170	\$170	\$163	\$163	\$163	\$163	\$163	\$163	\$163	\$1,989		
37	Colville and Spokane Settlements	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$4,600		
38	LB CRAC True-up															
39	Aluminum Hedging															
18   19   20   21   22   23   24   25   26   27   28   29   33   34   35   36   37   38   39   40   41	TOTAL OTHER REVENUES	\$12,018	\$9,737	\$10,594	\$10,249	\$10,813	\$8,387	\$8,598	\$8,731	\$8,845	\$8,868	\$9,360	\$16,055	\$122,254		
41												4				
42	Trading Floor Transmission	\$5,849	\$6,004	\$6,004	\$6,004	\$6,004	\$6,004	\$6,004	\$5,804	\$5,804	\$5,804	\$5,641	\$5,641	\$70,564		
43	Other Transmission Expenses	\$2,216	\$2,061	\$2,061	\$2,061	\$2,061	\$2,061	\$2,061	\$2,260	\$2,260	\$2,260	\$2,424	\$2,424	\$26,211		

	В	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE AF
1	Jul 17, 2009 @ 12:18		•			Re	evenues at Pro	posed Rates				•			•
2	_						Revenue (\$ T	housands)							
3							Fiscal Yea	ar 2010							
4															
5 6 7															
6														Fiscal Y	ear 2010
7		Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	<u>Total</u>	aMW GWh
8	GEN INPUTS:														
8 9 10 11 12 13 14 15	Redispatch	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$400	
10	Energy Imbalance	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
11	Federal RAS for Generation Dropping	\$51	\$51	\$51	\$51	\$51	\$51	\$51	\$51	\$51	\$51	\$51	\$51	\$612	
12	Synchronous Condensing	\$163	\$163	\$163	\$163	\$163	\$163	\$163	\$163	\$163	\$163	\$163	\$163	\$1,959	5 40301
13	Station Service	\$269	\$269	\$269	\$269	\$269	\$269	\$269	\$269	\$269	\$269	\$269	\$269	\$3,229	9 79567
14	Regulating Reserves	\$642	\$642	\$642	\$642	\$642	\$642	\$642	\$642	\$642	\$642	\$642	\$642	\$7,699	
15	Operating Reserves - Spinning & Supplemental	\$3,197	\$3,197	\$3,197	\$3,197	\$3,197	\$3,197	\$2,052	\$2,052	\$2,052	\$2,052	\$2,052	\$2,052	\$31,495	
16 17	COE/BOR Network/Delivery Facilities Segmentation	\$517	\$517	\$517	\$517	\$517	\$517	\$517	\$517	\$517	\$517	\$517	\$517	\$6,203	
17	Within-Hour Balancing Service for Wind Integration	\$3,214	\$3,214	\$3,214	\$3,214	\$3,214	\$3,214	\$3,214	\$3,214	\$3,214	\$3,214	\$3,214	\$3,214	\$38,574	
18	Total Interbusiness Line	\$8,087	\$8,087	\$8,087	\$8,087	\$8,087	\$8,087	\$6,942	\$6,942	\$6,942	\$6,942	\$6,942	\$6,942	\$90,171	14
19															
20	RESERVE SERVICES:														
21	External	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
22	Total Reserve Services	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
23															
24	TOTAL Ancillary and Reserves	\$8,087	\$8,087	\$8,087	\$8,087	\$8,087	\$8,087	\$6,942	\$6,942	\$6,942	\$6,942	\$6,942	\$6,942	\$90,171	14
25															
26	OTHER REVENUES														
27	Downstream Benefits and Storage (MWh)	70,190	10,264	23,245	52,260	53,085	152,833	174,525	215,620	206,324	230,778	187,731	157,687	1,534,543	175 1,535
28	Downstream Benefits and Pumping Power \$\$\$	\$731	\$710	\$710	\$710	\$711	\$714	\$733	\$762	\$782	\$800	\$792	\$765	\$8,921	
29	Slice True-Up (and Implementation costs)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	(\$5,282)	(\$5,282)	
30	Misc. Generation	\$285	\$285	\$285	\$285	\$285	\$285	\$285	\$285	\$285	\$285	\$285	\$285	\$3,420	
31	Energy Efficiency Rev's	\$1,367	\$1,367	\$1,367	\$1,367	\$1,367	\$1,367	\$1,367	\$1,367	\$1,367	\$2,733	\$2,733	\$2,733	\$20,500	
32	Green Tags and Green Premiums Bulk	\$404	\$378	\$357	\$320	\$296	\$589	\$446	\$489	\$467	\$477	\$423	\$394	\$5,040	
33	Green Premium West	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
34	Green Premium East	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
35	4(h)(10)c credit	\$8,057	\$8,057	\$8,057	\$8,057	\$8,057	\$8,057	\$8,057	\$8,057	\$8,057	\$8,057	\$8,057	\$8,057	\$96,689	
36	Network Wind Integration&Shaping	\$163	\$163	\$163	\$163	\$163	\$163	\$163	\$163	\$163	\$163	\$163	\$163	\$1,953	
37	Colville and Spokane Settlements	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$4,600	
38	LB CRAC True-up														
39	Aluminum Hedging														
40	TOTAL OTHER REVENUES	\$11,390	\$11,343	\$11,323	\$11,286	\$11,262	\$11,558	\$11,435	\$11,506	\$11,504	\$12,899	\$12,837	\$7,498	\$135,842	
18 19 20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40 41 42 43															
42	Trading Floor Transmission	\$7,418	\$7,418	\$7,418	\$7,418	\$7,418	\$7,418	\$7,418	\$7,418	\$7,418	\$7,418	\$7,418	\$7,418	\$89,018	
43	Other Transmission Expenses	\$2,513	\$2,513	\$2,513	\$2,513	\$2,513	\$2,513	\$2,513	\$2,513	\$2,513	\$2,513	\$2,513	\$2,513	\$30,159	

	В	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT	AU
1	Jul 17, 2009 @ 12:18				· · · · · ·		evenues at Pro		l .	-	l .					
2							Revenue (\$ T									
3							Fiscal Yea	ar 2011								
5																
5																
6														Fiscal \	ear 2011	
7 8 9		Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Total	<u>aMW</u>	GWh
8	GEN INPUTS:															
9	Redispatch	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$33	\$400		
10 11	Energy Imbalance	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
	Federal RAS for Generation Dropping	\$51	\$51	\$51	\$51	\$51	\$51	\$51	\$51	\$51	\$51	\$51	\$51	\$612		
12	Synchronous Condensing	\$163	\$163	\$163	\$163	\$163	\$163	\$163	\$163	\$163	\$163	\$163	\$163	\$1,959		0,301
13 14	Station Service	\$269	\$269	\$269	\$269	\$269	\$269	\$269	\$269	\$269	\$269	\$269	\$269	\$3,229	9 7	9,567
	Regulating Reserves	\$642	\$642	\$642	\$642	\$642	\$642	\$642	\$642	\$642	\$642	\$642	\$642	\$7,699		
15	Operating Reserves - Spinning & Supplemental	\$2,199	\$2,199	\$2,199	\$2,199	\$2,199	\$2,199	\$2,199	\$2,199	\$2,199	\$2,199	\$2,199	\$2,199	\$26,387		
16	COE/BOR Network/Delivery Facilities Segmentation	\$517	\$517	\$517	\$517	\$517	\$517	\$517	\$517	\$517	\$517	\$517	\$517	\$6,203		
17	Within-Hour Balancing Service for Wind Integration	\$4,687	\$4,687	\$4,687	\$4,687	\$4,687	\$4,687	\$4,687	\$4,687	\$4,687	\$4,687	\$4,687	\$4,687	\$56,246		
18	Total Interbusiness Line	\$8,561	\$8,561	\$8,561	\$8,561	\$8,561	\$8,561	\$8,561	\$8,561	\$8,561	\$8,561	\$8,561	\$8,561	\$102,735	14	
19																
20	RESERVE SERVICES:															
21	External	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
22	Total Reserve Services	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0		
20 21 22 23 24 25 26 27 28 29	TOTAL A	** ***	** ***		** =**		** ***	** -**	** -**	** ***	** ***	** ***	** ***	****	4.4	
24	TOTAL Ancillary and Reserves	\$8,561	\$8,561	\$8,561	\$8,561	\$8,561	\$8,561	\$8,561	\$8,561	\$8,561	\$8,561	\$8,561	\$8,561	\$102,735	14	
25																
26	OTHER REVENUES	=0.400	40.004		=0.000	==	450.000		0.4 = 0.00							
27	Downstream Benefits and Storage (MWh)	70,190	10,264	23,245	52,260	53,085	152,833	174,525	215,620	206,324	230,778	187,731	157,687	1,534,543	175	1,535
28	Downstream Benefits and Pumping Power \$\$\$	\$731	\$710	\$710	\$710	\$711	\$714	\$733	\$762	\$782	\$800	\$792	\$765	\$8,921		
29	Slice True-Up (and Implementation costs)	\$0	\$0 \$285	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$10,942	\$10,942		
30	Misc. Generation	\$285		\$285	\$285	\$285	\$285	\$285	\$285	\$285	\$285	\$285	\$285	\$3,420		
31	Energy Efficiency Rev's	\$1,367 \$404	\$1,367 \$378	\$1,367 \$357	\$1,367 \$320	\$1,367 \$296	\$1,367 \$589	\$1,367 <b>\$44</b> 6	\$1,367 <b>\$48</b> 9	\$1,367 \$467	\$2,733 \$477	\$2,733 \$423	\$2,733 \$394	\$20,500 \$5,040		
31 32 33	Green Tags and Green Premiums Bulk Green Premium West	\$404 \$0	\$378 \$0	\$357 \$0	\$320 \$0	\$296 \$0	\$569 \$0	\$446 \$0	\$489 \$0	\$467 \$0	\$477 \$0	\$423 \$0	\$394 \$0	\$5,040 \$0		
3/	Green Premium East	\$0 \$0	\$0 \$0	\$0 \$0	\$0 \$0	\$0 \$0	\$0 \$0	\$0 \$0								
34 35 36	4(h)(10)c credit	\$8,497	\$8.497	\$8.497	\$8,497	\$8,497	\$8,497	\$8,497	\$8,497	\$8,497	\$8,497	\$8,497	\$8,497	\$101,969		
36	Network Wind Integration&Shaping	\$0,497 \$163	\$6,497 \$163	\$6,497 \$163	\$6,497 \$163	\$6,497 \$163	\$0,497 \$163	\$0,497 \$163	\$6,497 \$163	\$6,497 \$163	\$6,497 \$163	\$6,497 \$163	\$6,497 \$163	\$1.953		
37	Colville and Spokane Settlements	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$383	\$4,600		
37 38	LB CRAC True-up	φυσυ	ψυσυ	φυσυ	φυσυ	φ303	φ303	φυσυ	φυσυ	φυσυ	ψυσυ	φυσυ	φ303	Ψ4,000		
39	Aluminum Hedging															
40	TOTAL OTHER REVENUES	\$11,830	\$11,783	\$11,763	\$11,726	\$11,702	\$11,998	\$11,875	\$11,946	\$11,944	\$13,339	\$13,277	\$24,162	\$157,345		
41		<b>,</b>	Ų,. CO	Ţ,. US	¥ · · ·,· = 3	Ţ,. <u>.</u>	<b>,</b>	<b></b>	Ţ,J.J	Ų,o.,	<b>,</b>	Ţ.J,=. /	¥= ., . ¥=	Ţ.J.,J		
42	Trading Floor Transmission	\$7,363	\$7,363	\$7,363	\$7,363	\$7,363	\$7,363	\$7,363	\$7,363	\$7,363	\$7,363	\$7,363	\$7,363	\$88,352		
43	Other Transmission Expenses	\$2,421	\$2,421	\$2,421	\$2,421	\$2,421	\$2,421	\$2,421	\$2,421	\$2,421	\$2,421	\$2,421	\$2,421	\$29,049		

	A	В	С	D	E	F	G	Н	1	J	K	L	M	N
1						1: Second		s					l l	
2							,							
3							Sur	plus Sales	FY 2010					
4														
5		<u>Oct</u>	<u>No</u>	<u>Dec</u>	<u>Jan</u>	<u>Feb</u>	Mar	<u>Apr</u>	May	<u>Jun</u>	<u>Jul</u>	<u>Aug</u>	<u>Sep</u>	<u>Annual</u>
6														
7	Monthly Hours	744	72	1 744	744	672	743	720	744	720	744	744	720	8,760
8														
9	Surplus Sales (aMW)	356	61	2 833	1,744	1,565	1,797	2,532	4,122	3,264	2,353	761	379	1,694
10	Secondary Revenue (\$ Thousand)	8,514	15,44	3 23,222	55,912	42,798	52,434	63,709	102,412	78,428	66,440	24,115	11,201	544,632
11	Average Sales Price (\$/MWh)	\$ 32.18	\$ 34.99	\$ 37.46	\$ 43.09	\$ 40.69	\$ 39.27	\$ 34.94	\$ 33.40	\$ 33.37	\$ 37.96	\$ 42.57	\$ 41.04 <b>\$</b>	36.70
12														
13														
14														
15														
16							Sur	plus Sales	FY 2011					
17														
18		Oct	No	<u>Dec</u>	<u>Jan</u>	Feb	Mar	<u>Apr</u>	May	<u>Jun</u>	<u>Jul</u>	Aug	<u>Sep</u>	Annual
19										<u> </u>				
20	Monthly Hours	744	72	1 744	744	672	743	720	744	720	744	744	720	8,760
21	-													
22	Surplus Sales (aMW)	717	69	3 949	1,997	1,700	2,028	2,321	3,666	3,018	2,433	978	493	1,751
23	Secondary Revenue (\$ Thousand)	22,235	21,04	9 30,042	64,900	48,333	61,709	60,252	93,306	73,618	71,649	31,736	15,114	593,944
	Average Sales Price (\$/MWh)	\$ 41.66	\$ 42.11	\$ 42.53	\$ 43.67	\$ 42.30	\$ 40.96	\$ 36.05	\$ 34.21	\$ 33.88	\$ 39.58	\$ 43.62	\$ 42.55 <b>\$</b>	38.72

	А	В	3	С		D	E	F		G		Н	ı		J		K	l	L		M		N
1			•			Table	e 4.8.2: I	Balancing	j Pi	urchas	es	•		•			•		•				
2																							
3									<u>E</u>	Balancin	gР	urchas	es FY	<u> 2010</u>									
4																							
5			<u>Oct</u>	Nov		Dec	<u>Jan</u>	<u>Feb</u>		Mar		<u>Apr</u>	<u>1</u>	/lay	<u>Jun</u>		<u>Jul</u>		<u>Aug</u>		<u>Sep</u>		<u>Annual</u>
6																							
	Monthly Hours		744	721		744	744	672		743		720		744	720		744		744		720		8,760
8																							
	Balancing Purchases (aMW)		76	326		358	437	369		196		212		3	12		23		175		143		193
10	Purchase Expenses (\$ Thousand)	\$ 1,	,730	\$ 11,109	\$	13,187	\$ 16,653	\$ 13,019	\$	8,550	\$	8,703	\$	85	\$ 355	\$	654	\$ 5	,919	\$	4,566	\$	84,529
	Average Purchase Price (\$/MWh)	\$ 30	0.26	\$ 34.93	\$	39.84	\$ 45.65	\$ 45.48	\$	43.61	\$	41.68	\$ 34	.60	\$ 41.70	\$	38.28	\$ 4	3.88	\$	43.20	\$	50.00
12																							
13																							
14																							
15									<u>E</u>	<u>Balancin</u>	g P	urchas	es FY	<u> 2011</u>									
16																							
17			<u>Oct</u>	<u>Nov</u>		<u>Dec</u>	<u>Jan</u>	<u>Feb</u>		<u>Mar</u>		<u>Apr</u>	<u>I</u>	<u>/lay</u>	<u>Jun</u>		<u>Jul</u>		<u>Aug</u>		<u>Sep</u>		<u>Annual</u>
18																							
	Monthly Hours		744	721		744	744	672		743		720		744	720		744		744		720		8,760
20			_																				
	Balancing Purchases (aMW)	_	7	216	_	277	373	320	_	177	_	246		21	36	_	4	<b>.</b> -	75	_	50	_	149
	Purchase Expenses (\$ Thousand)	•	240	\$ 8,751	Ψ.	11,180	\$ 14,772	\$ 11,714	\$	7,941		9,761			\$ 1,145	\$	131		2,812	\$	1,606	•	70,680
	Average Purchase Price (\$/MWh)	\$ 45	5.07	\$ 42.59	\$	44.62	\$ 47.55	\$ 47.48	\$	47.05	\$	42.77	\$ 39	.10	\$ 43.63	\$	40.46	\$ 5	0.07	\$	44.40	\$	54.11
24																							

Α		В		С		D		Е		F		G		Н
				Table	4.8.3	3: Winter	Hed	ging Purc	hase	es				
		<u>Winter</u>	Heg	<u>ding Con</u>	<u>tract</u>	: Purchas	<u>es (l</u>	<u>MW Purch</u>	ase	<u>d on HLH</u>	<u>ONL</u>	<u>.Y)</u>		
=>/				_										
<u>FY</u>		NOV		Dec		<u>Jan</u>		<u>Feb</u>		<u>ıvıar</u>		<u>Apr</u>		
2010		300		300		300		300		200		200		
2010		300		300		300		300		300		300		
2011		300		300		300		300		300		300		
2011		000		000		000		000		000		000		
		<u>W</u> i	nter	<u>Hedging</u>	Con <sup>-</sup>	<u>tracts Pu</u>	<u>rcha</u>	se Expen	se (\$	<u>Thousan</u>	<u>ld)</u>			
->.														
<u>FY</u>		<u>Nov</u>		<u>Dec</u>		<u>Jan</u>		<u>Feb</u>		<u>Mar</u>		<u>Apr</u>		<u>Total</u>
2040	<b>ው</b>	6 011	σ	7 270	<b>ው</b>	7.005	σ	6 011	Φ	7 662	Φ	7 270	¢	42 420
2010	Ф	0,011	Φ	1,319	Ф	7,095	Φ	0,011	Ф	7,003	Φ	1,319	Ф	43,138
2011	\$	7 095	\$	7 379	\$	7 095	\$	6 811	\$	7 663	\$	7 379	\$	43,421
	<u>FY</u> 2010 2011 <u>FY</u> 2010	<u>FY</u> 2010 2011	FY         Nov           2010         300           2011         300           Winter         Winter           2010         \$ Nov           2010         \$ 6,811	FY         Nov           2010         300           2011         300           Winter         FY           Nov           2010         6,811	Table           Winter Hegding Con           FY         Nov         Dec           2010         300         300           2011         300         300           Winter Hedging         FY         Nov         Dec           2010         \$ 6,811         \$ 7,379	Winter Hegding Contract   FY   Nov   Dec     2010   300   300   300	Table 4.8.3: Winter           Winter Hegding Contract Purchase           FY         Nov         Dec         Jan           2010         300         300         300           2011         300         300         300           Winter Hedging Contracts Pure           FY         Nov         Dec         Jan           2010         \$ 6,811         \$ 7,379         \$ 7,095	Table 4.8.3: Winter Hedging Contract Purchases (I Py Nov Dec Jan 2010 300 300 300 300           2010 300 300 300         300 300 300           Winter Hedging Contracts Purchases (I Py Nov Dec Jan 2010 \$ 6,811 \$ 7,379 \$ 7,095 \$ 1000)	Table 4.8.3: Winter Hedging Purc           Winter Hegding Contract Purchases (MW Purch           FY         Nov         Dec         Jan         Feb           2010         300         300         300         300           2011         300         300         300         300           Winter Hedging Contracts Purchase Expension         FY         Nov         Dec         Jan         Feb           2010         \$ 6,811         \$ 7,379         \$ 7,095         \$ 6,811	Table 4.8.3: Winter Hedging Purchases           Winter Hegding Contract Purchases (MW Purchases)           FY         Nov         Dec         Jan         Feb           2010         300         300         300         300           2011         300         300         300         300           Winter Hedging Contracts Purchase Expense (\$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	Table 4.8.3: Winter Hedging Purchases           Winter Hegding Contract Purchases (MW Purchased on HLH           FY         Nov         Dec         Jan         Feb         Mar           2010         300         300         300         300         300           2011         300         300         300         300         300           Winter Hedging Contracts Purchase Expense (\$ Thousand Purchase Expense)           FY         Nov         Dec         Jan         Feb         Mar           2010         \$ 6,811         \$ 7,379         \$ 7,095         \$ 6,811         \$ 7,663	Table 4.8.3: Winter Hedging Purchases           Winter Hegging Contract Purchases (MW Purchased on HLH ONL           FY         Nov         Dec         Jan         Feb         Mar           2010         300         300         300         300         300           2011         300         300         300         300         300           Winter Hedging Contracts Purchase Expense (\$ Thousand)         FY         Nov         Dec         Jan         Feb         Mar           2010         \$ 6,811         \$ 7,379         \$ 7,095         \$ 6,811         \$ 7,663         \$	Table 4.8.3: Winter Hedging Purchases           Winter Hegding Contract Purchases (MW Purchased on HLH ONLY)           FY         Nov         Dec         Jan         Feb         Mar         Apr           2010         300         300         300         300         300         300           2011         300         300         300         300         300         300         300           Winter Hegging Contracts Purchase Expense (\$ Thousand)           FY         Nov         Dec         Jan         Feb         Mar         Apr           2010         \$ 6,811         \$ 7,379         \$ 7,095         \$ 6,811         \$ 7,663         \$ 7,379	Table 4.8.3: Winter Hedging Purchases           Winter Hegding Contract Purchases (MW Purchased on HLH ONLY)           FY         Nov         Dec         Jan         Feb         Mar         Apr           2010         300         300         300         300         300         300           2011         300         300         300         300         300         300         300           Winter Hedging Contracts Purchase Expense (\$ Thousand)           FY         Nov         Dec         Jan         Feb         Mar         Apr           2010         \$ 6,811         \$ 7,379         \$ 7,095         \$ 6,811         \$ 7,663         \$ 7,379         \$

	A	В	С	D	Е		F
1		Ta	able 4.8.4 Augmen	tation Power Purch	ases		
2							
3	Price = Weighted a	verage annual purd	hase price for 193	7 from 70 WY run.			
4		<u>FY</u>	<u>MW</u>	<u>Hours</u>	<u>\$/MWh</u>	<u>Exp. (</u>	\$ Thousand)
5		2010	476	8760	42.74	\$	178,100
6		2011	680	8760	45.48	\$	271,045
7		2012	501	8784	48.08	\$	211,656
8		2013	699	8760	50.77	\$	310,848
9		2014	669	8760	52.56	\$	308,232
10		2015	865	8760	54.80	\$	415,263
11							
12					Average	\$	282,524



# **Chapter 5: Excerpts from Customer ASC Reports**

Avista Utilities
Franklin PUD
Idaho Power Company
NorthWestern Energy
PacifiCorp
Portland General Electric
Puget Sound Energy
Snohomish County PUD

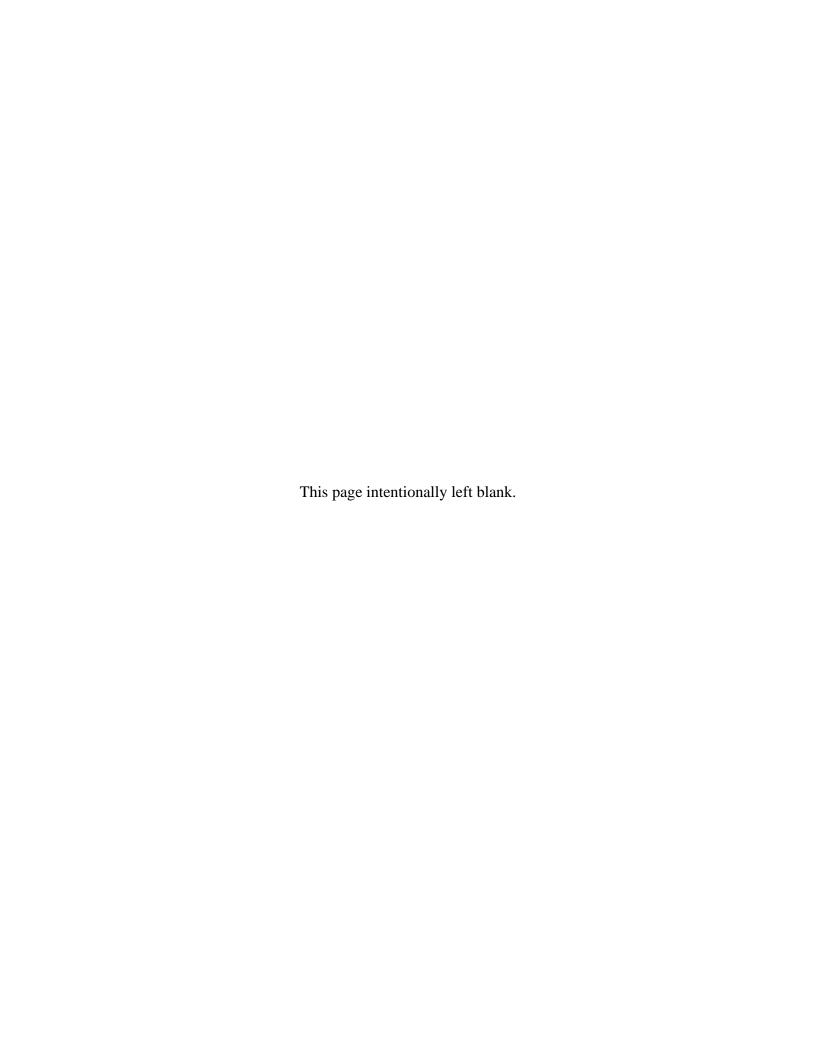


# FINAL AVERAGE SYSTEM COST REPORT

# **AVISTA UTILITIES**

July 2009





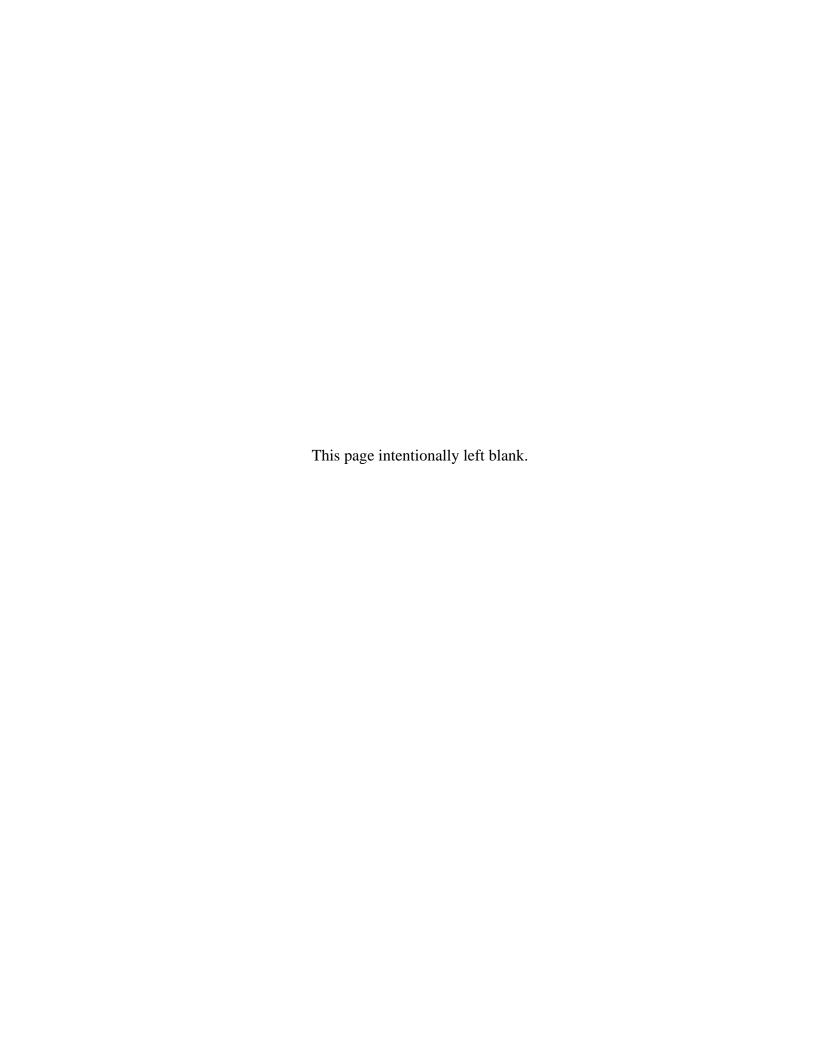
## FINAL AVERAGE SYSTEM COST REPORT

#### **FOR**

## **Avista Utilities**

Docket Number: ASC-10-AV-01 Effective Date: October 1, 2009

PREPARED BY BONNEVILLE POWER ADMINISTRATION U.S. DEPARTMENT OF ENERGY



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	July 21, 2009			



#### 1. FILING DATA

Utility: **Avista Utilities** 

1411 E. Mission Ave. Spokane, WA 99252-0001

http://www.avistautilities.com/residential/pages/default.aspx

#### Parties to the Filing:

Investor-Owned Utilities (IOUs):

Idaho Power Company (IPC)

NorthWestern Energy (NorthWestern or NWE)

PacifiCorp (PAC)

Portland General Electric (PGE)

Puget Sound Energy (PSE)

#### Consumer-Owned Utilities (COUs):

Franklin County PUD (Franklin) Snohomish County PUD (SNOPUD)

Other Participants to the Filing:

Idaho Public Utility Commission

**Public Power Council** 

Public Utility Commission of Oregon (OPUC)

Washington Utilities and Transportation Commission (WUTC)

ASC Base Period: CY 2007

Effective Exchange Period: FY 2010-2011 (October 1, 2009 – September 30, 2011)

#### Statement of Purpose:

Bonneville Power Administration (BPA) has conducted an Average System Cost (ASC) Review Process to determine Avista's ASC for FY 2010-2011 based on BPA's 2008 ASC Methodology (ASCM). This FY 2010-2011 Final Average System Cost Report (Final ASC Report) describes the process, evaluation, and results of BPA's ASC review.

General information can be found at <a href="http://www.bpa.gov/corporate/finance/ascm/index.cfm">http://www.bpa.gov/corporate/finance/ascm/index.cfm</a>.

NOTE: BPA previously advised parties that if the filing utility or an intervenor wished to preserve any issue regarding BPA's Final ASC Reports for subsequent administrative or judicial appeal, they must have raised such issue in their comments on BPA's Draft ASC Reports. If a party failed to do so, the issue would be waived for subsequent appeal.

#### 2. AVERAGE SYSTEM COST SUMMARY

#### 2.1. Base Period ASC

The 2008 ASCM requires utilities participating in the ASC Review Process, both IOUs and COUs, to submit to BPA "Base Period" financial and operational information. The Base Period is defined as the calendar year of the most recent FERC Form 1 data for IOUs, and most recent Annual Reports, including the most recent Cost of Service Analysis (COSA) for COUs. The submitted information includes the "Appendix 1," the Excel based workbook used in calculating the Base Period ASC. For purposes of this report, the Base Period is calendar year (CY) 2007.

The table below summarizes the CY 2007 Base Period ASC based on (1) the ASC information filed by Avista on October 15, 2008 (including errata, if applicable), and (2) the same information adjusted by BPA, including response to comments submitted by the utility and/or intervenors during the ASC Review Process. This table does not reflect the Exchange Period ASC, which is noted in subsequent tables.

**Table 2.1:** CY 2007 Base Period ASC (Results of Appendix 1 calculations)

	October 15, 2008 As Filed	July 21, 2009 Final Report
Production Cost	\$ 394,700,327	\$ 390,305,403
Transmission Cost	\$ 59,607,565	\$ 58,131,045
(Less) NLSL Costs	\$ 0	\$ 0
Contract System Cost (CSC)	\$ 454,307,891	\$ 448,436,447
Total Retail Load (MWh)	8,924,726	8,924,726
(Less) NLSL	0	0
Total Retail Load (Net of NLSL)	8,924,726	8,924,726
Distribution Losses	452,964	452,964
Contract System Load (CSL)	9,377,690	9,377,690
CY 2007 Base Period ASC (CSC/CSL)	\$48.45/MWh	\$47.82/MWh

#### 2.2. **ASC New Resource Additions**

In addition to the historical Base Period cost and load data, the exchanging utility may also provide its forecast of major new resource additions, and all associated costs, that are projected to come on-line through the end of the Exchange Period (FY 2010-2011). The forecast covers the period from the end of the Base Period (December 31, 2007) to the end of the Exchange Period (September 30, 2011). When a major new resource addition is projected to come on-line prior to the start of the Exchange Period, the associated costs are projected forward to the midpoint of the Exchange Period in order to calculate the Exchange Period ASC.

The 2008 ASCM also provides that changes to an established ASC are allowed to occur during the Exchange Period to account for major new resource additions and purchases that are projected to come on-line or be purchased and used to meet a utility's retail load during the Exchange Period (FY 2010-2011).

In either scenario, such changes in ASC must meet the same materiality threshold as a change in ASC resulting from major new resource additions, that is, a 2.5 percent or greater change in Base Period ASC. BPA allows utilities to submit stacks of individual resources that, when combined, meet the materiality threshold. However, each resource in the stack must result in an increase or decrease of Base Period ASC of 0.5 percent or more.

The tables below summarize the new major resource additions projected to come on-line during the forecast period, based on (1) the ASC information filed on October 15, 2008 (including errata, if applicable), and (2) the same information as adjusted by BPA, including response to comments submitted by the utility and/or intervenors during the ASC Review Process.

Table 2.2.1: New Resource Additions Coming On-Line Prior to Exchange Period (\$/MWh)

As-Filed FY 2010-2011 Exchange Period ASC					
Resource	<b>Montana Riverbed</b>	N/A	N/A	N/A	
Expected On-Line Date	2008				
Delta*	0				

Final Report FY 2010-2011 Exchange Period ASC					
Resource	<b>Montana Riverbed</b>	N/A	N/A	N/A	
Expected On-Line Date	N/A				
Delta*	0				

<sup>\*</sup>The Delta is the incremental change in the ASC as new resources come on-line. Avista did not complete a materiality test. BPA completed the calculation and determined the Montana Riverbed Lease 2008 value did not meet the minimum materiality threshold of 2.5 percent. *See* Section 5.9 for details.

Table 2.2.2: New Resource Additions Coming On-Line During the Exchange Period (\$/MWh)

As-Filed FY 2010-2011 Exchange Period ASC					
Resource Lancaster N/A N/A N/A					
Expected On-Line Date	2010				
Delta*	-2.50				

Final Report FY 2010-2011 Exchange Period ASC					
Lancaster/					
Resource	Montana Riverbed	N/A	N/A	N/A	
Expected On-Line Date	2010				
Delta*	3.19				

\*The Delta is the incremental change in the ASC as the new resources come on line. Lancaster power purchase agreement meets the minimum 2.5 percent materiality threshold. In addition, Montana Riverbed Lease will be grouped with Lancaster as a major new resource. *See* Section 5.8 for details.

#### 2.3. FY 2010-2011 Exchange Period ASC

The following table identifies the Exchange Period ASC as filed on October 15, 2008, including errata if applicable, as adjusted by BPA for this Final ASC Report. The ASC includes major new resource additions projected to come on-line prior to the start of the Exchange Period only. The Exchange Period ASC will adjust as necessary as additional major new resources come online, and as identified in Table 2.2.2 above. The procedures used in making the determinations and any required changes are prescribed by the 2008 ASCM and described in the following sections.

Table 2.3: Exchange Period FY 2010-2011 ASC (\$/MWh)
Prior to New Resource Additions

Date	October 15, 2008 As-Filed	July 21, 2009 Final Report
FY 2010-2011	49.51	44.61

#### 3. FILING REQUIREMENTS

#### 3.1. <u>Introduction</u>

Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. § 839c(c), established the Residential Exchange Program (REP). Any Pacific Northwest utility interested in participating in the REP may offer to sell power to BPA at the average system cost (ASC) of the utility's resources. In exchange, BPA offers to sell an "equivalent amount of electric power to such utility for resale to that utility's residential users within the region" at the BPA rate established pursuant to section 7(b)(l) of the Act. H.R. Rep. No. 976, Pt. I, 96th Cong., 2d Sess. 60 (1980). The cost benefits established by the REP are passed through directly to the exchanging utilities' residential and small farm consumers. 16 U.S.C. § 839c(c)(3).

The Northwest Power Act gives BPA's Administrator the authority to determine ASC on the basis of a methodology established in a public consultation proceeding. 16 U.S.C. § 839c(c)(7). The only express statutory limits on the Administrator's authority are found in sections 5(c)(7)(A), (B) and (C) of the Act. 16 U.S.C. §§ 839c(c)(7)(A), (B) and (C).

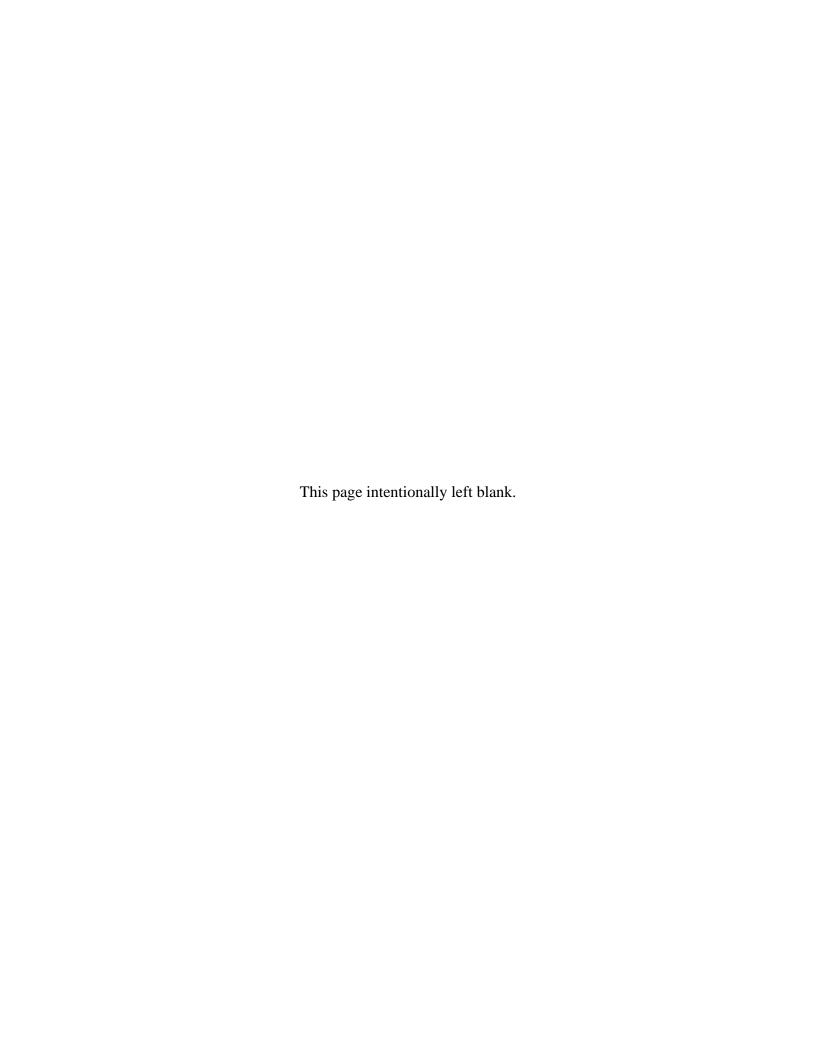
BPA's first ASC Methodology was developed in consultation with regional interests in 1981. *See* 48 Fed. Reg. 46,970 (Oct. 17, 1983). It was later revised in 1984. *See* 49 Fed. Reg. 39,293

# FINAL AVERAGE SYSTEM COST REPORT

# FRANKLIN COUNTY PUD

July 2009





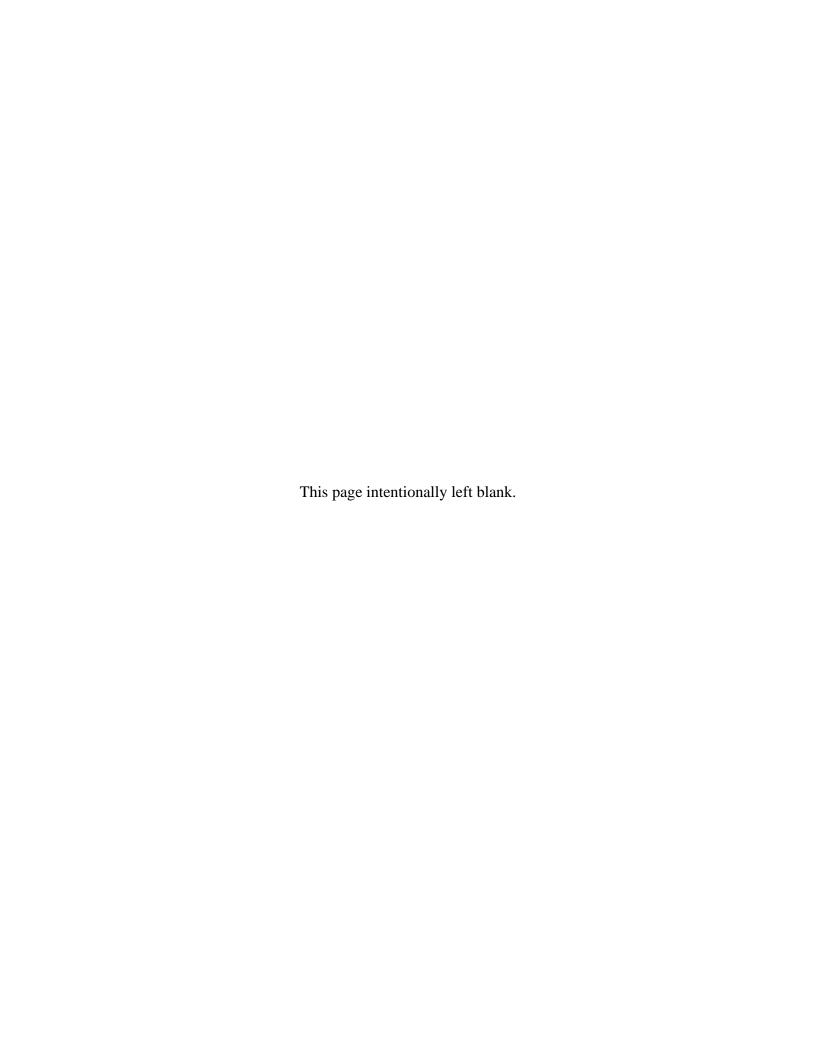
# FINAL AVERAGE SYSTEM COST REPORT

**FOR** 

# Public Utility District No. 1 of Franklin County

Docket Number: ASC-10-FR-01 Effective Date: October 1, 2009

PREPARED BY BONNEVILLE POWER ADMINISTRATION U.S. DEPARTMENT OF ENERGY



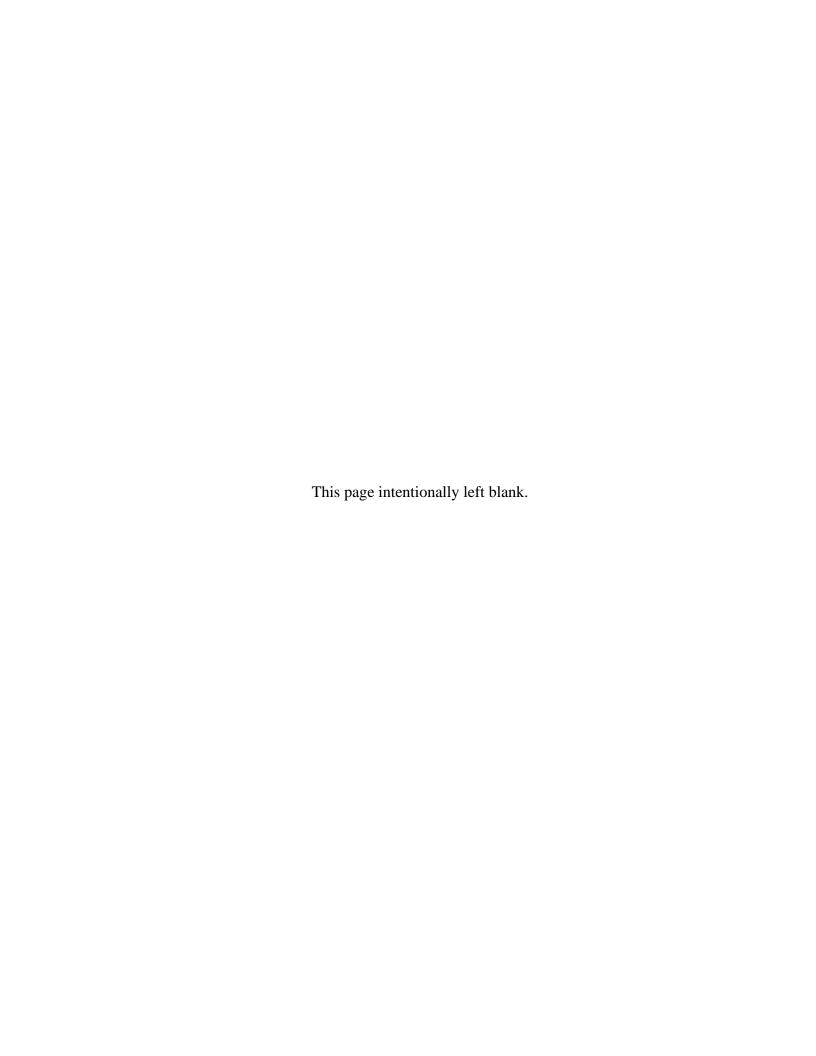
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#### 1. FILING DATA

<u>Utility</u>: **Public Utility District No. 1 of Franklin County** 

1411 W. Clark Street, Pasco, WA 99301

http://www.franklinpud.com/

#### Parties to the Filing:

Investor Owned Utilities (IOUs):

Avista Utilities (Avista)

Idaho Power Company (IPC)

NorthWestern Energy (NorthWestern or NWE)

PacifiCorp (PAC)

Portland General Electric (PGE)

Puget Sound Energy (PSE)

Consumer Owned Utilities (COUs):

Snohomish County PUD (SNOPUD)

Other Participants to the Filing:

Idaho Public Utility Commission

**Public Power Council** 

Public Utility Commission of Oregon (OPUC)

Washington Utilities and Transportation Commission (WUTC)

ASC Base Year: CY 2007

Effective Exchange Period: FY 2010-2011 (October 1, 2009 – September 30, 2011)

#### Statement of Purpose:

Bonneville Power Administration (BPA) has conducted an Average System Cost (ASC) Review Process to determine Public Utility District No. 1 of Franklin County's ASC for FY 2010-2011 based on BPA's 2008 ASC Methodology (ASCM). This FY 2010-2011 Final Average System Cost Report (Final ASC Report) describes the process, evaluation, and results of BPA's ASC review.

General information can be found at http://www.bpa.gov/corporate/finance/ascm/index.cfm.

NOTE: BPA previously advised parties that if the filing utility or an intervenor wished to preserve any issue regarding BPA's Final ASC Reports for subsequent administrative or judicial appeal, they must have raised such issue in their comments on BPA's Draft ASC Reports. If a party failed to do so, the issue would be waived for subsequent appeal.

#### 2. AVERAGE SYSTEM COST SUMMARY

#### 2.1. <u>Base Period ASC</u>

The 2008 ASCM requires utilities participating in the ASC Review Process, both IOUs and COUs, to submit to BPA "Base Period" financial and operational information. The Base Period is defined as the calendar year of the most recent FERC Form 1 data for IOUs; and the most recent Annual Reports, including the most recent Cost of Service Analyses (COSA), for COUs. The submitted information includes the "Appendix 1," the Excel based workbook used in calculating the Base Period ASC. For purposes of this report, the Base Period is calendar year (CY) 2007.

The table below summarizes the CY 2007 Base Period ASC based on (1) the ASC information filed by Franklin on October 15, 2008 (including errata, if applicable), and (2) the same information as adjusted by BPA, including response to comments submitted by the utility and/or intervenors during the ASC Review Process. This table does not reflect the Exchange Period ASC, which is noted in subsequent tables.

**Table 2.1: CY 2007 Base Period ASC** (Results of Appendix 1 calculations)

	October 15, 2008 As Filed	July 21, 2009 Final Report
Production Cost	\$44,996,444	\$44,845,428
Transmission Cost	\$ 333,260	\$300,363
(Less) NLSL Costs	\$0	\$0
Contract System Cost (CSC)	\$45,329,704	\$45,145,790
Total Retail Load (MWh)	886,305	886,305
(Less) NLSL	0	0
Total Retail Load (Net of NLSL)	886,305	886,305
Distribution Losses	41,443	41,443
Contract System Load (CSL)	927,748	927,748
CY 2007 Base Period ASC (CSC/CSL)	\$48.86/MWh	\$48.66/MWh

#### 2.2. **ASC New Resource Additions**

In addition to the historical Base Period cost and load data, the exchanging utility may also provide its forecast of major new resource additions, and all associated costs, that are projected to come on-line through the end of the Exchange Period (FY 2010-2011). The forecast covers the period from the end of the Base Period (December 31, 2007) to the end of the Exchange

Period (September 30, 2011). When a major new resource addition is projected to come on-line prior to the start of the Exchange Period, the associated costs are projected forward to the midpoint of the Exchange Period in order to calculate the Exchange Period ASC.

The 2008 ASCM also provides that changes to an established ASC are allowed to occur during the Exchange Period to account for major new resource additions and purchases that are projected to come on-line or be purchased and used to meet a utility's retail load during the Exchange Period (FY 2010-2011).

In either scenario, such changes in ASC must meet the same materiality threshold as a change in ASC resulting from major new resource additions, that is, a 2.5 percent or greater change in Base Period ASC. BPA allows utilities to submit stacks of individual resources that, when combined, meet the materiality threshold. However, each resource in the stack must result in an increase or decrease of Base Period ASC of 0.5 percent or more.

The tables below summarize the new major resource additions projected to come on-line during the forecast period, based on (1) the ASC information filed on October 15, 2008 (including errata, if applicable), and (2) the same information as adjusted by BPA, including response to comments submitted by the utility and/or intervenors during the ASC Review Process. Franklin did not submit information on new resources.

Table 2.2.1: New Resource Additions Coming On-Line Prior to Exchange Period (\$/MWh)

As-Filed FY 2010-2011 Exchange Period ASC		
Resource	N.A.	
Expected On-Line Date		
Delta*		

Final Report FY 2010-2011 Exchange Period ASC			
Resource Pipeline Contract			
Expected On-Line Date	01/01/08		
Delta*	(1.47)		

<sup>\*</sup>The Delta is the incremental change in the ASC as new resources come on line.

Table 2.2.2: New Resource Additions Coming On-Line During the Exchange Period (\$/MWh)

As-Filed FY 2010-2011 Exchange Period ASC		
Resource	N.A.	
Expected On-Line Date		
Delta*		

Final Report FY 2010-2011 Exchange Period ASC			
Resource	N.A.		
Expected On-Line Date			
Delta*			

<sup>\*</sup>The Delta is the incremental change in the ASC as new resources come on line.

#### 2.3. FY 2010-2011 Exchange Period ASC

The following table identifies the Exchange Period ASC as filed on October 15, 2008, including errata if applicable, as adjusted by BPA for this Final ASC Report. The ASC includes major new resource additions projected to come on-line prior to the start of the Exchange Period only. The Exchange Period ASC will adjust as necessary as additional major new resources come online, and as identified in Table 2.2.2 above. The procedures used in making the determinations and any required changes are prescribed by the 2008 ASCM and described in the following sections.

Table 2.3: Exchange Period FY 2010-2011 ASC (\$/MWh)
Prior to New Resource Additions

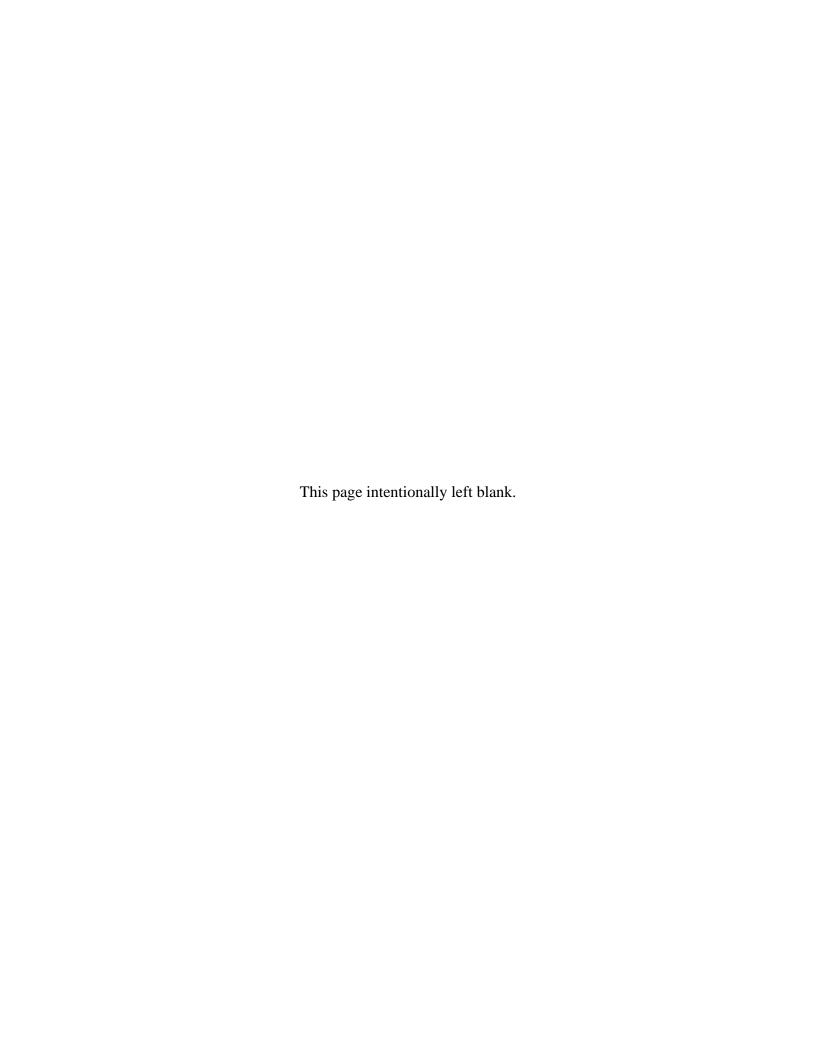
Date	October 15, 2008 As-Filed	July 21, 2009 Final Report	
FY 2010- 2011	46.15	49.28	

# FINAL AVERAGE SYSTEM COST REPORT

# **IDAHO POWER COMPANY**

July 2009





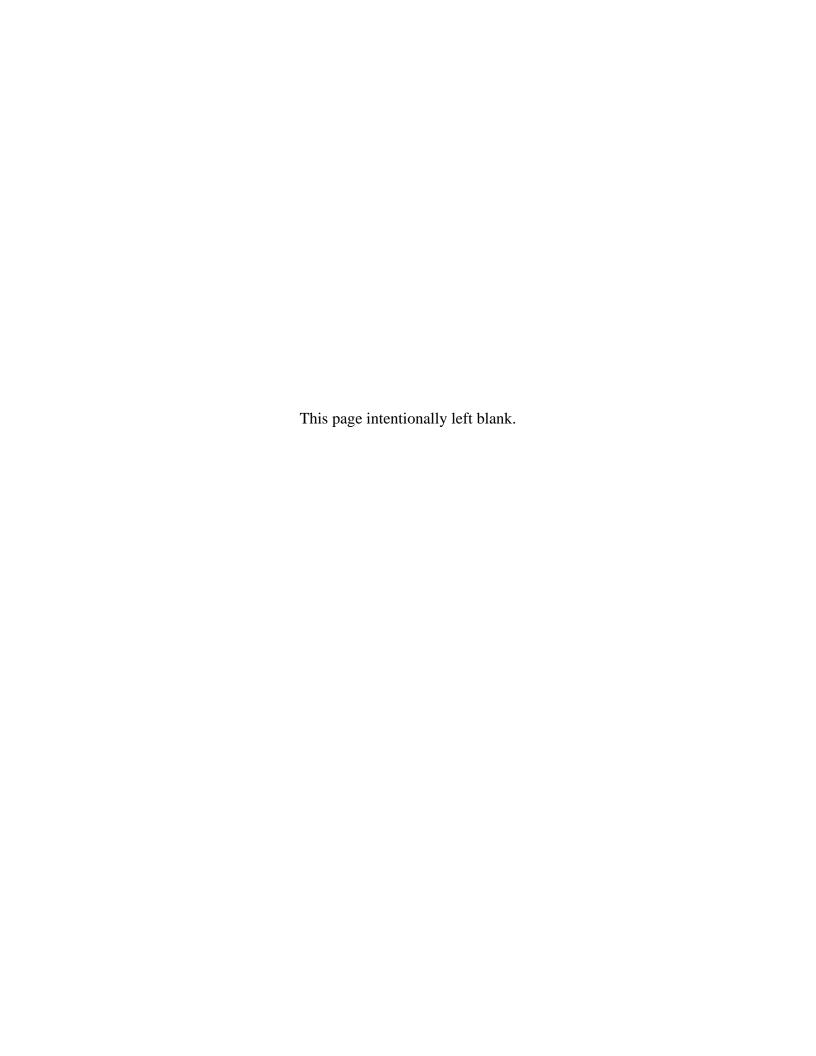
## FINAL AVERAGE SYSTEM COST REPORT

#### **FOR**

## **Idaho Power Company**

Docket Number: ASC-10-IP-01 Effective Date: October 1, 2009

#### PREPARED BY BONNEVILLE POWER ADMINISTRATION U.S. DEPARTMENT OF ENERGY



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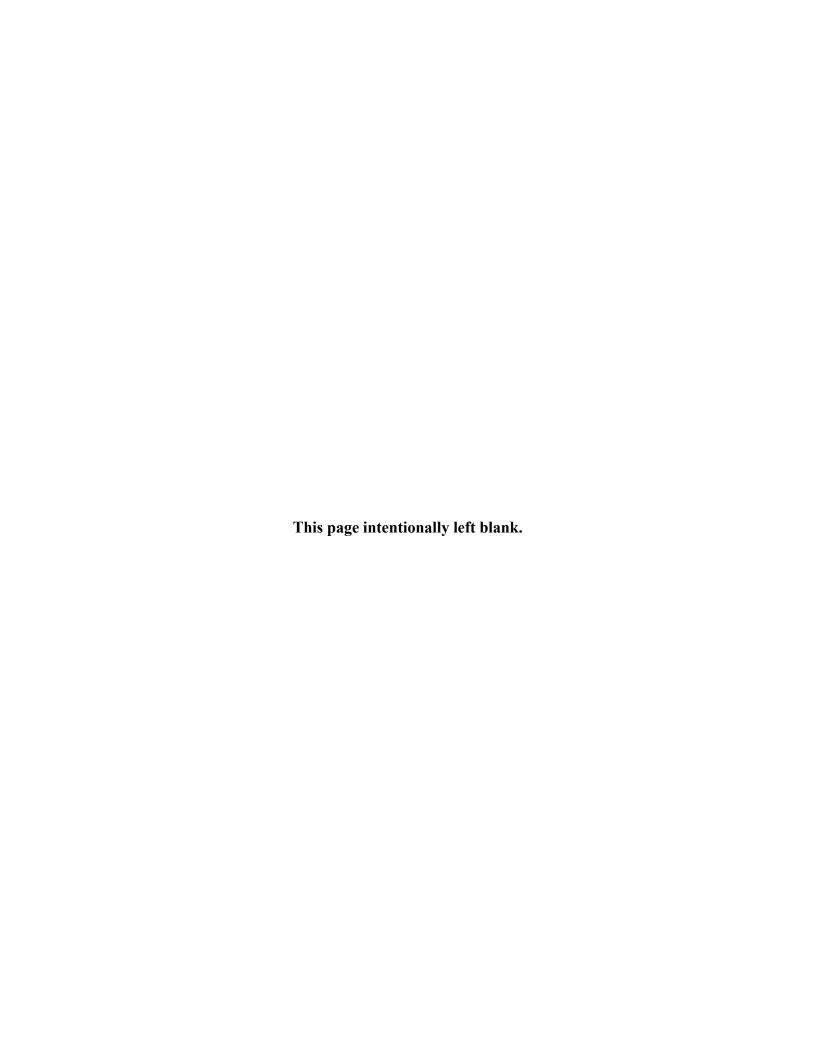
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#### 1. FILING DATA

<u>Utility</u>: **Idaho Power Company (IPC)** 

1221 W. Idaho St. Boise, ID 83702

http://www.idahopower.com/default.cfm

#### Parties to the Filing:

Investor-Owned Utilities (IOUs):

Avista Utilities (Avista)

NorthWestern Energy (NorthWestern or NWE)

PacifiCorp (PAC)

Portland General Electric (PGE)

Puget Sound Energy (PSE)

#### Consumer-Owned Utilities (COUs):

Franklin County PUD (Franklin) Snohomish County PUD (SNOPUD)

Other Participants to the Filing:

Idaho Public Utility Commission

**Public Power Council** 

Public Utility Commission of Oregon (OPUC)

Washington Utilities and Transportation Commission (WUTC)

ASC Base Period: CY 2007

Effective Exchange Period: FY 2010-2011 (October 1, 2009 – September 30, 2011)

#### Statement of Purpose:

Bonneville Power Administration (BPA) has conducted an Average System Cost (ASC) Review Process to determine IPC's ASC for FY 2010-2011 based on BPA's 2008 ASC Methodology (ASCM). This FY 2010-2011 Final Average System Cost Report (Final ASC Report) describes the process, evaluation, and results of BPA's ASC review.

General information can be found at http://www.bpa.gov/corporate/finance/ascm/index.cfm.

NOTE: BPA previously advised parties that if the filing utility or an intervenor wished to preserve any issue regarding BPA's Final ASC Reports for subsequent administrative or judicial appeal, they must have raised such issue in their comments on BPA's Draft ASC Reports. If a party failed to do so, the issue would be waived for subsequent appeal.

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#### 2. AVERAGE SYSTEM COST SUMMARY

#### 2.1. <u>Base Period ASC</u>

The 2008 ASCM requires utilities participating in the ASC Review Process, both IOUs and COUs, to submit to BPA "Base Period" financial and operational information. The Base Period is defined as the calendar year of the most recent FERC Form 1 data for IOUs; and most recent Annual Reports, including the most recent Cost of Service Analysis (COSA), for COUs. The submitted information includes the "Appendix 1," an Excel-based workbook used in calculating the Base Period ASC. For purposes of this report, the Base Period is calendar year (CY) 2007.

The table below summarizes the CY 2007 Base Period ASC based on (1) the ASC information filed by IPC on October 15, 2008 (including errata, if applicable), and (2) the same information as adjusted by BPA, including responses to comments submitted by the utility and/or intervenors during the ASC Review Process. This table does not reflect the Exchange Period ASC, which is noted in subsequent tables.

**Table 2.1: CY 2007 Base Period ASC** (Results of Appendix 1 calculations)

	October 15, 2008	July 21, 2009
	As Filed	Final Report
Production Cost	\$ 461,275,498	\$ 461,434,297
Transmission Cost	\$ 104,444,121	\$ 95,664,101
(Less) NLSL Costs	(\$ 20,611,958)	(\$ 25,276,624)
Contract System Cost (CSC)	\$ 545,107,660	\$ 531,821,775
Total Retail Load (MWh)	14,541,825	14,541,825
(Less) NLSL	(385,400)	(385,400)
Total Retail Load (Net of NLSL)	14,156,425	14,156,425
Distribution Losses	1,003,386	1,003,386
Contract System Load (CSL)	15,159,811	15,159,811
CY 2007 Base Period ASC		
(CSC/CSL)	\$ 35.96/MWh	\$ 35.08/MWh

#### 2.2. **ASC New Resource Additions**

In addition to the historical Base Period cost and load data, the exchanging utility may also provide its forecast of major new resource additions, and all associated costs, that are projected to come on-line through the end of the Exchange Period (FY 2010-2011). The forecast covers the period from the end of the Base Period (December 31, 2007) to the end of the Exchange Period (September 30, 2011). When a major new resource addition is projected to come on-line prior to the start of the Exchange Period, the associated costs are projected forward to the midpoint of the Exchange Period in order to calculate the Exchange Period ASC.

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The 2008 ASCM also provides that changes to an established ASC are allowed to occur during the Exchange Period to account for major new resource additions and purchases that are projected to come on-line or be purchased and used to meet a utility's retail load during the Exchange Period (FY 2010-2011).

In either scenario, such changes in ASC must meet the same materiality threshold as a change in ASC resulting from major new resource additions, that is, a 2.5 percent or greater change in Base Period ASC. BPA allows utilities to submit stacks of individual resources that, when combined, meet the materiality threshold. However, each resource in the stack must result in an increase of Base Period ASC of 0.5 percent or more.

The tables below summarize the new major resource additions projected to come on-line during the forecast period, based on (1) the ASC information filed on October 15, 2008 (including errata, if applicable), and (2) the same information as adjusted by BPA, including responses to comments submitted by the utility and/or intervenors during the ASC Review Process.

Table 2.2.1: New Resource Additions Coming On-Line Prior to Exchange Period (\$/MWh)

As-Filed FY 2010-2011 Exchange Period ASC				
Resource	Danskin	N/A	N/A	N/A
Expected On-Line Date	March 2008			
Delta*	0.71			

Final Report FY 2010-2011 Exchange Period ASC							
Resource Danskin N/A N/A N/A							
Expected On-Line Date	March 2008						
Delta*	1						

<sup>\*</sup>The Delta is the incremental change in the ASC as new resources come on line. Danskin did not meet the materiality threshold. *See* Section 5.6 for additional details.

Table 2.2.2: New Resource Additions Coming On-Line During the Exchange Period (\$/MWh)

As-Filed FY 2010-2011 Exchange Period ASC						
Resource N/A N/A N/A N/A						
Expected On-Line Date						
Delta*						

Final Report FY 2010-2011 Exchange Period ASC						
Resource N/A N/A N/A N/A						
Expected On-Line Date						
Delta*						

<sup>\*</sup>The Delta is the incremental change in the ASC as new resources come on line.

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## 2.3. FY 2010-2011 Exchange Period ASC

The following table identifies the Exchange Period ASC as filed on October 15, 2008, including errata if applicable, as adjusted by BPA for this Final ASC Report. The ASC includes major new resource additions projected to come on-line prior to the start of the Exchange Period only. The Exchange Period ASC will adjust as necessary as additional major new resources come online, and as identified in Table 2.2.2 above. The procedures used in making the determinations and any required changes are prescribed by the 2008 ASCM and described in the following sections.

Table 2.3: Exchange Period FY 2010-2011 ASC (\$/MWh)
Prior to New Resource Additions

Date	October 15, 2008 As-Filed	July 21, 2009 Final Report
FY 2010-2011	39.19	35.65

#### 3. FILING REQUIREMENTS

## 3.1. <u>Introduction</u>

Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. § 839c(c), established the Residential Exchange Program (REP). Any Pacific Northwest utility interested in participating in the REP may offer to sell power to BPA at the average system cost (ASC) of the utility's resources. In exchange, BPA offers to sell an "equivalent amount of electric power to such utility for resale to that utility's residential users within the region" at the BPA rate established pursuant to section 7(b)(l) of the Act. H.R. Rep. No. 976, Pt. I, 96th Cong., 2d Sess. 60 (1980). The cost benefits established by the REP are passed through directly to the exchanging utilities' residential and small farm consumers. 16 U.S.C. § 839c(c)(3).

The Northwest Power Act gives BPA's Administrator the authority to determine ASC on the basis of a methodology established in a public consultation proceeding. 16 U.S.C. § 839c(c)(7). The only express statutory limits on the Administrator's authority are found in sections 5(c)(7)(A), (B) and (C) of the Act. 16 U.S.C. §§ 839c(c)(7)(A), (B) and (C).

BPA's first ASC Methodology was developed in consultation with regional interests in 1981. *See* 48 Fed. Reg. 46,970 (Oct. 17, 1983). It was later revised in 1984. *See* 49 Fed. Reg. 39,293 (Oct. 5, 1984). In the late 1980s and mid-1990s, BPA and exchanging utilities executed a number of termination agreements that provided for payments to each utility through the remaining years of the Residential Purchase and Sale Agreements (RPSA) that implemented the REP. These termination agreements did not require the participating utilities to submit ASC filings. Subsequent REP Settlement Agreements with BPA's investor-owned utility customers

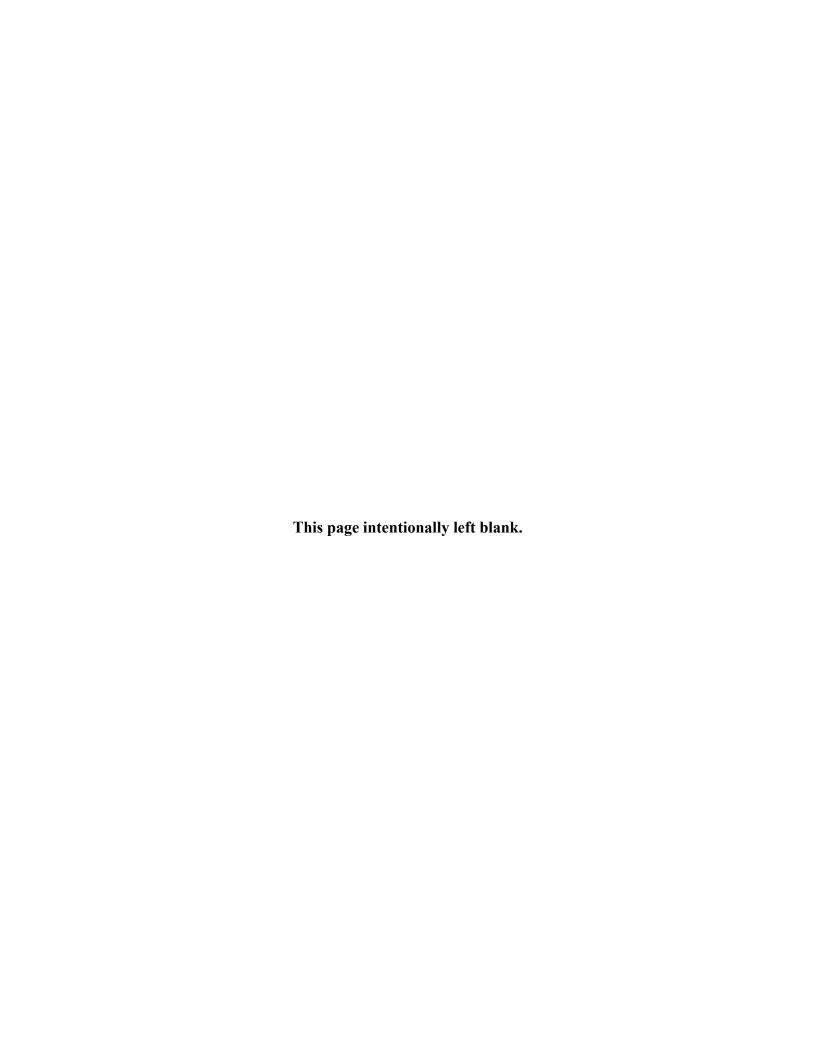
## FY 2010-2011

# FINAL AVERAGE SYSTEM COST REPORT

# NORTHWESTERN ENERGY

July 2009





## FY 2010 - FY 2011

## FINAL AVERAGE SYSTEM COST REPORT

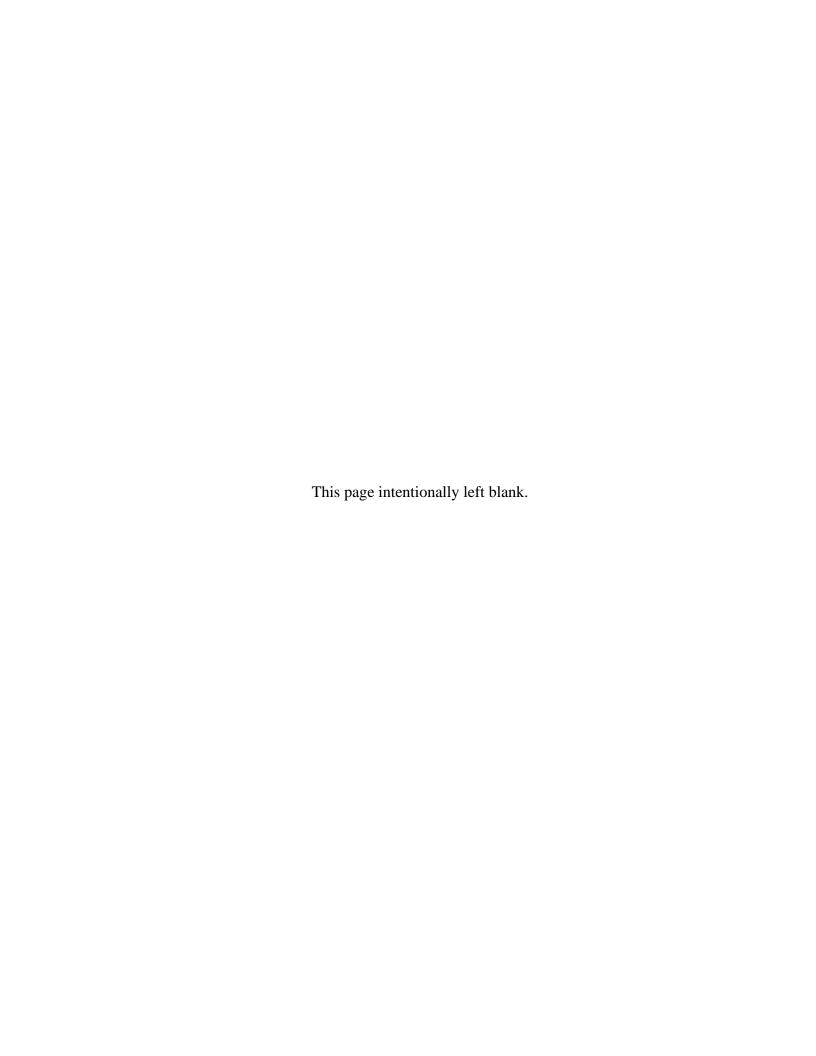
**FOR** 

## **NorthWestern Energy**

Docket Number: ASC-10-NW-01 Effective Date: October 1, 2009

## PREPARED BY BONNEVILLE POWER ADMINISTRATION U.S. DEPARTMENT OF ENERGY

July 21, 2009



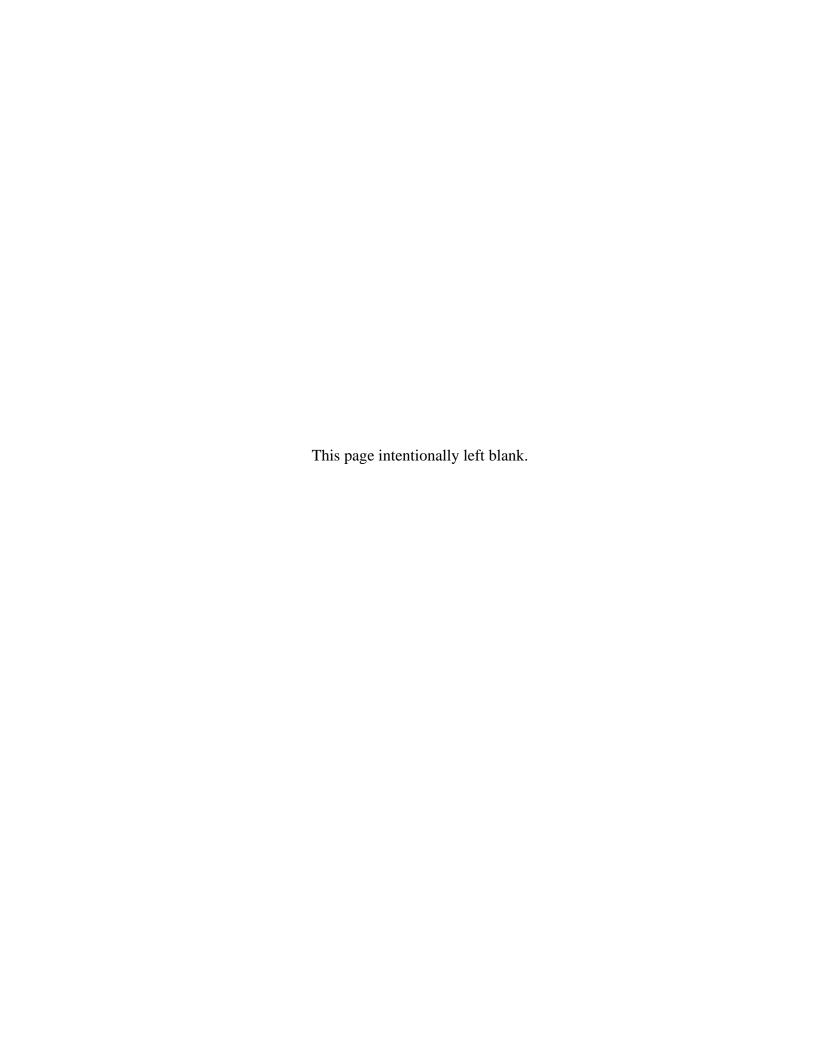
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#### 1. FILING DATA

<u>Utility</u>: **NorthWestern Energy** 

40 E. Broadway Butte, MT 59701

www.NorthWesternEnergy.com

#### Parties to the Filing:

Investor Owned Utilities (IOUs):

Avista Utilities (Avista) Idaho Power Company (IPC) Portland General Electric (PGE) PacifiCorp (PAC) Puget Sound Energy (PSE)

Consumer Owned Utilities (COUs):

Franklin County PUD (Franklin) Snohomish County PUD (SNOPUD)

Other Participants to the Filing:

Idaho Public Utility Commission
Public Power Council
Public Utility Commission of Oregon (OPUC)
Washington Utilities and Transportation Commission (WUTC)

ASC Base Period: CY 2007

Effective Exchange Period: FY 2010-2011 (October 1, 2009 – September 30, 2011)

#### Statement of Purpose:

Bonneville Power Administration (BPA) has conducted an Average System Cost (ASC) Review Process to determine NorthWestern Energy's ASC for FY 2010-2011 based on BPA's 2008 ASC Methodology (ASCM). This FY 2010-2011 Final Average System Cost Report (Final ASC Report) describes the process, evaluation, and results of BPA's ASC review.

General information can be found at <a href="http://www.bpa.gov/corporate/finance/ascm/index.cfm">http://www.bpa.gov/corporate/finance/ascm/index.cfm</a>.

NOTE: BPA previously advised parties that if the filing utility or an intervenor wished to preserve any issue regarding BPA's Final ASC Reports for subsequent administrative or judicial appeal, they must have raised such issue in their comments on BPA's Draft ASC Reports. If a party failed to do so, the issue would be waived for subsequent appeal.

#### 2. AVERAGE SYSTEM COST SUMMARY

## 2.1. <u>Base Period ASC</u>

The 2008 ASCM requires utilities participating in the ASC Review Process, both IOUs and COUs, to submit to BPA "Base Period" financial and operational information. The Base Period is defined as the calendar year of the most recent FERC Form 1 data for IOUs; and the most recent Annual Reports, including the most recent Cost of Service Analyses (COSA), for COUs. The submitted information includes the "Appendix 1," the Excel based workbook used in calculating the Base Period ASC. For purposes of this report, the Base Period is calendar year (CY) 2007.

The table below summarizes the CY 2007 Base Period ASC based on (1) the ASC information filed by NWE on October 15, 2008 (including errata, if applicable), and (2) the same information as adjusted by BPA, including response to comments submitted by the utility and/or intervenors during the ASC Review Process. This table does not reflect the Exchange Period ASC, which is noted in subsequent tables.

**Table 2.1: CY 2007 Base Period ASC** (Results of Appendix 1 calculations)

	October 15, 2008	<b>July 21, 2009</b>
	As Filed	Final Report
Production Cost	\$337,095,343	\$342,080,537
Transmission Cost	\$31,980,992	\$30,083,720
(Less) NLSL Costs	\$0	\$0
Contract System Cost (CSC)	\$369,076,335	\$372,164,257
Total Retail Load (MWh)	5,863,531	5,863,531
(Less) NLSL	0	0
Total Retail Load (Net of NLSL)	5,863,531	5,863,531
Distribution Losses	257,995	257,995
Contract System Load (CSL)	6,121,526	6,121,526
CY 2007 Base Period ASC (CSC/CSL)	\$60.29/MWh	\$60.80/MWh

### 2.2. ASC New Resource Additions

In addition to the historical Base Period cost and load data, the exchanging utility may also provide its forecast of major new resource additions, and all associated costs, that are projected to come on-line through the end of the Exchange Period (FY 2010-2011). The forecast covers the period from the end of the Base Period (December, 31, 2007) to the end of the Exchange Period (September, 30, 2011). When a major new resource addition is projected to come on-line

prior to the start of the Exchange Period, the associated costs are projected forward to the midpoint of the Exchange Period in order to calculate the Exchange Period ASC.

The 2008 ASCM also provides that changes to an established ASC are allowed to occur during the Exchange Period to account for major new resource additions and purchases that are projected to come on-line or be purchased and used to meet a utility's retail load during the Exchange Period (FY 2010-2011).

In either scenario, such changes in ASC must meet the same materiality threshold as a change in ASC resulting from major new resource additions, that is, a 2.5 percent or greater change in Base Period ASC. BPA allows utilities to submit stacks of individual resources that, when combined, meet the materiality threshold. However, each resource in the stack must result in an increase or decrease of Base Period ASC of 0.5 percent or more.

The tables below summarize the new major resource additions projected to come on-line during the forecast period, based on (1) the ASC information filed on October 15, 2008 (including errata, if applicable), and (2) the same information as adjusted by BPA, including in response to comments submitted by the utility and/or intervenors during the ASC Review Process. NWE did not submit information on new resources.

Table 2.2.1: New Resource Additions Coming On-Line Prior to Exchange Period (\$/MWh)

As-Filed FY 2010-2011 Exchange Period ASC		
Resource	NA.	
Expected On-Line Date		
Delta*		

Final Report FY 2010-2011 Exchange Period ASC		
Resource NA.		
Expected On-Line Date		
Delta*		

<sup>\*</sup>The Delta is the incremental change in the ASC as new resources come on line.

Table 2.2.2: New Resource Additions Coming On-Line During the Exchange Period (\$/MWh)

As-Filed FY 2010-2011 Exchange Period ASC		
Resource	NA.	
Expected On-Line Date		
Delta*		

Final Report FY 2010-2011 Exchange Period ASC				
Resource	NA.			
Expected On-Line Date				
Delta*				

\*The Delta is the incremental change in the ASC as new resources come on line.

#### 2.3. FY 2010-2011 Exchange Period ASC

The following table identifies the Exchange Period ASC as filed on October 15, 2008, including errata if applicable, and adjusted by BPA for this Final ASC Report. The ASC includes major new resource additions projected to come on-line prior to the start of the Exchange Period only. The Exchange Period ASC will adjust as necessary as additional major new resources come online, and as identified in Table 2.2.2 above. The procedures used in making the determinations and any required changes are prescribed by the 2008 ASCM and described in the following sections.

Table 2.3: Exchange Period FY 2010-2011 ASC (\$/MWh)
Prior to the New Resource Additions

Date	October 15, 2008 As-Filed	July 21, 2009 Final Report
FY 2010- 2011	55.30	57.57

#### 3. FILING REQUIREMENTS

### 3.1. <u>Introduction</u>

Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. § 839c(c), established the Residential Exchange Program (REP). Any Pacific Northwest utility interested in participating in the REP may offer to sell power to BPA at the average system cost ASC of the utility's resources. In exchange, BPA offers to sell an "equivalent amount of electric power to such utility for resale to that utility's residential users within the region" at the BPA rate established pursuant to section 7(b)(l) of the Act. H.R. Rep. No. 976, Pt. I, 96th Cong., 2d Sess. 60 (1980). The cost benefits established by the REP are passed through directly to the exchanging utilities' residential and small farm consumers. 16 U.S.C. § 839c(c)(3).

The Northwest Power Act gives BPA's Administrator the authority to determine ASC on the basis of a methodology established in a public consultation proceeding. 16 U.S.C. § 839c(c)(7). The only express statutory limits on the Administrator's authority are found in sections 5(c)(7)(A), (B) and (C) of the Act. 16 U.S.C. § 839c(c)(7)(A), (B) and (C).

BPA's first ASC Methodology was developed in consultation with regional interests in 1981. *See* 48 Fed. Reg. 46,970 (Oct. 17, 1983). It was later revised in 1984. *See* 49 Fed. Reg. 39,293 (Oct. 5, 1984). In the late 1980s and mid-1990s, BPA and exchanging utilities executed a number of termination agreements that provided for payments to each utility through the

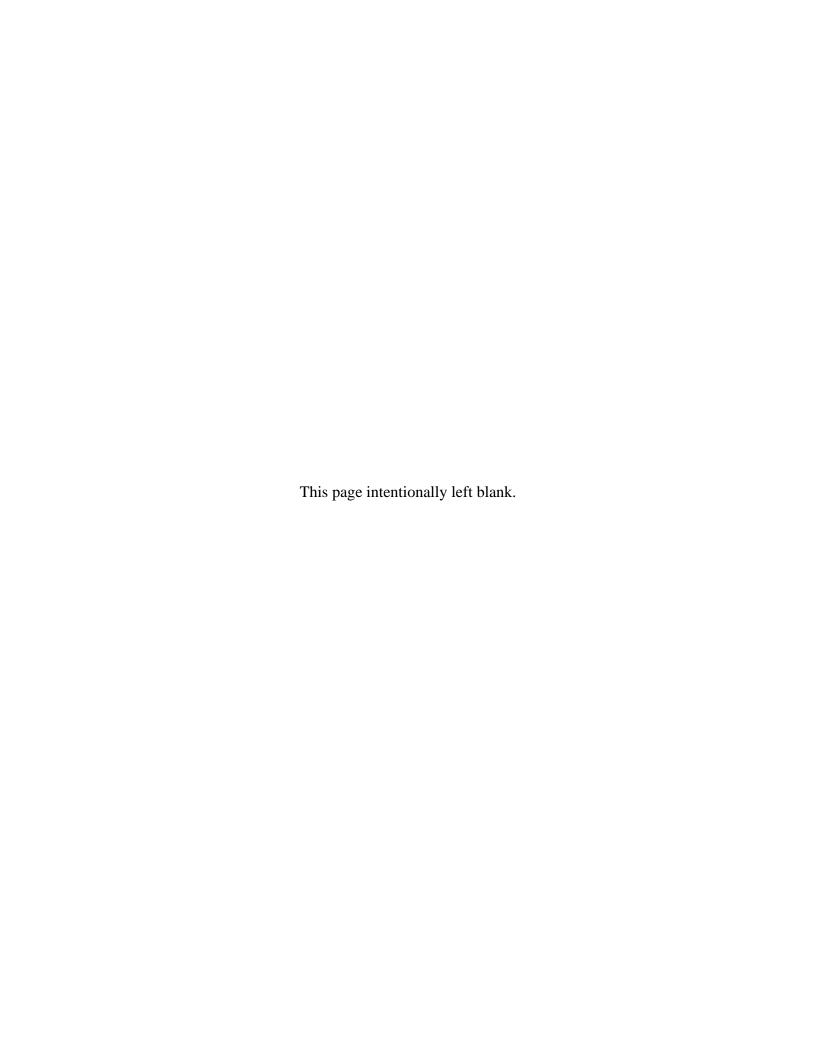
# FY 2010-2011

# FINAL AVERAGE SYSTEM COST REPORT

# **PACIFICORP**

July 2009





## FY 2010 - FY 2011

## FINAL AVERAGE SYSTEM COST REPORT

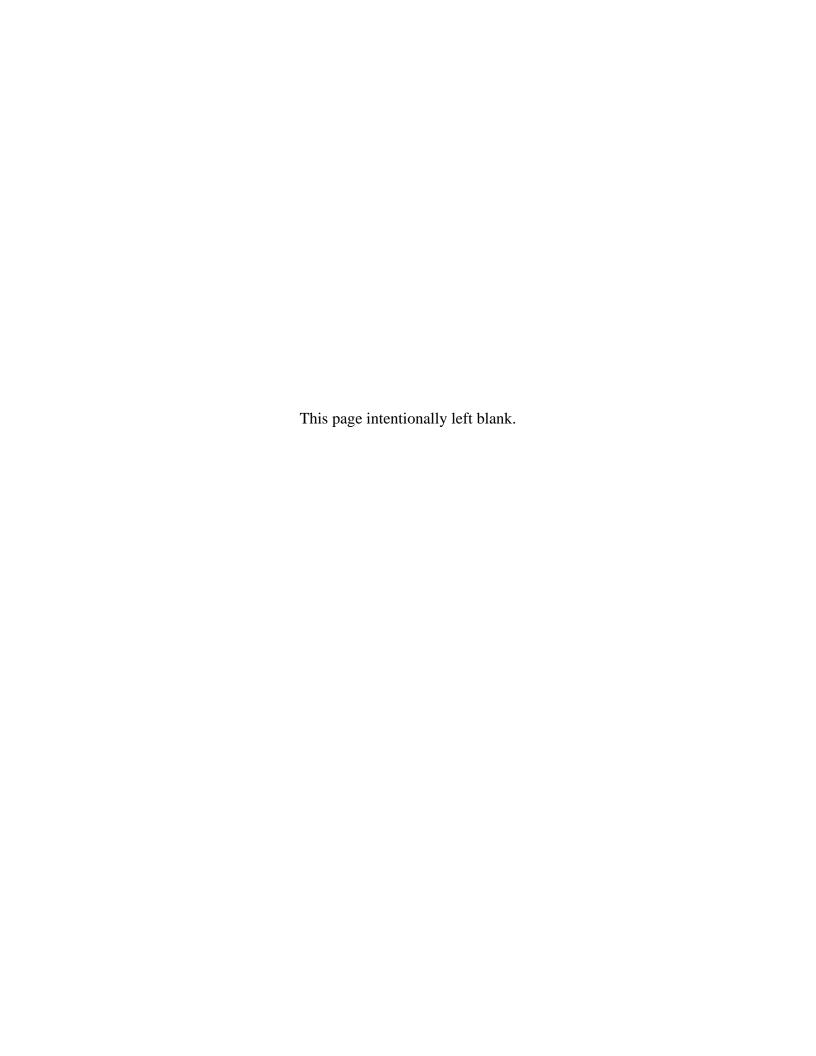
### **FOR**

## **PacifiCorp**

Docket Number: ASC-10-PA-01 Effective Date: October 1, 2009

PREPARED BY BONNEVILLE POWER ADMINISTRATION U.S. DEPARTMENT OF ENERGY

July 21, 2009



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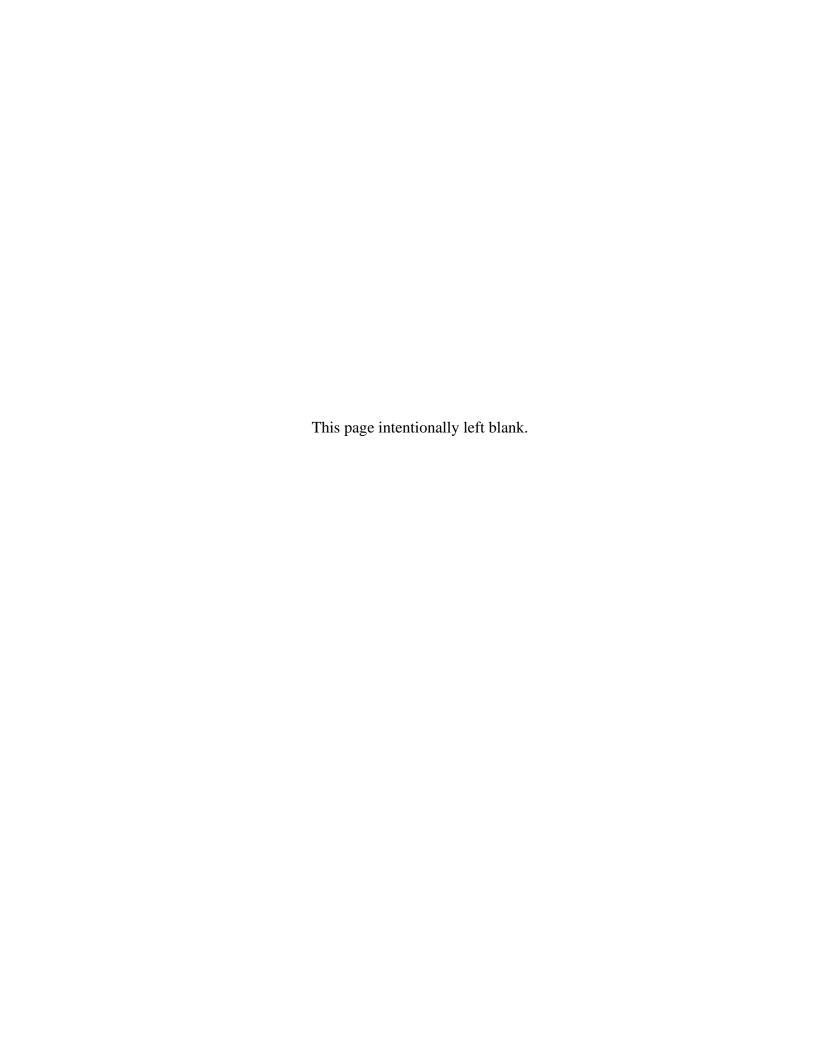
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#### 1. FILING DATA

<u>Utility</u>: **PacifiCorp** 

825 NE Multnomah Portland, OR 97232

http://www.pacificorp.com

## Parties to the Filing:

Investor-Owned Utilities (IOUs):

Avista Utilities (Avista) Idaho Power Company (IPC)

NorthWestern Energy (NorthWestern or NWE)

Portland General Electric (PGE) Puget Sound Energy (PSE)

Consumer-Owned Utilities (COUs):

Franklin County PUD (Franklin) Snohomish County PUD (SNOPUD)

Other Participants to the Filing:

Idaho Public Utility Commission

**Public Power Council** 

Public Utility Commission of Oregon (OPUC)

Washington Utilities and Transportation Commission (WUTC)

ASC Base Period: CY 2007

Effective Exchange Period: FY 2010-2011 (October 1, 2009 – September 30, 2011)

#### **Statement of Purpose:**

Bonneville Power Administration (BPA) has conducted an Average System Cost (ASC) Review Process to determine PAC's ASC for FY 2010-2011 based on BPA's 2008 ASC Methodology (ASCM). This Final FY 2010-2011 Average System Cost Report (Final ASC Report) describes the process, evaluation, and results of BPA's ASC review.

General Information can be found at http://www.bpa.gov/corporate/finance/ascm/index.cfm.

NOTE: BPA previously advised parties that if the filing utility or an intervenor wished to preserve any issue regarding BPA's Final ASC Reports for subsequent administrative or judicial appeal, they must have raised such issue in their comments on BPA's Draft ASC Reports. If a party failed to do so, the issue would be waived for subsequent appeal.

#### 2. AVERAGE SYSTEM COST SUMMARY

## 2.1. <u>Base Period ASC</u>

The 2008 ASCM requires utilities participating in the ASC Review Process, both IOUs and COUs, to submit to BPA "Base Period" financial and operational information. The Base Period is defined as the calendar year of the most recent FERC Form 1 data for IOUs, and the most recent Annual Reports, including the most recent Cost of Service Analysis (COSA) for COUs. The submitted information includes the "Appendix 1," the Excel-based workbook used in calculating the Base Period ASC. For purposes of this report, the Base Period is calendar year (CY) 2007.

The table below summarizes the CY 2007 Base Period ASC based on (1) the ASC information filed by PAC on October 15, 2008 (including errata, if applicable), and (2) the same information as adjusted by BPA, including response to comments submitted by the utility and/or intervenors during the ASC Review Process. This table does not reflect the Exchange Period ASC, which is noted in subsequent tables.

**Table 2.1: CY 2007 Base Period ASC** (Results of Appendix 1 calculations)

	October 15, 2008 As Filed	July 21, 2009 Final Report
Production Cost	\$946,472,681	\$946,500,846
Transmission Cost	\$177,422,214	\$174,532,323
(Less) NLSL Costs	\$0	\$0
Contract System Cost (CSC)	\$1,123,894,895	\$1,121,033,170
Total Retail Load (MWh) (Less) NLSL Total Retail Load (Net of NLSL) Distribution Losses	21,476,886 0 21,476,886 575,581	21,476,886 0 21,476,886 575,581
Contract System Load (CSL)	22,052,467	22,052,467
CY 2007 Base Period ASC (CSC/CSL)	\$50.96/MWh	\$50.83/MWh

### 2.2. ASC New Resource Additions

In addition to the historical Base Period cost and load data, the exchanging utility may also provide its forecast of major new resource additions, and all associated costs, that are projected to come on-line through the end of the Exchange Period (FY 2010-2011). The forecast covers the period from the end of the Base Period (December 31, 2007) to the end of the Exchange

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Period (September 30, 2011). When a major new resource addition is projected to come on-line prior to the start of the Exchange Period, the associated costs are projected forward to the midpoint of the Exchange Period in order to calculate the Exchange Period ASC.

The 2008 ASCM also provides that changes to an established ASC are allowed to occur during the Exchange Period to account for major new resource additions and purchases that are projected to come on-line or be purchased and used to meet a utility's retail load during the Exchange Period (FY 2010-2011).

In either scenario, such changes in ASC must meet the same materiality threshold as a change in ASC resulting from major new resource additions, that is, a 2.5 percent or greater change in Base Period ASC. BPA allows utilities to submit stacks of individual resources that, when combined, meet the materiality threshold. However, each resource in the stack must result in an increase or decrease of Base Period ASC of 0.5 percent or more.

The tables below summarize the new major resource additions projected to come on-line during the forecast period, based on (1) the ASC information filed on October 15, 2008 (including errata, if applicable), and (2) the same information as adjusted by BPA, including response to comments submitted by the utility and/or intervenors during the ASC Review Process.

Table 2.2.1: New Resource Additions Coming On-Line Prior to Exchange Period (\$/MWh)

As-Filed FY 2010-2011 Exchange Period ASC					
Resource Group 1 Chehalis (525 MW) Group 3 Group 4					
Expected On-Line Date	08/01/08	10/01/08	04/01/09	04/01/09	
Delta*	0.46	-3.10	0.67	0.38	

Final Report FY 2010-2011 Exchange Period ASC					
Resource Group A					
Expected On-Line Date	10/01/08				
Delta*	2.40				

<sup>\*</sup>The Delta is the incremental change in the ASC as new resources come on line. *See* Section 5.5.1 of this report regarding regrouping.

Table 2.2.2: New Resource Additions Coming On-Line During the Exchange Period (\$/MWh)

As-Filed FY 2010-2011 Exchange Period ASC					
Resource N/A N/A N/A N/A					
Expected On-Line Date					
Delta*					

Final Report FY 2010-2011 Exchange Period ASC					
Resource Group B N/A N/A N/A					
Expected On-Line Date	10/01/10				
Delta*	1.80				

<sup>\*</sup>The Delta is the incremental change in the ASC as new resources come on line. *See* Section 5.5.1 of this report regarding regrouping.

## 2.3. FY 2010-2011 Exchange Period ASC

The following table identifies the Exchange Period ASC as filed on October 15, 2008, including errata if applicable, as adjusted by BPA for this Final ASC Report. The ASC includes major new resource additions projected to come on-line prior to the start of the Exchange Period only. The Exchange Period ASC will adjust as necessary as additional major new resources come online, and as identified in Table 2.2.2 above. The procedures used in making the determinations and any required changes are prescribed by the 2008 ASCM and described in the following sections.

Table 2.3: Exchange Period FY 2010-2011 ASC (\$/MWh)
Prior to the New Resource Additions

Date	October 15, 2008 As-Filed	July 21, 2009 Final Report
FY 2010 - 2011	51.40	54.80

## 3. FILING REQUIREMENTS

#### 3.1. Introduction

Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. § 839c(c), established the Residential Exchange Program (REP). Any Pacific Northwest utility interested in participating in the REP may offer to sell power to BPA at

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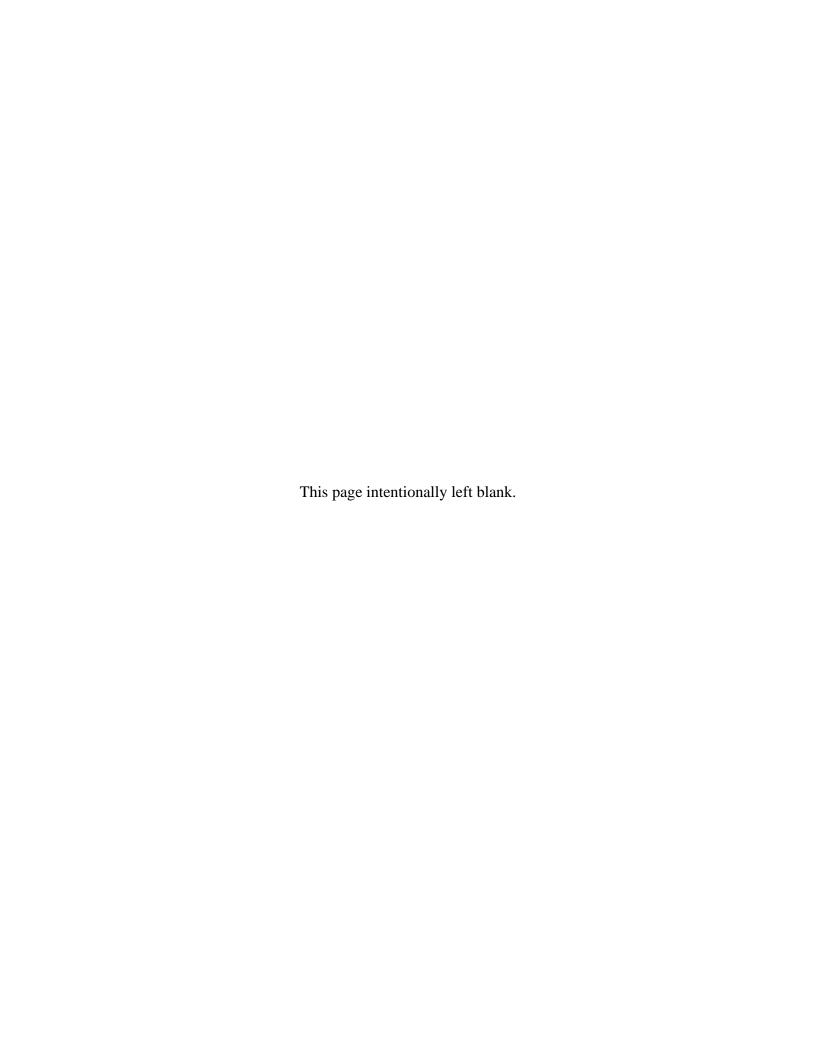
## FY 2010-2011

# FINAL AVERAGE SYSTEM COST REPORT

## PORTLAND GENERAL ELECTRIC

July 2009





## FY 2010 - 2011

## FINAL AVERAGE SYSTEM COST REPORT

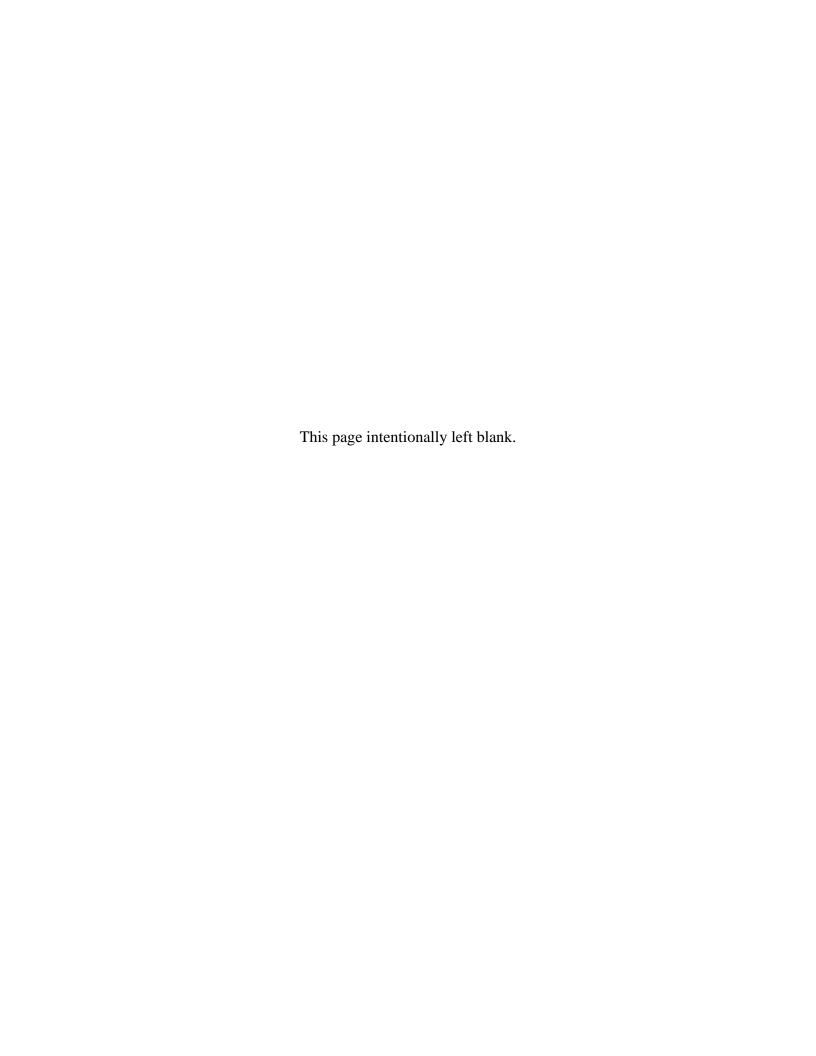
**FOR** 

## **Portland General Electric**

Docket Number: ASC-10-PG-01 Effective Date: October 1, 2009

PREPARED BY BONNEVILLE POWER ADMINISTRATION U.S. DEPARTMENT OF ENERGY

July 21, 2009



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#### 1. FILING DATA

**<u>Utility</u>**: **Portland General Electric (PGE)** 

121 SW Salmon Street Portland, Oregon 97201

http://www.portlandgeneral.com/

## Parties to the Filing:

Investor-Owned Utilities (IOUs):

Avista Utilities (Avista) Idaho Power Company (IPC)

NorthWestern Energy (NorthWestern or NWE)

PacifiCorp (PAC)

Puget Sound Energy (PSE)

# Consumer-Owned Utilities (COUs):

Franklin County PUD (Franklin) Snohomish County PUD (SNOPUD)

Other Participants to the Filing:

Idaho Public Utility Commission

**Public Power Council** 

Public Utility Commission of Oregon (OPUC)

Washington Utilities and Transportation Commission (WUTC)

ASC Base Period: CY 2007

Effective Exchange Period: FY 2010-2011 (October 1, 2009 – September 30, 2011)

### Statement of Purpose:

Bonneville Power Administration (BPA) has conducted an Average System Cost (ASC) Review Process to determine PGE's ASC for FY 2010-2011 based on BPA's 2008 ASC Methodology (ASCM). This FY 2010-2011 Final Average System Cost Report (Final ASC Report) describes the process, evaluation, and results of BPA's ASC review.

General information can be found at <a href="http://www.bpa.gov/corporate/finance/ascm/index.cfm">http://www.bpa.gov/corporate/finance/ascm/index.cfm</a>.

NOTE: BPA previously advised parties that if the filing utility or an intervenor wished to preserve any issue regarding BPA's Final ASC Reports for subsequent administrative or judicial appeal, they must have raised such issue in their comments on BPA's Draft ASC Reports. If a party failed to do so, the issue would be waived for subsequent appeal.

#### 2. AVERAGE SYSTEM COST SUMMARY

# 2.1. <u>Base Period ASC</u>

The 2008 ASCM requires utilities participating in the ASC Review Process, both IOUs and COUs, to submit to BPA "Base Period" financial and operational information. The Base Period is defined as the calendar year of the most recent FERC Form 1 data for IOUs; and most recent Annual Reports, including the most recent Cost of Service Analyses (COSA), for COUs. The submitted information includes the "Appendix 1," the Excel based workbook used in calculating the Base Period ASC. For purposes of this report, the Base Period is calendar year (CY) 2007.

The table below summarizes PGE's CY 2007 Base Period ASC based on (1) the ASC information filed by PGE on October 15, 2008 (including errata, if applicable), and (2) the same information as adjusted by BPA, including response to comments submitted by the utility and/or intervenors during the ASC Review Process. This table does not reflect the Exchange Period ASC, which is noted in subsequent tables.

**Table 2.1: CY 2007 Base Period ASC** (Results of Appendix 1 calculations)

	October 15, 2008 As Filed	July 21, 2009 Final Report
Production Cost	\$905,934,811	\$951,698,149
Transmission Cost	\$116,700,294	\$111,726,269
(Less) NLSL Costs	(\$1,725,798)	\$0
Contract System Cost (CSC)	\$1,020,909,307	\$1,063,424,418
Total Retail Load (MWh)	17,461,742	17,461,742
(Less) NLSL	(31,637)	0
Total Retail Load (Net of NLSL)	17,430,105	17,461,742
Distribution Losses	942,875	942,875
Contract System Load (CSL)	18,372,980	18,404,617
CY 2007 Base Period ASC		
(CSC/CSL)	\$55.57/MWh	\$57.78/MWh

Note: PGE's NLSL adjustment would have increased PGE's ASC, which is not permitted by the ASCM. See 2008 ASCM ROD at 93.

# 2.2. **ASC New Resource Additions**

In addition to the historical Base Period cost and load data, the exchanging utility may also provide its forecast of major new resource additions, and all associated costs, that are projected to come on-line through the end of the Exchange Period (FY 2010-2011). The forecast covers

the period from the end of the Base Period (December 31, 2007) to the end of the Exchange Period (September 30, 2011). When a major new resource addition is projected to come on-line prior to the start of the Exchange Period, the associated costs are projected forward to the midpoint of the Exchange Period in order to calculate the Exchange Period ASC.

The 2008 ASCM also provides that changes to an established ASC are allowed to occur during the Exchange Period to account for major new resource additions and purchases that are projected to come on-line or be purchased and used to meet a utility's retail load during the Exchange Period (FY 2010-2011).

In either scenario, such changes in ASC must meet the same materiality threshold as a change in ASC resulting from major new resource additions, that is, a 2.5 percent or greater change in Base Period ASC. BPA allows utilities to submit stacks of individual resources that, when combined, meet the materiality threshold. However, each resource in the stack must result in an increase or decrease of Base Period ASC of 0.5 percent or more.

The tables below summarize the new major resource additions projected to come on-line during the forecast period, based on (1) the ASC information filed on October 15, 2008 (including errata, if applicable), and (2) the same information as adjusted by BPA, including response to comments submitted by the utility and/or intervenors during the ASC Review Process.

PGE submitted information on new resources with its October 15, 2008, ASC filing. The Biglow Canyon III wind project is scheduled to come on-line in October of 2010. No other new resource information was submitted that showed any resources coming on-line during the Exchange Period.

Table 2.2.1: New Resource Additions Coming On-Line Prior to Exchange Period (\$/MWh)

As-Filed FY 2010-2011 Exchange Period ASC			
Resource Group 1			
Expected On-Line Date	September 2009		
Delta*	1.75		

Final Report FY 2010-2011 Exchange Period ASC			
Resource Group 1			
Expected On-Line Date	September 2009		
Delta*	2.78		

<sup>\*</sup>The Delta is the incremental change in the ASC as new resources come on line. See Section 6.2 for details.

Table 2.2.2: New Resource Additions Coming On-Line During the Exchange Period (\$/MWh)

As-Filed FY 2010-2011 Exchange Period ASC			
Resource Biglow Canyon III			
Expected On-Line Date	October 2010		
Delta*	1.86		

Final Report FY 2010-2011 Exchange Period ASC			
Resource Biglow Canyon III			
Expected On-Line Date	October 2010		
Delta* 2.64			

<sup>\*</sup>The Delta is the incremental change in the ASC as new resources come on line. See Section 6.2 for details.

# 2.3. FY 2010-2011 Exchange Period ASC

The following table identifies the Exchange Period ASC as filed on October 15, 2008, including errata if applicable, as adjusted by BPA for this Final ASC Report. The ASC includes major new resource additions projected to come on-line prior to the start of the Exchange Period only. The Exchange Period ASC will adjust as necessary as additional major new resources come online, and as identified in Table 2.2.2 above. The procedures used in making the determinations and any required changes are prescribed by the 2008 ASCM and described in the following sections.

Table 2.3: Exchange Period FY 2010-2011 ASC (\$/MWh)
Prior to New Resource Additions

Date	October 15, 2008 As-Filed	July 21, 2009 Final Report
FY 2010- 2011	59.51	55.57

### 3. FILING REQUIREMENTS

# 3.1. <u>Introduction</u>

Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. § 839c(c), established the Residential Exchange Program (REP). Any Pacific Northwest utility interested in participating in the REP may offer to sell power to BPA at the average system cost ASC of the utility's resources. In exchange, BPA offers to sell an "equivalent amount of electric power to such utility for resale to that utility's residential users

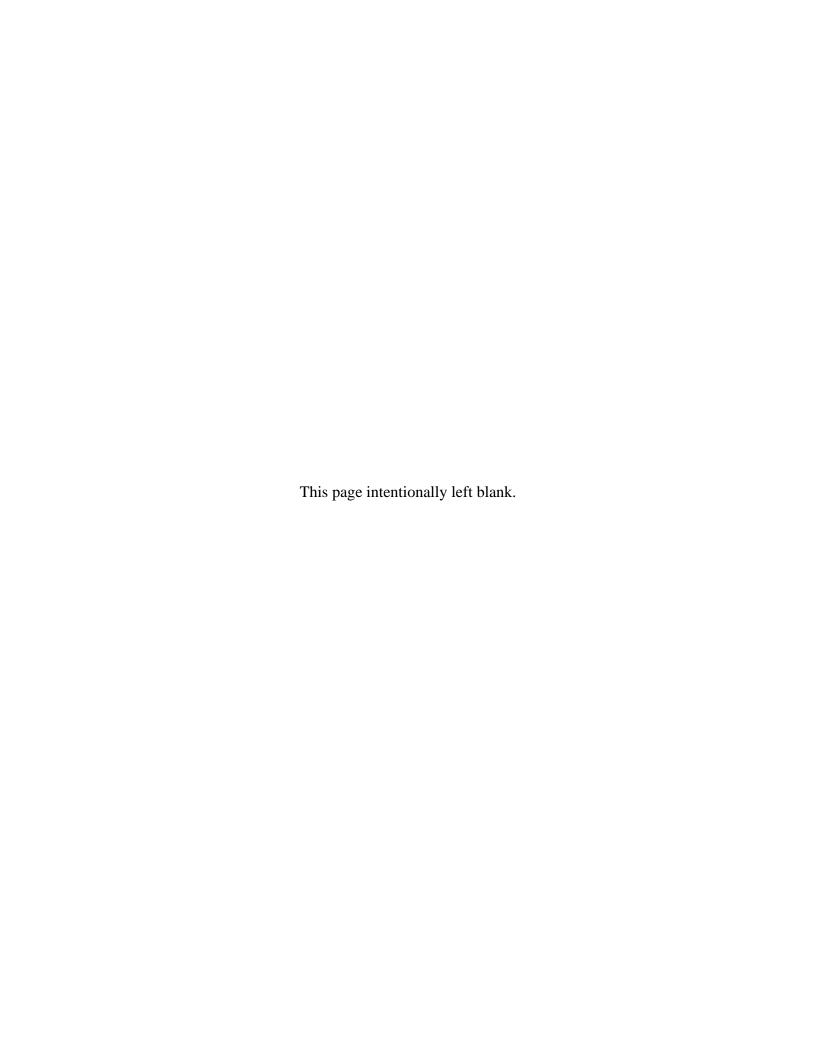
# FY 2010-2011

# FINAL AVERAGE SYSTEM COST REPORT

# **PUGET SOUND ENERGY**

July 2009





# FY 2010-2011

# FINAL AVERAGE SYSTEM COST REPORT

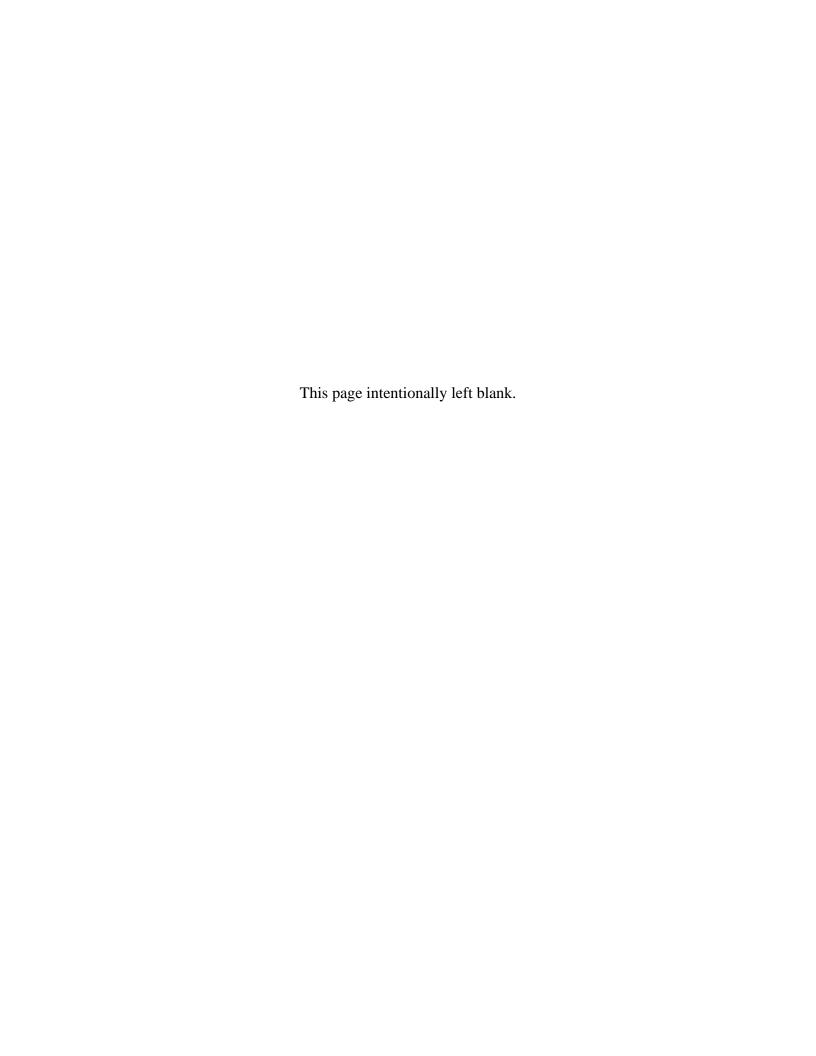
# **FOR**

# **Puget Sound Energy**

Docket Number: ASC-10-PS-01 Effective Date: October 1, 2009

PREPARED BY BONNEVILLE POWER ADMINISTRATION U.S. DEPARTMENT OF ENERGY

July 21, 2009



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#### 1. FILING DATA

**Utility**: **Puget Sound Energy** 

10885 NE 4th Street P.O. Box 97034

Bellevue WA 98009-9734

http://www.pse.com

## Parties to the Filing:

Investor Owned Utilities (IOUs):

Avista Utilities (Avista) Idaho Power Company (IPC)

NorthWestern Energy (NorthWestern or NWE)

PacifiCorp (PAC)

Portland General Electric (PGE)

Consumer Owned Utilities (COUs):

Franklin County PUD (Franklin) Snohomish County PUD (SNOPUD)

Other Participants to the Filing:

Idaho Public Utility Commission

**Public Power Council** 

Public Utility Commission of Oregon (OPUC)

Washington Utilities and Transportation Commission (WUTC)

ASC Base Period: CY 2007

Effective Exchange Period: FY 2010-2011 (October 1, 2009 – September 30, 2011)

#### Statement of Purpose:

Bonneville Power Administration (BPA) has conducted an Average System Cost (ASC) Review Process to determine PSE's ASC for FY 2010-2011 based on BPA's 2008 ASC Methodology (ASCM). This FY 2010-2011 Final Average System Cost Report (Final ASC Report) describes the process, evaluation, and results of BPA's ASC review.

General Information can be found at <a href="http://www.bpa.gov/corporate/finance/ascm/index.cfm">http://www.bpa.gov/corporate/finance/ascm/index.cfm</a>.

NOTE: BPA previously advised parties that if the filing utility or an intervenor wished to preserve any issue regarding BPA's Final ASC Reports for subsequent administrative or judicial appeal, they must have raised such issue in their comments on BPA's Draft ASC Reports. If a party failed to do so, the issue would be waived for subsequent appeal.

#### 2. AVERAGE SYSTEM COST SUMMARY

# 2.1. <u>Base Period ASC</u>

The 2008 ASCM requires utilities participating in the ASC Review Process, both IOUs and COUs, to submit to BPA "Base Period" financial and operational information. The Base Period is defined as the calendar year of the most recent FERC Form 1 data for IOUs, and the most recent Annual Reports, including the most recent Cost of Service Analysis (COSA) for COUs. The submitted information includes the "Appendix 1," the Excel based workbook used in calculating the Base Period ASC. For purposes of this report, the Base Period is calendar year (CY) 2007.

The table below summarizes the CY 2007 Base Period ASC based on (1) the ASC information filed by PSE on October 15, 2008 (including errata, if applicable), and (2) the same information as adjusted by BPA, including responses to comments submitted by the utility and/or intervenors during the ASC Review Process. This table does not reflect the Exchange Period ASC, which is noted in subsequent tables.

**Table 2.1: CY 2007 Base Period ASC** (Results of Appendix 1 calculations)

	October 15, 2008	<b>July 21, 2009</b>
	As Filed	Final Report
Production Cost	\$1,256,004,114	\$1,241,342,190
Transmission Cost	\$107,712,563	\$106,415,114
(Less) NLSL Costs	\$0	\$0
Contract System Cost (CSC)	\$1,363,716,676	\$1,347,757,304
Total Retail Load (MWh)	21,626,537	21,626,537
` '	21,020,337	, ,
(Less) NLSL	21.626.527	0
Total Retail Load (Net of NLSL)	21,626,537	21,626,537
Distribution Losses	1,092,140	1,092,140
Contract System Load (CSL)	22,718,677	22,718,677
CY 2007 Base Period ASC (CSC / CSL)	\$60.03/MWh	\$59.32/MWh

# 2.2. ASC New Resource Additions

In addition to the historical Base Period cost and load data, the exchanging utility may also provide its forecast of major new resource additions, and all associated costs, that are projected to come on-line through the end of the Exchange Period (FY 2010-2011). The forecast covers the period from the end of the Base Period (December 31, 2007) to the end of the Exchange Period (September 30, 2011). When a major new resource addition is projected to come on-line

prior to the start of the Exchange Period, the associated costs are projected forward to the midpoint of the Exchange Period in order to calculate the Exchange Period ASC.

The 2008 ASCM also provides that changes to an established ASC are allowed to occur during the Exchange Period to account for major new resource additions and purchases that are projected to come on-line or be purchased and used to meet a utility's retail load during the Exchange Period (FY 2010-2011).

In either scenario, such changes in ASC must meet the same materiality threshold as a change in ASC resulting from major new resource additions, that is, a 2.5 percent or greater change in Base Period ASC. BPA allows utilities to submit stacks of individual resources that, when combined, meet the materiality threshold. However, each resource in the stack must result in an increase or decrease of Base Period ASC of 0.5 percent or more.

The tables below summarize the new major resource additions projected to come on-line during the forecast period, based on (1) the ASC information filed on October 15, 2008 (including errata, if applicable), and (2) the same information as adjusted by BPA, including responses to comments submitted by the utility and/or intervenors during the ASC Review Process.

Table 2.2.1: New Resource Additions Coming On-Line Prior to Exchange Period (\$/MWh)

As-Filed FY 2010-2011 Exchange Period ASC						
Resource Group 1 N/A N/A						
Expected On-Line Date	12/01/08					
Delta* 2.62						

Final Report FY 2010-2011 Exchange Period ASC							
Resource Group 1 N/A N/A N/A							
Expected On-Line Date	12/01/08						
Delta* 1.28							

<sup>\*</sup>The Delta is the incremental change in the ASC as new resources come on-line. *See* Section 5.5.3 of this report.

Table 2.2.2: New Resource Additions Coming On-Line During the Exchange Period (\$/MWh)

As-Filed FY 2010-2011 Exchange Period ASC					
Resource	Group 2	N/A	N/A	N/A	
Expected On-Line Date	10/01/10				
Delta*	2.41				

Final Report FY 2010-2011 Exchange Period ASC					
Resource Group 2 N/A N/A N/A					
Expected On-Line Date	10/01/10				
Delta*	4.65				

<sup>\*</sup>The Delta is the incremental change in the ASC as new resources come on-line. *See* Section 5.5.2 of this report.

# 2.3. FY 2010-2011 Exchange Period ASC

The following table identifies the Exchange Period ASC as filed on October 15, 2008, including errata if applicable, as adjusted by BPA for this Final ASC Report. The ASC includes major new resource additions projected to come on-line prior to the start of the Exchange Period only. The Exchange Period ASC will adjust as necessary as additional major new resources come online, and as identified in Table 2.2.2 above. The procedures used in making the determinations and any required changes are prescribed by the 2008 ASCM and described in the following sections.

Table 2.3: Exchange Period FY 2010-2011 ASC (\$/MWh)
Prior to New Resource

Date	October 15, 2008 As-Filed	July 21, 2009 Final Report
FY 2010- 2011	63.20	56.98

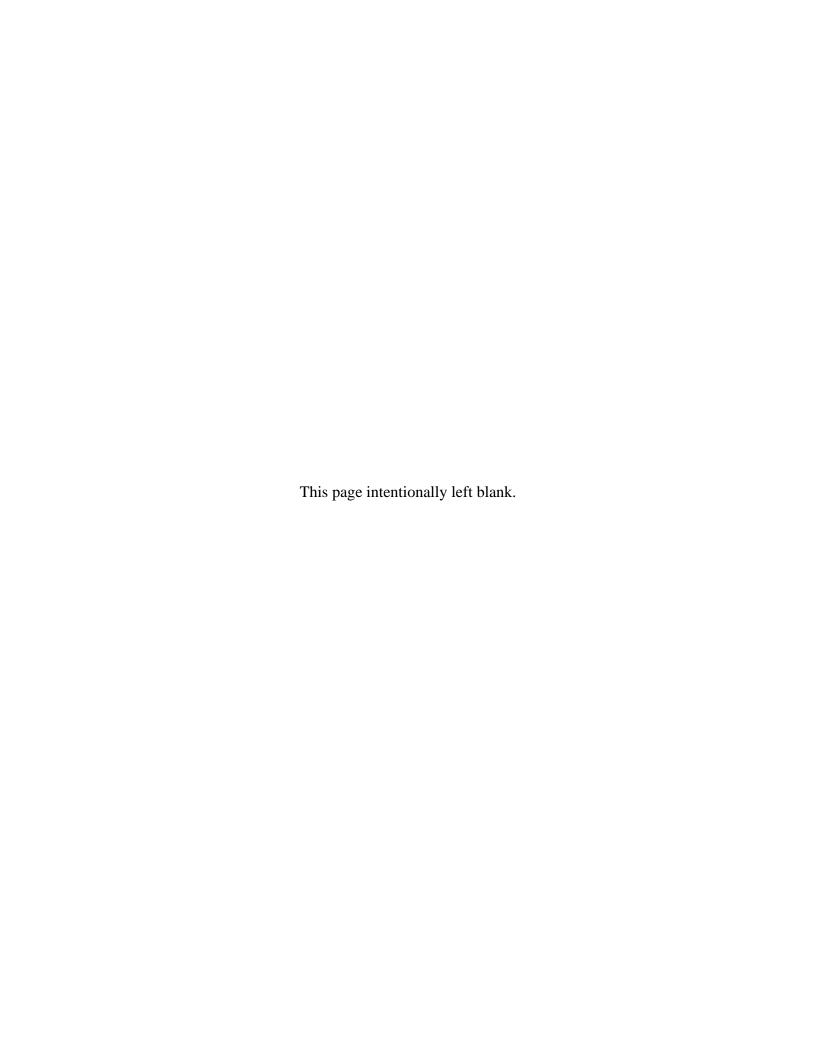
# FY 2010-2011

# FINAL AVERAGE SYSTEM COST REPORT

# SNOHOMISH COUNTY PUD

July 2009





# FY 2010-2011

# FINAL AVERAGE SYSTEM COST REPORT

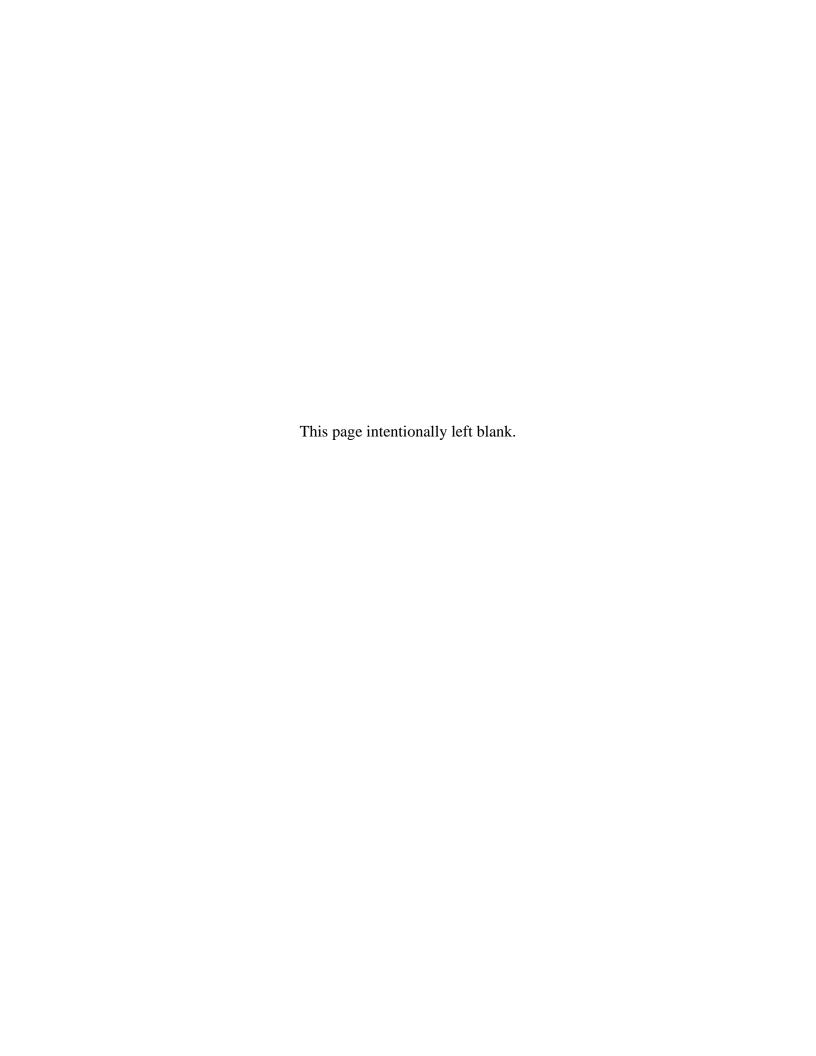
**FOR** 

# **Snohomish County Public Utility District**

Docket Number: ASC-10-SN-01 Effective Date: October 1, 2009

PREPARED BY BONNEVILLE POWER ADMINISTRATION U.S. DEPARTMENT OF ENERGY

July 21, 2009



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### 1. FILING DATA

**Utility: Snohomish County PUD** 

2320 California Street Everett, Washington 98201 http://www.snopud.com

# <u>Parties to the Filing</u>:

Investor-Owned Utilities (IOUs):

Avista Utilities (Avista)
Idaho Power Company (IPC)
NorthWestern Energy (NorthW

NorthWestern Energy (NorthWestern or NWE)

PacifiCorp (PAC)

Portland General Electric (PGE)

Puget Sound Energy (PSE)

Consumer-Owned Utilities (COUs):

Franklin County PUD (Franklin)

Other Participants to the Filing:

Idaho Public Utility Commission
Public Power Council
Public Utility Commission of Oregon (OPUC)
Washington Utilities and Transportation Commission (WUTC)

ASC Base Period: CY 2007

Effective Exchange Period: FY 2010-2011 (October 1, 2009 – September 30, 2011)

## Statement of Purpose:

Bonneville Power Administration (BPA) has conducted an Average System Cost (ASC) Review Process to determine Snohomish's ASC for FY 2010-2011 based on BPA's 2008 ASC Methodology (ASCM). This FY 2010-2011 Final Average System Cost Report (Final ASC Report) describes the process, evaluation, and results of BPA's ASC review.

General Information can be found at http://www.bpa.gov/corporate/finance/ascm/index.cfm.

NOTE: BPA previously advised parties that if the filing utility or an intervenor wished to preserve any issue regarding BPA's Final ASC Reports for subsequent administrative or judicial appeal, they must have raised such issue in their comments on BPA's Draft ASC Reports. If a party failed to do so, the issue would be waived for subsequent appeal.

## 2. AVERAGE SYSTEM COST SUMMARY

# 2.1. Base Period ASC

The 2008 ASCM requires utilities participating in the ASC Review Process, both IOUs and COUs, to submit to BPA "Base Period" financial and operational information. The Base Period is defined as the calendar year of the most recent FERC Form 1 data for IOUs, and the most recent Annual Reports, including the most recent Cost of Service Analysis (COSA) for COUs. The submitted information includes the "Appendix 1," the Excel based workbook used in calculating the Base Period ASC. For purposes of this report, the Base Period is calendar year (CY) 2007.

The table below summarizes the CY 2007 Base Period ASC based on (1) the ASC information filed by Snohomish on October 15, 2008 (including errata, if applicable), and (2) the same information as adjusted by BPA, including response to comments submitted by the utility and/or intervenors during the ASC Review Process. This table does not reflect the Exchange Period ASC, which is noted in subsequent tables.

**Table 2.1:** CY 2007 Base Period ASC (Results of Appendix 1 calculations)

	October 15, 2008 As Filed	July 21, 2009 Final Report
Production Cost	\$269,400,580	\$269,544,820
Transmission Cost	\$30,449,717	\$30,330,696
(Less) NLSL Costs	\$0	\$0
Contract System Cost (CSC)	\$299,850,297	\$299,875,515
Total Retail Load (MWh)	6,774,641	6,774,641
(Less) NLSL	0	0
Total Retail Load (Net of NLSL)	6,774,641	6,774,641
Distribution Losses	338,732	247,274
Contract System Load (CSL)	7,113,373	7,021,916
CY 2007 Base Period ASC (CSC/CSL)	\$42.15/MWh	\$42.71/MWh

# 2.2. ASC New Resource Additions

In addition to the historical Base Period cost and load data, the exchanging utility may also provide its forecast of major new resource additions, and all associated costs, that are projected to come on-line through the end of the Exchange Period (FY 2010-2011). The forecast covers the period from the end of the Base Period (December 31, 2007) to the end of the Exchange

Period (September 30, 2011). When a major new resource addition is projected to come on-line prior to the start of the Exchange Period, the associated costs are projected forward to the midpoint of the Exchange Period in order to calculate the Exchange Period ASC.

The 2008 ASCM also provides that changes to an established ASC are allowed to occur during the Exchange Period to account for major new resource additions and purchases that are projected to come on-line or be purchased and used to meet a utility's retail load during the Exchange Period (FY 2010-2011).

In either scenario, such changes in ASC must meet the same materiality threshold as a change in ASC resulting from major new resource additions, that is, a 2.5 percent or greater change in Base Period ASC. BPA allows utilities to submit stacks of individual resources that, when combined, meet the materiality threshold. However, each resource in the stack must result in an increase or decrease of Base Period ASC of 0.5 percent or more.

The tables below summarize the new major resource additions projected to come on-line during the forecast period, based on (1) the ASC information filed on October 15, 2008 (including errata, if applicable), and (2) ) the same information as adjusted by BPA, including response to comments submitted by the utility and/or intervenors during the ASC Review Process.

Table 2.2.1: New Resource Additions Coming On-Line Prior to Exchange Period (\$/MWh)

As-Filed FY 2010-2011 Exchange Period ASC						
Resource N/A Resource #1 Resource #2 N/A						
Expected On-Line Date		10/01/08	03/01/09			
Delta*		0.25	2.41			

Final Report FY 2010-2011 Exchange Period ASC					
Resource Enron Group A N/A					
Expected On-Line Date	01/01/08	03/01/09			
Delta*	-2.48	4.09			

<sup>\*</sup>The Delta is the incremental change in the ASC as new resources come on line. *See* Section 5.5.3 of this report regarding regrouping.

Table 2.2.2: New Resource Additions Coming On-Line During the Exchange Period (\$/MWh)

As-Filed FY 2010-2011 Exchange Period ASC					
Resource	Resource #3	Resource #4	N/A	N/A	
Expected On-Line Date	10/01/10	10/01/10			
Delta*	3.87	0.25			

Final Report FY 2010-2011 Exchange Period ASC					
Resource Morgan Stanley N/A N/A					
Expected On-Line Date	10/01/10				
Delta*	-1.76				

<sup>\*</sup>The Delta is the incremental change in the ASC as new resources come on line. *See* Section 5.5.3 of this report regarding regrouping.

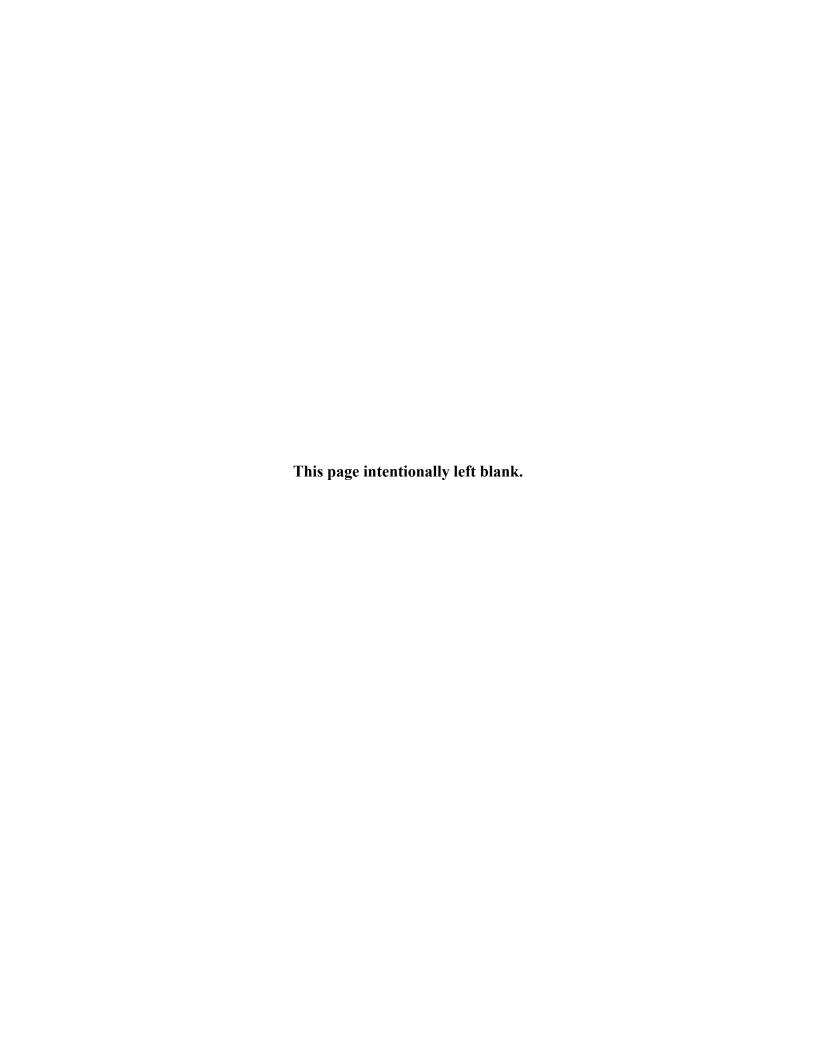
# 2.3. FY 2010-2011 Exchange Period ASC

The following table identifies the Exchange Period ASC as filed on October 15, 2008, including errata if applicable, as adjusted by BPA for this Final ASC Report. The ASC includes major new resource additions projected to come on-line prior to the start of the Exchange Period only. The Exchange Period ASC will adjust as necessary as additional major new resources come online, and as identified in Table 2.2.2 above. The procedures used in making the determinations and any required changes are prescribed by the 2008 ASCM and described in the following sections.

Table 2.3: Exchange Period FY 2010-2011 ASC (\$/MWh)
Prior to New Resource

Date	October 15, 2008 As-Filed	July 21, 2009 Draft Report		
FY 2010 - 2011	46.96	47.67		

# APPENDIX A 7(C)(2) INDUSTRIAL MARGIN STUDY



# Appendix A

# 7(c)(2) Industrial Margin Study

#### 1. INTRODUCTION

Section 7(c)(1)(B) of the Northwest Power Act provides that rates applicable to DSI customers shall be set "at a level which the Administrator determines to be equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers in the region."

Section 7(c)(2) provides that this determination shall be based on "the Administrator's applicable wholesale rates to such public body and cooperative customers and the typical margins included by such public body and cooperative customers in their retail industrial rates." This section further provides that the Administrator shall take into account

- (1) the comparative size and character of the loads served;
- (2) the relative costs of electric capacity, energy, transmission, and related delivery facilities provided and other service provisions; and
- (3) direct and indirect overhead costs, all as related to the delivery of power to industrial customers

#### 2. PURPOSE

The purpose of this study is to describe the calculation of the "typical margin" included by the Administrator's public body and cooperative customers in their retail industrial rates. The resulting margin is added to the PF-07 energy charges. These adjusted PF-07 energy charges and Demand Charges are applied to the DSI billing determinants to determine the IP-07 rate.

## 3. METHODOLOGY

# 3.1 Administrator's Applicable Wholesale Rates to Public Body and Cooperative Customers

BPA applies the PF-07 demand and energy charges (before any 7(b)(2) or floor rate adjustments) to the forecasted DSI billing determinants.

# 3.2 Typical Margin

The "typical margin" includes "other overhead costs" charged by the utilities in the study. BPA power revenue requirements are accounted for in the PF rate charges, and distribution costs are included by adding in a charge for BPA DSI delivery facilities. An overall margin is derived by

weighting individual utility margins according to the proportion of industrial energy load served by each utility relative to total industrial energy load included in the study.

# 3.3 Margin Determination Factors

- 3.3.1 7(c)(2)(A) Comparative Size and Character of the Loads Served. The data base used for the study includes utilities that serve at least one industrial customer with a peak demand of at least 3.5 MW.
- 3.3.2 7(c)(2)(B) Relative Costs of Electric Capacity, Energy, Transmission, and Related Delivery Facilities Provided and Other Service Provisions. The utility margins in this study are based to the extent possible on utility cost of service analyses and incorporate allocated costs to the industrial customer class. The utilities segregate these costs into various cost categories, and only those categories considered to be appropriate margin costs are included in BPA industrial margin calculation.

In the past, BPA has accounted for "other service provisions" through a character of service adjustment for service to the first quartile. Because the DSI contracts no longer include these provisions, BPA has not made this adjustment as part of this study.

**3.3.3 7(c)(2)(C) – Direct and Indirect Overhead Costs**. BPA relies on cost of service studies and other spreadsheets prepared by the public body and cooperative customers to incorporate the per unit overhead costs associated with service to large industrial customers.

# 4. APPLICATION OF THE METHODOLOGY

The derivation of the margin involves two steps. First, an individual margin is determined for each utility in the study. Second, each margin is weighted according to energy sales to derive an overall margin. BPA DSI delivery facilities charge is added as a later step to replace the distribution costs that otherwise would be included in the margin.

# 4.1 Data Base

The data base was collected from qualifying utilities by the Public Power Council (PPC) under the terms of a confidentiality agreement. Under the terms of that agreement, the names of the individual utilities and their industrial customers were deleted from the data base and the names were not publicly disclosed. Furthermore, all parties wishing to evaluate the utility margin data were required to sign confidentiality agreements. All reported utility data reported has been identified by a randomly assigned number. This is essentiality the same way margin data was displayed in the 2002 industrial margin study. The data base consists of cost information from 30 utilities that have an industrial load of at least 3.5 MW. Attachment A displays each utility's percentage of total energy, its inflated and weighted individual margin, and the overall energy-weighted typical industrial margin for all utilities.

# 4.2 Utility Margins

The individual utility margins are based on categorical costs allocated by the utilities to their industrial customers. The categories of costs include production, transmission, distribution, revenue taxes, and other overhead costs. The data for each of the utilities in the study are included as Attachment B. The total dollar amounts assigned by the utility to each category, divided by the total kWh energy sales to the appropriate industrial class, yields a mills/kWh figure for that cost category. Various costs assigned to the "other" category are added to arrive at each utility's industrial margin.

# 4.3 Summary of Results

The final results of each step in the margin calculation for each utility are shown in Attachment A. The weighted industrial margin is 0.57 mills/kWh. This margin has been added to the PF-10 energy charges and applied to the forecasted DSI billing determinants.

Utility Code Number	Test Period Energy (KWh)	Total Cost	Production	Transmission	Distribution	Other	Revenue Tax	Weighted Margin
2	205,901,980	40.37	33.54	0.74	3.63	0.00	2.46	0.0000
6(a)	46,850,000	51.45	33.08	5.47	9.34	0.64	2.92	0.0024
6(b)	60,446,000	41.79	26.19	5.06	7.41	0.55	2.59	0.0026
6(c)	463,006,000	42.28	27.96	5.54	5.52	0.63	2.62	0.0230
6(d)	191,102,000	55.20	30.37	2.46	7.53	3.23	1.53	0.0486
9	642,300,490	49.36	46.08	0.08	0.34	0.00	2.85	0.0002
18	41,602,900	47.29	39.70	1.08	5.56	0.16	0.79	0.0005
24(a)	34,829,000					0.04		0.0001
24(b)	232,582,000					0.01		0.0002
24(c)	870,068,000					0.00		0.0002
24(d)	20,930,000					0.11		0.0002
27	122,921,925	37.30	36.82	0.38	0.04	0.06	0.01	0.0006
33(a)	404,177					1.00		0.0000
33(b)	46,768					0.98		0.0000
34(a)	883,847,000	35.67	18.31	3.24	12.26	1.08	0.78	0.0756
34(b)	647,043,000	40.00	18.31	3.24	16.60	1.08	0.78	0.0553
34(c)	1,142,044,000	32.96	19.34	3.19	8.37	1.28	0.78	0.1149
37	152,300,891	44.80	35.81	4.49	4.50	0.01	0.00	0.0001
38	57,980,000	26.05	24.58	0.02	0.16	0.00	1.30	0.0000
48	267,535,027	18.40	14.90	0.60	2.50	0.40	0.00	0.0084
49	135,521,839	71.76	42.93	20.15	5.55	0.00	3.12	0.0000
54	628,234		4.41	0.16	0.63	0.26	0.00	0.0000
56	42,095,000	53.60	50.15	0.04	1.94	0.33	1.15	0.0011
58	890,690,506	35.46	29.34	4.62	1.45	0.05	0.00	0.0032
64	401,856,000					0.18		0.0056
66	137,729,000	31.29	26.65	2.65	1.68	0.01	0.30	0.0001
69	29,114,880	43.02	34.59	2.37	3.63	0.00	2.43	0.0000
72	186,557,000	39.50	30.84	2.08	4.15	0.18	2.24	0.0026
86	75,723,640	34.25	23.26	5.47	3.13	0.15	2.25	0.0009
87	59,070,320					5.02		0.0234
93(a)	110,588,400					5.00		0.0436
93(b)	202,967,376					2.18		0.0349
93(c)	2,173,245,133					0.41		0.0709
93(d)	623,470,000					0.56		0.0275
97	176,302,116	53.11	40.80	6.15	5.16	0.04	0.96	0.0006
99	283,411,200					0.05		0.0011
103(a)	44,395,500	42.85	21.99	8.92	9.86	0.03	2.05	0.0001
103(b)	349,201,178					0.57		0.0158
104	16,490,000	50.99	31.79	4.47	11.25	0.04	3.45	0.0000
106	70,085,364	48.29	38.72	0.11	8.14	0.79	0.53	0.0044
113	487,626,018	38.75	30.99	2.73	5.03	0.00	0.00	0.0000
115	16,204,800	63.46	32.23	5.85	25.09	0.29	0.00	0.0004
122	87,307,518	46.60	36.26	0.51	8.57	0.64	0.64	0.0044
Total	12,684,022,180							0.5735

Utility Number: # 2	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power	¢6,006,015	¢6 006 015				
Taxes Assigned to Purchased Power	\$6,906,015 \$418,062					\$418,062
Fixed Operations Expense						
Supervisory Operating Expense	\$133,780			\$133,780		
Labor/O&M	\$142,500			\$142,500		
Distribution/Operations	\$7,500			\$7,500		
Distribution/Maintenance	\$12,000			\$12,000		
Transmission Lines/Maintenance	\$1,000		\$1,000			
General Plant/Maintenance and Misc. Op. Exp.	\$620			\$620		
Administrative Expense	\$67,600		\$227	\$67,373		
Taxes on Operations Expense	\$88,699					\$88,69
Transmisson Capital Expenditures	\$150,000		\$150,000			
Reserve Funding						
C&R Discount account (books out below)	\$42,000	\$42,000				
Emergency Reserve	\$50,000		\$168	\$49,832		
Debt Service	\$339,777		\$1,142	\$338,635		
Incomes						
Other revenue	-\$5,000		-\$17	-\$4,983		
Collection of C&R	-\$42,000			<b>.</b> ,,,,,,,		
Annual MWh Sales 205,902						
Mills/kWh	\$40.37	33.54	0.74	3.63	0.00	2.4

Utility Number: # 6(a)	Total Industrial (C.1)	Production	Transmission	Distribution	Other	Revenue taxes
Generation VAR (Generation) Purchased Power	\$212,755 \$7,511 \$1,329,480	\$7,511				
Transmission	\$256,323		\$256,323			
Distribution	\$313,767			\$436,091		
Customer Service, Accounts & Sales  Meter reading Cust Records & Collection Low income Electric Marketing  CILT on Retail Revenue (Contributions in Lieu of Taxes)  Secondary Cost of Service (customer facilities)	\$443 \$1,249 \$25,004 \$4,844 \$137,028		-\$17	\$443 \$1,249 -\$29	\$25,004 \$4,844	\$137,028
Annual MWh Sales 46,850						
Mills/kWh	51.45	33.08	5.47	9.34	0.64	2.93

Utility Number: # 6(b)	Total Industrial (D)	Production	Transmission	Distribution	Other	Revenue taxes
Generation VAR (Generation) Purchased Power	\$235,452 \$8,079 \$1,339,273	\$8,079				
Transmission	\$305,925		\$305,925			
Distribution	\$446,607			\$446,607		
Customer Service, Accounts & Sales Meter reading Cust Records & Collection Low income Electric Marketing	\$295 \$750 \$28,546 \$4,844			\$295 \$750		
CILT on Retail Revenue (Contributions in Lieu of Taxes)	\$156,436					\$156,436
Secondary Cost of Service (customer facilities)	-\$76	-\$18	-\$23	-\$33	-\$2	
Annual MWh Sales 60,446						
Mills/kWh	41.79	26.19	5.06	7.41	0.55	2.59

Utility Number: # 6(c)	Total Industrial (A)	Production	Transmission	Distribution	Other	Revenue taxes
Generation VAR (Generation) Purchased Power	\$2,008,219 \$70,559 \$10,868,335	\$70,559				
Transmission	\$2,565,406		\$2,565,406			
Distribution	\$2,553,347			\$2,553,347		
Customer Service, Accounts & Sales  Meter reading Cust Records & Collection Low income Electric Marketing  CILT on Retail Revenue (Contributions in Lieu of Taxes)	\$886 \$3,748 \$221,368 \$69,743 \$1,213,126			\$886 \$3,748		
Annual MWh Sales 463,006						
Mills/kWh	42.28	27.96	5.54	5.53	0.63	2.6

Utility Number: # 6(d)	Total Industrial (B)	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power	\$5,803,760	\$5,803,760				
Transmission	\$470,366		\$470,366			
Distribution	\$1,439,075			\$1,439,075		
CILT on Retail Revenue (Contributions in Lieu of Taxes	\$291,685					\$291,685
Other	\$617,056				\$617,056	
Annual MWh Sales 191,102						
Mills/kWh	45.12	30.37	2.46	7.53	3.23	1.53

Utility Number: # 9						_
	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Generation	\$15,092,617	\$15,092,617				
Purchased Power	\$14,986,318					
Transmission						
Distribution	\$151,655			\$151,655		
Customer Accounts	\$2,344				\$2,344	
Administrative and General	\$123,970	\$122,709		\$1,242	\$19	
Taxes	\$1,831,677					\$1,831,677
Interest and Debt Service Expense	\$449,470	\$444,967		\$4,503		
Capital Projects Funded From Rates						
Transmission	\$51,699		\$51,699			
Distribution	\$57,312			\$57,312		
General	\$15,635			\$15,635		
Other Direct Assignment	\$10,557	\$10,557				
Other Revenues	-\$1,068,551	-\$1,057,682	\$0	-\$10,703	-\$165	
Annual MWh Sales 642,300						
Mills/kWh	49.36	46.08	0.08	0.34	0.00	2.85

Utility Number: # 18						_
	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power	\$1,651,830	\$1,651,830				
Transmission	\$28,509		\$28,509			
Distribution	\$147,429			\$147,429		
Customer	\$8,652				\$8,652	
G&A	\$42,768		\$6,605	\$34,158	\$2,005	
Depreciation	\$56,047		\$9,082	\$46,965		
Taxes	\$32,757					\$32,757
Interest	\$83,899		\$13,595	\$70,304		
Other Expenses	\$23,337		\$3,604	\$18,639	\$1,094	
Overcollection in prior years	-\$70,516		-\$10,891	-\$56,320	-\$3,305	
Other Operating Revenue	-\$37,386		-\$5,774	-\$29,860	-\$1,752	
Annual MWh Sales 41,603						
Mills/kWh	47.28	39.71	1.08	5.56	0.16	0.79

Four industrial customers are sold power under special contracts. Customer 1 is charged a margin of \$110/month; customers 2, 3, & 4 are charged \$200/month.

Total energy sold Customer 1 34,829 MWh

Margin = \$0.04/MWh

Total energy sold Customer 2 232,582 MWh

Margin = \$0.01/MWh

Total energy sold Customer 3 870,068 MWh

Margin = \$0.003/MWh

Total energy sold Customer 4 20,930 MWh

Margin = \$0.12/MWh

Utility Number: # 27						Devenue
	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power	\$4,525,439	\$4,525,439				
Transmission	\$30,213		\$30,213			
Distribution	\$3,114			\$3,114		
Customer	\$5,859				\$5,859	
G&A	\$51,689		\$39,853	\$4,108	\$7,728	
Depreciation	\$8,509		\$7,714	\$795		
Taxes	\$1,202					\$1,202
Interest	\$2,348		\$2,129	\$219		
Other Expenses	\$479		\$369	\$38	\$72	
Overcollection in prior years	-\$173		-\$133	-\$14	-\$26	
Other Operating Revenue	-\$43,292		-\$33,379	-\$3,440	-\$6,473	
Annual MWh Sales 122,922						
Mills/kWh	37.30	36.82	0.38	0.04	0.06	0.01

Two industrial customers are sold power under a special contract. They are charged a margin of 1.95 mills/kWh for power < 19.1 aMW, and 0.98 mills/kWh for power > 19.1 aMW.

Total energy sold Customer 1 404.2 MWh Amount \$0.98/MWh applied 394 MWh Amount \$1.95/MWh applied 9,098 MWh

Margin = 1.004

Total energy sold Customer 2 46.8 MWh

Amount \$0.98/MWh applied 0

Amount \$1.95/MWh applied 46.8 MWh

Margin = 0.98

Utility Number: # 34(a)						
	Large General Service: 1	Production	Transmission	Distribution	Other	Revenue taxes
Generation	\$5,095,753	\$5,095,753				
Purchased Power	\$9,942,842	\$9,942,842				
Transmission	\$2,859,810		\$2,859,810			
Conservation	\$1,501,264	\$1,501,264				
Distribution	\$11,357,022			\$11,357,022		
Total Retail Service	\$958,555				\$958,555	
Network Adjustment	-\$517,053			-\$517,053		
Gradualism	-\$358,410	-\$358,410				
City General Fund Streetlight Bill	\$686,122					\$686,122
Annual MWh Sales 883,847						
Mills/kWh	35.67	18.31	3.24	12.27	1.09	0.78

Utility Number: # 34(b)	Large General					Revenue
	Service: 2	Production	Transmission	Distribution	Other	taxes
Generation	\$3,730,478	\$3,730,478				
Purchased Power	\$7,278,915	\$7,278,915				
Transmission	\$2,093,598		\$2,093,598			
Conservation	\$1,099,040	\$1,099,040				
Distribution	\$8,314,203			\$8,314,203		
Total Retail Service	\$701,735				\$701,735	
Network Adjustment	\$2,425,211			\$2,425,211		
Gradualism	-\$262,383	-\$262,383				
City General Fund Streetlight Bill	\$502,293					\$502,293
Annual MWh Sales 647,043						
Mills/kWh	40.00	18.31	3.24	16.60	1.09	0.78

Utility Number: # 34(c)	Large General					Revenue
	Service: 3	Production	Transmission	Distribution	Other	taxes
Generation	\$6,494,353	\$6,494,353				
Purchased Power	\$12,671,793	\$12,671,793				
Transmission	\$3,644,724		\$3,644,724			
Conservation	\$1,913,307	\$1,913,307				
Distribution	\$8,314,203			\$8,314,203		
Total Retail Service	\$1,457,105				\$1,457,105	
Network Adjustment	-\$616,205			-\$616,205		
Gradualism	\$1,012,668	\$1,012,668				
City General Fund Streetlight Bill	\$886,558					\$886,558
Annual MWh Sales 1,142,044						
Mills/kWh	32.96	19.34	3.19	8.37	1.28	0.78

Utility Number: # 37						Revenue
	Total Industrial	Production	Transmission	Distribution	Other	taxes
Generation Purchased Power	\$3,152,494 \$2,095,522					
Transmission	\$642,044		\$642,044			
Distribution	\$642,766			\$642,766		
Customer Accounts	\$1,192				\$1,192	
Administrative and General	\$289,393	\$205,545	\$41,862	\$41,909	\$78	
Annual MWh Sales 152,301						
Mills/kWh	44.80	35.81	4.49	4.50	0.01	0.00

Utility Number: # 38							
	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes	
Purchased Power	\$1,111,817	\$1,111,817					
Generation	\$142,231						
Transmission	\$2,333		\$2,333				
Distribution	\$19,462			\$19,462			
Customer Service, Accounts & Sales							
Mun Ser Tran Meter Read	\$1,435			\$1,435			
Mun Ser Tran Credit Bill	\$77				\$77		
Administrative and General							
Salaries & Benefits	\$11,531	\$9,907	\$163	\$1,456	\$5		
Property Insurance	\$12,661	\$10,878	\$178	\$1,598	\$6		
Outside Services	\$34,986	\$30,060	\$493	\$4,417	\$16		
Maint of General Plant	\$3,862	\$3,349	\$55	\$458			
Warehouse	\$4,093	\$3,517	\$58	\$517	\$2		
Engineering	\$7,956	\$6,836	\$112	\$1,004	\$4		
Energy Services	\$6,332	\$5,440	\$89	\$799	\$3		
Energy Services - Conservation	\$8,802	\$7,563	\$124	\$1,111	\$4		
Misc General Expense	\$6,620	\$5,688	\$93	\$836	\$3		
Debt Service Expense	\$249,489	\$249,489					
Transfers							
Return on Original Investment	\$14,652	\$12,589	\$206	\$1,850	\$7		
Payments in Lieu of Taxes	\$75,264			·		\$75,264	
Net Capital Improvement Projects from Rates	\$77,012	\$66,169	\$1,085	\$9,722	\$36		
Less:							
Revenues (not from rates)	\$279,952	\$240,536	\$3,945	\$35,340	\$130		
Annual MWh Sales 57,980							
Mills/kWh	26.06	24.58	0.02	0.16	0.00	1.30	

Utility Number: # 48						D
(in mills/kWh)	Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Expenses						
Generated Power Revenues from Resale of Gen. Power	\$0.0239 -\$0.0090					
Transmission	\$0.0006		\$0.0006			
Distribution	\$0.0025			\$0.0025		
Other	\$0.0004				\$0.0004	
Annual MWh Sales 267,535						
Mills/kWh	18.40	14.90	0.60	2.50	0.40	0.00

Utility Number: # 49								
	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes		
Purchased Power	\$6,110,426					tuxtoo		
Sales from resale	-\$292,173							
Transmission	\$878,490		\$878,490					
Distribution	\$121,417			\$121,417				
Customer Service, Accounts & Sales Meter Reading Cust. Records & Collection Info. & Insert Advertising	\$403 \$977 \$101			\$403 \$977	\$101			
Broadband	\$1,306,623		\$1,146,263	\$160,227	\$132			
Taxes	\$423,071					\$423,071		
Debt Service	\$574,049		\$503,597	\$70,394	\$58			
Capital Improvements from Rates								
Transmission	\$11,076		\$11,076					
Substations	\$75,240			\$75,240				
Underground	\$56,118			\$56,118				
Vehicles	\$4,763		\$4,179	\$584				
Customer - Dist Additions	\$159,310			\$159,310				
Customer - Transformers	\$81,607			\$81,607				
Customer - Meters & AMR	\$192			\$192				
Broadband	\$33,143		\$29,075		\$3			
Buildings	\$3,314		\$2,907		, -			
Improvements System	\$203,258		\$178,312		\$21			
Improvements General	\$18,646		\$16,358		\$2			
Administrative and General	\$160,881		\$141,136	\$19,728	\$16			
Less: Misc. Revenues								
Late Charges	-\$75				-\$75			
Misc. Service	-\$85		-\$74	-\$10				
Rent from Electric Property	-\$11,803		-\$10,354		-\$1			
Broadband Revenue	-\$7,235		-\$6,347	-\$887	-\$1			
Interest Income	-\$89		-\$78	-\$11				
Misc. Non Operating Rev.	-\$851		-\$747	-\$104				
Less: Outside Funding Sources	-\$186,074		-\$163,237	-\$22,818	-\$19			
Annual MWh Sales 135,522								
Mills/kWh	71.76	42.93	20.15	5.55	0.00	3.12		

Utility Number: # 54						Revenue
	Total Industrial	Production	Transmission	Distribution	Other	taxes
Transmission	\$51,747		\$51,747			
Distribution	\$202,727			\$202,727		
Customer Service						
Customer Accounts	\$7,328				\$7,328	
Conservation	\$1,407,194	\$1,407,194				
Sales	\$107,882				\$107,882	
Debt Service	\$619,553	\$524,672	\$19,294	\$75,587		
Capital Improvements recovered in rates	\$354,190	\$299,948	\$11,030	\$43,212		
Administrative and General	\$930,036	\$736,540	\$27,085	\$106,109	\$60,302	
Annual MWh Sales 628,234						
Mills/kWh	5.46	4.41	0.16	0.64	0.26	0.00

Utility Number: # 56						_
	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power	\$1,387,888	\$1,387,888				
Generated Power	\$586,037	\$586,037				
Transmission	\$1,320		\$1,320			
Distribution	\$71,299			\$71,299		
Consumer Accounts	\$263				\$263	
Public Relations & Info	\$11,873				\$11,873	
Energy Services (Conservation)	\$46,696	\$46,696				
Administration & General	\$63,036	\$55,590	\$116	\$6,264	\$1,066	
Tax (franchise)	\$24,352					\$24,352
Tax (property)	\$24,044					\$24,044
Capital Budget	\$94,009	\$82,904	\$173	\$9,342	\$1,590	
less Financing from Reserves	-\$38,189		-\$70		-\$646	
Reserve Funding	\$31,767	\$28,014	\$58	\$3,157	\$537	
"Spread Net Revenue to Others"	-\$48,279	-\$42,576	-\$89	-\$4,798	-\$817	
Annual MWh Sales 42,095						
Mills/kWh	53.60	50.15	0.04	1.94	0.33	1.15

Utility Number: # 58	Total Industrial (C.1)	Production	Transmission	Distribution	Other	Revenue taxes
Production	\$52,260,139	\$52,260,139				
Transmission	\$8,238,211		\$8,238,211			
Distribution	\$2,588,187			\$2,588,187		
Customer Bill-Related Exp.	\$80,587				\$80,587	
Customer Service	\$10				\$10	
Annual MWh Sales 890,691						
Mills/kWh	35.46	29.34	4.63	1.45	0.05	0.00

Single industrial customer, rates set through contract. Margin over Wholesale Cost of Power is \$5,870/mo.

Total Industrial sales in 2004: 401,856 MWh

Margin = 0.175

Utility Number: # 66	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power	\$3,670,353			Distribution	<b>5</b> 6.	laxes
Transmission	\$364,827		\$364,827			
Demand	\$227,092			\$227,092		
Customer						
Actual	\$521				\$521	
Accounting	\$984				\$984	
Meters & Services	\$4,582			\$4,582		
Revenue Related	\$41,037					\$41,037
Annual MWh Sales 137,729						
Mills/kWh	31.29	26.65	2.65	1.68	0.01	0.30

Utility Number: # 69						
						Revenue
Durah and Dawer	Total Industrial	Production	Transmission	Distribution	Other	taxes
Purchased Power	\$1,035,622	\$1,035,622				
Transmission	\$712		\$712			
Distribution	\$59,107			\$59,107		
Customer Service, Accounts & Sales						
Supervision	\$12				\$12	
Meter Reading	\$18			\$18		
Customer Records Collection	\$54			\$54		
Uncollectable Accounts	\$4				\$4	
Misc. Customer Accounts	\$12				\$12	
Customer Communication & Education	\$9				\$9	
Customer Assistance	\$49				\$49	
Advertising	\$1				\$1	
Administrative & General	\$41,855		\$497	\$41,297	\$61	
Total Interest/Debt Service Expense	\$46,721		\$556	\$46,165		
Capital Projects Funded from Rates Production						
Transmission	\$67,619		\$67,619			
General	\$18,698		\$222	\$18,476		
Other (Increases in inventory)	\$2,281		\$27	\$2,254		
Taxes						
State Utility Tax	\$45,972					
FICA	\$3,966		\$47	\$3,913	\$6	45,972
State Privelege Tax	\$24,261					24,261
Other Taxes	\$652					652
Incomes:						
Other Contributions						
Construction Fund Transfer	-\$36,498		-\$434		<u>.</u>	
Other Fund Transfers	-\$7,756		-\$92		-\$11	
Other Contributions	-\$19,618		-\$233	-\$19,357	-\$28	
Other Revenues	-\$2,655		-\$32	-\$2,620	-\$4	
BPA C&R Credit	-\$14,355	-\$14,355				
Conservation Augmentation Reimbursement	-\$14,221	-\$14,221				
Annual MWh Sales 29,115						
Mills/kWh	43.02	34.59	2.37	3.63	0.00	2.44

Utility Number: # 72						
	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Power	\$5,754,034	\$5,754,034				
Transmission	\$388,142		\$388,142			
Distribution	\$774,768			\$774,768		
Customer Related	\$33,610				\$33,610	
Revenue Taxes	\$418,166					\$418,166
Annual MWh Sales 186,557						
Mills/kWh	39.50	30.84	2.08	4.15	0.18	2.24

Utility Number: # 86						_
	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Power	\$1,758,827	\$1,758,827				
Transmission	\$257,503		\$257,503			
Distribution	\$87,087			\$87,087	\$12	
Customer Service, Accounts & Sales Supervision	\$320				\$320	
Meter Reading Customer Service	\$3,151 \$4,064			\$3,151		
Cashiering Cash: over/short	\$2,405 \$1				\$2,405 \$1	
Customer Accounts Delinquency Reporting Mail - PUD Billing	\$29,000 \$760 \$129 \$724			\$29,000	\$760 \$129 \$724	
Product & Service Substn. Maint. & Repair Service Exp. Mail Service Exp. Mail Service Postage Total Non-Operating Expense	\$253 \$428 \$3,258 \$3,939		\$ 286 \$ 2,178	\$ 253 \$ 133 \$ 1,009	\$ 9 \$ 71	
Public Purpose - Supervision	\$520				\$ 520	
Administrative & General Expense	\$101,505	\$ -	\$ 67,865	\$ 31,425	\$ 2,215	
Debt Service Distribution General Plant 4/5 Settlement (will check out) Generation Plant Substations	\$609 \$356 \$124,423 \$2,225 \$487	\$ - \$ 2,225	\$ 85,043	\$ 609 \$ 356 \$ 39,380 \$ 487		
Taxes	\$170,130					\$ 170,130
Rate-Financed Capital Expenditures Generation Distribution General Plant Capitalized Interest and A&G	\$197 \$22,010 \$21,383 \$1,532	\$ 197 \$ -	\$ 1,024	\$22,010 \$ 21,383 \$ 474		
Annual MWh Sales 75,724						
Mills/kWh	34.24	23.26	5.47	3.13	0.15	2.25

Two industrial customers are sold power under special contracts. Each is charged a different margin.

Total energy sold Customer 1 39,018 MWh

Margin = \$5.04/MWh

Total energy sold Customer 2

Margin = \$4.49/Mh

20,053 MWh

Four industrial customers are sold power under special contracts. Each is charged a different margin.

Total energy sold Customer 1

110,588 MWh

Margin = \$5.00/MWh

Total energy sold Customer 2

202,967 MWh

Margin = \$2.18/Mh

Total energy sold Customer 3

2,173,245 MWh

Margin = \$0.41/MWh

Total energy sold Customer 4

623,470 MWh

Margin = \$0.56/Mh

Utility Number: # 97						
	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power	\$7,193,153	\$7,193,153				
Transmission	\$538,019		\$538,019			
Distribution	\$332,877			\$332,877		
Customer Accounts	\$5,427				\$5,427	
Customer Service	\$527				\$527	
Administrative and General	\$360,927		\$221,458	\$137,018	\$2,451	
Depreciation and Amortization Generation Transmission Distribution General Amortization  Tax Expense Property US Unemployment, FICA, State Unemployment, Workers Comp Gross Revenue Tax	\$658 \$57,079 \$274,219 \$42,588 \$38,239 \$9,656 \$30,715 \$160,277	\$658	\$57,079 \$26,310 \$23,623 \$18,846	\$274,219 \$16,278 \$14,616		\$9,656 \$160,277
Interest Expense Long Term Debt Non Operating Margin	\$437,998 -\$15,610		\$270,585 -\$9,578	·	-\$106	
Miscellaneous Revenues	-\$102,599		-\$62,953	·	•	
Annual MWh Sales 176,302					<u> </u>	
Mills/kWh	53.11	40.80	6.15	5.16	0.04	0.96

Three large industrial customers are sold power under a special tariff schedule. Each customer is charged a margin of \$387/month.

Total annual MWh sales = 283,411 MWh.

Margin = \$0.049/Mh

Utility Number: # 103 (a)						
	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power	\$837,167	\$837,167				
Generation	\$37,352	\$37,352				
Transmission	\$106,309		\$106,309			
Distribution	\$117,563			\$117,563		
Customer Service, Accounts and Sales	\$808				\$808	
Administrative and General	\$130,160	\$18,554	\$52,807	\$58,397	\$401	
Taxes	\$91,042					\$91,042
Interest/Debt Service Expense	\$202,147	\$28,905	\$82,267	\$90,976		
Capital Project Funded from Rates (Power Production)	\$369,640	\$52,854	\$150,431	\$166,355		
Other Contributions	\$70,923	\$10,110	\$28,774	\$31,820	\$219	
Less: Other Revenues	-\$60,905	-\$8,682	-\$24,710	-\$27,326	-\$188	
Annual MWh Sales 44,396						
Mills/kWh	42.85	21.99	8.92	9.86	0.03	2.05

# Utility Number: # 103(b)

Two large industrial customers are sold power under special contracts. Each customer is charged a margin of \$100,000.

Total annual MWh sales = 349,201 MWh.

Margin = \$0.57/Mh

Utility Number: # 104						Davanua
	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power	\$524,167	\$524,167				
Transmission	\$73,054		\$73,054			
Demand	\$149,480			\$149,480		
Distribution	\$34,158			\$34,158		
Customer Related	\$595				\$595	
Revenue Related	\$56,858					\$56,858
Direct Assignment	\$2,571	\$0	\$730	\$1,835	\$6	
Annual MWh Sales 16,490						
Mills/kWh	50.99	31.79	4.47	11.25	0.04	3.45

Utility Number: # 106						
	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power	\$2,713,692	\$2,713,692				
Distribution	\$261,858			\$261,858		
Customer Service						
Meter Reading	\$958			\$958		
Customer Records & Collections	\$2,724			\$2,724		
Energy Services (Conservation)	\$38,008				\$38,008	
Ruralite & Customer Info	\$1,091				\$1,091	
Sales	\$361				\$361	
Supervision	\$2,209			\$1,923	\$286	
Administrative and General	\$122,505			\$106,656	\$15,849	
Тах	\$37,144					\$37,144
Depreciation						
Transmission	\$7,999		\$7,999			
Distribution	\$76,949			\$76,949		
General	\$16,869			\$16,869		
Total Depreciation	\$101,817					
Interest Expense	\$102,040			\$102,040		
Other Expense	\$314			\$273	\$41	
Annual MWh Sales 70,085						
Mills/kWh	48.29	38.72	0.11	8.14	0.79	0.53

Utility Number: # 113						
	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power	\$14,885,596	\$ 14,885,596				
Generated Power	\$242,706	\$ 242,706				
Transmission	\$1,444,368		\$1,444,368			
Distribution	\$1,862,469			\$ 1,862,469		
Customer (meters, billing)	\$800.102			\$800,102		
Contract credits	-\$340,987	-\$19,027	-\$113,230	-\$208,730		
Annual MWh Sales 487,626						
Mills/kWh	38.75	30.99	2.73	5.03	0.00	0.00

Utility Number: # 115						
	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power	\$522,295	\$522,295				
Transmission	\$94,834		\$94,834			
Distribution	\$406,659			\$406,659		
Customer	\$4,633				\$4,633	
Annual MWh Sales 16,205						
Mills/kWh	63.46	32.23	5.85	25.10	0.29	0.00

Utility Number: # 122						
	Total Industrial	Production	Transmission	Distribution	Other	Revenue taxes
Purchased Power	\$3,165,390	\$3,165,390				
Transmission	\$14,347		\$14,347			
Distribution	\$242,525			\$242,525		
Customer	\$26,960				\$26,960	
G&A	\$278,509		\$14,078	\$237,977	\$26,454	
Depreciation	\$135,397		\$7,562	\$127,835		
Taxes	\$55,528					\$55,528
Interest	\$128,225		\$7,162	\$121,063		
Other	\$8,629		\$436	\$7,373	\$820	
Under Collection	\$49,377		\$2,496	\$42,191	\$4,690	
Annual MWh Sales 87,308						
Mills/kWh	46.60	36.26	0.51	8.57	0.64	0.64

# APPENDIX B

**Letter from Mike Weedall** 



# THE OF AME

#### Department of Energy

Bonneville Power Administration P.O. Box 3621 Portland, Oregon 97208-3621

**ENERGY EFFICIENCY** 

June 28, 2005

In reply refer to: PN-1

Dear Interested Party:

You will find attached the Bonneville Power Administration's (BPA) Final Post-2006 Conservation Program Structure.

BPA initiated a collaborative conservation planning process last September to solicit recommendations for our post-2006 conservation program structure (i.e., the FYs 2007-09 rate period). Based on the recommendations from the Conservation Workgroup, BPA issued its proposal for a 30-day public review and comment period on March 28, 2005. BPA received over 50 comment letters on the proposal, and we appreciate the many very thoughtful and constructive suggestions for improving the proposed program.

We have reviewed and considered these comments in preparing the attached Final Post-2006 Conservation Program Structure. The first document is a summary of the key issues raised in the comment letters and BPA's final decision on those key issues. The second document is a more detailed description of the final program structure.

This is a major step in designing our future conservation programs. However, the work is not finished. There is a Conservation Workgroup Phase 2 Committee with nine very experienced utility representatives acting as a sounding board for BPA in establishing the incentive levels BPA will pay for cost-effective measures under this final program structure. This is a simplified approach for structuring the list of cost-effective measures that will be easier to implement, and will include the appropriate level of oversight, utility verification and measurement of savings. BPA's desire is to be clear about how customers can receive their reimbursements under BPA's new programs. It is not our intent to dictate to customers how they should design and run their conservation programs. Again, BPA appreciates the dedication and hard work of the Phase 2 Committee.

BPA representatives will be happy to meet with power sales customers, utility groups or stakeholder organizations to discuss the decisions related to our Final Post-2006 Conservation Program. Please contact Becky Clark at 503-230-3158 to make the necessary arrangements.

Sincerely,

Table Tourland

Mike Weedall

Energy Efficiency Vice President

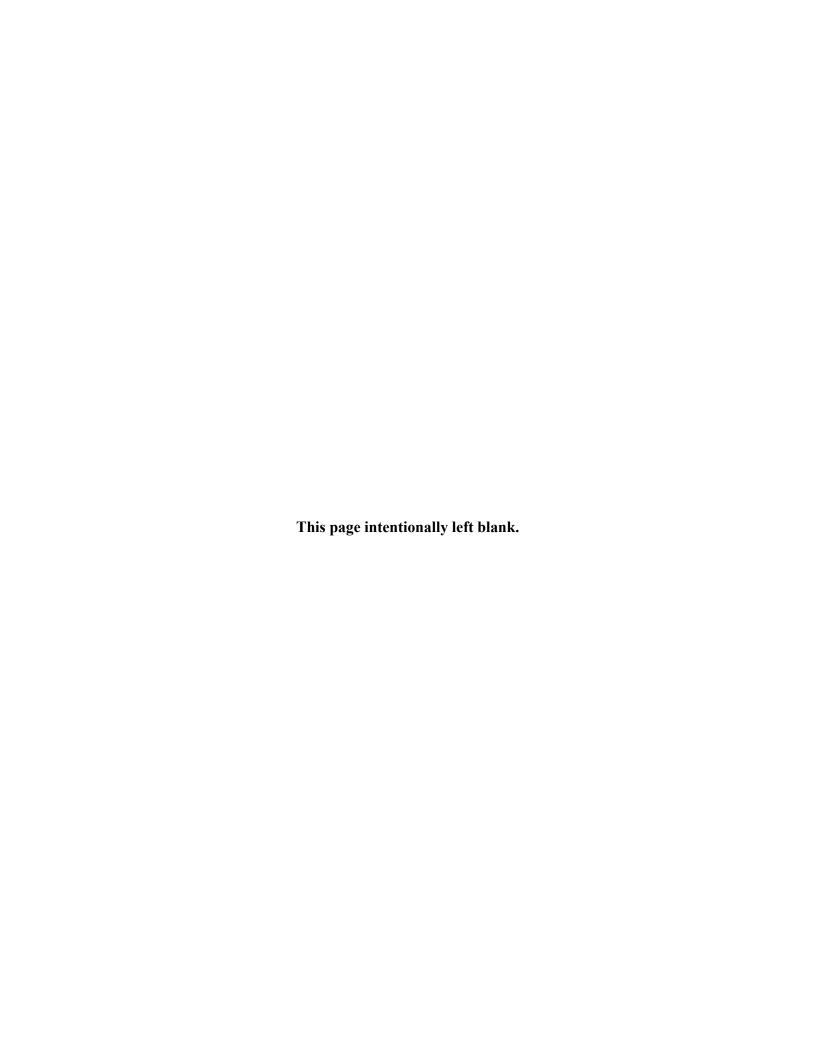
Enclosures 2:

Summary of Key Issues Raised in Public Comment Process

Final Post-2006 Conservation Program Structure



# APPENDIX C Post-2006 Key Issues



#### Energy Efficiency Bonneville Power Administration

## **Final Post-2006 Conservation Program Structure**

## **Summary of Key Issues Raised in Public Comment Process**

At the suggestion of Bonneville Power Administration (BPA), a Post-2006 Conservation Workgroup composed of over 65 utility representatives and conservation stakeholders was formed in the fall of 2004. This group met frequently to discuss new and existing approaches to BPA's conservation program for the post-2006 period. In January 2005, this group provided BPA recommendations and comments to help design the proposal that BPA distributed for public comment.

BPA issued its Post-2006 Conservation Program Structure Proposal for a 30-day public review and comment period on March 28, 2005. The close of comment period ended April 28, 2005. BPA received 56 comment letters and e-mails. Comments received are important to BPA and help provide guidance to improve upon BPA's and the region's efforts to develop conservation and energy efficiency.

After the brief program overview presented below, this document provides a statement of what was proposed for each key issue raised during the public comment period, a summary of the comments received on that topic, and BPA's response and evaluation for each issue. Again BPA appreciates the efforts of those parties taking the time to review the proposal. BPA has taken care to provide clarification of its program elements in response to any and all concerns raised in comments BPA received.

## **Program Overview**

The portfolio of energy efficiency programs BPA will be offering for the post-2006 period is very similar to what is currently available. The key features of the final program are as follows:

- 1. a conservation rate credit (CRC) program (patterned after the current C&RD);
- 2. a **bilateral contracts program** for utility and federal agency customers (similar to the current ConAug program);
- 3. a **third-party contracts program** for cost-efficient, region-wide approaches (similar to the VendingMi\$er program and includes support market transformation via the Northwest Energy Efficiency Alliance ((NEEA)));
- 4. support for critical **infrastructure** elements, including program evaluations to assure programs are achieving their intended targets;
- 5. a separately funded renewable resource option; and
- 6. a spending amount of \$80 million/year intended to achieve BPA's 52 aMW/year share of the Northwest Power and Conservation Council's (Council) regional cost-effective conservation target at a weighted average cost of \$1.5 million/aMW.

# **Key Issues: What was Proposed, Comment Summary, Evaluation and Final Decision**

<u>aMW Target Gap Proposal</u>: Based upon the Northwest Power and Conservation Council's (Council) Fifth Power Plan, there is a regional conservation target over the 2007-11 period of about 700 aMW. BPA's responsibility to achieve its share of this regional target is based on the amount of regional firm load that BPA supplies with federal power. BPA estimates that it is responsible for about 40 percent of the 700 aMW or 280 aMW. While this amount equates to an annual target of 56 aMW, BPA proposed that it is reasonable to adjust the amount of its target to take into account the amount of "naturally occurring" conservation (about 7 percent or 4 aMW/year). As a result, BPA proposed to pursue a 52 aMW/year conservation target for the total of 260 aMW over the 2007-11 period.

BPA's existing and proposed conservation program structure is not focused on a centralized conservation acquisition program. To the contrary, most BPA programs are structured to provide funding support to BPA's customers and others to pursue and achieve regional conservation. Consequently, BPA proposed to include any and all of the conservation that is achieved and attributed to BPA's funding mechanisms toward the 52 aMW annual target, including the conservation achieved by investor owned utilities (IOUs) under the rate credit program and the conservation accomplished by BPA funding support for NEEA.

Summary of Comments Received: Some comments suggested that BPA should not reduce its share of the regional conservation target for "naturally occurring" conservation (NEEC; NWEC; SCL); others agreed with this reduction (Benton REA; PPC). Some comments stated that the target was too low and that BPA should consider the IOU exchange load as part of the calculation for determining BPA's share of the regional conservation target (Council; NEEC; NWEC; PSE; WCTED). Others agreed that BPA should count the IOU conservation accomplished with BPA funds, even though BPA is not responsible for the IOU conservation (Benton REA; PPC). Another comment suggested that BPA should be responsible for only 38 percent of the regional conservation (rather than rounding to 40 percent) (Inland). Another concern that was raised related to the "gap" between the Council's five-year Action Plan (2005-09) and BPA's planned conservation horizon from 2007-11 (Council; NWEC). They felt that there was a "gap" in 2005 and 2006 between BPA's current targets and the new ones and that it would be very difficult for BPA to "close the gap" with the proposed funding levels for 2007-09. One commenter indicated that the aMW target was too high and that more residential measures were needed (Benton PUD).

Evaluation and Final Decision: With conservation being the least-cost resource for the region, BPA is aware that achieving the targets set by the Council are important to the region as a whole. Determining a reasonable percentage of the region's conservation target requires BPA to consider several factors, such as load and conservation that is naturally occurring. A factor that BPA believes is reasonable to reconsider, as expressed in comments above, is the duration of the planning horizon. As proposed, BPA is committed to achieving the 52 aMW/year conservation target. BPA will work toward this amount for the 2005-09 period, rather than the proposed 2007-11 period. This change reflects an adjustment and commitment by BPA to align the new conservation targets with the same five-year planning horizon in the Council's Fifth Power Plan. BPA expects to meet its 2002-06 target (220 aMW averaging 44 aMW/year) by the end of FY

2006. BPA will seek to acquire an additional 16 aMW on top of the 220 aMW target by the end of 2006 in order to be on track to meet the new target of 52 aMW/year (see table below).

Average Annual Target

New target for 2005 and 2006 52 aMW/year

Old target for 2005 and 2006 44 aMW/year

Additional aMW BPA will acquire to close gap 8 aMW/year X 2 years = **16 aMW** between the old and new targets for 2005 and 2006

As indicated in the March 28 proposal, BPA will count all conservation savings achieved with its funds toward the new target.

**Budget Proposal:** BPA's proposed annual budget (capital and expense) for achieving the target of 52 aMW/year was \$75 million. For the 2007-2009 rate period, the conservation rate credit (CRC) would be \$0.0005/kWh (1/2 mill) on utility-purchased firm power from BPA and the equivalent treatment for IOU residential benefit payments. This equates to roughly \$42 million. It is anticipated that \$6 million per year out of the \$42 million will be spent on renewable resource-related initiatives. BPA proposed paying an average of approximately \$1.4M/aMW (which includes some administration allowance and infrastructure support costs) across the entire portfolio of programs.

Summary of Comments Received: Many commenters suggested that the budget was too low (Council; EPUD; EWEB; Faste; Franklin PUD; Interfaith GWC; ODOE; NEEC; NWEC; SCL; WCTED) with some proposing a budget increase of \$25 to \$35 M/year to achieve the higher targets (Council; EPUD; NEEC; NWEC). They indicated that it will cost closer to \$1.8 to \$1.9 M/aMW and not the \$1.4 M/aMW that BPA proposed. Several comments recommended that BPA establish a "backstop" funding mechanism or contingency plan in case the proposed budget was insufficient to capture the new targets (Benton PUD; Council; EWEB; NWEC; WCTED). Some comments recommended that more funds are needed for infrastructure support and to address inflation (SCL; NWEC). One comment suggested that the budget was sufficient as proposed (SUB).

Evaluation and Final Decision: The fundamental question for BPA is what is the minimum spending level that will produce the targeted conservation savings level. Based on the comments received and further assessment, the spending level should be increased by \$5M/year. This will provide \$80M/year to capture the 52 aMW/year target. A majority of the comments received on this issue expressed support for this amount of funding. This increased amount of funding will provide customers and the region greater program flexibility at an average cost of \$1.54M/aMW across the entire portfolio of programs, including the administrative cost allowances and infrastructure support (see Table 1). BPA believes these additional funds will facilitate achieving the Council's new targets by providing utilities a reasonable level of administrative allowance for the rate credit and the bilateral contract programs and more funds for incentives across the program portfolio BPA will be offering.

 Table 1: Final Conservation Program Annual aMW Targets and Budgets

<b>Program</b>	<u>aMW</u>	<b>Budget</b>	Cost/aMW
Rate Credit (at 0.5 mills = \$42M*/year)+	20	\$36M	\$1.8M
Utility & Fed. Agency Bilateral Contracts+	17	\$26M	\$1.5M
Third-Party Contracts	5	\$7M	\$1.4M
Market Transformation (via NEEA)	10	\$10M	\$1.0M
Infrastructure Support and Evaluation	<u>=</u>	<u>\$1M</u>	
Total	52	\$80M	\$1.5M

<sup>+ -</sup> includes a 15 percent administrative cost allowance.

<u>Administrative Allowance Proposal</u>: BPA proposed to include up to 10 percent administrative costs in the rate credit and bilateral contracts programs. Small utilities (7.5 aMW and under) would be allowed up 20 percent for administrative costs, provided they pursue cost-effective measures (or renewables) with the remaining 80 percent.

Summary of Comments Received: Many of the comments stated that allowing 10 percent for administrative costs under the rate credit was too low (Benton PUD; Cowlitz; EPUD; Franklin; Grays Harbor; Hermiston; Idaho Falls; Lincoln Electric; Okanogan; PPC; PNGC; Richland; SCL; SUB; Umatilla; Whatcom). It was suggested that 20 percent was more realistic given the new oversight and reporting requirements under the proposed rate credit program (Canby; Cowlitz; EPUD; Idaho Falls; Okanogan; Pacific; PPC; PNGC; SCL; SUB). One commenter thought 10 percent was too low and 20 percent was too high (Inland). A few commenters appreciated BPA including the up to 10 percent administrative costs under the bilateral contracts program (Cowlitz; Lincoln Electric; PPC).

Evaluation and Final Decision: BPA understands the concerns expressed in many comments regarding the administrative costs associated with implementing the new programs. BPA recognizes that many customers view a successful conservation program to include allowance for administration. BPA agrees with comments recommending an increase in the amount allowed under the program for administrative costs. BPA believes it is reasonable to increase the administrative allowance by 5 percent to allow up to 15 percent administrative costs in the rate credit and utility/federal agency bilateral contract programs. For the bilateral contracts, the 15 percent administrative allowance will be added to BPA's incentive amount that is invoiced. Small utilities will be allowed up to 30 percent for administrative costs. BPA also wants to continue to discuss with the region whether or not going forward into the next rate period with the 15 percent administrative expense is the right level or if a further adjustment is appropriate.

<u>Willingness To Pay (BPA incentives) Proposal</u>: BPA proposed a \$75M/year budget to achieve 52 aMW/year. This equates to an average cost of \$1.44M/aMW across the portfolio of energy

<sup>\* -</sup> assumes \$6M/year of the \$42M/year from a separate renewables budget will be spent on renewables.

efficiency programs, including the 10 percent administrative allowance and 1M/year for infrastructure support.

BPA would attempt to minimize willingness to pay adjustments. BPA may adjust payments with six months notice, if necessary, to compensate for such things as changes in codes, market prices, technology penetration or to stay on pace with targets. Adjustments would apply to measures installed after the date the adjustment notice is effective. No retroactive adjustments would be applied.

Summary of Comments Received: Some commenters suggested that BPA should allow payment up to the cost-effective level or threshold (EPUD; Idaho Falls; Lincoln Electric; Okanogan; PPC; Richland). Other comments recommended that BPA should not change our energy conservation measure (ECM) incentives more than once a year and only if there is a +/-10 percent change (Hermiston; PNGC). One comment stated that the levels BPA proposed are too low (Pacific). A few comments suggested that BPA should allow funding for code enforcement and count those aMW saving toward the target (PPC; SCL; SUB), allowing utilities to bring in conservation at an average rate and providing an incentive to get the most savings at the least cost (SUB). One comment suggested that BPA pay based on value to the system (the same as C&RD does now) (PNGC). Another comment suggested that there was not a rationale for paying less per aMW in the bilateral contract program than in the rate credit program (EWEB).

**Evaluation and Final Decision:** As discussed earlier, BPA will increase its budget by \$5M/year which results in a new weighted average cost of \$1.54M/aMW across the entire program portfolio. The proposed cost was \$1.44M/aMW. The increase to the new 15 percent administrative allowance and the \$1M/year infrastructure support budget are covered in this revised cost target. BPA will continue to refine the details on BPA's incentives for cost-effective measures. BPA is receiving input from a Conservation Workgroup Phase 2 Committee composed of nine experienced utility representatives.

Since this is only a three-year rate period, BPA plans to make incentive payment adjustments on a six-month basis, but only if absolutely necessary. BPA is sensitive to comments that continual program changes can compromise program effectiveness. Hence, BPA will strive to implement changes as we do today on an annual basis.

<u>Cost-Effective Measures Proposal</u>: BPA proposed to pay only for cost-effective measures as defined by the Council in its Fifth Power Plan.

Summary of Comments Received: Many comments suggested that BPA should not use the Council's total resource cost (TRC) approach, but rather the utility-specific utility test cost (UTC) parameter and that non-energy benefits need to be included in the analysis (Benton PUD; Benton REA; EWEB; Franklin; Grays Harbor; Lincoln Electric; Port Angeles). Some commenters felt that the cost-effectiveness criteria BPA is relying on was arbitrary and that they did not agree with the TRC approach (Benton REA; EWEB; Franklin; Hermiston; Umatilla). Some comments noted that the TRC ignores values to consumers or utilities that are very real economic values (Cowlitz; EWEB; Grays Harbor). Several did not support limiting the list of approved ECMs to only cost-effective measures (Benton PUD; Cowlitz; EPUD; Franklin; Grays Harbor; Hermiston; Idaho Falls; Lincoln Electric; Okanogan; Pacific; Richland; SnoPUD; Umatilla; Wells REC). Other comments recommended that more residential measures be

included in the approved ECM list (Benton PUD; Port Angeles). Some comments suggested that BPA consider packaging like measures (SCL; WCTED). One comment supported BPA's position and stated that there are other cost-effective measures not included in the Council's plan (Council).

**Evaluation and Final Decision:** In general, conservation is considered the least-cost resource to meet increases in load demand in the Pacific Northwest. The Northwest Power Act provides that BPA support the development of cost-effective conservation. The Act includes a definition of the term "cost-effective" which applies to any conservation measure or resource BPA funds. BPA is not persuaded by comments that suggest use of an alternative standard or definition of cost-effective measures. If the region is to pursue non-cost-effective measures, then the region cannot achieve the least-cost approach mapped by the Council. BPA payment for measures that are not cost-effective has the potential to drive up BPA's overall budget and rates since non-cost-effective measures would not count against the annual 52 aMW target, since that target is for cost-effective conservation. Paying only for cost-effective conservation measure also ensures resources are being acquired at the lowest cost to the region. Both BPA's Strategic Direction (July 2004) and regional Dialogue Policy (February 2005) reinforced the achievement of "cost-effective" conservation by BPA. Thus, BPA concludes that conservation programs should follow the TRC mandate of the Council.

However, within this cost-effective constraint, BPA will make its programs as accommodating as possible toward customers' conservation strategies and priorities. For example, BPA proposed that "only cost-effective measures on the Regional Technical Forum (RTF) list would be allowed." BPA does not consider the RTF list to be exhaustive and has repeatedly said there may be cost-effective measures that can be implemented that are not on the list. For example, most industrial and almost all non-lighting commercial measures cannot be on a deemed list, yet many are cost-effective in most applications. The following provides additional clarification regarding this issue:

- Measures must be cost effective, but do not need to be on an approved measure list.
- Measures may be added through the rate period.

<u>Incremental Conservation Proposal</u>: BPA proposed that its conservation funding be used by our customers for energy efficiency savings and related activities beyond what they are required by law and/or regulatory requirements to accomplish.

Summary of Comments Received: A few comments opposed the incremental requirement stating that it was "unreasonable discrimination," that it punishes utilities that have been investing in conservation, especially in the state of Oregon, and that it sends the wrong signal (CUB; EPUD; EWEB; OPUC; SnoPUD). They felt that utilities that spend 3 percent of their retail revenues on conservation should be exempt from the incremental requirement. Other commenters agreed that the IOUs should be required to provide incremental savings (NWEC; PPC). Several comments suggested that NEEA contributions be allowed under the rate credit (Council; Cowlitz; EWEB; NEEA; NEEC; PPC; SCL; WCTED), although one comment agreed with BPA's proposal to not allow NEEA contributions to qualify for the rate credit (Inland).

**Evaluation and Final Decision:** BPA agrees that customers cannot be expected to face an ill-defined threat that their conservation activities my be defined as non-incremental. For this reason, BPA will add a "state" qualifier to the statement such that it will read "required by state WP-10-FS-BPA-05A

law or regulation." This will be used to determine incrementality. A public utility board of directors decision to pursue a particular conservation program, for example, would not, in itself, make that conservation non-incremental.

As background, incremental spending is currently required under the existing C&RD program. BPA appreciates the fact that Oregon enacted legislation that requires the state's IOUs to charge a 3 percent public purpose charge. BPA understands that this program has been successful in facilitating development of conservation and renewable resources associated with service to consumers served by the IOUs. However, BPA does not agree that it is unreasonable discrimination to require incremental spending in this case. It is not in the best interest of the region to offer a conservation credit through power rates to customers to simply subsidize programs or costs otherwise required by state law or regulation.

As explained above, BPA thus believes it is reasonable to retain the requirement that use of the CRC be incremental to spending required by state law and/or regulatory requirements.

<u>Eligibility Proposal</u>: With respect to eligibility to participate in the rate credit program, preference and federal agency customers are eligible to participate in the CRC and can submit proposals under the bilateral contract program, and the IOUs are eligible to participate in the CRC. BPA did not propose to make the direct service industrial customers (DSIs) eligible for the CRC or bilateral contracts programs because of the extreme financial risk associated with installing conservation measures on such unstable loads.

Summary of Comments Received: Two comments strongly suggested that DSIs should not be excluded from participation in the rate credit (Port Townsend Paper; Alcoa). One stated that BPA should develop non-discriminatory eligibility requirements for its programs, but if DSIs are ineligible, then they should be offered the discounted rate (Alcoa). On the other hand, there were some comments supporting BPA's proposal that the DSIs not be eligible for the rate credit (SUB). Another commenter suggested that IOUs should only be able to invest in conservation in residential and farm loads and that any IOU rate credit benefits should be carefully monitored (Inland). One comment stated that BPA should clarify rate credit eligibility for customers with pre-subscription contracts (PPC).

**Evaluation and Final Decision:** BPA's proposal to exclude the DSIs from participating in the CRC because as a power customer class the aluminum-related DSIs have only operated at a minimal level during the current rate period and are highly dependent on market conditions (both world alumina prices and electricity). As a result it is not clear what the measure life would be for any installed ECMs in aluminum-related facilities. The aluminum-related DSI load has been severely curtailed over recent years, particularly when power demand is reduced due to economic business conditions that are totally unrelated to energy efficiency at DSI facilities.

Therefore, BPA clarifies that only aluminum-related DSI loads will not be eligible for the CRC and bilateral contract programs.

<u>Decrement Proposal</u>: BPA proposed to continue its current practice of not decrementing the slice/block customers under the rate credit program, but requiring load decrements under the bilateral contracts program. The decrement would not apply to the NEEA contract. Whether or not the decrement applies to other third-party contracts involving slice/block customers would be

determined on a case-by-case basis. Customers would be kept informed of any potential conservation activities in their service areas and if a decrement would be applied should they decide to participate in any proposed third-party conservation initiative.

Summary of Comments Received: Several commenters opposed any decrement and stated that the decrement is a barrier to achieving the higher conservation targets (Benton PUD; Council; EWEB; Grays Harbor; NEEC; NWEC; PNGC; Port Angeles; SnoPUD; Umatilla). A couple of comments claimed the approach in BPA's proposal was inconsistent (i.e., not decrementing the rate credit, but decrementing the bilateral contracts) (NEEC; NWEC). One comment suggested that decrementing the slice/block customers was appropriate (Inland). Some comments suggested that BPA consider "sharing the benefits and losses" of the decrement between BPA and the decremented customers (EWEB; NWEC; SUB). Another comment letter agreed with decrementing the bilateral contracts (Lincoln Electric).

**Evaluation and Final Decision:** The issue of decrement was one of the most challenging for BPA and the Conservation Workgroup. The preponderance of views from the Workgroup were consistent with the approach proposed by BPA, which is basically to continue the decrementing policy being used in the 2002-06 rate period. Based upon input BPA received, BPA believes that the "no decrement" decision is warranted under the rate credit program and under the NEEA contract. In these instances BPA is providing funding through the CRC or via a funding mechanism to a regionally supported conservation organization. BPA is not directly expending dollars to acquire conservation savings from these parties to meet and serve BPA's firm power load obligations. Thus, while BPA will take into account any actual conservation savings achieved through these programs, BPA will not correspondingly reduce or decrement the amount of federal power customers are eligible to buy from BPA. On the other hand, customer participation in bilateral conservation acquisition contracts with BPA could result in reduction in the amount of federal power being purchased to the extent such contracts obligate the customer to deliver actual energy savings. BPA believes, as stated in the original proposal, that decrementing is important to minimize cross-utility subsidies and to ensure that the benefits from conservation flow to BPA and its customers. BPA considers this strategy, along with the change to pay only for cost-effective measures, a positive step toward BPA's goal of achieving conservation at the lowest possible cost.

<u>Donations Proposal</u>: Third-party subcontracts with energy organizations would be allowed provided cost-effective aMW savings result. Utilities could not take administrative payments on pass-through contracts. Administrative costs must be tied to actual program delivery. Because BPA contracts directly with NEEA to conduct market transformation activities on behalf of all the loads paying into the conservation budget, utilities would not be allowed rate credit reimbursement for contributions to NEEA.

Summary of Comments Received: Many commenters suggested that BPA allow rate credit reimbursement for NEEA donations and BPA should count the associated aMW savings toward the target (Council; Cowlitz; EWEB; NEEA; NEEC; PPC; SCL; WCTED). One comment expressed support for not allowing NEEA donations under the rate credit (Inland). Several commenters indicated that we should not limit donations to low income weatherization since BPA is requiring the funds only be spent on cost-effective measures (EPUD; EWEB; PSE; SUB).

**Evaluation and Final Decision:** In part because of the almost unanimous support for a change to BPA's proposal, BPA has decided to allow the rate credit to be used for contributions to NEEA. BPA will include these funds in determining its share of the NEEA aMW achieved and will count those aMW toward its new target. Third-party subcontracts with energy organizations will be allowed provided cost-effective aMW savings result. For example, if a utility chooses to subcontract with a local low-income (CAP) agency, the utility might specify that its funds go towards CFL installations in low income homes. There will be no cap on these types of activities since they will produce cost-effective conservation savings.

Small Utility Option Proposal: BPA proposed that small utilities (defined under the C&RD as those with a total load of 7.5 aMW or less) would be required to pursue cost-effective conservation measures that are achievable in their service area if they chose to participate in BPA's conservation programs. A variety of options and tools will be available for small utilities. These options and tools would provide several avenues to make it practical for even very small utilities to participate without incurring overly burdensome overhead (e.g., standard offers, off-the-shelf programs and templates, pooling, third-party options, etc.). A small utility could choose to use anywhere between 0 percent to 20 percent of its rate credit for administrative costs. Some small utilities could choose to simplify their spending of their rate credit by purchasing renewables. Small utilities would report savings through the RTF database in the same manner that all other utilities report.

**Summary of Comments Received:** Some commenters recommended that BPA retain the existing C&RD small utility policy (*Columbia Power; NRU; PPC*), with one commenter recommending that the threshold should be increased from the current 7.5 aMW to 15 aMW (*Irecoop*). One commenter requested further clarification of what small utilities could do to qualify for their rate credit (*NRU*). Some commenters did not want the *pro rata* approach for renewables to apply to small customers (*Fairchild AFB; USDOE-Richland*).

Evaluation and Final Decision: BPA wants to make participation in the rate credit feasible for small utilities, while ensuring that dollars actually go to cost-effective conservation and renewables. BPA will make several changes in response to comments to help make small utility participation feasible. BPA will include up to 30 percent for administrative costs, ensure that small utilities who wish to spend their rate credit dollars on renewables can do so without being affected by a *pro rata* adjustment if renewables are over subscribed by customers (exceed the \$6M/year cap), provide a checklist of simple programs and initiatives suitable for a small utility to implement, and modify the performance reporting requirements to align more with their capabilities. More detail on these changes is included in Attachment 1. These changes, and others BPA will seek through ongoing work with these utilities, should facilitate small utilities' achievement of conservation and renewables with rate credit dollars within their limited staff resources. BPA will keep the 7.5 aMW size limit definition and maintain the proposed requirement that small utilities acquire cost-effective conservation (or renewables) in order to participate in the rate credit program.

<u>Third-Party Involvement Proposal</u>: BPA proposed that this third-party contract component of the program portfolio would allow BPA to contract to third parties when these contracts would lower the cost of acquiring conservation or where needed to affect markets that cannot be changed at a local level. In general, regional programs would be designed to operate in

coordination with local utility programs. For example, regional bulk purchases of a technology might be delivered locally. These third-party contracts may include activities such as the market transformation efforts of NEEA, bulk purchases and vendor programs.

Pre-committed funding for NEEA (\$10 million per year for the next three years) is included in this mechanism, and no decrement is proposed for the NEEA bilateral contract.

#### **Kev Features**

- Reasonable administration costs for third-party contracts would be negotiated.
- Region-wide programs and efforts would be coordinated with local utilities.
- A determination of whether or not a decrement applies for other third-party programs would be determined on a case-by-case basis.
- Customers would be kept informed of conservation activities in their service territories and whether or not a decrement would be applied.

**Summary of Comments Received:** Many comments indicated that third-party bilateral contracts were OK, but only with local utility approval for the vendors to work in their service areas (Benton PUD; Franklin; Hermiston; Lincoln Electric; Okanogan; PPC; PNGC; Richland; Umatilla). One commenter endorsed the approach if cost-effective savings result (Inland).

**Evaluation and Final Decision:** BPA will contract with third parties when these contracts would lower the cost of acquiring conservation or where needed to affect markets that cannot be changed at a local level. BPA will only pay third parties to work in utility service territories that have agreed to participate in the third-party program. This policy of requiring pre-approval of utility partners is a continuation of BPA's current policy and is consistent with the recommendations of the majority of the comments BPA received on this issue. The use of the phrase "customers would be kept informed" in the proposal about third-party contractors was not intended to imply any change from the current policy of getting utility agreement for third-party activity before sending any third parties to do BPA funded conservation in the service territories of our customers. BPA believes having access to third-party vendors as part of it overall conservation portfolio would help lower the cost of acquiring conservation, especially when it needs to affect markets that cannot be changed at a local level. Utilities will not face a decrement for conservation done by third parties without their prior agreement to that result.

Rate Credit Performance Requirements Proposal: BPA proposed that utilities would report at least semi-annually to BPA. Use of the RTF reporting software would be required. If, at the first semi-annual report, the utility was not meeting its targets (50 percent or less of its expected rate credit spending), the utility would have to prepare and have BPA approve an action plan that provides sufficient proof of achievable intent by the end of the first year after the program starts. If by the third semi-annual report the utility was not performing (i.e., is 75 percent or less than its expected rate credit spending progress), BPA would have the option of cutting off the rate credit at the beginning of the third year. At the end of the third year of the rate credit program, there would be a true-up required for all participating utilities.

**Summary of Comments Received:** Several commenters supported the six-month reporting requirement (Cowlitz; Pacific; PNGC). One commenter recommended that the initial check-in occur after one year rather than at six months (Canby). Another commenter recommended reporting on a quarterly basis (Council). A few commenters recommended that BPA re-evaluate

the rate credit program if the goals are not being met (*Lincoln Electric; Okanogan; PPC*). Another commenter suggested that peers rather than BPA should judge performance and be able to suggest remedies for the BPA program design (*SUB*).

**Evaluation and Final Decision:** BPA's goal is to achieve the targeted rate credit aMW by the end of the rate period. A shorter rate period (three years instead of five) coupled with the need for utilities to develop and field programs to target cost-effective technologies that many utilities are not currently targeting, means utilities will need to develop and implement a plan early in the new rate period for achieving the conservation. BPA realizes it may need to provide tools and resources to assist utilities in this effort. The semi-annual reporting will enable BPA to identify and provide assistance to those utilities who need additional help soon enough that the targets for the rate period can be met.

BPA's intent is to provide assistance to utilities as needed to ensure the rate credit aMW is achieved. The reporting requirement provides the "flag" that allows BPA to identify and assist those utilities that need help. BPA will retain the requirement for semi-annual progress reports via the RTF reporting system. To address commenters' concerns, utilities will need to submit an Action Plan only if sufficient progress has not been made (i.e., 50 percent or less of its expected rate credit has been spent) at the end of the first full program year. BPA staff will be available to assist utilities in developing an Action Plan that will indicate how the utility will spend its rate credit funds by the end of the rate period (9/30/09). BPA's goal is for every participating utility to spend the full amount of its rate credit on qualified conservation and/or renewables activities by the end of the rate period. If at the 18-month period (third progress report) participants still have not made sufficient progress on their rate credit spending (i.e., 75 percent or less of their expected rate credit has been spent), then BPA may send a notification letter that the rate credit will be withdrawn for the third year of the program (i.e., customers will be required to pay the full PF or other appropriate power rate) so the funds can be reallocated. At the end of the third year of the rate credit program (9/30/09), there will be a final true-up required for participating utilities to make sure BPA's rate credit funds were spend on qualified measures. BPA is making these changes because it understands the concern about having a hard spending requirement too early in the new program's start-up period.

With regard to the bilateral contracts, since these are pay-for-performance type contracts, BPA will have a pretty good idea of how the delivered savings are proceeding. However, BPA will retain the right to withdraw budget commitments if participants are not making sufficient progress on delivering the agreed upon savings. This will be done on a case-by-case basis and in conjunction with the affected customer.

Oversight Proposal: Purpose: The expenditure of funds included in the published BPA rates for purposes of achieving conservation (and renewables, if applicable) is an activity for which BPA has fiduciary responsibility. In addition, by providing constructive oversight, BPA may be able to provide assistance to utilities to improve the programs and reporting.

(a) BPA proposed that BPA or BPA's agent shall have the right to conduct inspections of units or completed units and monitor or review utility's procedures, records, verified energy savings method and results, or otherwise oversee the utility's implementation of conservation programs funded through dollars included in BPA's rates. The number, timing, and extent of such audits shall be at the discretion of BPA. Such site reviews are expected to be conducted

annually. Such audits shall occur at BPA's expense. Financial audits shall be in compliance with the audit standards established by the Comptroller General of the United States. BPA may contact appropriate federal, state, or local jurisdictions regarding environmental, health, or safety matters related to units or completed units.

(b) Prior to any oversight visit physical inspection, BPA shall give the utility written notice. If physical inspections are required by BPA, the utility shall have 30 days to arrange for the inspection of units or completed units. The oversight visit would include (but is not limited to): a review of energy audit or measure installation procedures, technical documents, records, and/or verified savings methods and results.

Summary of Comments Received: Regarding the rate credit, several commenters were concerned about the oversight being overly burdensome (i.e., don't use the past receipt and acceptance approach) (Benton REA; Cowlitz; Lincoln Electric; Okanogan; PPC; Umatilla). Some of the commenters suggested that only one audit should be necessary over the third-year rate period if participants are in substantial compliance (EPUD; Hermiston; PPC; PNGC; Umatilla). A few commenters indicated that our current ConAug oversight approach should be used for the rate credit (Hermiston; Port Angeles; SCL). One commenter recommended that BPA consider relying on participants' CPA or state auditors to meet BPA financial audit requirements (Umatilla). Another commenter objected to creating third-party transactions whereby BPA interfaces with end-users (SUB). One commenter recommended that reporting not be broken down to member level of pooling customers (PNGC).

Evaluation and Final Decision: To carry out its fiduciary responsibility, BPA believes that it must preserve the oversight rights described in its proposal. Although the detailed contract language on "oversight" has extensive language about the rights BPA has, the actual implementation of the oversight has not been onerous. Utilities experienced with ConAug oversight reiterated that it has not been a burden in reality. The Conservation Workgroup recommendations endorsed this approach to oversight for the new rate credit program. BPA does want to clarify that it will require only one oversight visit per year under the rate credit program and that it will try to coordinate that visit with any bilateral contract oversight requirements, if reasonable. Accordingly, BPA will aim to have one oversight visit for all of its conservation programs for each participating utility, unless major issues surface.

Another clarification relates to confusion about another utility performing oversight on a customer's contracts. This was never intended. Third-party evaluation contractors could be used for evaluations, but they will perform confidential work for research purposes not contract oversight. No utilities will be tasked with looking at the books of other utilities.

Renewables Proposal: BPA proposed a renewables option under the rate credit program that requires customers to commit up-front as to the portion of their rate credit they will apply to renewables for the full three years of the rate period and to do so by 7/1/06. This up front commitment would provide certainty of the amount of rate credit money that was available for conservation. Further, BPA proposed capping the level of renewables funding under the rate credit to \$6 M/year. If customers subscribe for more than \$6M/year, then BPA proposes to pro rate their shares down to the \$6M/year cap.

Summary of Comments Received: Some commenters recommended that BPA allow annual sign-ups for renewables, rather than a three-year commitment up-front as proposed (Benton

REA; PPC). A few commenters indicated that they would like to continue to have an option of purchasing green power under the new rate credit (Benton PUD; PPC; USDOE-Richland). In addition, some commenters recommended that the federal customers should not be subject to pro-rating (Fairchild AFB; USDOE-Richland). Another commenter wanted BPA to reconsider the pro-rating approach for over subscription on renewables (SnoPUD). One commenter was opposed to the \$6M/year renewables cap (Interfaith GWC; Whatcom). Some commenters wanted customer-side renewables and related R&D funded under the rate credit (EPUD; EWEB; Ferry County; SCL).

Evaluation and Final Decision: Consistent with commenters' recommendations, BPA will require a three-month advance notice prior to each year of the rate period (2007-09) with a \$6M/year cap that will be pro rated if customers over subscribe. Small utilities (7.5 aMW and under) and BPA's federal agency power customers will be exempt from this *pro rata* requirement. This will provide sufficient advance notice to BPA regarding the amount of rate credit and thus aMW that will be achieved with the rate credit funds but provides additional flexibility for customers that manage their rate credit on an annual basis. Exempting small utilities and federal agency customers from the *pro rata* requirement will not compromise the plans these customers may put in place satisfy their rate credit obligations. BPA will issue for public review and comment a menu of renewable resource-related activities that will qualify for the rate credit prior to the program start date.

<u>Starting Programs Early Proposal</u>: BPA proposed to begin the CRC program when the new rate period started (i.e., October 1, 2006). Also, BPA planned to have the new bilateral contracts ready for signature in the fall of 2005, but not provide any funding until the new rate period started (i.e., again, October 1, 2006).

Summary of Comments Received: A few commenters recommended that BPA allow customers that have met their C&RD spending requirements to start funding projects/programs for the new rate credit early (e.g., similar to what BPA did with the C&RD during the 2001-02 energy crisis) (Benton PUD; Idaho Falls; Wells REC;). One commenter recommended that BPA allow for a smooth transition to future programs and that BPA should provide an option for customers to discontinue their participation in the rate credit (Idaho Falls).

Evaluation and Final Decision: BPA has worked hard over the last several years to provide stable level funding for its conservation programs. Allowing customers to implement the new programs early will provide continuity in the delivery of cost-effective conservation and helps avoid a potential "slow-down" in the achievement of aMW savings as customers transition from the old programs to the new ones. Accordingly, BPA, in response to the comments received on this issue, will allow customers that have used all their C&RD credits and have filed a final close-out report to spend their funds under the new rate credit starting in CY 2006 (targeted for January 1, 2006) and claim spending on approved, cost-effective ECMs when the new rate credit kicks in (October 1, 2006). This approach will require customers to indicate their willingness to participate in the new rate credit program (should it be approved in the rate process) and follow the implementation rules as defined by BPA. (Note: There is a risk to utilities if they begin before the new rates are finalized. This is similar to the risk some utilities assumed when they started their rate credit conservation activities early in 2001 before the current rate period.)

In response to a commenter's request, BPA will include a mechanism or procedure for customers to discontinue participation in the rate credit should they choose to do so. However, the customer has to continue to pay the full PF or appropriate power rate, including the 0.5 mill adder, for the remaining portion of the rate period.

Also, in response to commenters' recommendations and because BPA recognizes some customers may slow down their bilateral program efforts until the new bilateral contracts are available for execution, BPA will offer new bilateral contracts for execution this fall (targeting October 1, 2005). This will allow customers to begin implementing projects under the new contracts (with the new rules and incentive levels) during the current rate period. BPA believes this approach will allow BPA to maximize the use of existing rate period conservation budgets to facilitate achieving the higher targets presented in the Council's Fifth Power Plan.

#### **Attachment 1**

# Post-2006 Conservation Program: Small Utility Option under the Conservation Rate Credit

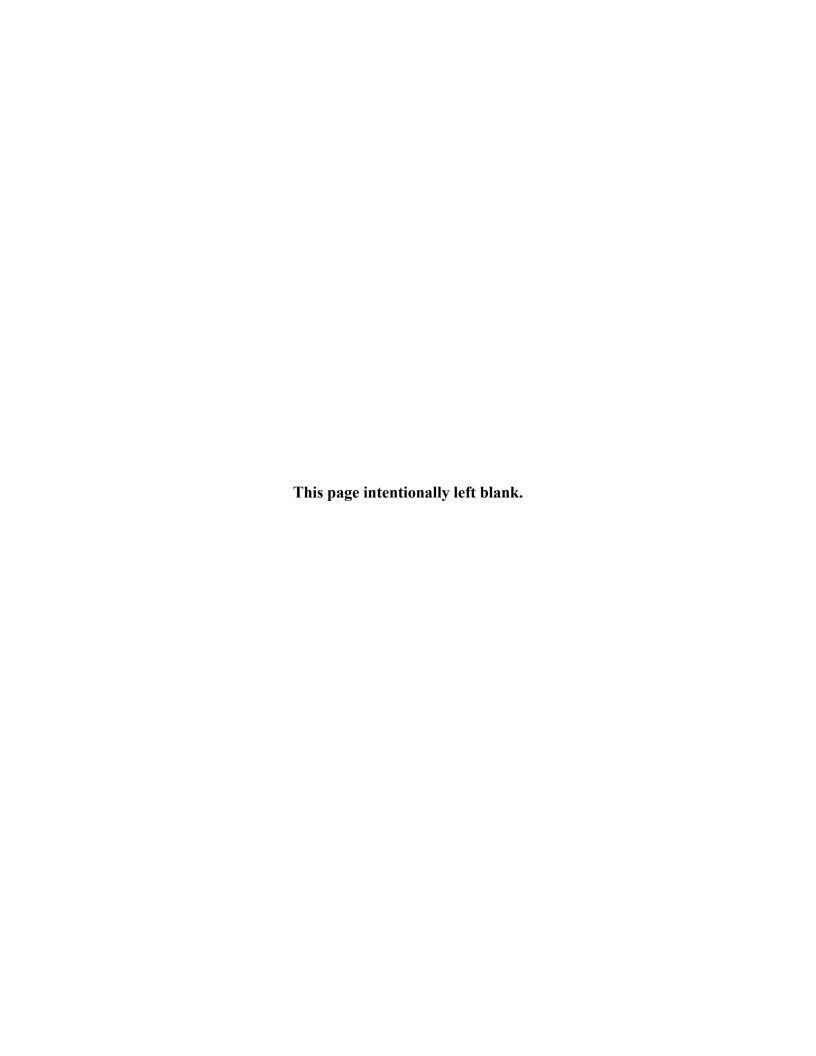
Keep the 7.5 aMW size limit and maintain the requirement that small utilities must acquire cost-effective conservation (or renewables) in order to receive the conservation rate credit (CRC). The following CRC Program elements would be available to small utilities with an annual CRC that is less than \$32,851:

- Allow up to 30 percent of their CRC amount to be used for administrative costs, to include any information, education and outreach (marketing) efforts regarding energy efficiency.
- Require only one BPA oversight visit during the three-year CRC rate period (unless the utility requests a more frequent review).
- Allow use of a third party (or utility pooling) to run utility conservation programs (using some or all of the 30 percent administrative allowance to pay the third party).
- Small utility customers can satisfy their remaining 70 percent CRC spending by implementing appropriate (to their service areas) cost-effective measures, such as:
  - > CFL programs
  - > Appliance Rebate programs
  - > SGC Manufactured Homes program
  - ➤ Energy Star New Construction program
  - > Other qualifying cost-effective measures and standard offers

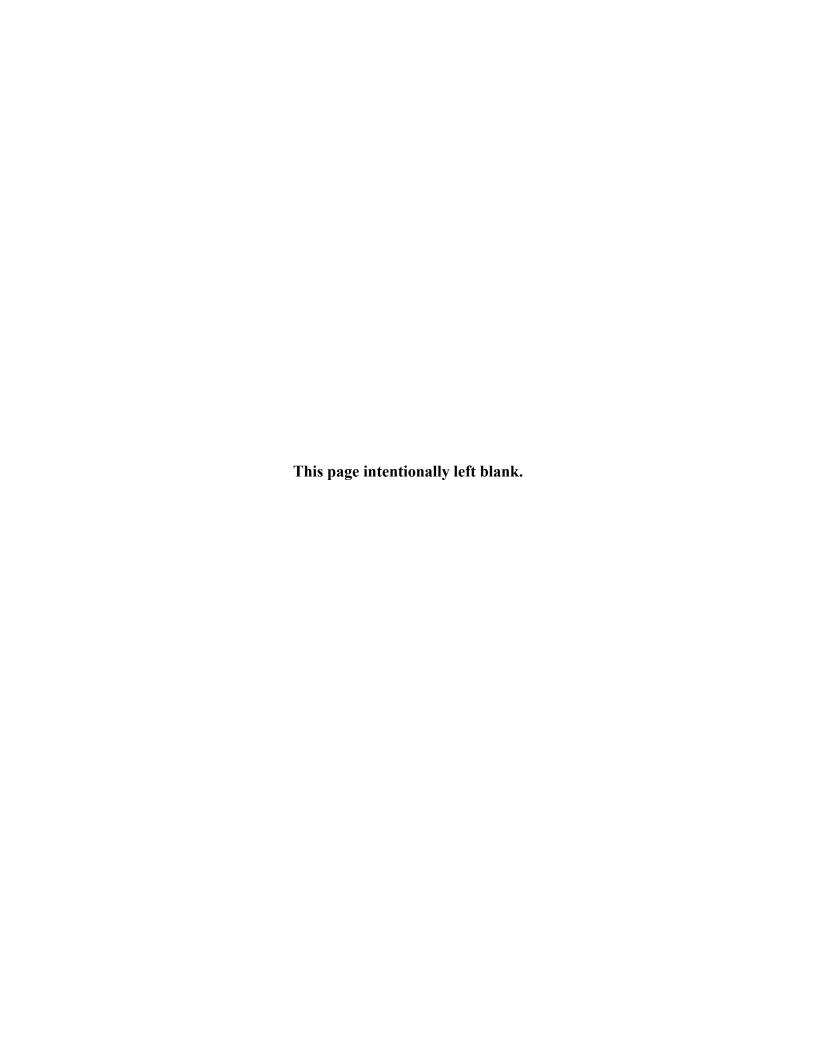
However, if small utility customers don't have sufficient opportunities to implement costeffective measure programs with their end-use consumers, then the following options are available to help ensure that they will be successful in meeting their full CRC obligation:

- Allow donations for cost-effective measures to low-income weatherization organizations with no cap (e.g., CFLs).
- Allow purchase of the renewables (with no *pro rata* adjustment if renewables are over subscribed ((i.e., exceed \$6M/year cap)) by CRC participants).
- Allow donations to NEEA (or other organizations that will use BPA's funds to install costeffective measures) with no cap.

BPA's AEs and EERs are available to work with small utilities to develop a reasonable game plan for achieving CRC success under the new program requirements. BPA will continue to explore new program options for small utility customers.



# APPENDIX D Post-2006 Program Structure



#### Energy Efficiency Bonneville Power Administration

## **Final Post-2006 Conservation Program Structure**

This document describes BPA's final Post-2006 Conservation Program structure. A companion document, "Response to Key Issues Raised in Public Comment Process," summarizes the key issues raised in the 56 public comment letters and e-mails BPA received regarding BPA's Post-2006 Conservation Program Proposal. The companion document also summarizes BPA's final decisions on these key issues that are incorporated into this final program structure. This document is organized as follows.

**Section I: Introduction.** The program purpose and BPA's strategic direction are described in this section. The five-year (FYs 05 – 09) aMW targets are identified. The five program principles that were included in BPA's Final Record of Decision on the short-term Regional Dialogue Policy are described along with seven key policy directives that help frame the post-2006 conservation programs. Finally, the timeframe anticipated for implementation of these final programs is explained.

**Section II: Program Portfolio and Structure.** This section includes a description of the portfolio of programs followed by a more detailed description of program design features for each of the four portfolio components: a rate credit; utility and federal agency customer bilateral contracts; third-party contracts; and regional infrastructure support. Features that are consistent across all programs are identified up front. Oversight requirements and tracking and reporting activities are described in Appendix 1 and the small utility option for the rate credit program is described in Appendix 2.

#### Appendices:

- 1. Sample of BPA Reporting, Oversight, and Evaluation Requirements.
- 2. Small Utility Option under the Conservation Rate Credit

#### I. Introduction

#### Purpose

The purpose of this document is to describe the portfolio of programs that BPA will offer during the 2007 through 2009 timeframe and through 2011 (pending the outcome of post-2009 rate case decisions and/or future long-term power sales contract requirements). BPA anticipates that this portfolio will: (1) facilitate BPA's ability to achieve its share of the regional conservation targets as defined by the Northwest Power and Conservation Council's (Council) Fifth Power Plan; (2) enable BPA to achieve its strategic objective described below; and (3) provide consistency with BPA's Regional Dialogue policy decisions. In addition, the seven BPA policy directives described below provided supplemental guidance to the portfolio design.

#### **Strategic Direction**

<u>Strategic Objective 3:</u> BPA ensures development of all cost-effective energy efficiency in the loads BPA serves, facilitates development of regional renewable resources, and adopts cost-effective non-construction alternatives to transmission expansion.

**Explanation of S3:** BPA will continue to treat energy efficiency as a resource and define our goals in terms of megawatts of energy efficiency acquired. Even if we adopt tiered rates, we are very likely to continue to need limited amounts of new resources. We expect conservation to continue to be a cost-effective resource to meet this limited need, with first priority by law. Accordingly, our goal is to continue to ensure that the cost-effective conservation in the load we serve gets developed, since this amount is very unlikely to exceed our total need. We will ensure this amount is developed with the smallest possible BPA outlay. We will do this through a combination of acquisition of conservation, adoption of policies and rates that support others' development or acquisition of cost-effective conservation, and support of market transformation that results in more efficient electric energy use.

#### **Program Principles**

The following five conservation principles were included in BPA's Final Record of Decision on the short-term Regional Dialogue Policy (dated February 2005). They provide the framework for future conservation program design purposes.

- Conservation Targets from Council's Plan: BPA will use the Council's plan to identify the regional cost-effective conservation targets upon which the agency's share (approximately 40 percent<sup>1</sup>) of cost-effective conservation is based.
- Conservation Achieved at the Local Level: The bulk of the conservation to be achieved is
  best pursued and achieved at the local level. There are some initiatives that are best served
  by regional approaches (for example, market transformation through the Northwest Energy
  Efficiency Alliance). However, the knowledge local utilities have of their consumers and
  their needs reinforces many of the successful energy efficiency programs being delivered
  today.
- Achieve Conservation at Lowest Cost Possible to BPA: BPA will seek to meet its
  conservation goals at the lowest possible cost to BPA. While only cost-effective measures
  and programs are a given, the region can benefit by working together to jointly drive down
  the cost of acquiring those resources.
- Administrative Support: BPA will continue to provide an appropriate level of funding for local administrative support to plan and implement conservation programs.
- Funding for Education, Outreach and Low-Income Weatherization: BPA will continue
  to provide an appropriate level of funding for education, outreach, and low-income
  weatherization such that these important initiatives complement a complete and effective
  conservation portfolio.

<sup>&</sup>lt;sup>1</sup> Based on the FY03 White Book information.

In addition to the five approved principles listed above, BPA's Post-2006 Conservation Program Structure is guided by the following key policy directives:

- **Benefits Must Flow to BPA:** BPA must realize directly the benefit of the savings achieved from the conservation acquisition programs it funds. (Note: the decrement will only be required in conjunction with slice/block customers' bilateral acquisition agreements and in some third-party contractor programs, as appropriate and with utility agreement.)
- Cost-Effective Measures: BPA will only pay for cost-effective measures as defined in the Council's Power Plan.
- Accountability: BPA needs to be sure it is getting what it pays for -- incremental, reliable
  and verifiable conservation savings. Measurement and verification will be included in all
  program mechanisms. This will include managing performance risks upfront such that BPA
  will avoid any need to "backstop" underachievement.
- Tracking Progress: BPA will monitor and report, on a regular basis, how our utilities and
  other parties are spending the conservation funds it provides across all components of the
  conservation portfolio.
- Flexibility: BPA will retain flexibility to shift budgets and targets across all program
  elements of the conservation portfolio and across program years to ensure the Council's
  target is met at the lowest cost possible.
- Leveraging and Coordination: BPA will coordinate and synchronize its efforts with those
  of others as part of an effective and efficient regional effort to achieve cost-effective
  conservation.
- Local Control: BPA will foster local utility initiative and control of conservation efforts to the maximum extent it can, consistent with meeting cost and verification goals.

#### **Timeframe**

It is anticipated that this program structure will be implemented for BPA's FYs 2007 to 2011 period. However, new power sales contracts and/or post-2009 rate case decisions may require that elements of this program structure be adjusted. This program approach will be ready for implementation on or before October 1, 2006. BPA will allow customers that have used all their C&RD credits and have filed a final closeout report to spend their funds under the new rate credit starting in calendar year 2006 (targeted for January 1, 2006) and to claim spending on approved, cost-effective measures when the new rate credit kicks in (October 1, 2006). This approach will require customers to indicate their willingness to participate in the new rate credit program (should it be approved in the rate process) and follow the implementation rules as defined by BPA. Only qualified ECMs implemented after the customers have satisfied their C&RD obligations and indicated to BPA that they want to begin the new program will be allowed. (Note: There is a risk to utilities if they begin before the new rates are finalized. This is similar to the risk some utilities assumed when they started their rate credit conservation activities early in 2001 before the start of the current rate period.) BPA will include a

mechanism or procedure for customers to discontinue participation in the rate credit. However, should they choose to discontinue participation, they will have to pay the full PF or appropriate power rate, including the 0.5 mill adder, for the remaining portion of the rate period.

BPA will offer new bilateral contracts for execution by customers in the fall of 2005 (targeting October 1, 2005). Customers may choose to close out current ConAug contracts and transition to new bilateral conservation acquisition agreements. Customers can begin implementing projects and receiving reimbursement from BPA under the new contracts (with modified terms and incentive levels) once the new contracts have been executed. However, commercial and industrial projects already purchased or approved under ConAug will be subject to the current ConAug incentive levels and contract terms. Payment for projects under the new bilateral contracts can only occur after the execution date for the new agreement. BPA believes this approach will allow BPA to maximize the use of existing rate period conservation budgets to facilitate achieving the higher targets presented in the Council's Fifth Power Plan.

Commitment to Achieving the Target: BPA believes it is important to maintain a steady level of support for conservation over time and will continue to provide a strong energy efficiency program with a firm commitment to achieving its share of the Council's conservation target. This commitment has been demonstrated in the current rate period. BPA more than quadrupled its budget for installing energy conservation measures and capturing conservation savings from about \$15M in 2001 to over \$70M in 2002. Since that substantial increase in funding for conservation, BPA has maintained a high level of support for delivering conservation savings each year. In the 2007-09 rate period, BPA proposes to continue this support and increase the funding level from about \$70M/year, on average, to \$80M/year, on average.

### II. Program Portfolio and Structure

#### **Program Design Features**

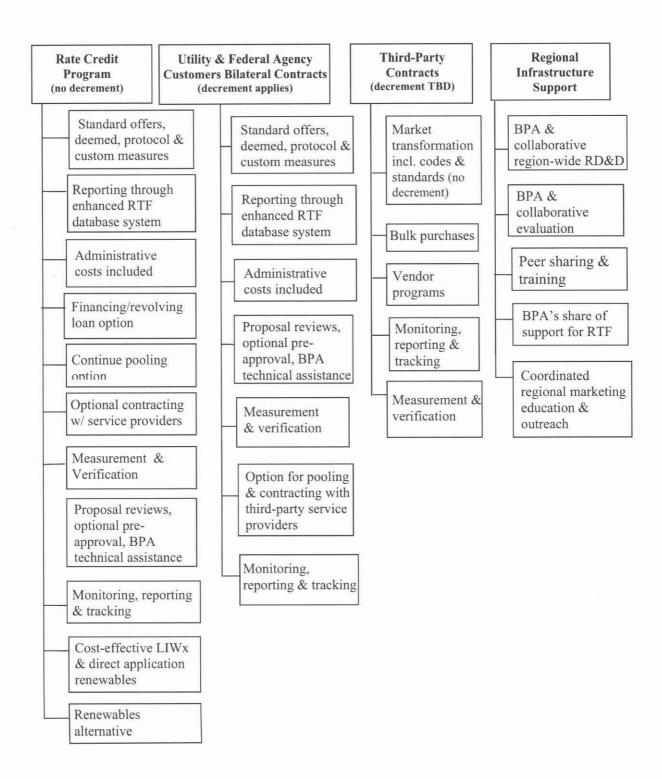
BPA's Post-2006 Conservation Program is a portfolio of programs and supporting activities designed to achieve BPA's share of the regional cost-effective conservation target (as identified by the Council's Fifth Power Plan). The portfolio includes: (1) a rate credit program; (2) utility and federal agency customer acquisition program; (3) third-party acquisition initiatives; and (4) support for regional infrastructure necessary to effectively carry out the other portfolio elements. Options are provided under the rate credit program for small utilities. In addition, under the rate credit program, a renewables alternative is provided.

The program portfolio is shown in the following chart and explained in further detail in the remainder of this document.

#### Post 2006 Conservation Program aMW Targets

Based upon the Council's Fifth Power Plan, there is a regional conservation target over the 2005-2009 period of about 700 aMW. BPA's responsibility to achieve its share of this regional target is based on the amount of regional firm load that BPA supplies with federal power. BPA estimates that it is responsible for about 40 percent of the 700 aMW or 280 aMW. While this amount equates to an annual target of 56 aMW, BPA will adjust the amount of its target to take

## **BPA's Final Post-2006 Conservation Program Structure**



into account the estimated amount of "naturally occurring" conservation (about 7 percent or 4 aMW/year). This results in an average annual conservation target of 52 aMW/year for a total of 260 aMW over the 2005-2009 period. BPA will increase its near-term conservation targets for the 2005-09 period, rather than the originally proposed 2007-11 period. This change reflects an adjustment and commitment by BPA to align the new conservation targets with the same five-year planning horizon in the Council's Fifth Power Plan. BPA expects to meet its 2002-06 target (220 aMW averaging 44 aMW/year) by the end of FY 2006. To meet the 52 aMW/year target in 2005 and 2006 (i.e., an additional 8 aMW/year from the Council's new target), BPA will seek to acquire an additional 16 aMW in 2006.

BPA will conduct an evaluation to estimate the accuracy of this assumption about naturally occurring conservation and whether the assumption should be modified going forward. BPA's commitment is to ensure development of the five-year target, recognizing that there will be variations in the pace of the delivered savings on an annual basis.

As indicated in the March 28 proposal, BPA will count all conservation savings achieved with its funds toward the new target. For example, BPA will count 50 percent of NEEA's conservation acquisition towards BPA's targets since BPA provides 50 percent of NEEA's funding. BPA will also count the conservation savings that result from IOU rate credit expenditures.

#### Eligibility

All BPA customers (including the IOUs), with the exception of the aluminum-related DSIs, will be eligible to participate in the rate credit program. All BPA preference and federal agency customers will be eligible to participate under the bilateral contract program.

#### **Incremental Requirements**

BPA's conservation funding must be used by our customers for energy efficiency savings and related activities beyond what they are required by state law and/or regulatory requirements to accomplish. A public utility board of directors decision to pursue a particular conservation program, for example, would not, in itself, make that funding non-incremental.

#### Decrement

BPA believes, as stated in the original proposal, that decrementing is necessary to minimize cross-utility subsidies and to ensure that the benefits from conservation flow to BPA and its customers. BPA will continue its current practice of not decrementing the slice/block or participating IOU customers under the rate credit program, but will continue requiring a load decrement for these customer groups in conjunction with the bilateral contracts program. The decrement will not apply to the NEEA contract. Whether or not the decrement applies to other third-party contracts involving slice/block customers will be determined on a case-by-case basis. Customers will be asked if they want to participate in any third-party program in their service area. Customers will be informed if a decrement applies to the program at the time they are asked.

This approach continues the policy we currently apply and ensures that BPA realizes a load reduction from the conservation BPA pays for and that BPA and its customers see the full benefit from the conservation acquisitions. For the rate credit program, this approach, while not resulting in a BPA load reduction, reduces a barrier to utility participation in BPA's conservation

programs and is consistent with the Conservation Workgroup's recommendations. However, BPA does not believe this approach is consistent with how conservation should be acquired, so the decision to not decrement the rate credit program for the 2007-09 rate period is not meant to set any precedent for future conservation program activities post 2009.

BPA considers this strategy, along with the change to pay only for cost-effective measures, a positive step toward BPA's goal of achieving cost-effective conservation at the lowest possible cost.

#### Renewables Alternative

Under the rate credit program, eligible customers can choose to use their credits for qualified renewable resource related activities. BPA will require a three-month advance notice prior to each year of the rate period (2007-09) with a \$6M/year cap that will be pro rated if customers over subscribe. Small utilities (7.5 aMW and under) and BPA's federal agency power customers will be exempt from this *pro rata* requirement. This is intended to provide sufficient advance notice to BPA regarding the amount of rate credit and thus aMW that will be achieved with the rate credit funds, and provides additional flexibility for customers that manage their rate credit on an annual basis. A list of eligible renewable measures will be distributed for public review and comment prior to the start of the new rate credit program.

#### Budget

BPA's annual budget (capital and expense) for acquiring the target of 52 aMW/year is \$80 million (see Table 1). BPA has an additional \$6 million per year from BPA's Generating Renewable Program Fund for renewables. For the 2007 – 2009 rate period, the rate credit will be \$0.0005/kWh (1/2 mill) on utility-purchased power from BPA and the equivalent treatment for IOU residential benefit payments. This equates to roughly \$42 million (including

Table 1: Program Annual aMW Targets and Budgets

Program	<u>aMW</u>	Budget	Cost/aMW
Rate Credit (at 0.5 mills = \$42M*/year with IOUs and Pre-Subers included)**	20	\$36M	\$1.8M
Utility & Fed. Agency Bilateral Contracts**	17	\$26M	\$1.5M
Third- Party Contracts	5	\$7M	\$1.4M
Market Transformation (via NEEA)	10	<u>\$10M</u>	\$1.0M
Infrastructure Support and Evaluation	,===	<u>\$1M</u>	
Total	52	\$80M	\$1.5M

<sup>\*</sup> Assumes \$6M/year of the \$42 M/year from a separate renewable budget will be spent on renewables.

<sup>\*\*</sup> Includes a 15 percent administration allowance.

participation by pre-subscription contract holders and IOUs). BPA anticipates that \$6 million per year will be spent on renewable resource related initiatives. As shown in Table1, BPA will pay a weighted average of \$1.5 M/aMW (which includes a 15 percent administration allowance for the rate credit and bilateral contracts programs) across the entire portfolio of programs.

#### **Features Consistent For All Programs**

There are several features that will be consistent across all of the conservation programs:

- BPA will pay only for qualified cost-effective measures from the RTF list as defined by the Council's Fifth Power Plan, as well as for approved calculated and custom program designs, and for additional deemed measures that are approved throughout the rate period.
- The list of qualified, cost-effective measures, deemed kWh savings and payment rate per measure will generally be consistent across programs. However, BPA retains the flexibility to negotiate custom agreements.
- BPA's willingness to pay may vary by sector and measure, and will reflect the actual cost to acquire resources in each sector. It may also reflect program implementation realities.
- BPA's will consider measure life in our determination of willingness to pay levels for specific measures.
- BPA will strive to simplify implementation by using averages that take advantage of measure similarity.
- Packaging of measures will be allowed, but BPA will only pay an amount equivalent to payment for the cost-effective measures in the package.
- BPA will attempt to minimize the frequency of adjustments to willingness to pay
  adjustments. For example, BPA may adjust payments with six months notice, if necessary,
  to compensate, for changes in codes, market prices, technology penetration or, if needed, to
  stay on pace with targets. Adjustments will apply to measures installed after the date the
  adjustment notice is effective. No retroactive adjustments will be applied.
- Utilities may request the RTF review the eligibility of new measures or measures previously
  deemed to not be regionally cost effective. If the RTF recommends the requested measures
  as cost-effective, BPA will review the RTF's recommendations to determine whether or not
  BPA will pay an incentive for the measure.
- Semi-annual reporting will be required.
- BPA retains the flexibility to shift funds between programs and program elements, and across
  fiscal years as needed to ensure the conservation targets are achieved at the lowest cost
  possible.
- Oversight and verification will be similar to the current requirements under the ConAug program. Participating utilities will be required to support evaluations (see Appendix 1).
- Information on individual utility expenditures and achievements resulting from BPA funding will be made available to the public, as appropriate.

#### Rate Credit Program

#### Overview

A rate credit will be established to facilitate local development of conservation. The aMW purchased with rate credit money will be counted towards BPA's aMW target. Load forecasts will not be reduced and no decrement off block or slice will be required. If IOU's participate,

they will participate under the same rules and conditions that apply to all utilities. Utilities will make a commitment to BPA if they plan to participate in the rate credit program no later than three months prior to the start of the rate period (program start October 1, 2006; notification to participate required by July 1, 2006). The utility will make the commitment by submitting a letter to BPA that states that the utility will participate and that the utility agrees to abide by the program rules as documented in the appropriate GRSPs and the Implementation Manual. If a utility chooses to discontinue participation, the utility must provide BPA notice no later than July 1 for the following October 1 to September 30 fiscal year period. A Rate Credit Implementation Manual, similar to the existing C&RD Implementation Manual, will be prepared and distributed approximately six months prior to program implementation and three months before utility commitments to the rate credit are required. An overview of this program is shown on the chart. Key features of this proposed program include:

#### **Key Features**

- Customers may choose to be reimbursed from the rate credit for administration costs at a rate of up to 15 percent of the customer's eligible annual rate credit.
- Monthly credit amount is equal to the forecasted eligible annual credit/12.
- Each utility may choose the incentive level to pay the end user but is credited only the amount BPA offers for each cost-effective measure.
- Rate credits will be provided for qualified deemed, deemed calculated, custom/protocol projects and standard offers.
- BPA engineers will provide custom proposal reviews to the extent engineering resources are available
- Utilities will report at least semi-annually to BPA via the RTF reporting system. If, at the second semi-annual report (end of the first full year of the program), the utility is not meeting its targets (50 percent or less of its expected rate credit spending), the utility will have to prepare and have BPA approve an Action Plan that provides sufficient proof of achievable intent by the end of the first year after the program starts (10/1/07). BPA staff will be available to assist utilities in developing an Action Plan that will indicate how the utility will spend its rate credit funds by the end of the rate period (9/30/09). BPA's goal is for every participating utility to spend the full amount of its rate credit on qualified conservation and/or renewables activities by the end of the rate period. If at the 18-month period (third progress report 4/1/08) participants still have not made sufficient progress on their rate credit spending (i.e., 75 percent or less of their expected rate credit has been spent), then BPA may send a notification letter that the rate credit will be withdrawn for the third year of the program (i.e., customers will be required to pay the full PF or other appropriate power rate) so the funds can be reallocated. After the end of the third year of the rate credit program (9/30/09), there will be a final true-up required for participating utilities.
- The existing RTF web-based information and reporting system will be used. The RTF database will include all measures in the current C&RD database and the cost-effective measures for which BPA is willing to pay an incentive during the new rate period (FYs 2007-09). The reporting system will be enhanced to include means for utilities (at their option) to enter savings acquired from non-cost-effective measures, measures the utility pays for with its own money, and for identifying savings from lost opportunity measures.
- Measurement and verification for non-deemed measures at a level similar to that done under the current ConAug program will be required (see Appendix 1).

- Utility records related to spending of BPA funds will be subject to federal financial review.
- BPA will conduct an annual oversight visit (see Appendix 1 for further detail).
- Pooling of utility funding is allowed (optional), but there will be a 15 percent cap on total administration costs for the pool.
- Utilities may contract independently with third-party service providers to operate their programs (optional).
- An annual commitment to renewables will be allowed (see earlier Renewables Alternative section).

#### Rate Credit Eligibility

- Only qualified, cost-effective conservation and direct application (customer side) renewable measures will be eligible for a rate credit and renewables option.
- There will be a no cap on the total dollars in the rate credit program that a utility may either
  contract to low income weatherization organizations or spend on utility low income
  programs. No double counting of savings will be allowed, and utilities may not claim
  administration costs on the amount of money contracted or passed through.
- Third party subcontracts with energy organizations will be allowed provided cost-effective aMW savings result. Utilities may not take administration payments on pass-through contracts. BPA will include these funds in determining its share of the NEEA aMW achieved and will count these aMWs toward BPA's target.

#### **Small Utility Option**

#### Overview

Small utilities are defined as those with a 7.5 aMW or smaller total load. BPA wants to make participation in the rate credit feasible for small utilities, while ensuring that dollars actually go to cost-effective conservation and renewables. Small utilities will be required to acquire cost-effective measures (or renewables) in order to participate in the rate credit program. BPA will allow up to 30 percent of their rate credit for administrative costs, ensure that small utilities who wish to spend their rate credit dollars on renewables can do so without being affected by a *pro rata* adjustment if renewables are over subscribed by customers (exceed the \$6M/year cap), provide a checklist of simple programs and initiatives suitable for a small utility to implement, and modify the performance reporting requirements to align more with their capabilities. More detail on these changes is included in Attachment 2.

### **Utility and Federal Agency Bilateral Contracts Program**

#### Overview

BPA anticipates this bilateral program component of the program portfolio to be a five-year program and is committing funding for a three-year period (2007 though 2009). This program is needed because the conservation resources are not evenly distributed across the region. BPA may shift money between the bilateral contract and other programs in the portfolio, as appropriate.

Streamlined, standardized umbrella agreements will be written with interested utilities (participation is optional). Similar to the current ConAug program, each agreement will have exhibits that provide specific program details. Utilities can select from available program exhibits to customize the selection of programs best suited to their service territory. BPA will fund both standard offer and custom designed programs. BPA (or its designated contractor) will conduct oversight. BPA will make a budget commitment to the utility for the duration of the contract subject to utility performance. Similar to the current ConAug program, BPA (or its designated contractor) will provide limited engineering assistance for project scoping and, if requested, pre-approval of projects. The proposed Utility and Federal Agency Bilateral Program is an acquisition program and, as such, the decrement will apply to all slice/block customers. Key features of this proposed program include:

#### **Key Features**

- Reimbursement of administration costs at a rate up to 15 percent of the allowable costs may be included with the project budget and reimbursed by BPA.
- Each utility may choose the incentive level to pay the end user but is credited only the amount BPA offers for each cost-effective measure.
- BPA engineers will provide custom proposal reviews to the extent engineering resources are available.
- Measurement, verification and oversight will be similar to that done under the current ConAug program.
- Incentives will be provided for qualified deemed, standard offers and custom/protocol projects.
- Stranded cost repayment provisions will be put in place between each participating utility and BPA.
- BPA will strive to provide simplified contracts.
- BPA will strive to provide a streamlined approval process

#### Measure Eligibility

Only qualified cost-effective conservation and direct application (customer-side) renewable measures will be eligible.

#### **Third-Party Contracts**

#### Overview

This third-party contract component of the program portfolio will allow BPA to contract to third parties when these contracts will lower the cost of acquiring conservation or where needed to affect markets that cannot be changed at a local level. BPA will only pay third parties to work in utility service territories that have agreed to participate in the third-party program. This policy of requiring pre-approval of utility partners is a continuation of BPA's current policy. In general, regional programs will be designed to operate in coordination with local utility programs. For example, regional bulk purchases of a technology might be delivered locally. BPA anticipates transferring funds between third-party contracts and utility and federal agency bilateral contracts,

as needed, to balance the level of effort needed at both the regional and local levels and to achieve the targets at the lowest possible cost.

Pre-committed funding for NEEA (\$10 million per year for the 2007-09 period) is included in this mechanism and no decrement will be applied for the NEEA contract.

#### **Key Features**

- BPA will negotiate reasonable administration costs for third-party contracts.
- Region-wide programs and efforts will be coordinated with local utilities.
- The decrement will not apply to NEEA.
- A determination of whether or not a decrement applies for other third-party programs will be determined on a case-by-case basis.
- Customers will be notified as to whether or not a decrement will apply to any third-party program of interest to the utility before the utility agrees to participate.

#### **Infrastructure Support**

#### Overview

A number of proposed support activities will be undertaken to optimize expenditures through BPA's energy efficiency programs, to leverage other available resources and to reduce the overall cost of accomplishing the conservation. These activities may include:

- Setting up a mechanism for peer sharing (e.g., so utilities can share successful program ideas and marketing materials).
- Conducting limited BPA and collaboratively funded RD&D to ensure we are developing the next wave of energy efficiency technologies.
- Performing evaluations (process and impact) and market assessments to ensure BPA's
  programs are achieving the intended result and to gather the information necessary to make
  mid-stream program adjustments. Co-funding from other affected organizations may be
  solicited for these evaluations/assessments. BPA may also contribute to a regional
  evaluation designed to assess how much naturally occurring conservation has been achieved.
- Enhancing and supporting the RTF database to include expanding the reporting elements and website to allow bilateral contract acquisition reporting and tracking and to track lost opportunity acquisition.
- Developing, with utility guidance, tool kit components such as utility program marketing and implementation materials that utilities need and may choose to use to launch new programs.
- Developing templates and other program design "off the shelf" materials that small utilities can easily use.

#### Tracking and Reporting

BPA is upgrading the RTF/C&RD database to allow utilities to report both bilateral and rate credit program accomplishments in an on-line database. BPA will continue to rely on invoicing for reimbursement under bilateral agreements. BPA is also expanding the database to allow utilities to report conservation savings from other funding sources as well.

# Appendix 1 Sample of Reporting, Oversight, and Evaluation Requirements

#### Reporting:

Purpose: Tracking progress to meeting the regional goals in real time will be important if the region is going to be able to respond and adapt to shortfalls. In addition, the use of public funds requires a minimum level of accounting.

All utilities will report at least semi-annually, using the RTF database, on their accomplishments and expenditures of funds, whether from the rate credit or bilateral contracts. BPA will strive to have this single source of reporting meet as many needs as possible to avoid duplicative or inconsistent reporting needs. All data received will be in the public domain except where consumer business confidentiality is needed.

#### Oversight and Verification:

Purpose: The expenditure of funds included in the published BPA rates for purposes of achieving conservation (and renewables, if applicable) is an activity for which BPA has fiduciary responsibility. In addition, by providing constructive oversight, BPA may be able to provide assistance to utilities to improve the programs and reporting. BPA will aim to have one oversight visit per year for all of its conservation programs for each participating utility, unless major issues surface.

- (a) Bonneville Power Administration (BPA) or BPA's agent shall have the right to conduct inspections of units or completed units and monitor or review a utility's procedures, records, verified energy savings method and results, or otherwise oversee the utility's implementation of conservation programs funded through dollars included in BPA's rates. The number, timing, and extent of such audits shall be at the discretion of BPA. Such site reviews are expected to be conducted annually. Such audits shall occur at BPA's expense. Financial audits shall be in compliance with the audit standards established by the Comptroller General of the United States. BPA may contact appropriate federal, state, or local jurisdictions regarding environmental, health, or safety matters related to units or completed units.
- (b) Prior to any oversight visit physical inspection, BPA shall give the utility written notice. If physical inspections are required by BPA, the utility shall have 30 days to arrange for the inspection of units or completed units. The oversight visit will include: review of energy audit or measure installation procedures, technical documents, records, and/or verified savings methods and results.

#### **Evaluations:**

Purpose: Evaluations are needed to determine barriers to program success, identify ways to improve programs, help track program accomplishments, and to assess the market conditions,

the accuracy of the savings estimates, and to answer the ultimate question of whether programs are meeting their expected goals.

- (a) BPA may conduct, and the utility shall cooperate with, evaluations of conservation impacts and project implementation processes to assess the amount, cost effectiveness, and reliability of conservation in the utilities' service areas or region. After consultation with the participating utilities, BPA shall determine the timing, frequency, and type of such evaluations.
- (b) BPA anticipates that many of the evaluations will be done collaboratively with other organizations to share costs and improve the usefulness of the evaluations. In some cases, this will result in the evaluation being managed by another party on behalf of BPA and others. Such evaluation contract management responsibilities might be shared with other parties, including among others, the NEEA, the RTF, the Power Council, the Energy Trust of Oregon, or another utility.
- (c) BPA will determine the specific requirements for evaluations with consideration for the schedules and reasonable needs of the utility and the utility's customers.
- (d) Unless requested by the program managers to improve program operation, any evaluation of the project initiated by BPA shall be conducted at BPA's expense or shared regional expense and such costs shall be excluded from the implementation budget. Utility or other entities who cooperate with the evaluation are implicitly recognized as providing some resource/cost, but will not be considered for direct reimbursement by BPA, except under unusual circumstances. Cooperation with the evaluation is a cost of the partnership in delivering the programs.

# Appendix 2 Post-2006 Conservation Program: Small Utility Option under the Conservation Rate Credit

BPA will continue to define small utility as those utilities with loads of 7.5 aMW or under. BPA intention is that small utilities acquire cost-effective conservation (or renewables) in order to receive the conservation rate credit (CRC). The following CRC Program elements will be available to small utilities:

- Up to 30 percent of a small utility's CRC amount may be used for administrative costs, (which include information, education and outreach (marketing) efforts regarding energy efficiency).
- Only one BPA oversight visit will be required during the three-year CRC rate period (unless the utility requests a more frequent review).
- Third-party (or utility pooling) to run utility conservation programs (using some or all of the 30 percent administrative allowance to pay the third-party) is allowed.
- Small utility customers can satisfy their remaining 70 percent CRC spending by implementing appropriate (to their service areas) cost-effective measures, such as:
  - CFL programs
  - > Appliance Rebate programs
  - SGC Manufactured Homes program
  - ➤ Energy Star New Construction program
  - Other qualifying cost-effective measures and standard offers

However, if small utility customers don't have sufficient opportunities to implement costeffective measure programs with their end-use consumers, then the following options are available to help ensure that they will be successful in meeting their full CRC obligation:

- Donations for cost-effective measures to low income weatherization organizations with no cap (e.g., CFLs).
- Purchase of the renewables (with no pro rata adjustment if renewables are over subscribed ((i.e., exceed \$6M/year cap)) by CRC participants).
- Donations to NEEA (or other organizations that will use BPA's funds to install cost-effective measures) with no cap.

BPA's AEs and EERs are available to work with small utilities to develop a reasonable game plan for achieving CRC success under the new program requirements. BPA will continue to explore new program options for small utility customers.