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

2007 Wholesale Power Rate Case Final Proposal

SECTION 7(b)(2) RATE TEST STUDY AND DOCUMENTATION

July 2006

WP-07-FS-BPA-06
WP-07-FS-BPA-06A

2007 Wholesale Power Rate Case Final Proposal

SECTION 7(b)(2) RATE TEST STUDY

July 2006

WP-07-FS-BPA-06

This page intentionally left blank.

SECTION 7(b)(2) RATE TEST STUDY

TABLE OF CONTENTS

Page

TABLES

APPENDIXES

COMMONLY USED ACRONYMS

AC	Alternating Current
AEP	American Electric Power Company, Inc.
AER	Actual Energy Regulation
AFUDC	Allowance for Funds Used During Construction
AGC	Automatic Generation Control
aMW	Average Megawatt
Alcoa	Alcoa Inc.
AMNR	Accumulated Modified Net Revenues
ANR	Accumulated Net Revenues
AOP	Assured Operating Plan
ASC	Average System Cost
Avista	Avista Corporation
BASC	BPA Average System Cost
BiOp	Biological Opinion
BPA	Bonneville Power Administration
Btu	British thermal unit
C&R Discount	Conservation and Renewables Discount
CAISO	California Independent System Operator
CBFWA	Columbia Basin Fish & Wildlife Authority
CCCT	Combined-Cycle Combustion Turbine
CEC	California Energy Commission
CFAC	Columbia Falls Aluminum Company
Cfs	Cubic feet per second
CGS	Columbia Generating Station
COB	California-Oregon Border
COE	U.S. Army Corps of Engineers
Con Aug	Conservation Augmentation
C/M	Consumers / Mile of Line for Low Density Discount
ConMod	Conservation Modernization Program
COSA	Cost of Service Analysis
Council	Northwest Power Planning 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
CT	Combustion Turbine
CY	Calendar Year (Jan-Dec)
DC	Direct Current
DDC	Dividend Distribution Clause
DJ	Dow Jones
DOE	Department of Energy
DOP	Debt Optimization Program
DROD	Draft Record of Decision

DSI	Direct Service Industrial Customer or Direct Service Industry
ECC	Energy Content Curve
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.
Energy Northwest, Inc.	Formerly Washington Public Power Supply System (Nuclear)
EPA	Environmental Protection Agency
EPP	Environmentally Preferred Power
EQR	Electric Quarterly Report
ESA	Endangered Species Act
EWEB	Eugene Water & Electric Board
F&O	Financial and Operating Reports
FB CRAC	Financial-Based Cost Recovery Adjustment Clause
FBS	Federal Base System
FCCF	Fish Cost Contingency Fund
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FERC	Federal Energy Regulatory Commission
FERC SR	Federal Energy Regulatory Commission Special Rule
FELCC	Firm Energy Load Carrying Capability
Fifth Power Plan	Council's Fifth Northwest Conservation and Electric Power Plan
FPA	Federal Power Act
FPS	Firm Power Products and Services (rate)
FY	Fiscal Year (Oct-Sep)
GAAP	Generally Accepted Accounting Principles
GCPs	General Contract Provisions
GEP	Green Energy Premium
GI	Generation Integration
GSR	Generation Supplied Reactive and Voltage Control
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
ICNU	Industrial Customers of Northwest Utilities
ICUA	Idaho Consumer-Owned Utilities Association, Inc.
IOU	Investor-Owned Utility
IP	Industrial Firm Power (rate)
IP TAC	Industrial Firm Power Targeted Adjustment Charge
IPC	Idaho Power Company
ISO	Independent System Operator
JP	Joint Party

JP1	Cowlitz County Public Utility District, Northwest Requirements Utilities and Members, Western Public Agencies Group and Members, Public Power Council, Industrial Customers of Northwest Utilities
JP2	Grant County Public Utility District No. 2, Benton County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, Western Public Agencies Group and Members, Western Public Agencies Group and Members(Grays Harbor)
JP3	Benton County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, Western Public Agencies Group and Members (Grays Harbor)
JP4	Cowlitz County Public Utility District, Eugene Water & Electric Board, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, Grant County Public Utility District No. 2
JP5	Benton County Public Utility District, Cowlitz County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Northwest Requirements Utilities and Members, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, specified members of WA[1]
JP6	Avista Corporation, Idaho Power Corporation, PacifiCorp, Portland General Electric Company, Puget Sound Energy, Inc.
JP7	NONE
JP8	Northwest Energy Coalition, Save Our *Wild* Salmon
JP9	Alcoa, Inc., Industrial Customers of Northwest Utilities, Public Power Council, Northwest Requirements Utilities and Members, Pacific Northwest Generating Cooperative and Members, PacifiCorp, Western Public Agencies Group and Members, Avista Corporation, Portland General Electric Company

[1] The members of Western Public Agencies Group and Members (WA) that are participating in the JP5 designation include: Benton REA, the cities of Ellensburg and Milton, the towns of Eatonville and Steilacoom, Washington, Alder Mutual Light Co., Elmhurst Mutual Power and Light Co., Lakeview Light and Power Co., Parkland Light and Water Co., Peninsula Light Co., the Public Utility Districts of Grays Harbor, Kittitas, Lewis and Mason Counties, the Public Utility District No. 3 of Mason County, and the Public Utility District No. 2 of Pacific County, Washington.

JP10	Alcoa, Inc., Cowlitz County Public Utility District, Industrial Customers of Northwest Utilities
JP11	Cowlitz County Public Utility District, Eugene Water & Electric Board, Grant County Public Utilities District No. 2, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma
JP12	Alcoa, Inc., Industrial Customers of Northwest Utilities, Public Power Council, Western Public Agencies Group and Members, Northwest Requirements Utilities and Members, Pacific Northwest Generating Cooperative and Members
JP13	Columbia River Inter-Tribal Fish Commission, Confederated Tribes and Bands of the Yakama Nation, Nez Perce Tribe
JP14	Benton County Public Utility District, Cowlitz County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Industrial Customers of Northwest Utilities, Northwest Requirements Utilities and Members , Public Power Council, Seattle City Light, City of Tacoma, Western Public Agencies Group and Members, Springfield Utility Board, Pacific Northwest Generating Cooperative and Members
JP15	Calpine Corporation, Northwest Independent Power Producers Coalition, PPM Energy, Inc., TransAlta Centralia Generation, LLC
kAf	Thousand Acre Feet
kcfs	kilo (thousands) of cubic feet per second
ksfd	thousand second foot day
kV	Kilovolt (1000 volts)
kW	Kilowatt (1000 watts)
kWh	Kilowatt-hour
LB CRAC	Load-Based Cost Recovery Adjustment Clause
LCP	Least-Cost Plan
LDD	Low Density Discount
LLH	Light Load Hour
LOLP	Loss of Load Probability
m/kWh	Mills per kilowatt-hour
MAC	Market Access Coalition Group
MAf	Million Acre Feet
MCA	Marginal Cost Analysis
Mid-C	Mid-Columbia
MIP	Minimum Irrigation Pool
MMBTUMMBtu	Million British Thermal Units
MNR	Modified Net Revenues
MOA	Memorandum of Agreement
MOP	Minimum Operating Pool

MORC	Minimum Operating Reliability Criteria
MT	Market Transmission (rate)
MVAr	Mega Volt Ampere Reactive
MW	Megawatt (1 million watts)
MWh	Megawatt-hour
NCD	Non-coincidental Demand
NWEC	Northwest Energy Coalition
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Council
NF	Nonfirm Energy (rate)
NFB Adjustment	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp) Adjustment
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NOB	Nevada-Oregon Border
NORM	Non-Operating Risk Model
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPA	Northwest Power Act
NPCC	Northwest Power and Conservation Council
NPV	Net Present Value
NR	New Resource
NR (rate)	New Resource Firm Power (rate)
NRU	Northwest Requirements Utilities
NTSA	Non-Treaty Storage Agreement
NUG	Non-Utility Generation
NWPP	Northwest Power Pool
NWPPC	Northwest Power Planning Council
OATT	Open Access Transmission Tariff
O&M	Operation and Maintenance
OMB	Office of Management and Budget
OPUC	Oregon Public Utility Commission
ORC	Operating Reserves Credit
OY	Operating Year (Aug-Jul)
PA	Public Agency
PacifiCorp	PacifiCorp
PBL	Power Business Line
PDP	Proportional Draft Points
PF	Priority Firm Power (rate)
PFR	Power Function Review
PGE	Portland General Electric Company
PGP	Public Generating Pool
PMA	Power Marketing Agencies

PNCA	Pacific Northwest Coordination Agreement
PNGC	Pacific Northwest Generating Cooperative
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration/Point of Interconnection
POM	Point of Metering
PPC	Public Power Council
PPLM	PP&L Montana, LLC
Project Act	Bonneville Project Act
PSA	Power Sales Agreement
PSC	Power Sales Contract
PSE	Puget Sound Energy
PSW	Pacific Southwest
PTP	Point-to-Point Transmission
PUD	Public or People's Utility District
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
Reclamation	Bureau of Reclamation
Renewable Northwest	Renewable Northwest Project
RD	Regional Dialogue
REP	Residential Exchange Program
RFP	Request for Proposal
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model
RL	Residential Load (rate)
RMS	Remote Metering System
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RTO	Regional Transmission Operator
SCCT	Single-Cycle Combustion Turbine
Slice	Slice of the System (product)
SME	Subject Matter Expert
SN CRAC	Safety-Net Cost Recovery Adjustment Clause
SOS	Save Our *Wild* Salmon
SUB	Springfield Utility Board
SUMY	Stepped-Up Multiyear
SWPA	Southwestern Power Administration
TAC	Targeted Adjustment Charge
TBL	Transmission Business Line
Tcf	Trillion Cubic Feet
TPP	Treasury Payment Probability
Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load
Tribes	Columbia River Inter-Tribal Fish Commission, Nez Perce, Yakama Nation, collectively

UAI Charge	Unauthorized Increase Charge
UAMPS	Utah Associated Municipal Power Systems
UDC	Utility Distribution Company
UP&L	Utah Power & Light
URC	Upper Rule Curve
USBR	U.S. Bureau of Reclamation
USFWS	U.S. Fish and Wildlife Service
VOR	Value of Reserves
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council (formally called WSCC)
WMG&T	Western Montana Electric Generating and Transmission Cooperative
WPAG	Western Public Agencies Group
WPRDS	Wholesale Power Rate Development Study
WSCC	Western Systems Coordination Council (now WECC)
WSPP	Western Systems Power Pool
WUTC	Washington Utilities and Transportation Commission
Yakama	Confederated Tribes and Bands of the Yakama Nation

This page intentionally left blank.

1. INTRODUCTION

Section 7(b)(2) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. § 839e(b)(2), directs the Bonneville Power Administration (BPA) to conduct, after July 1, 1985, a comparison of the projected rates to be charged its preference and Federal agency customers for their firm power requirements, over the rate test period plus the ensuing 4 years, with the costs of power (hereafter called rates) to those customers for the same time period if certain assumptions are made. The effect of this rate test is to protect BPA's preference and Federal agency customers' wholesale firm power rates from certain specified costs resulting from certain provisions of the Northwest Power Act. The rate test can result in a reallocation of costs from the general requirements loads of preference and Federal agency customers to other BPA loads.

The rate test involves the projection and comparison of two sets of wholesale power rates for the general requirement loads of BPA's public body, cooperative, and Federal agency customers (collectively, the 7(b)(2) Customers). The two sets of rates are: (1) a set for the test period and the ensuing four years assuming that Section 7(b)(2) is not in effect (known as Program Case rates); and (2) a set for the same period taking into account the five assumptions listed in section 7(b)(2) (known as 7(b)(2) Case rates). Certain specified costs allocated pursuant to section 7(g) of the Northwest Power Act are subtracted from the Program Case rates. Next, each nominal rate is discounted to the beginning of the test period of the relevant rate case. The discounted Program Case rates are averaged, as are the 7(b)(2) Case rates. Both averages are rounded to the nearest tenth of a mill for comparison. If the average of the Program Case rates is greater than the average of the 7(b)(2) Case rates, the rate test triggers. The difference between the average of the Program Case rates and the average of the 7(b)(2) Case rates determines the amount to be reallocated from the 7(b)(2) Customers to other BPA loads in the rate test period.

1.1 Purpose and Organization of Study

The purpose of this Study is to describe the application of the *Section 7(b)(2) Implementation Methodology (Implementation Methodology)* and the results of such application. The accompanying Section 7(b)(2) Rate Test Study Documentation, WP-07-FS-BPA-06A, contains the documentation of the computer models and data used to perform the 7(b)(2) rate test.

This Study is organized into three major sections. The first section provides an introduction to the study, as well as a summary of the section *7(b)(2) Legal Interpretation* and *Implementation Methodology*. The second section describes the methodology used in conducting the rate test. It provides a discussion of the calculations performed to project the two sets of power rates that are compared in the rate test. The third section presents a summary of the results of the rate test for the WP-07 Final Rate Proposal. The appendices to the study provide documentation on: the financing benefit assumptions (Appendix A Financing Analysis), documentation on the resources contained in the 7(b)(2) Resource Stack (Appendix B), documentation on the amounts and operating costs of Non-Dedicated Mid-Columbia Hydroelectric Resources (Appendix C), and documentation on conservation resource savings and their acquisition costs (Appendix D).

1.2 Basis of Study

1.2.1 Legal Interpretation

As the first phase of its 1985 general rate case, BPA published the *Legal Interpretation of Section 7(b)(2) of the Northwest Power Act*, 49 Fed. Reg. 23,998 (1984). The *Legal Interpretation* is hereby incorporated by reference. Major provisions of the Legal Interpretation are listed below.

- The 7(b)(2) Case is modeled by limiting the differences between the Program Case and the 7(b)(2) Case to the five assumptions specified in section 7(b)(2) and the unavoidable natural consequences of those assumptions, and reflecting the effects of these assumptions on the ratemaking processes that remain the same between the Program Case and the 7(b)(2) Case.

- BPA will reallocate costs resulting from the rate test trigger, pursuant to section 7(b)(3) of the Northwest Power Act, in a manner that is consistent with section 7(a) of the Northwest Power Act.

- Applicable 7(g) costs are subtracted from the Program Case rates before those rates are compared with the rates in the 7(b)(2) Case.

- "Within or adjacent" Direct Service Industrial (DSI) customer loads are assumed to be served by the 7(b)(2) Customers for the entire rate test period.

- The DSI loads assumed to be served by the 7(b)(2) Customers are assumed to be served wholly with firm power.

- Appendix B to S. Rep. No. 272, 96th Cong., 1st Sess. (1979), is used to determine which DSI loads are "within or adjacent" to 7(b)(2) customer service areas, with modifications to reflect the actual status of BPA service to the DSIs.

- To determine "Federal Base System (FBS) resources not obligated to other entities," DSI loads not "within or adjacent" are assumed to receive service from non-7(b)(2) Customers as the pre-Northwest Power Act BPA-DSI power sales contracts expire.

- Section 7(b)(2)(D) identifies three types of additional resources that are assumed, in the 7(b)(2) Case, to meet the 7(b)(2) Customers' loads after the Federal Base System (FBS) resources are exhausted. Specific additional resources are assumed to be used in the order of least cost first; generic resources then are used if necessary.

1.2.2 Implementation Methodology

A hearing pursuant to section 7(i) of the Northwest Power Act was held during 1984 on Implementation Methodology issues. The issues addressed in the hearing are discussed in the *Administrator's Record of Decision for Section 7(b)(2) Implementation Methodology* (7(b)(2) ROD), published in August 1984. The 7(b)(2) ROD is hereby incorporated by reference. The major issues resolved in the 7(b)(2) ROD are discussed below.

- Reserve benefits provided under the Northwest Power Act are quantified using the same Value of Reserves analysis used in the relevant rate case, modified to reflect that "within or adjacent" DSI loads are less than the total amount of DSI loads served by BPA. (*See* Wholesale Power Rate Development Study (WPRDS), WP-07-FS-BPA-05, Appendix B.) Within this rate proposal, reserve benefits provided under the Northwest Power Act are forecast to be zero. BPA is forecasting no power sales to the DSIs under the IP rate schedule. These circumstances eliminate the need for a financing benefits analysis to quantify the Value of Reserves for this PBL power rate case.

- Financing benefits in the 7(b)(2) Case are quantified for planned or existing resources that have been acquired by BPA or are planned to be acquired in the Program Case during the 7(b)(2) rate test period. The financing benefits in the 7(b)(2) Case are estimated by BPA's Financial Advisor, Public Financial Management, which estimates the sponsor's financial cost for the 7(b)(2) Case resources assuming that BPA did not acquire the resource output. Without the financing benefits that are present in the Program Case, the resources required to meet the 7(b)(2) Customers' loads in the 7(b)(2)

Case could be more expensive. When ownership of a resource is by non-preference customers, or is unidentifiable, the resource is assumed to be financed by a proxy financing entity comprised of all of the region's preference utilities, with shares in proportion to the utilities' firm power loads.

- Natural consequences result from reflecting the five specific section 7(b)(2) assumptions in the 7(b)(2) Case rates while keeping all the underlying ratemaking premises and processes the same for both cases. Three natural consequences were identified for possible modeling in the rate test: elasticity of demand, the level of surplus firm power available, and the size of secondary energy markets.

- The 7(b)(2) rate test in this rate case is conducted using a single automated Excel ® spreadsheet called RAM 2007. The outputs of this spreadsheet model are in the Section 7(b)(2) Rate Test Study Documentation, WP-07-FS-BPA-06A. The modeling sequence is described in the WPRDS.

- The projected rate for each year of the section 7(b)(2) rate test period is discounted back to the first year of the rate proposal test period using a factor based on BPA's projected borrowing rate for each of the rate test years. The discounted rates then are averaged for each Case and the result rounded to the nearest tenth of a mill. The rate test triggers if the average of the discounted rates for the Program Case exceeds the average of the discounted rates for the 7(b)(2) Case by one tenth of a mill or more. If the rate test triggers, the difference between the two rates is multiplied by the general requirements of the preference customers in the test year to determine the amount of costs to be reallocated from the preference customers to other BPA loads in the test year.

2. METHODOLOGY

Implementing section 7(b)(2) consists of incorporating the determinations from the *Legal Interpretation* and the 7(b)(2) ROD into the RAM2007 model.

2.1 Sequence of Steps

The Rate Design Step of RAM2007 simulates BPA's ratemaking process by performing the steps needed to develop wholesale power rates and is used as the Program Case for the 7(b)(2) rate test. The 7(b)(2) Case sections of RAM2007 simulate BPA's ratemaking process with changes to reflect the five 7(b)(2) assumptions.

2.1.1 Program Case in RAM2007

RAM2007 calculates annual Program Case rates for the 2007 rate case rate period FY 2007-2009 and the following four years FY 2010-2013. 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 for the three-year rate period.

2.1.1.1 Sales

The sales forecast used to develop rates for the Program Case covers the period FY 2007-2013, and is the same forecast used to develop BPA's proposed rates. Sales forecasts were developed for the region's publicly owned utilities by aggregating utility-specific forecasts for those customers. The forecast exchange loads were obtained from the information provided by the utilities in the form of total system loads. The total system loads were then adjusted by the historical residential load factor to produce the exchange loads. The residential load factor was calculated by dividing actual residential loads by actual system loads. For purposes of the

7(b)(2) rate test, BPA is forecasting it will sell no power to the DSIs under the IP rate schedule. Sales to Federal agencies and capacity/energy exchanges are contractually determined and are input to RAM2007.

BPA's total sales obligations are comprised of public utility, investor-owned utility (IOU), DSI, Federal agency, Residential Exchange, and FPS contractual sales. All PF, IP, and NR forecast sales are entered into RAM2007 with diurnally and seasonally differentiated energy and seasonally differentiated demand billing determinants. Documentation for these forecasts of regional power loads appears in the Load Resource Study, WP-07-FS-BPA-01, and Load Resource Study Documentation, WP-07-FS-BPA-01A.

2.1.1.2 Load/Resource Balance

RAM2007 does not perform a load/resource balance calculation for the Program Case. Instead, the model depends on the load/resource balance performed in the Load Resource Study, WP-07-FS-BPA-01. Data from the Load Resource Study, WP-07-FS-BPA-01, are used to calculate the energy allocation factors (EAFs) to ensure that resources are allocated to serve loads in the order prescribed by the Northwest Power Act. The FBS serves Priority Firm Power (PF) loads (contract, Federal agency, public utility, and Residential Exchange loads) until FBS resources are exhausted. Residential Exchange resources then are used to serve any remaining PF load. DSI, New Resource, and Surplus Firm Power loads are combined into a single rate pool. Remaining Residential Exchange and new resources are used to serve this combined rate pool.

2.1.1.3 Revenue Requirement

FBS costs are based on the net interest and depreciation associated with the Federal investment in the hydro projects; planned net revenues; hydro operation and maintenance expenses; annual costs related to the Columbia Generating Station, WNP-1 and WNP-3, not including the costs associated with the WNP-3 Settlement Agreement; fish and wildlife costs; costs of the Trojan nuclear plant; costs of hydro efficiency improvements; costs of system augmentation; and costs of balancing purchase power. Residential Exchange resource costs are based on the average system costs (ASCs) of utilities participating in the Residential Exchange Program (REP), including cost adjustments for deeming utilities. New resource costs are those of the long-term generating contracts and renewable resources. Conservation costs include operating expenses, amortization, net interest and planned net revenues associated with the investment in BPA legacy conservation, conservation augmentation, and energy efficiency programs. Other BPA costs include PBL and agency administrative and general expenses and depreciation, net interest, and planned net revenues associated with PBL and agency investment in capital equipment. Transmission costs are the annual expenses associated with PBL's purchase of BPA and non-Federal transmission and ancillary services.

2.1.1.4 Cost Allocation

Allocation of projected costs to customer classes is performed on an average energy basis in RAM2007. Generation costs are allocated by the use of Energy Allocation Factors (EAFs) calculated using the results of the Load Resource Study, WP-07-FS-BPA-01. Conservation and billing credit costs, BPA’s administrative and general expenses, and energy service business costs are allocated across all BPA firm loads. The cost allocation procedures for the Program Case are the same as those used to develop BPA’s proposed rates.

2.1.1.5 Rate Design

The adjustments made to allocated costs in RAM2007 for the Program Case are the same as those made to develop BPA’s proposed rates. These include adjustments for: (1) secondary and other revenue credits; (2) the surplus firm power revenue surplus/deficiency; (3) the section 7(c)(2) delta and margin; and (4) the DSI floor rate adjustment. These rate design adjustments are discussed below in brief. Fuller descriptions are in the WPRDS.

Secondary and Other Revenues are earned from the sale of secondary energy that is made available by the assumption of the average of 50 water years for secondary energy generation capability. Secondary revenues are credited to loads served by FBS and new resources. RAM2007 uses the secondary energy sales revenue forecast produced by the Risk Analysis Model (RiskMod), documented in the Risk Analysis Study, WP-07-FS-BPA-04.

The Surplus Firm Power Revenue Surplus/Deficiency results when available surplus firm power is sold at other than its fully allocated cost. In addition, BPA assumes that long-term extra-regional contracts are in an exchange or power mode depending on the circumstances of the individual contracts. The fully allocated cost of the surplus firm power, less the revenues received from the sale of that power after adjusting for transmission costs, equals the surplus firm power revenue surplus/deficiency. The surplus/deficiency is allocated to firm loads served by FBS and new resources. The revenues from capacity sales are also treated as the surplus firm power revenue surplus/deficiency and are allocated to all firm loads served by FBS and new resources.

The 7(c)(2) Adjustment is made to account for the difference between the costs allocated to the DSIs and the revenues resulting from the applicable DSI rate. A net margin is used in determining the applicable DSI rate. The net margin subsumes the Value of Reserves credit and the typical margin adjustment. The net margin is 0.573 mills/kWh in nominal dollars.

The DSI Floor Rate test ensures that the DSI rate will not be lower than the IP rate in effect for Operating Year (OY) 1985, pursuant to section 7(c)(2) of the Northwest Power Act. If the DSI rate is below that floor rate, the DSI rate is raised to the floor rate and an adjustment is necessary to credit additional revenues from the DSIs to other firm power customers.

2.1.2 7(b)(2) Case in RAM2007

The 7(b)(2) Case section of RAM2007 calculates 7(b)(2) Case rates the same way as the Program Case rates, except where section 7(b)(2) of the Northwest Power Act requires specific assumptions to be made that modify the Program Case.

2.1.2.1 Sales

The sales forecasts input to RAM2007 to calculate rates for the 7(b)(2) Case are the same sales forecasts used in the Program Case, with the following modifications. The 7(b)(2) Case utility sales are adjusted to exclude estimates of programmatic conservation savings, competitive acquisitions conservation, and billing credits. The 7(b)(2) Case also excludes REP loads. Sales to "within or adjacent" DSIs, adjusted to exclude estimates of the Conservation/Modernization program, are assumed to be transferred to the service territories of the preference customers for the entire rate test period as 100 percent firm loads. Sales to DSIs not "within or adjacent" are assumed not to have occurred. For the rate test period, no power sales to DSIs are forecast for the Program Case, and thus no DSI loads are added in the 7(b)(2) Case.

2.1.2.2 Resources

The size of the FBS is identical for the Program Case and the 7(b)(2) Case. However, the FBS that is available to serve requirements load is slightly larger in the 7(b)(2) Case because some of the "other obligations" served in the Program Case were not in existence at the time of the passage of the Northwest Power Act and are not served in the 7(b)(2) Case. If the FBS is insufficient to serve 7(b)(2) Customer loads through the test period in the 7(b)(2) Case, additional resources are assumed to come on-line. Consistent with the 7(b)(2) ROD, three types of additional resources can be added to serve 7(b)(2) Customer loads. The first type is actual and planned acquisitions by BPA from 7(b)(2) Customers consistent with the Program Case. The second type is the existing resources of 7(b)(2) Customers not dedicated to serving their regional loads. These first two types of resources include any BPA programmatic conservation and are used to serve remaining 7(b)(2) Customer load in order of least cost first. The third type of additional resources, generic resources, is based on the costs of resources acquired by BPA from non-7(b)(2) Customers consistent with the Program Case. These resources are brought on-line if the first two types of resources are insufficient to meet the 7(b)(2) Customer requirements.

2.1.2.3 Financing Benefits

The financing benefits analysis required by section 7(b)(2)(E)(i) of the Northwest Power Act was performed by BPA's financial advisor, Public Financial Management. The financial advisor's analysis is Appendix A to this Study. It shows that the estimated financing benefit of BPA's participation in resource acquisitions of BPA-sponsored conservation and generation resources by public utilities is 18 basis points lower than the 7(b)(2) Case without BPA backing using 25-year term financing. The financing benefit of BPA backing for conservation resources in the Program Case would be 18 and 17 basis points lower than the financing costs in the 7(b)(2) Case if financing terms of 20 and 15 years were used. This increases the financing costs for additional resources in the 7(b)(2) Case, thereby increasing the 7(b)(2) Case power cost of the 7(b)(2) Customers. For the Cowlitz Falls Project, the estimated benefit of BPA's participation is 5 basis points between an assumed revenue bond issued with and without a BPA contract for the Project. In the 7(b)(2) Case, resources acquired from non-7(b)(2) Customers, such as independent power producers, have a cost of financing that is 137 basis points lower than the Program Case, in which BPA would be using non-tax-exempt financing.

2.1.2.4 Load/Resource Balance

The 7(b)(2) Case section of RAM2007 adjusts the established load/resource balance from the Program Case to comport with the different loads and resource use restrictions found in the 7(b)(2) Case. The Program Case is in load/resource balance during the rate period. The size of the FBS and the amounts of balancing purchase power and augmentation power are the same in the 7(b)(2) Case as in the Program Case. In addition, the Program Case assumes a small amount of new resource power that is not assumed in the 7(b)(2) Case. This is more than offset by the reduction in "other obligations" served before requirements loads in the 7(b)(2) Case. Therefore, before going into the 7(b)(2) resource stack, the total resources available to serve firm load are slightly greater in the 7(b)(2) Case than in the Program Case. The 7(b)(2) Case PF class loads are larger than the sum of the Program Case PF loads. In the 7(b)(2) Case, no conservation savings are assumed to have occurred. The slightly larger FBS resource amount available to serve loads and the larger load for service under posted rates in the 7(b)(2) Case results in the need to select additional resources from the 7(b)(2) resource stack.

2.1.2.5 Revenue Requirement

The revenue requirement in the 7(b)(2) Case is comprised of the same types of costs and budget information as in the Program Case, with some modifications. The 7(b)(2) Case excludes Program Case revenue requirement amounts budgeted for conservation, direct generation acquisitions, and REP costs. In addition, the FPS contracts excluded from the 7(b)(2) Case (other obligations not in force at the time of the Act) provide no revenues. Repayment studies are then performed for each year of the 7(b)(2) rate test period using the same method as the Program Case.

2.1.2.6 Cost Allocation

Section 7(b)(2) Customers are allocated FBS and new resource costs according to their use of the respective resources. Purchasers of surplus firm power are allocated FBS costs and new resource costs according to their use of the resources.

2.1.2.7 Rate Design

Rate design adjustments in the 7(b)(2) Case are performed in the same manner as in the Program Case.

3. SUMMARY OF RESULTS

Results for the two Cases are summarized in Tables 1 and 2 below.

3.1 Program Case

The Program Case rate for each year is based on the costs of the resources used to serve the 7(b)(2) Customers. The resource costs are then adjusted as described above and in the WPRDS (WP-07-FS-BPA-05). Table 1 below shows the projection of undiscounted nominal Program Case rates.

3.2 7(b)(2) Case

The annual amount to be paid by 7(b)(2) Customers for their power needs in the 7(b)(2) Case is based on the cost of FBS resources and the cost of additional new resources. These power costs include adjustments for reserves and financing, *i.e.,* the absence of the reserve benefits and financing benefits implicit in the cost of power in the Program Case. The power costs are then subject to the same cost and revenue adjustment allocations as the Program Case rates. Table 2 below shows the projection of undiscounted nominal 7(b)(2) Case rates.

3.3 The Section 7(b)(2) Rate Test

RAM2007 performs the section 7(b)(2) rate test after it calculates the two sets of test period rates. First, the projected Program Case rates are reduced by the applicable 7(g) costs for each year. The applicable 7(g) costs are described in section 7(b)(2) as "conservation, resource and conservation credits, experimental resources and uncontrollable events." The 7(g) costs quantified for BPA's final rate proposal rate test are comprised of BPA's acquired and projected conservation and billing credits, energy efficiency costs, and C&RD costs. The projected rates for each year then are discounted to the beginning of FY 2007 using factors based on BPA's projected borrowing rate for each year. Table 3 shows BPA's future borrowing rates that were used in the discounting procedure and the corresponding cumulative discount factors. The discounted rates for each case then are averaged over the test period, rounded to one decimal place, and compared (see Table 4). As shown in Table 4, the rate test triggers by 5.9 mills/kWh. Therefore, a rate adjustment, valued at about $361 million per year, is required.

TABLE 1
PROGRAM CASE RATES
(nominal mills/kWh)

Line No.	Fiscal Year	A Rate	B Applicable 7(g) Costs	C Net Rate *
1	2007	30.63	1.93	28.70
2	2008	30.11	1.91	28.20
3	2009	31.90	1.97	29.93
4	2010	31.95	2.02	29.94
5	2011	33.45	1.98	31.47
6	2012	33.34	1.94	31.40
7	2013	34.82	1.97	32.86

* Column A minus Column B.

TABLE 2
7(b)(2) CASE RATES
(nominal mills/kWh)

Line No.	Fiscal Year	A 7(b)(2) Rate
1	2007	23.02
2	2008	21.65
3	2009	23.02
4	2010	21.66
5	2011	23.38
6	2012	21.38
7	2013	23.32

TABLE 3
DISCOUNT FACTORS FOR THE RATE TEST

Line No.	Fiscal Year	A Annual BPA Borrowing Rate [1]	B Cumulative Discount Factor [2]
1	2007	.0667	.9375
2	2008	.0698	.8763
3	2009	.0722	.8173
4	2010	.0752	.7601
5	2011	.0759	.7065
6	2012	.0757	.6568
7	2013	.0755	.6107

[1] 2007 Revenue Requirement Study Documentation, WP-07-E-BPA-02A, Chapter 6.
[2] Column B_t = Column $B_{t-1}/(1 + \text{Column } A_t)$; Fiscal Year 2006 equals 1.

TABLE 4
COMPARISON OF RATES FOR TEST
(2002 mills/kWh)

Line No.	Fiscal Year	A Discounted Program Case Rate	B Discounted 7(b)(2) Case Rate
1	2007	26.91	21.59
2	2008	24.71	18.97
3	2009	24.46	18.81
4	2010	22.75	16.46
5	2011	22.23	16.52
6	2012	20.62	14.04
7	2013	20.07	14.24
8	Average Rate	23.1	17.2
9	Difference of Average Rates		5.9

This page intentionally left blank.

APPENDIX A

Section 7(b)(2)
Report to Bonneville Power Administration on Estimated Financing Costs for Section 7(b)(2) Rate Test for 2002 Rate Case

This page intentionally left blank.

FINAL REPORT

TO

BONNEVILLE POWER ADMINISTRATION

ON

ESTIMATED FINANCING COSTS

FOR

SECTION 7(b)(2) RATE TEST

PREPARED BY

PUBLIC FINANCIAL MANAGEMENT

PFM®
The PFM Group
Public Financial Management, Inc.
PFM Asset Management LLC
PFM Advisors

APPENDIX A TO:

7(b)(2) RATE TEST STUDY, WP-07-FS-BPA-06A

This page intentionally left blank.

SECTION 1

PURPOSE OF REPORT

The purpose of this report is to provide our recommended financing costs that will be used by Bonneville Power Administration ("BPA") as inputs in their calculation of the "reduced public body and cooperative financing costs" as described in Section 7(b)(2)(E) of the Northwest Power Act. We also discuss certain assumptions and rationale used in arriving at these recommended financing costs. In providing the enclosed summary of our conclusions and assumptions, we have relied upon our professional experience and expertise in matters concerning the overall credit markets, the activities of BPA and other public and private utilities in the Pacific Northwest ("PNW") and throughout the country.

SECTION 2

INTRODUCTION

The Northwest Power Act requires that the Administrator of BPA periodically review and revise the rates for the sale of Federal power and for the transmission of non-Federal power. As part of the process of reviewing and revising the rates for firm power to be charged its preference, Direct Service Industry ("DSI"), Investor Owned Utility ("IOU"), and other customers, the Administrator must follow the requirements of Section 7(b)(2) of the Northwest Power Act. Section 7(b)(2)(E) requires that the Administrator assume that:

> "the quantifiable monetary savings, during such five-year period, to public body, cooperative and Federal agency customers resulting from reduced public body and cooperative financing costs as applied to the total amount of resources, other than Federal Base System resources, identified under subparagraph (D) of this paragraph, and reserve benefits as a result of the Administrator's actions under this chapter were not achieved."

Section 7(b)(2)(D) specifies the assumptions to be made to meet public body, cooperative, and Federal agency customer (7(b)(2) Customers) loads. After meeting contractual obligations with

Federal Base System ("FBS") resources, additional resources can be added to meet loads of the 7(b)(2) Customers. These additional resources can include: actual and planned resources acquired from 7(b)(2) Customers; existing 7(b)(2) Customer resources not dedicated to their own loads; and generic resources acquired from non-7(b)(2) Customers. These resources are assumed to include any conservation programs undertaken or acquired by BPA.

The quantifiable monetary savings associated with the "reserve benefits" per Section 7(b)(2)(E)(ii) relates to reserves that could be made available to BPA by the nature of BPA's contracts with DSI customers. Prior DSI contracts had provided the Federal Columbia River Power System (FCRPS) with reserves through BPA's ability to restrict or interrupt portions of the DSI loads. In prior 7(b)(2) rate cases, the DSI loads were assumed to be served by utilities in the Northwest instead of by BPA. The 7(b)(2) rate test also requires the assumption that these utilities would have had to provide their own reserve resources, and that the utilities would finance reserve resources without BPA participation. BPA's analysis of the restriction rights value in its 7(b)(2) rate cases had contained the assumption that the financing costs associated with such reserves would be different were they acquired by regional utilities.

Similar to BPA's 2002 Power Rate Case, BPA's Power Business Line is forecasting a zero purchase of supplemental reserves from the DSls in the 2007 Power Rate Case. Therefore, the 7(b)(2) study will not include resource acquisitions by the Joint Operating Agency (JOA) for the replacement of supplemental reserves provided by the DSls.

This report provides our conclusions concerning financing costs for BPA's public body, cooperative and Federal agency customers to be used in the 7(b)(2) rate case prescribed in the Northwest Power Act. The conclusions presented in this report represent our opinions as financial advisors familiar with the municipal and governmental utility credit markets and with bond issues for both public power agencies and IOUs in the Pacific Northwest. Given the assumptions noted in this report, our conclusions represent the most probable situation, had the hypothetical situation described in the Northwest Power Act occurred.

SECTION 3
EXECUTIVE SUMMARY

This report derives and provides estimates of the interest rates and differentials associated with financing for the different classes of resources identified in Section 7(b)(2) of the Northwest Power Act. Prior 7(b)(2) rate cases have utilized both historic and projected interest rate assumptions for several financing structures. Historic interest rate assumptions have been applied to the financing of prior expenditures for "Named Resources", conservation resources and other forms of generation resources. Projected interest rate assumptions have been applied to the financing of prospective expenditures for potential conservation and generation resources. This report also derives and provides estimates of interest rates and differentials associated with the different classes of resources in the Program Case. Historic interest rate assumptions have been applied to the financing of prior expenditures for conservation resources and other forms of generation resources. Projected interest rate assumptions have been applied to the financing of prospective expenditures for potential conservation and generation resources. In the case of certain Named Resources, actual historical financing costs were utilized. Table A contains a summary of historical and projected interest rate assumptions for various resource categories. It is important to note that Table A has been developed from the format provided in prior 7(b)(2) rate study analyses. The prior studies sought to provide historical and prospective interest rates for long-term, fixed-rate financings. As such, the rates provided in the prior studies were for level debt service financing structures with an assumed final maturity of roughly 30 years. In order to estimate the average interest rate for a 30-year financing, prior studies used various interest rate measures for bonds having a term of 25 years. We concur that the selection of interest rate indices having a 25-year term represents a reasonable estimate of the financing costs for 30-year, level debt service borrowings. In Table A, we have again provided interest rate assumptions based on indices and market data for 25-year maturities, along with assumptions for 15-year and 20-year maturities to finance conservation investments. (See Table D).

TABLE A – Summary of Historical and Projected Interest Rate Assumptions

	Program Case Interest Rate	7(b)(2) Case Interest Rate	Interest Rate Differential
Resource	With BPA Backing	Without BPA Backing	Basis Points
Historical Named			
Idaho Falls	N/A	N/A	N/A
Cowlitz Falls (25 Yr)	4.20% Actual **(1)**	4.25%	5
Projected Conservation **(2)**			
BPA Sponsored (25 Yr)	5.24%	5.42%	18
Other Public (20 Yr)	5.17%	5.34%	17
Other Public (15 Yr)	4.93%	5.09%	16
Projected Generation			
Public (25 Yr)	5.24%	5.42%	18
Non-7(b)(2) (25 Yr)	6.79%	5.42%	-137

N/A = Not Applicable.

(1) Actual True Interest Cost of refunding issue sold August 24, 2003.

(2) The interest rates provided for various Projected Conservation categories are assumed for either BPA or JOA borrowings having the maturities so listed. In the 2007 Power Rate Case Section 7(b)(2) Study, BPA assumes that conservation measures related to 2001 and prior had a useful life of 20-years, and for years 2002 and after that a useful life of 15-years applies. Those expenditures are assumed to be financed by the JOA over a useful life of 20 and 15 years,

depending on the vintage year of the investment. During fiscal years 1995-2005, BPA issued $452 million in conservation bonds with varying terms. The weighted average term was 12.25 years, with a weighted average interest rate of 5.89%. In the 2007 Rate Case study period, BPA projects to borrow $257 million using five-year maturities with a weighted average interest rate of 6.18%. Since the term of these conservation bonds is not comparable with the longer term maturities that are being projected in the 2007 case, the rates were not included in the table

The Program Case Interest Rates and 7(b)(2) Case Interest Rates shown in Table A above are derived from historic borrowing cost and interest rate information compiled for the purposes of the Section 7(b)(2) rate test. The historic interest rate differentials are a reasonable basis for establishing assumptions for projected interest rate differentials for borrowing costs for the period encompassing BPA's 2007 Power Rate Case.

A general observation from the data provided in Table A is that for most financing categories, the 7(b)(2) Case interest rates are higher than those assumed in the Program Case. When there is a positive number in the "Interest Rate Differential" column, it represents that amount by which the 7(b)(2) Case interest rate is higher (or more costly) than the Program Case. We highlight this to clarify potential confusion that may arise as a result of information provided in prior 7(b)(2) rate study assumptions. In the 2002 Financing Cost Study for the Section 7(b)(2) Rate Test (Prior 2002 Study), there appear to have been inconsistencies in how figures were listed in Table A. In some instances, when interest rates for the 7(b)(2) Case were higher (and more costly) than the Program Case, the basis point differential was presented as a positive number (consistent with the presentation in Table A above). However, in other instances, when 7(b)(2) interest rate assumptions were greater than those for the Program Case, the figure in the Interest Rate Differential column was listed as a negative number – possibly implying that the 7(b)(2) Case interest rate was less than the Program Case. We do not know why the figures appear to have been reported differently, or if the reporting affected how the figures were actually used in determining 7(b)(2) power rates. This observation should serve as a reminder that some aspects of prior 7(b)(2) interest rate assumptions may serve as valid methodologies or assumptions going forward, while other elements of prior studies may not be applicable to the current project.

The interest rate averages listed above in Table A would serve as the assumed interest rates for the Program Case and 7(b)(2) Case for the prospective maturity terms outlined.

SECTION 4
ASSUMPTIONS

In developing our interest rate assumptions, we have used the types of financing that most likely would be, or could have been, used at the time of funding the hypothetical resources acquired according to the terms of the 7(b)(2) rate test. We have relied upon common and accepted legal and financing structures for the hypothetical public financing entity that the 7(b)(2) Customers are assumed to have formed. Similarly, discrete borrowings undertaken by 7(b)(2) Customers and non-7(b)(2) Customers would be assumed to be financed using customary public financing methods for long-term fixed rate financing. Such assumptions as to legal and financing structure represent, in our opinion, the most prevalent means for financing large-scale resource acquisition programs similar to what BPA or its customers could have undertaken or would utilize in the future.

As noted above, the Northwest Power Act requires that an estimate be provided of the financing costs to customers in the 7(b)(2) Case because the customers themselves would have to finance the acquisition of additional resources needed to meet their firm loads after BPA's FBS resources are exhausted. An assumption has been made, with which we concur, that the 7(b)(2) Customers would have formed a Joint Operating Agency ("JOA") where the financing would have been the responsibility of the participant agencies in the financing. This would have been a similar, but not identical, legal structure to Energy Northwest and other JOA's such that underlying legal obligations would have been clearly enforceable.

The member agencies of the JOA are listed in Appendix A along with their respective shares. All of the member agencies are assumed to have signed "take-or-pay agreements," such that each would pay for its proportionate share of the debt service on the financing regardless of whether or not the project produced the expected levels of output. In the event that one participant failed to pay its share of debt service, each remaining participant would be responsible for an increased level of debt service of up to 125 percent of the member agency's original commitment. Based on such a typical financing structure, and in concurrence with the assumptions contained in prior 7(b)(2) rate studies, we have assumed that a financing by a JOA consisting of the assumed member agencies would have received and been able to maintain a rating in the "A" category from both Moody's and S&P - two well regarded bond rating agencies. In the case of the JOA or 7(b)(2) Customer issuing revenue bonds with the advantage of a BPA "take-or-pay" or "capability" power sales contract, we have assumed that the financing would have received and maintained a rating in the "Aa/AA“ from both Moody's and S&P.

In estimating the financing costs for specific Named Resources, such as the Cowlitz Falls Project, we have assumed a rating based upon the particular sponsor's credit rating. Therefore, the ability of the Public Utility District No. 1 of Lewis County (Lewis County PUD), for example, to service its own load with the resource is also assumed in order to meet requirements for investment grade ratings from both Moody's and S&P. Similarly, we have estimated financing costs for other anticipated conservation and generation resource providers, assuming that suitable uses for the resource output were available.

SECTION 5
ASSUMPTIONS CONCERNING RESOURCE ACQUISITIONS

In previous rate cases, BPA has assumed the JOA would have undertaken two phases of resource acquisition. The first phase assumed the acquisition of peaking resources to replace the reserve benefits provided by the DSI load that are not provided in the 7(b)(2) Case. Unlike some prior rate cases, BPA's Power Business Line is forecasting a zero purchase of Supplemental Reserves from the DSIs in the 2007 rate case. Therefore, the 7(b)(2) study will not include resource acquisitions by the JOA for the replacement of supplemental reserves provided by the DSIs.

The second phase of resource acquisition program assumes the acquisition of individual projects involving conservation resource and generation resource programs sponsored by 7(b)(2) Customers as well as a variety of other sponsors. As part of its resource acquisition programs, BPA has solicited resources through its Competitive Resource Acquisition Program, unsolicited proposals, BPA Billing Credits, and other programs.

The City of Idaho Falls entered into a Power Purchase Agreement dated April 1, 1982, with BPA for the purchase of all power and energy produced from three hydroelectric generating plants operated by the City of Idaho Falls (the Idaho Falls Project). Lewis County PUD entered into a Power Purchase Agreement dated May 23, 1991, with BPA for the output of the Cowlitz Falls Hydroelectric Project (the Cowlitz Falls Project). BPA has solicited for resources through the BPA Billing Credits Policy contained in section 6(h) of the Northwest Power Act and the Competitive Resource Acquisition Program, which includes the Resource Contingency Program. Under the BPA Billing Credits Policy, BPA has contracted for the output of four projects consisting of South Fork Tolt, Wynocchee, Short Mountain Landfill, and Smith Creek. The total output of these four projects totals 20.0 aMW. Under the terms of the BPA Billing Credits Policy, BPA's obligation to purchase the output is subject to the availability of the resource and, therefore, we do not believe the existence of the BPA power purchase agreement to be material to the credit rating of the financing associated with these particular resources.

In general, the hypothetical financing agency consisting of the 7(b)(2) Customers would apportion the risks of resource acquisition due to non-completion, technical difficulties or other factors among the member agencies in proportion to their ownership shares. Similarly, individual resource sponsors are assumed to accept such risks without allocation to third parties. Thus, the risks of non-completion or technical difficulties are not assumed to be factors that would impact the financing costs of particular resources.

We have assumed that all financings will utilize traditional fixed-rate debt with a level debt service structure. In the case of the JOA entity issuing revenue bonds, the financing would rank as parity debt with the revenue bonds assumed to have been issued in FY 1981-1982. The revenue bonds or project financings issued by, or entered into by, 7(b)(2) Customers, non-7(b)(2) Customers or other entities would have comparable features.

Financing of the Cowlitz Falls Project and the Idaho Falls Project is assumed to have occurred at the time when the sponsors of each of the projects issued revenue bonds to provide for the capital costs of each respective resource. Resources to be acquired from non-7(b)(2) Customers are assumed to be acquired on a project finance basis. In the Program Case, BPA would contract to purchase power output. In the 7(b)(2) Case, BPA would contract with the JOA.

In addition, it is assumed that all financings by 7(b)(2) Customers are structured to take full advantage of tax-exempt financing, subject to the provisions of applicable tax law. Also, we would note that section 9(f) of the Northwest Power Act requires certain certifications by the Administrator prior to the acquisition of resources, which must be met in order that the exemption from gross income in section 103 (a)(l) of the Internal Revenue Code of 1986 be achieved. As a result, the assumption is made for the purposes of the resource acquisitions contemplated with BPA, that the tax-exemption for financings will not be adversely affected and that BPA will be able to provide the certifications required under the Northwest Power Act.

We would also note that the assumed credit ratings on revenue bonds involving an obligation of BPA have remained stable in spite of recent events. Uncertain water conditions, the financial requirements of BPA's resource acquisition programs, fish and wildlife issues, and other items are significant issues affecting the PNW and BPA's credit ratings. However, for the purposes of the 7(b)(2) rate case, no change in credit ratings is projected for BPA, or the 7(b)(2) Customers, as it pertains to the financing feasibility of particular resources financed with debt issued in the public credit markets.

SECTION 6

IDAHO FALLS PROJECT

On April 1, 1982, the City of Idaho Falls, Idaho executed a Power Purchase Agreement whereby BPA agreed to a long-term purchase of the output of three hydroelectric generating plants to be constructed in the service territory of the City of Idaho Falls. The City of Idaho Falls provided for the capital costs of constructing the three hydroelectric generating plants with the proceeds of revenue bonds issued in 1981. These bonds were subsequently refinanced on multiple occasions. This agreement is scheduled to expire on September 30, 2006, but BPA personnel are assuming the agreement is extended during the 2007-2013 time period for purposes of conducting the 7(b)(2) Rate Test.

Under the terms of the Power Purchase Agreement with the City of Idaho Falls, the City may deliver to BPA a notice of withdrawal of the total project generation effective no earlier than three years from the year in which such notice is given, but not before July 1, 1988, or after July 1, 1998. Because the revenues of the City's Electric System (as defined) secure the City of Idaho Falls revenue bonds issued to finance the Project, we do not believe the existence of the BPA Power Purchase Agreement to be material to the credit rating of these bonds. Therefore, the cost of the Idaho Falls Project resource would not change as a result of the financing assumptions required by the 7(b)(2) rate case.

SECTION 7

COWLITZ FALLS PROJECT

On May 23, 1991, Lewis County PUD entered into an Amendatory Contract for Power Purchase (the Contract) whereby BPA agreed to enter into a long-term purchase of the output of a hydroelectric generating plant known as the Cowlitz Falls Project (Cowlitz Falls Project). BPA and Lewis County PUD agreed that Lewis County PUD would finance construction of the Project through the issuance of revenue bonds, with BPA agreeing to pay to or on behalf of Lewis County PUD amounts equal to Project Power Costs (as defined) including Annual Debt Service (as defined) on such revenue bonds for the life of the Contract. On August 27, 1991, Lewis County PUD issued $171,095,000 in Public Utility District No.1 of Lewis County, Washington, Cowlitz Falls Hydroelectric Project Revenue Bonds, Series 1991. The bonds were rated Aa/AA with annual debt service payments of approximately $13,465,000 and a final maturity of October 1, 2024. The callable bonds of this series were again refunded on August 23, 1993. The remaining 1991 bonds and the callable bonds issued in 1993 were refunded again on June 19, 2003.

Under the terms of the Contract, the primary source of security for the bonds is revenues received from BPA pursuant to the Contract and a Payment Agreement (the Payment Agreement). Under the Contract, BPA is obligated to pay all project costs, including debt service, whether or not the project is completed or power is delivered. If BPA does not make payment under the Contract, it is obligated to pay debt service under the Payment Agreement directly to the bond trustee. Debt Service on the bonds is an operating and maintenance (O&M) expense of BPA, having priority over payments of BPA's Treasury debt and repayment of the Federal investment in the Columbia River Power System.

Because the revenues from the Contract and the Payment Agreement secure Lewis County PUD’s revenue bonds issued to finance the Project, we believe that the Contract and Payment Agreement are the primary support for the current credit ratings. BPA retains the "dry hole risk" for the Project and is obligated to pay debt service on the Bonds for their full term whether the Project is operating or not. For the purposes of the 7(b)(2) test, Lewis County PUD is assumed to accept the "dry hole risk" and that the Cowlitz Falls Project output would be dedicated to serving Lewis County PUD’s own load.

The original bonds were priced on Tuesday, August 27, 1991, with a True Interest Cost of 7.10%. The refunding Bonds priced on Tuesday, August 23, 1993 had a True Interest Cost of 5.61%. The refunding Bonds priced on June 19, 2003 had a True Interest Cost of 4.20%. Of the $146,210,000 of bonds sold in 2003, $135,930,000 were guaranteed by municipal bond insurance companies and rated AAA. The uninsured bonds maturing in years 2005 through 2007 were rated Aa2/AA-. As stated earlier, we believe that a bond issued on behalf of the 7(b)(2) Customers would have carried a rating in the A category. During the months preceding the

Lewis County sale, there were several bond issues sold for A-rated electric utilities. However, in most every case, these bonds were also guaranteed by a municipal bond insurance policy – and rated AAA. Interest rates on these insured bonds were comparable to those of the Lewis County bonds. In our opinion, the net financing cost differential between AA- and A-rated bonds that were both backed by AAA-rated insurance policies would have been a function of the price charged by the insurance companies. In the case of the Lewis County bonds, one insurance policy for a portion of the bonds was priced at .33% of the total amount of insured debt service. The other policy applied to a different grouping of bonds was priced at .475% of insured debt service. The amount of these premiums is taken into account in the calculation of the 4.20% True Interest Cost on the bonds. In our opinion, at the time the Lewis County bond sold, an approximate market insurance premium for an A-rated issuer would have been approximately .75% of insured debt service. A recalculation of the Lewis County True Interest Cost with the .75% assumed insurance premium produces a rate of 4.25%. In our opinion, we believe that the borrowing advantage to the 7(b)(2) Customers from the BPA backing is approximately equal to the 5 basis point differential between the two True Interest Costs.

SECTION 8
JOA BORROWING COSTS

For purposes of establishing assumptions for JOA borrowing costs, we feel it is appropriate to utilize the historical interest rate assumptions from prior 7(b)(2) rate studies. However, we feel that there are more appropriate measures for more recent rates and projected interest rate assumptions. Prior 7(b)(2) historical assumptions were based upon an analysis of bond issues for selected public power agencies for the period from January 1, 1982 to March 8, 1999. The analysis compared the True Interest Cost for each financing for each FY to the Bond Buyer 25-Bond Revenue Bond Index (Revenue Bond Index). The Revenue Bond Index consisted of revenue bonds maturing in 30 years. At times, roughly 10 of the 25 bonds included in the index are electric power related financings. In general, the Revenue Bond Index consists of issuers with an average rating equivalent to Moody's "A1" and Standard & Poor's "A+" with a concentration of issuers rated "A1/A +" or "AA/Aa" from at least one rating agency.

The prior 7(b)(2) rate studies then analyzed the relationship between bonds of different rating categories to the Revenue Bond Index. In this portion of the analysis, it was decided to eliminate Energy Northwest from the list of power revenue bond issuers with at least "AA" from either rating agency in order to assess the effect that the sometimes heavy issuance of refunding revenue bonds by Energy Northwest may have had on the Revenue Bond Index and the various rating categories. For each year prior to FY 1996, the study determined the average percentage represented by: (1) the true interest costs of large public power issues in a given year, divided by: (2) the Revenue Bond Index in place on the sale dates. This calculation was performed for bond issues in the A-rated category and bond issues in the AA-rated category – excepting Energy Northwest issues. The annual average of the individual issue percentages in each rating class was then multiplied by the average Revenue Bond Index for the entire fiscal year to arrive at an assumption for the average borrowing costs for A-rated and AA-rated issuers during that year.

The Prior 2002 Study recognized: (1) the diminishing data set of A-rated public power bonds due to the increasing use of AAA bond insurance, and (2) the existence of useful market indices such as the Bloomberg Capital Markets fair value yield curves. The Bloomberg Capital Markets calculates daily indexes for several rating categories and maturity ranges for power revenue bonds. The information appears to be generally consistent with information included from prior years based upon the actual issuance of power revenue bonds by different rated issuers. The interest rate assumptions employed by the Prior 2002 Study (replicated in Table B) for FY 1998 and prior years are derived from the Bloomberg yield curves. The Bloomberg yield curves provide data for electric revenue bonds of several credit rating categories, including bonds rated A-, A+, AA- and AA+. In order to estimate rates for bonds in the A and AA rated categories, we took the average of published rates for the A- and A+ categories for the A-rated data, and took the average of published rates for the AA- and AA+ categories for the AA-rated data. Interest rate estimates are for financings with level debt service and a 30-year final maturity. The Bloomberg rates for 25-year maturities were used as the best estimates of financing costs for this financing structure. These averages for FY 1998 and prior fiscal years are found in Table B. Table B provides the following information:

(1) the annual average of the Revenue Bond Index,

(2) the calculated hypothetical AA-rated (and thus BPA-backed) average financing cost,

(3) the calculated hypothetical A-rated (and thus JOA-backed) average financing cost, and

(4) the interest rate differential between #s (3) and (4) for fiscal years prior to 1999.

TABLE B - HISTORICAL INTEREST RATE ASSUMPTIONS FROM PRIOR 7(B)(2) RATE STUDIES

FY End 9/30	Revenue Bond Index	BPA Rate	JOA Rate	Difference
1982	13.25%	12.65%	13.31%	0.66%
1983	10.13%	9.86%	10.47%	0.61%
1984	10.43%	10.69%	10.74%	0.05%
1985	9.90%	10.35%	10.10%	-0.25%
1986	8.26%	8.49%	8.42%	-0.07%
1987	7.68%	7.77%	7.68%	-0.09%
1988	8.40%	8.50%	8.48%	-0.02%
1989	7.17%	7.01%	7.13%	0.12%
1990	7.51%	7.62%	7.49%	-0.13%
1991	7.20%	6.96%	7.02%	0.06%
1992	6.69%	6.33%	6.35%	0.02%
1993	6.06%	5.73%	5.81%	0.08%
1994	6.08%	5.63%	5.98%	0.35%
1995	6.57%	6.34%	6.51%	0.17%
1996	6.01%	5.80%	5.96%	0.16%
1997	5.87%	5.61%	5.76%	0.15%
1998	5.41%	5.15%	5.31%	0.16%

For more recent years' interest rate assumptions, and for the 2007 7(b)(2) Rate Case, we suggest utilizing the same methodology for establishing the estimated rates for A and AA rated electric revenue bonds. We used the database of Bloomberg interest rates for AA-rated and A-rated, 25-year tax-exempt electric revenue bonds as the best proxies for BPA and JOA borrowing costs. We are also of the opinion that the best assumptions for financing costs during the 2007 7(b)(2) Rate Case period are historical interest rates over just the past ten years. We feel this time period will provide a sufficient data set for the 7(b)(2) Rate Test period of FY 2007-2013. It also eliminates from the data set the period during the early 1980s that was characterized by very high interest rates. We feel that the economic conditions and interest rates of the past ten years have a greater likelihood of being replicated than do the conditions of the early 1980s. For this reason, we have based our future interest rate assumptions for each of the various financing structures on the data from FY 1996 and forward.

Based on the Bloomberg Fair Market yield curves over the past ten fiscal years, the average AA-rated, 25-year electric revenue bond yield was 5.24%. This figure represents an 18 basis point advantage relative to the 5.42% average for the A-rated average for the comparable period. Table C provides these figures for the past ten fiscal years.

TABLE C – RECENT AVERAGE AA AND A RATED, 25-YEAR ELECTRIC REVENUE BONDS

FY End 9/30	AA Bloomberg BPA Rate	A Bloomberg JOA Rate	Difference
1996	5.80%	5.96%	0.16%
1997	5.61%	5.76%	0.15%
1998	5.15%	5.31%	0.16%
1999	5.14%	5.24%	0.10%
2000	5.82%	5.92%	0.10%
2001	5.26%	5.42%	0.16%
2002	5.10%	5.34%	0.24%
2003	4.89%	5.19%	0.30%
2004	4.87%	5.10%	0.23%
2005	4.68%	4.91%	0.23%
Averages	5.24%	5.42%	0.18%

For the current 7(b)(2) rate study, we have been advised by BPA personnel of the potential consideration of resource financings that would have repayment periods of other than 30 years. Specifically, there is consideration to potential financing of conservation and generation resources that would have terms of 35 years. Our analysis indicates that the average rates listed above of 5.24% and 5.42% would have each been 3 basis points higher for 35-year maturities. We were also advised that the financing terms for conservation investments would be for 15 and 20 year terms, depending on the vintage year of the prior conservation investments made by BPA through its customers. Table D below provides various historical and projected interest rate assumptions for borrowings with final maturities of 15 and 20 years.

TABLE D – VARIOUS TERM STRUCTURE INTEREST RATE ASSUMPTIONS

FY End 9/30	Program Case 15-Year	7(b)(2) Case 15-Year	Program Case 20-Year	7(b)(2) Case 20-Year
09/30/96	5.53	5.66	5.71	5.84
09/30/97	5.35	5.47	5.50	5.61
09/30/98	4.93	5.03	5.07	5.17
09/30/99	4.93	5.02	5.12	5.22
09/29/00	5.53	5.62	5.79	5.88
09/28/01	4.97	5.12	5.21	5.37
09/30/02	4.78	5.01	5.04	5.27
09/30/03	4.43	4.67	4.79	5.06
09/30/04	4.44	4.63	4.79	5.01
06/01/05	4.22	4.42	4.52	4.76
Period Average	4.93	5.09	5.17	5.34

The period averages listed above would serve as the assumed interest rates for the 2007 7(b)(2) Rate Case prospective 15 and 20 year financings.

In our opinion, the above-assumed projected borrowing rates are reasonable estimates for borrowing costs of municipal issuers during the 2007-2013 time periods. Many factors influence the movement of tax-exempt interest rates and the relationships between borrowing rates for differently rated securities. Among these factors are: the timing of particular financings; the absolute levels of interest rates; the perceived credit quality of particular issuers; and the overall supply and demand for tax -exempt and taxable securities. If any of these factors were to change over time, then historical interest rate spread relationships could increase or decrease, which would change the assumed borrowing interest rate differentials calculated above.

SECTION 9
NON-7(b)(2) CUSTOMER BORROWING COSTS

Private developers, industrial companies, utility subsidiaries, governmental and quasi-governmental entities all represent viable sponsors for developing power projects whose output could be made available to BPA. Financing vehicles available to project sponsors will be either recourse, where the sponsor's balance sheet is relied upon for credit support, or non-recourse. In a non-recourse project financing, the strength of the project, not the strength of the sponsor, provides the support for the debt. Project financings would derive considerable financing benefits from inclusion of a BPA power purchase contract.

For the purposes of this analysis, it is assumed that BPA would enter into an all encompassing power purchase agreement whereby BPA would be obligated to pay an amount sufficient to cover a project's fixed and variable costs. As a result, the project's financing should be indifferent to the level of electricity actually purchased. Other factors including power delivery requirements, security deposits, performance criteria, regulatory out provisions, milestone criteria, force majeure events, security interests, events of default and remedies upon default are presumed to be resolved in a fashion that enables a project to be financed upon standard commercial terms.

Project sponsors which are private entities may or may not be able to qualify for tax-exempt financing for a particular project and generally may do so only where a facility qualifies as an "exempt facility" such as a waste to energy facility. Projects financed with tax-exempt financing would likely occur at interest rates comparable to those for the hypothetical JOA discussed in section 8. Projects financed with private sources of capital would likely be financed with high leverage, which is usually 75 or 80 percent but can be as much as 100 percent, which allows for a minimization of equity investment by the project sponsor. We assume that a project financing with a BPA contract would provide the means for securing debt financing at pricing which would be at the upper end of the quality range for similar projects. The perceived credit quality of the BPA contract obligation among potential financing sources would increase financing options for a given project.

For purposes of historical non-7(b)(2) resource financing, we again feel it is reasonable to utilize the historical interest rate assumptions contained in the prior financing studies for the 7(b)(2)

Rate Test. Prior 7(b)(2) financing studies have assumed that private debt financing for a project with a BPA contract could have been arranged at 50 basis points over the lender's cost of funds, which was assumed to have been the six-month's London Interbank Offered Rate (LIBOR), with 100 percent financing of project costs. The prior financing studies then adjusted for the possible effects of entering into interest rate swaps or conversion agreements which could have the effect of fixing the interest rates on all or a portion of a financing for a period of time or the remaining term to maturity for the transaction. In order to adjust the variable LIBOR interest rates to an estimated fixed interest rate for comparison purposes, prior financing studies assumed a 50 basis point addition to the LIBOR based interest rates to represent the amortized cost of an interest rate swap. Table E below provides the I8-year history of monthly averages for six-month LIBOR utilized in the Prior 2002 Study, along with the calculated borrowing rates for the same period. Table E also provides the JOA rates for utilized in the most Prior 2002 Study. The assumptions are the same as those listed and discussed in Section 8.

TABLE E - HISTORICAL INTEREST RATE ASSUMPTIONS FROM PRIOR 7(B)(2) RATE STUDIES

FY End 9/30	6-Mo. LIBOR	Adjusted Non 7(b)(2) Fixed Rate	JOA Rate	Difference
1982	15.41%	16.41%	13.31%	-3.10%
1983	10.29%	11.29%	10.47%	-0.82%
1984	11.27%	12.27%	10.74%	-1.53%
1985	9.57%	10.57%	10.10%	-0.47%
1986	7.65%	8.65%	8.42%	-0.23%
1987	6.55%	7.55%	7.68%	0.13%
1988	7.67%	8.67%	8.48%	-0.19%
1989	9.38%	10.38%	7.13%	-3.25%
1990	8.27%	9.27%	7.49%	-1.78%
1991	6.85%	7.85%	7.02%	-0.83%
1992	4.22%	5.22%	6.35%	1.13%
1993	3.41%	4.41%	5.81%	1.40%
1994	4.29%	5.29%	5.98%	0.69%
1995	6.25%	7.25%	6.51%	-0.74%
1996	5.37%	6.37%	5.96%	-0.41%
1997	5.53%	6.53%	5.76%	-0.77%
1998	5.74%	6.74%	5.31%	-1.43%

Once again, the greater amounts of historical data and proliferation of market indices allows us to refine this methodology used in the prior studies. For more recent years' interest rate assumptions, and for the 2007 7(b)(2) Rate Case, we suggest utilizing the Bloomberg database of interest rates for AA-rated, 25-year taxable utility bonds as the best proxy for potential non-7(b)(2) project financing costs. We have based our future interest rate assumptions for each of the various financing structures on the data from FY 1996 and forward. Table F below provides the past ten years' averages for the Bloomberg AA-rated, 25-year utility bonds as compared to the JOA financing costs assumed for the same periods. Again, the JOA financing cost assumptions are those provided in Section 8.

TABLE F - RECENT AVERAGE BLOOMBERG AA AND A RATED, 25-YEAR ELECTRIC REVENUE BONDS

FY End 9/30	AA Bloomberg Taxable Utility Non 7(b)(2) Rate	A Bloomberg Tax-Exempt Bond JOA Rate	Difference
1996	7.13%	5.96%	-1.17%
1997	7.21%	5.76%	-1.45%
1998	6.50%	5.31%	-1.19%
1999	6.67%	5.24%	-1.43%
2000	7.74%	5.92%	-1.82%
2001	7.43%	5.42%	-2.01%
2002	6.85%	5.34%	-1.51%
2003	6.29%	5.19%	-1.10%
2004	6.23%	5.10%	-1.13%
2005	5.80%	4.91%	-0.89%
Averages	6.79%	5.42%	-1.37%

In our opinion, the above-assumed borrowing rates are reasonable estimates based upon the actual borrowing costs of taxable and tax-exempt borrowers the indicated time periods. Many factors influence the movement of interest rates and the relationships between borrowing rates for differently rated securities. Among these factors are: the timing of particular financings; the absolute levels of interest rates; the perceived credit quality of particular issuers; and the overall supply and demand for tax-exempt and taxable securities. If any of these factors were to change over time, then historical interest rate spread relationships could increase or decrease, which would change the assumed borrowing interest rate differentials calculated above.

ATTACHMENT A

PARTICIPATION IN HYPOTHETICAL PUBLIC FINANCING ENTITY

PARTICIPANT	% SHARE
Eugene Water and Electric Board	3.70
Seattle	13.72
Tacoma	6.66
PUD #1 of Chelan County	2.53
PUD #1 of Cowlitz County	6.35
PUD #1 of Douglas County	.92
PUD #2 of Grant County	4.11
PUD #1 of Snohomish County	9.41
PUD #1 of Clark	6.00
SUBTOTAL - GENERATORS (9)	53.40
Springfield	1.24
PUD #1 of Benton County	2.44
Central Lincoln PUD	1.67
Clatskanie PUD	1.21
Franklin PUD	1.13
PUD #1 of Grays Harbor County	1.73
PUD #1 of Lewis County	1.10
Umatilla Electric Cooperative Association	1.14
SUBTOTAL - NONGENERATORS WITH A GREATER THAN 1% SHARE (8)	11.65
SUBTOTAL - REMAINING NONGENERATORS (100)	34.95
TOTAL (117)	100.00

This page intentionally left blank.

APPENDIX B

Section 7(b)(2)
Resource Stack Tables

This page intentionally left blank.

WP-07 Rate Case - 7(b)(2) Rate Test Resource Stack
Resources Grouped by the Three Resource Types Outlined by Section 7(b)(2)(D) of the Pacific N.W. Electric Power Planning and Conservation Act
All Costs are in 1980 dollars

A		B	C	D	E	F	G	H	I	J	K	L	M	N
Project	Year Placed in Service	Resource % Share of (aMW)	Interest Rate (%)	Capital Investment ($ooo)	Annual O & M ($ooo)	Annual Fuel ($ooo)	Year Available	Capacity Factor	Life	Annual Capital Cost ($ooo)	Discounted[2] Capital Cost Total ($ooo)	Discounted[2] O & M and Fuel Total ($ooo)	Dollars per AMW Total Cost ($ooo)	Mills per KWH Total Cost
Type I Resources - Actual and Planned Resource Acquisitons by BPA from 7(b)(2) Preference Customers:														
Conservation Resources[1]:														
BPA PROG CONS[1,6]	1982	32.4	5.34	53,020	4,258	0	2007	100	20	4,378	52,668	4,258	87,849	10.03
BPA PROG CONS[1,6]	1983	68.6	5.34	167,249	2,383	0	2007	100	20	13,810	166,136	2,383	122,827	14.02
BPA PROG CONS[1,6]	1984	16.6	5.34	57,165	7,114	0	2007	100	20	4,720	56,782	7,114	192,458	21.97
BPA PROG CONS[1,6]	1985	17.0	5.34	84,461	20,225	0	2007	100	20	6,974	83,898	20,225	306,244	34.96
BPA PROG CONS[1,6]	1986	23.5	5.34	78,745	4,149	0	2007	100	20	6,502	78,220	4,149	175,253	20.01
BPA PROG CONS[1,6]	1987	17.2	5.34	54,788	3,004	0	2007	100	20	4,524	54,424	3,004	166,942	19.06
BPA PROG CONS[1,6]	1988	15.6	5.34	43,738	4,969	0	2007	100	20	3,612	43,453	4,969	155,199	17.72
BPA PROG CONS[1,6]	1989	20.8	5.34	33,534	9,402	0	2007	100	20	2,769	33,311	9,402	102,675	11.72
BPA PROG CONS[1,6]	1990	13.2	5.34	25,535	25,236	0	2007	100	20	2,108	25,359	25,236	191,648	21.88
BPA PROG CONS[1,6]	1991	19.0	5.34	31,080	25,534	0	2007	100	20	2,566	30,869	25,534	148,429	16.94
BPA PROG CONS[1,6]	1992	37.4	5.34	40,690	41,863	0	2007	100	20	3,360	40,421	41,863	110,005	12.56
BPA PROG CONS[1,6]	1993	59.6	5.34	61,130	34,923	0	2007	100	20	5,048	60,728	34,923	80,244	9.16
BPA PROG CONS[1,6]	1994	51.3	5.34	74,698	32,253	0	2007	100	20	6,168	74,202	32,253	103,757	11.84
BPA PROG CONS[1,6]	1995	65.9	5.34	51,342	28,098	0	2007	100	20	4,239	50,996	28,098	60,011	6.85
BPA PROG CONS[1,6]	1996	56.3	5.34	30,813	28,846	0	2007	100	20	2,544	30,605	28,846	52,798	6.03
BPA PROG CONS[1,6]	1997	54.7	5.34	19,030	14,598	0	2007	100	20	1,571	18,899	14,598	30,619	3.50
BPA PROG CONS[1,6]	1998	33.4	5.34	14,918	17,104	0	2007	100	20	1,232	14,821	17,104	47,792	5.46
BPA PROG CONS[1,6]	1999	30.3	5.34	10,990	11,507	0	2007	100	20	907	10,911	11,507	36,993	4.22
BPA PROG CONS[1,6]	2000	14.7	5.34	191	8,460	0	2007	100	20	16	192	8,460	29,429	3.36
BPA PROG CONS[1,6]	2001	18.5	5.34	31	10,804	0	2007	100	20	3	36	10,804	29,297	3.34
BPA PROG CONS[1,6]	2002	25.7	5.09	15,021	9,122	0	2007	100	15	1,456	14,693	9,122	61,777	7.05
BPA PROG CONS[1,6]	2003	24.7	5.09	11,909	8,989	0	2007	100	15	1,154	11,645	8,989	55,692	6.36
BPA PROG CONS[1,6]	2004	31.0	5.09	9,932	8,087	0	2007	100	15	963	9,718	8,087	38,290	4.37
BPA PROG CONS[1,6]	2005	21.6	5.09	10,932	22,627	0	2007	100	15	1,060	10,697	22,627	102,852	11.74
BPA PROG CONS[1,6]	2006	26.6	5.09	21,049	23,090	0	2007	100	15	2,040	20,586	23,090	109,464	12.50
BPA PROG CONS[1,6]	2007	33.0	5.09	15,035	39,835	0	2007	100	15	1,457	14,703	39,835	110,178	12.58
BPA PROG CONS[1,6]	2008	33.0	5.09	14,737	38,774	0	2007	100	15	1,428	14,410	38,774	107,442	12.27

WP-07 Rate Case - 7(b)(2) Rate Test Resource Stack
Resources Grouped by the Three Resource Types Outlined by Section 7(b)(2)(D) of the Pacific N.W. Electric Power Planning and Conservation Act
All Costs are in 1980 dollars

A		B	C	D	E	F	G	H	I	J	K	L	M	N
Project	Year Placed in Service	Resource % Share of (aMW)	Interest Rate (%)	Capital Investment ($ooo)	Annual O & M ($ooo)	Annual Fuel ($ooo)	Year Available	Capacity Factor	Life	Annual Capital Cost ($ooo)	Discounted[2] Capital Cost Total ($ooo)	Discounted[2] O & M and Fuel Total ($ooo)	Dollars per AMW Total Cost ($ooo)	Mills per KWH Total Cost
Type I Resources Continued:														
BPA PROG CONS[1, 6]	2009	33.0	5.09	14,437	37,894	0	2007	100	15	1,399	14,118	37,894	105,075	11.99
BPA PROG CONS[1, 6]	2010	33.0	5.09	17,650	36,652	0	2007	100	15	1,711	17,266	36,652	108,925	12.43
BPA PROG CONS[1, 6]	2011	33.0	5.09	17,230	35,857	0	2007	100	15	1,670	16,852	35,857	106,483	12.16
BPA PROG CONS[1, 6]	2012	33.0	5.09	16,825	35,495	0	2007	100	15	1,631	16,459	35,495	104,958	11.98
BPA PROG CONS[1, 6]	2013	33.0	5.09	16,438	35,164	0	2007	100	15	1,593	16,075	35,164	103,513	11.82
Hydroelectric Resources Contracted by BPA from 7(b)(2) Preference Customers:														
COWLITZ FALLS	1994	26.0	4.25	91,803	1,429	0	2007	100	35	5,087	79,060	22,209	111,285	12.70
IDAHO FALLS		12.6	5.42	0	2,030	0	2007	100	35	0	0	31,549	71,540	8.17
Thermal Resources Contracted by BPA from 7(b)(2) Preference Customers:														
WAUNA-Steam-Cogen.[3]		22.8	5.42	0	5,566	0	2007	100	25	0	0	75,248	132,014	15.07
Billing Credit Resources Contracted by BPA from 7(b)(2) Preference Customers:														
BILLING CREDITS	various	17.5	5.42	28,334	699	0	2007	100	25	2,096	28,336	9,450	86,368	9.86
Type II Resources - Existing 7(b)(2) Preference Customer Resources Not Dedicated to Regional Preference Loads:														
WANAPAM 2007 ND[4]		119.5	5.45	0	7,616	0	2007	100	35	0	0	118,364	28,300	3.23
PRIEST RAPIDS 2007 ND[4]		98.2	5.45	0	6,487	0	2007	100	35	0	0	100,818	29,333	3.35
ROCKY REACH 2007 ND[4]		293.9	5.45	0	19,437	0	2007	100	35	0	0	302,080	29,367	3.35
ROCK ISLAND 2007 ND[4]		140.1	5.45	0	16,444	0	2007	100	35	0	0	255,565	52,119	5.95
WELLS 2007 ND[4]		193.9	5.45	0	10,850	0	2007	100	35	0	0	168,625	24,847	2.84
Dalles Dam Fishway		4.6		0	228	0	2007	100	30	0	0	3,343	24,225	2.77
Nine Canyon Wind Project		8.5	5.45	0	1,379	0	2007	100	30	0	0	20,220	79,294	9.05
BOARDMAN COAL PLANT[5]	1980	49.0		0	3,179	2,874	2007	100	30	0	0	88,755	60,378	6.89
Type II Resources for Which Information was not Available:														
Roosevelt Landfill - Owned by Klickitat Cty. PUD[5]														
Frederickson Combustion Turbine[5]														
Felt River Hydro Project - Owned by Fall River Rural Elect. Coop.[5]														

WP-07 Rate Case - 7(b)(2) Rate Test Resource Stack
Resources Grouped by the Three Resource Types Outlined by Section 7(b)(2)(D) of the Pacific N.W. Electric Power Planning and Conservation Act
All Costs are in 1980 dollars

A		B	C	D	E	F	G	H	I	J	K	L	M	N
Project	Year Placed in Service	Resource % Share of (aMW)	Interest Rate (%)	Capital Investment ($ooo)	Annual O & M ($ooo)	Annual Fuel ($ooo)	Year Available	Capacity Factor	Life	Annual Capital Cost ($ooo)	Discounted[2] Capital Cost Total ($ooo)	Discounted[2] O & M and Fuel Total ($ooo)	Dollars per AMW Total Cost ($ooo)	Mills per KWH Total Cost
Type III Resources - Actual and Planned Generic Resource Acquisitons by BPA from Non-7(b)(2) Customers - See Note 7														
BPA Wind Project Purchases:														
FOOTE CREEK 1 - WIND		5.6	5.42	10,378	231	0	2007	100	30	708	10,381	3,387	81,952	9.36
FOOTE CREEK 2 - WIND		0.7	5.42	1,125	25	0	2007	100	30	77	1,129	367	71,238	8.13
FOOTE CREEK 4 - WIND		5.8	5.42	12,905	287	0	2007	100	30	880	12,903	4,208	98,339	11.23
STATELINE WIND		21.9	5.42	25,538	561	0	2007	100	30	1,742	25,543	8,226	51,399	5.87
CONDON WIND PROJECT		9.9	5.42	30,152	671	0	2007	100	30	2,056	30,147	9,839	134,633	15.37
KLONDIKE PHASE 1		7.4	5.42	10,035	223	0	2007	100	30	684	10,030	3,270	59,910	6.84

Footnote References:

Note 1: The dollar costs for conservation investments in this table are the correct ones that will be incorporated into final rates. The dollar costs for conservation are different in this table when compared to the conservation costs that were used to perform the initial rate calculations. Nevertheless, the changes in the dollar amounts would not have caused a difference in the calculation of priority firm power rates.

Note 2: The discount rate used to discount the annual capital cost, O&M costs, and fuel costs was 5.42%.

Note 3: The Wauna steam turbine plant produces steam for the James River Wauna paper plant located near Clatskanie, OR. Fuel for the steam generator is natural gas. The output of the plant is owned by the Western Generation Agency, a joint venture of EWEB and Clatskanie PUD, two 7(b)(2) preference customers. The name plate rating of the steam generator is 36MW, average firm capacity is approximately 26.4aMW. BPA is limited to purchasing 236,000MWh of energy in a year.

Note 4 - The MW totals for these Mid-Columbia Hydro resources are allocations of energy assigned to IOU and other non-preference customers from this hydro-project using 1937 critical water planning based on PNW Loads and Resources Study No. 30.

Note 5 - Operating and financial information concerning this resource is in the process of being requested, or has been requested from the owner or operator of the facility. If additional information is made available, it will be included in the determination of final rates.

Note 6 - The impact of lost revenues due to the reduction in loads is not included in conservation costs.

Note 7 - Section 7(b)(2)(D) provides that Type III resources are only used to meet the loads present in the 7(b)(2) Case after Type I and Type II resources in the resource stack have been totally used. Type III wind project resources already purchased by BPA along with any other generic resources of whatever size required to meet any remaining loads are priced at the average cost of all Type III resources that would be needed to meet 7(b)(2) Case loads over the rate test period. Since Type I and Type II resources are sufficient to meet the 7(b)(2) Case loads in the Initial Rate Proposal, Type III resources are not used in conducting the 7(b)(2) rate test.

This page intentionally left blank.

APPENDIX C

Documentation of the Amount of Mid-Columbia Hydro Resources
Owned by 7(b)(2) Preference Customers That is Not Dedicated to
Regional Preference Loads During the 7(b)(2) Rate Test Period

AND

Projected Annual Operating Cost of Mid-Columbia Hydro Resources

This page intentionally left blank.

Mid-Columbia Dams
Preference Customer Owned Resources
Portions of Projects Not Dedicated to Serving Preference Regional Loads
2007 Rate Case

	Percentage of Project Serving IOUs	Percentage of Project Serving Publics/Other	Energy in Megawatts IOUs	Energy in Megawatts Publics/Other	Total Firm Energy	2007 Operating Cost/$ per MWh	Projected IOU 2007 Annual Operating Cost
Wells Dam, Project Owner = Douglas County PUD, FERC license renewal 5/31/2012, Purchaser Agreement Expires 8/31/2018	59.21%	40.79%	193.86	133.55	327.41	13.59780	$23,091,969
Wanapum Dam, Project Owner = Grant County PUD, FERC License Exp. 10/31/2009, Purchaser Agreement Expires 10/31/2009	41.53% [1]	58.47% [1]	119.47 [1]	167.99 [1]	287.46	15.48760	$16,208,659
Priest Rapids Dam, Project Owner = Grant County PUD, FERC License Exp. 10/31/2005, New Purchaser Agreement became effective 11/01/2005	29.37% [1]	70.63% [1]	98.24 [1]	236.22 [1]	334.46	16.04420	$13,807,356
Rocky Reach Dam, Project Owner = Chelan County PUD, FERC License Exp. 2006, Purchaser Agreement Expires 2011	59.10%	40.90%	293.90	203.39	497.29	16.06880	$41,370,154
Rock Island Dam, Project Owner = Chelan County PUD, FERC License Exp. 2029, Purchaser Agreement Expires 2012	50.00%	50.00%	140.11	140.11	280.22	28.51640	$34,999,991
Energy - MW Allocations			**845.58**	**881.26**	**1,726.84**		
Percentages of load being served by customer type			**48.97%**	**51.03%**	**100.00%**		

Note 1: The amount of energy and the percentage of the projects firm energy was based on the average of the seven years annual amount projected to be scheduled to utilities during the 2007-2013 year time period for Wanapum and Priest Rapids Developments.

Projections of Wells Hydroelectric Project Annual Operating Costs
BPA's Wholesale Power 2007 Rate Case
Section 7(b)(2) Resource Stack Supporting Documentation

		See Note 1 below.		(Whole Dollars) See Note 2 below.		Projected Operating Budget	Projected Operating Budget
		2002	**2003**	**2004**	**2005**	**2006**	**2007**
GDP Inflation Factors Projections				1.0200	1.017	1.017	1.021
Operating Revenues		31,421,628	33,362,705	34,029,959	34,608,468	36,000,000	38,000,000
Operating Expenses:							
Operating Expenses		11,425,212	12,126,150	12,368,673	12,578,940	12,792,782	13,061,430
Maintenance Expenses		3,903,632	4,343,317	4,430,183	4,505,496	4,582,089	4,678,313
Depreciation Expenses		3,176,248	3,234,136	3,386,196	3,477,250	3,569,853	3,664,029
Taxes		1,187,047	1,110,937	1,133,156	1,152,420	1,172,011	1,196,623
Other Operating Expenses						3,328,975	4,513,189
Total Operating Expenses	*	19,692,139	20,814,540	21,318,208	21,714,106	25,445,710	27,113,584
Operating Income		11,729,489	12,548,165	12,711,751	12,894,362	10,554,290	10,886,416
Capital Contributions							
Interest Income (Expense)/Gains on Debt Retirements	*	1,167,305	415,934	425,000	425,000	425,000	425,000
Interest on Long-Term Debt - See Note 3		8,368,696	8,073,613	6,304,514	7,136,234	6,906,529	6,612,261
Other Debt Expense		1,118,883	1,154,165	1,177,248	1,197,261	1,217,614	1,243,184
Total Interest & Other Expense	*	9,487,579	9,227,778	7,481,762	8,333,495	8,124,143	7,855,445
Excess of Revenues & Contributions Over Cost of Services		3,409,215	3,736,321	5,654,989	4,985,867	2,855,147	3,455,971
Operating Costs Before Adjustments (* Sum of numbers asterisks)		28,012,413	29,626,384	28,374,970	29,622,601	33,144,853	34,544,029
Budget/Operating Cost Adjustments							
Less Depreciation Expense		(3,176,248)	(3,234,136)	(3,386,196)	(3,477,250)	(3,569,853)	(3,664,029)
Plus Principal On Debt - 2002 & 2003 assumed base amounts w/o refunding		6,700,000	7,020,000	8,005,000	7,580,000	7,825,000	8,120,000
Subtotal		31,536,165	33,412,248	32,993,774	33,725,351	37,400,000	39,000,000
Adjustment to reconcile to Project Owner's Projections		2,960,404	1,788,333	2,925,186	2,926,649	0	0
Projected Operating Budget		34,496,569	35,200,581	35,918,960	36,652,000	37,400,000	39,000,000
Projected Operating Budget per owner /operator - See Note 6		N/A	N/A	N/A	N/A	37,400,000	N/A
Projected Project Owners Operating Budget escalated for inflation						$37,400,000	$39,000,000
Average Firm Energy Output (PNW L&R Study #30) (327.41MW) times the number of hours in a year (8760)						2,868,112	2,868,112
Projected Project Cost per MWh						**$13.0399**	**$13.5978**

Projections of Wells Hydroelectric Project Annual Operating Costs
BPA's Wholesale Power 2007 Rate Case
Section 7(b)(2) Resource Stack Supporting Documentation

Selected Balance Sheet Items Wells Hydroelectric Project :

	(Whole Dollars)					
	2002	**2003**	**2004**	**2005**	**2006**	**2007**
Electric Plant Gross (Dam placed in service 1970)	218,644,307	219,795,112	225,746,388	231,816,690	237,990,187	244,268,633
Construction Work in Progress	2,073,613	5,951,276	6,070,302	6,173,497	6,278,446	6,410,293
Accumulated Deprec. & Amortization (15-95 year lives)	(52,112,747)	(54,920,735)	(58,306,931)	(61,784,181)	(65,354,034)	(69,018,063)
Net Electric Plant	168,605,173	170,825,653	173,509,759	176,206,006	178,914,599	181,660,863
Unamortized Debt Discount & Losses	4,166,489	6,044,646				
Other Deferred Charges	22,415,127	21,926,873				
Total Non Current Assets	195,186,789	198,797,172				
Reserve and Contingency Fund-Restricted	5,312,034	5,086,716				
Other Restricted Funds	27,332,990	19,803,614				
Total Restricted Funds	32,645,024	24,890,330				
Current and Accrued Assets	5,748,248	6,162,434				
Total Assets	233,580,061	229,849,936				
Long-Term Debt	163,790,000	143,285,000				
Unamortized Long-Term Debt Premiums	0	5,189,636				
Deferred Credits	162,129	170,023				
Total Non Current Liabilities	163,952,129	148,644,659				
Current & Accrued Liabilities	6,481,573	14,322,597				
Total Liabilities	170,433,702	162,967,256				
Retained Earnings	63,146,359	66,882,680				
Total Liabilities & Retained Earnings	233,580,061	229,849,936				

Projections of Wells Hydroelectric Project Annual Operating Costs
BPA's Wholesale Power 2007 Rate Case
Section 7(b)(2) Resource Stack Supporting Documentation

Notes:

1. The financial information for the years 2002 and 2003 was from Douglas County PUD No. 1's audited financials. A copy of the 2004 financial has been requested along with additional financial information.

2. The operating costs for the years 2004-2007 were based on the 2003 audited number adjusted per GNP Price Deflator Inflation Projection obtained from DRI.

3. Per Note 4 - Long-Term Debt 2003 Financial Statement projections of future debt service requirements, the following amounts of interest and principle to be paid relating to the Wells Hydroelectric project revenue bonds were projected:

	2004	2005	2006	2007
Projected Principal Payments	8,005,000	7,580,000	7,825,000	8,120,000
Projected Interest Payments	6,304,514	7,136,234	6,906,529	6,612,261
Total Debt Service	14,309,514	14,716,234	14,731,529	14,732,261

4. Under the power sales contracts to the IOUs the power purchasers pay all expenses and costs associated with the project net of depreciation and capitalized items, including debt service whether the project operates or not.

5. Bond holder resolutions requires the district to maintain a 125% debt service coverage ratio.

6. BPA sent a data request to Douglas County PUD #1 dated 5/11/2005 for the projected operating costs of the Well's Hydroelectric project for the years 2006-2013. Douglas County PUD #1 responded in a letter dated 5/24/2005, "Our current best estimate of projected power costs is $37.4 million during BPA's FY2006, and escalating approximately l.6% thereafter through FY2013." BPA projections for inflation will be based on the GNP Price Deflator Inflation Projection obtained from DRI.

Wells Dam Allocation for 2007 - 2013
PNW Loads and Resource Study
2007 - 2013 Fiscal Years
1937 Water Year
[30] 2007 Initial Rate Case

Wells Dam, Project Owner = Douglas County PUD, license renewal 5/31/2012, Purchaser Agreement Expires 8/31/2018

Wells Energy in Megawatts	2007	2008	2009	2010	2011	2012	2013
Canadian Entitlement Amount	23.45	22.95	23.40	24.35	24.55	24.25	24.00
3 AVWP-Avista Share	10.95	10.97	10.95	10.92	10.91	10.92	10.93
4 COLV-Colville Share	14.75	14.77	14.75	14.71	14.70	14.72	14.73
5 DOPD-Douglas Share	93.93	94.06	93.93	93.66	93.61	93.69	93.75
6 OKPD-Okanogan Share	25.04	25.08	25.05	24.98	24.96	24.98	25.00
7 PGE-Portland Gen. Elec. Share	63.56	63.66	63.57	63.39	63.35	63.41	63.46
8 PPL-PacifCorp Share	21.60	21.64	21.61	21.54	21.53	21.55	21.57
9 PSE-Puget Sound Energy Share	97.98	98.13	98.00	97.71	97.65	97.74	97.82
10 Wells After Encroachment	327.81	328.31	327.86	326.91	326.71	327.01	327.26
and Canadian Entitlement	327.81	328.31	327.86	326.91	326.71	327.01	327.26
IOU Allocations	194.09	194.40	194.13	193.56	193.44	193.62	193.78
Public Power Allocations	133.72	133.91	133.73	133.35	133.27	133.39	133.48
TOTAL	327.81	328.31	327.86	326.91	326.71	327.01	327.26

Wells Percentage Share	2007	2008	2009	2010	2011	2012	2013
3 AVWP-Avista Share	3.34%	3.34%	3.34%	3.34%	3.34%	3.34%	3.34%
4 COLV-Colville Share	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%
5 DOPD-Douglas Share	28.65%	28.65%	28.65%	28.65%	28.65%	28.65%	28.65%
6 OKPD-Okanogan Share	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%
7 PGE-Portland Gen. Elec. Share	19.39%	19.39%	19.39%	19.39%	19.39%	19.39%	19.39%
8 PPL-PacifCorp Share	6.59%	6.59%	6.59%	6.59%	6.59%	6.59%	6.59%
9 PSE-Puget Sound Energy Share	29.89%	29.89%	29.89%	29.89%	29.89%	29.89%	29.89%
10 Wells After Encroachment	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
IOU Allocations	59.21%	59.21%	59.21%	59.21%	59.21%	59.21%	59.21%
Public Power Allocations	40.79%	40.79%	40.79%	40.79%	40.79%	40.79%	40.79%
TOTAL	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Projections of Wanapum Hydroelectric Project Annual Operating Costs
BPA's Wholesale Power 2007 Rate Case
Section 7(b)(2) Resource Stack Supporting Documentation

GDP Inflation Factors Projections					1.017	1.017	1.021
		(in whole dollars)					
		Financial Statement Information			Projected Operating Budget	Projected Operating Budget	Projected Operating Budget
		2002	**2003**	**2004**	**2005**	**2006**	**2007**
Operating Revenues		$39,654,100	$37,623,004	$30,184,495	$32,000,000	$35,500,000	$36,000,000
Operating Expenses - See Notes 1, 2, and 3 below:							
Generation		12,623,551	11,099,675	10,388,384	10,564,987	10,744,592	10,970,228
Transmission		977,237	948,778	969,101	985,576	1,002,331	1,023,380
Administrative and General		6,759,515	6,451,674	5,423,216	5,515,411	5,609,173	5,726,966
Depreciation Expenses		4,924,752	5,031,141	5,152,363	5,440,350	6,505,942	7,589,649
Taxes		852,347	764,649	803,820	817,485	831,382	848,841
Other Operating Expenses						3,804,777	4,646,241
Total Operating Expenses	*	26,137,402	24,295,917	22,736,884	23,323,809	28,498,197	30,805,305
Net Operating Income		13,516,698	13,327,087	7,447,611	8,676,191	7,001,803	5,194,695
Non Operating Revenues and (Expenses)							
Interest Income (Expense)/Gains on Debt Retirements	*	958,126	476,575	219,143	180,000	180,000	180,000
Interest on Long-Term Debt - See Note 2	*	(7,177,896)	(7,838,985)	(6,275,562)	(7,712,258)	(7,460,490)	(7,188,412)
Amortization of Debt Expense and Discounts		(713,449)	(806,562)	(749,297)	(747,000)	(745,000)	(743,000)
Total Non Operating Expenses		(6,933,219)	(8,168,972)	(6,805,716)	(8,279,258)	(8,025,490)	(7,751,412)
Excess (Shortfall) of Revenues Over Cost of Services		$6,583,479	$5,158,115	$641,895	$396,933	($1,023,687)	($2,556,717)
Operating Costs Before Adjustments (* Sum of numbers asterisks)		$32,357,172	$31,658,327	$28,793,303	$30,856,067	$35,778,687	$37,813,717

Projections of Wanapum Hydroelectric Project Annual Operating Costs
BPA's Wholesale Power 2007 Rate Case
Section 7(b)(2) Resource Stack Supporting Documentation

Schedule of Power Costs:

	(in whole dollars) Financial Statement Information			Projected Operating Budget	Projected Operating Budget	Projected Operating Budget
	2002	**2003**	**2004**	**2005**	**2006**	**2007**
Operating Costs Before Adjustments (from prior page)	$32,357,172	$31,658,327	$28,793,303	$30,856,067	$35,778,687	$37,813,717
Budget/Operating Cost Adjustments - See Note 3 below:						
Less Extraordinary maintenance paid by Reserve Funds	(255,008)	(90,831)	0	0	0	0
Less Depreciation Expense - See Note 4	(4,924,752)	(5,031,141)	(5,152,363)	(5,440,350)	(6,505,942)	(7,589,649)
Less 15% of prior year second series debt installments	(1,711,094)	(1,675,494)	(1,892,772)	(1,908,116)	(2,145,625)	(2,145,960)
Plus (less) exclusion of interest on special funds	(56,168)	(108,416)	(115,046)	(117,002)	(118,991)	(121,490)
Plus capitalized interest	487,658	299,965	1,437,425	1,411,909	1,435,911	1,460,322
Plus principal and sinking fund payments on debt - See Note 4	10,955,000	9,924,804	5,180,000	5,180,000	5,410,000	7,205,000
Plus 15% of current year's interest and sinking fund installments	2,793,083	2,614,184	1,933,948	2,145,625	2,145,960	2,378,060
Bond issuance costs	8,209	31,606	0	0	0	0
Net Costs Chargeable to Power Purchasers -	$39,654,100	$37,623,004	$30,184,495	$32,128,133	$36,000,000	$39,000,000

	2005	2006	2007
Projected Operating Cost Projections	$32,128,133	$36,000,000	$39,000,000
Average Firm Energy Output (PNW L&R Study #30) (287.46MW) times the number of hours in a year (8760)	2,518,150	2,518,150	2,518,150
Projected Project Cost per MWh	**$12.7586**	**$14.2962**	**$15.4876**

Projections of Wanapum Hydroelectric Project Annual Operating Costs
BPA's Wholesale Power 2007 Rate Case
Section 7(b)(2) Resource Stack Supporting Documentation

Selected Balance Sheet Items - Wanapum Hydroelectric Project:

	2002	2003	2004	2005	2006	2007
Electric Plant Gross (Dam placed in service 1963)	258,738,862	$263,178,360	$272,017,524	325,297,099	379,482,427	434,588,906
Land and land rights	16,441,695	16,441,695	16,441,695	16,441,695	16,441,695	16,441,695
Construction work in progress	9,865,278	21,230,005	53,279,575	54,185,328	55,106,479	56,263,715
Accumulated Deprec. & Amortization (15-95 year lives)	(100,896,839)	(105,929,169)	(111,130,577)	(116,570,927)	(123,076,869)	(130,666,518)
Net Electric Plant (See Note 4)	184,148,996	194,920,891	230,608,217	279,353,195	327,953,732	376,627,798
Deferred relicensing costs	15,969,794	21,492,288	25,954,022			
Unamortized debt expense	1,308,608	2,115,744	1,886,648			
Other Deferred Charges and other assets	9,306	0	33,566			
Total Non Current Assets	201,436,704	218,528,923	258,482,453			
Restricted Assets Current	18,796,718	30,027,733	27,831,707			
Current and Accrued Assets	18,027,531	17,559,743	8,415,820			
Total Current Assets	36,824,249	47,587,476	36,247,527			
Total Assets	$238,260,953	$266,116,399	$294,729,980			
Long-term debt-net of discounts	$130,986,005	$175,234,571	$170,574,771			
Current portion of long-term debt	11,025,000	4,905,000	5,180,000			
Current & accrued liabilities	24,983,524	9,156,639	40,633,275			
Other liabilities						
Total Liabilities	166,994,529	189,296,210	216,388,046			
Retained Earnings - restricted for debt service	7,654,084	6,797,772	7,107,257			
Retained Earnings - restricted other	0	0	0			
Retained Earnings - unrestricted	63,612,340	70,022,417	71,234,677			
Total Liabilities & Retained Earnings	$238,260,953	$266,116,399	$294,729,980			

Projections of Wanapum Hydroelectric Project Annual Operating Costs
BPA's Wholesale Power 2007 Rate Case
Section 7(b)(2) Resource Stack Supporting Documentation

Notes:

1. The financial information for the years 2002, 2003, and 2004 was from Grant County PUD No. 2's audited financials, primarily the audited financial statements on the individual developments (enterprise funds), and the Schedules of Power Costs and Allocation to Power Purchasers.

2. The operating cost projections for the years 2005-2007 were based on the 2004 and prior years audited reports as adjusted for the GNP Price Deflator Inflation Projection obtained from DRI. Specific projections for depreciation expense and debt service were based on the 2004 audited financial statement' notes and other supplementary information.

3. Debt Service Information
The actual interest (a) and principle (b) on the Wanapum Bonds for the years 2002-2004 was taken from the Statement of Cash Flows. The projected interest (a) and projected principal (b) for 2005-2007 on the Wanapum Revenue Bonds was obtained from Note 5 of the 2004 financial statements (p134), Scheduled debt service requirements. A portion of the information for 2002-2004 was from the Schedules of Power Costs Chargeable to Power Purchasers. The projections for capitalized interest expense for 2005-2007 was computed using an assumed interest rate of 2.65% applied to the balance of construction work in progress at the beginning of the year.

	2002	2003	2004	2005	2006	2007
Actual/Projected Interest on Wanapum Bonds (a)	7,546,528	7,166,547	7,815,774	9,124,167	8,896,401	8,648,734
Less Capitalized interest expenses	(487,657)	(299,965)	(1,437,425)	(1,411,909)	(1,435,911)	(1,460,322)
Adjustment in interest expense	119,025	972,403	(102,787)			
Total Interest Expense per operating statement	7,177,896	7,838,985	6,275,562	7,712,258	7,460,490	7,188,412
Actual/Projected Principal payments on Priest Rapids Bonds (b)	11,570,000	19,025,000	4,905,000	5,180,000	5,410,000	7,205,000
Total Debt Service (a) + (b)	19,116,528	26,191,547	12,720,774	14,304,167	14,306,401	15,853,734
15% of Current year's debt service requirement	2,867,479	3,928,732	1,908,116	2,145,625	2,145,960	2,378,060

4. Under the Power Sales Contracts (See Note 1, accounting policies, revenue recognition), the power purchasers of the project pay all expenses and costs associated with producing and delivering the power, plus 115% of their share of the amounts required for debt service payments. Depreciation, extraordinary maintenance, and other charges are paid by the Reserve and Replacement Fund, Supplemental Repair and Renewal Fund, and Construction Fund and are not considered costs of producing and delivering power for this purpose.

5. Projection of depreciation expense is based on a 2% recovery rate of applied to the plant in service balance at the beginning of the year. Electric plant financial information can be found at Note 3 of the Wanapum Project's financial segment information (p129 of 2004 F.S.).

6. BPA sent a data request to Grant County PUD #2 dated 5/11/2005 for the projected operating costs of the Wanapum Hydroelectric project for the years 2006-2013. Grant County PUD#2 did not respond to the data request. BPA sent a projection of operating costs to Grant County PUD#2 on September 19, 2005, and asked it to please review and make corrections to the projections. Grant County PUD #2 did not choose to comment on the projections of operating costs for the Wanapum

Wanapum Allocation for 2007 - 2013
PNW Loads and Resource Study
2007 - 2013 Fiscal Years
1937 Water Year
[30] 2007 Initial Rate Case

Wanapum Energy in Megawatts	2007	2008	2009	2010	2011	2012	2013
Wanapum Dam, Project Owner = Grant County PUD, FERC License Exp. 10/31/2009, Existing Purchaser Agreement Expires 10/31/2009, New Contracts Provisions become effective 11/01/09							
1 Wanapum	386.49	386.49	386.49	386.63	386.65	386.65	386.65
2 Wanapum Before Enc	386.49	386.49	386.49	386.63	386.65	386.65	386.65
Canadian Entitlement Amount	27.60	27.00	27.50	28.66	28.91	28.56	28.26
Wanapum							
3 AVWP - Avista Share	23.61	23.65	23.61	13.00	11.18	10.94	10.92
4 COPD - Cowlitz County PUD Share	7.77	7.79	7.78	4.27	3.73	3.73	3.48
5 CWPC - Clear Water PUD Share	0.00	0.00	0.00	0.26	0.29	0.29	0.29
6 EWEB - Eugene Water & Electric Share	6.62	6.63	6.62	3.64	3.15	3.16	3.16
7 FGRV - Forest Grove Share	2.02	2.02	2.02	1.23	1.15	1.15	1.15
8 FREC - Fall River Electric Coop. Share	0.00	0.00	0.00	0.40	0.43	0.43	0.43
9 GCPD - Grant County PUD Share	105.06	105.31	105.10	148.99	160.37	162.20	164.08
10 ICLP - Idaho City Light PUD Share	0.00	0.00	0.00	0.11	0.11	0.11	0.11
11 KITT - Kittitas County PUD Share	0.00	0.00	0.00	0.26	0.29	0.29	0.29
12 KOOT - Kootenai Share	0.00	0.00	0.00	0.52	0.57	0.57	0.57
13 LREC - Lost River Electric Cooperative Share	0.00	0.00	0.00	0.09	0.09	0.09	0.09
14 LVE - Lower Valley Electric Coop. Share	0.00	0.00	0.00	0.69	0.75	0.75	0.75
15 MCMN - McMinnville Share	2.02	2.02	2.02	1.23	1.15	1.15	1.15
16 MTFR - Milton Freewater Share	2.02	2.02	2.02	1.23	1.15	1.15	1.15
17 NLEC - Northern Lights Electric Coop. Share	0.00	0.00	0.00	0.52	0.57	0.57	0.57
18 PGE - Portland General Electric Share	53.83	53.94	53.85	29.55	25.26	25.00	24.74
19 PPL - Pacific Power and Light Share	53.83	53.94	53.85	29.55	25.26	25.00	24.74
20 PSE - Puget Sound Energy Share	31.09	31.15	31.10	16.99	14.62	14.38	14.11
21 RREC - Raft River Electric Coop. Share	0.00	0.00	0.00	0.11	0.11	0.11	0.11
22 SCL - Seattle City Light Share	0.00	0.00	0.00	13.11	13.76	13.52	13.25
23 SLEC -Salmon River Electric Coop. Share	0.00	0.00	0.00	0.09	0.09	0.09	0.09
24 TPU - Tacoma Public Utilities Share	0.00	0.00	0.00	13.11	13.76	13.52	13.25
25 UNEC - United Electric Coop. Share	0.00	0.00	0.00	0.20	0.23	0.23	0.23
26 UNKMKT - Unknown Market Purchaser Share	0.00	0.00	0.00	7.75	8.60	8.61	8.62
27 Wanapum After Encroachment	287.87	288.47	287.97	286.90	286.67	287.04	287.33
27 and Canadian Entitlement	287.87	288.47	287.97	286.91	286.67	287.04	287.33
IOU and Market Purchaser Allocations	162.36	162.68	162.41	96.84	84.92	83.93	83.13
Public Power Allocations	125.51	125.79	125.56	190.06	201.75	203.11	204.20
TOTAL	287.87	288.47	287.97	286.90	286.67	287.04	287.33

IOU and Market Purchaser Energy -
Seven Year Average Allocation **119.47**

Wanapum Allocation for 2007 - 2013
PNW Loads and Resource Study
2007 - 2013 Fiscal Years
1937 Water Year
[30] 2007 Initial Rate Case

Wanapum Percentage Share	2007	2008	2009	2010	2011	2012	2013
3 AVWP - Avista Share	8.20%	8.20%	8.20%	4.53%	3.90%	3.81%	3.80%
4 COPD - Cowlitz County PUD Share	2.70%	2.70%	2.70%	1.49%	1.30%	1.30%	1.21%
5 CWPC - Clear Water PUD Share	0.00%	0.00%	0.00%	0.09%	0.10%	0.10%	0.10%
6 EWEB - Eugene Water & Electric Share	2.30%	2.30%	2.30%	1.27%	1.10%	1.10%	1.10%
7 FGRV - Forest Grove Share	0.70%	0.70%	0.70%	0.43%	0.40%	0.40%	0.40%
8 FREC - Fall River Electric Coop. Share	0.00%	0.00%	0.00%	0.14%	0.15%	0.15%	0.15%
9 GCPD - Grant County PUD Share	36.50%	36.50%	36.50%	51.93%	55.95%	56.51%	57.11%
10 ICLP - Idaho City Light PUD Share	0.00%	0.00%	0.00%	0.04%	0.04%	0.04%	0.04%
11 KITT - Kittitas County PUD Share	0.00%	0.00%	0.00%	0.09%	0.10%	0.10%	0.10%
12 KOOT - Kootenai Share	0.00%	0.00%	0.00%	0.18%	0.20%	0.20%	0.20%
13 LREC - Lost River Electric Cooperative Share	0.00%	0.00%	0.00%	0.03%	0.03%	0.03%	0.03%
14 LVE - Lower Valley Electric Coop. Share	0.00%	0.00%	0.00%	0.24%	0.26%	0.26%	0.26%
15 MCMN - McMinnville Share	0.70%	0.70%	0.70%	0.43%	0.40%	0.40%	0.40%
16 MTFR - Milton Freewater Share	0.70%	0.70%	0.70%	0.43%	0.40%	0.40%	0.40%
17 NLEC - Northern Lights Electric Coop. Share	0.00%	0.00%	0.00%	0.18%	0.20%	0.20%	0.20%
18 PGE - Portland General Electric Share	18.70%	18.70%	18.70%	10.30%	8.81%	8.71%	8.61%
19 PPL - Pacific Power and Light Share	18.70%	18.70%	18.70%	10.30%	8.81%	8.71%	8.61%
20 PSE - Puget Sound Energy Share	10.80%	10.80%	10.80%	5.92%	5.10%	5.01%	4.91%
21 RREC - Raft River Electric Coop. Share	0.00%	0.00%	0.00%	0.04%	0.04%	0.04%	0.04%
22 SCL - Seattle City Light Share	0.00%	0.00%	0.00%	4.57%	4.80%	4.71%	4.61%
23 SLEC -Salmon River Electric Coop. Share	0.00%	0.00%	0.00%	0.03%	0.03%	0.03%	0.03%
24 TPU - Tacoma Public Utilities Share	0.00%	0.00%	0.00%	4.57%	4.80%	4.71%	4.61%
25 UNEC - United Electric Coop. Share	0.00%	0.00%	0.00%	0.07%	0.08%	0.08%	0.08%
26 UNKMKT - Unknown Market Purchaser Share	0.00%	0.00%	0.00%	2.70%	3.00%	3.00%	3.00%
27 Wanapum After Encroachment and Canadian Entitlement	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Wanapum Percentage Share	2007	2008	2009	2010	2011	2012	2013
IOU Percentage of Allocations	56.40%	56.39%	56.40%	33.75%	29.62%	29.24%	28.93%
Public Power Percentage of Allocations	43.60%	43.61%	43.60%	66.25%	70.38%	70.76%	71.07%
TOTAL	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

IOU and Market Purchaser Percentage - Seven Year Average Allocation **41.53%**

Projections of Priest Rapids Hydroelectric Project Annual Operating Costs
BPA's Wholesale Power 2007 Rate Case
Section 7(b)(2) Resource Stack Supporting Documentation

GDP Inflation Factors Projections					1.017	1.017	1.021
		(in whole dollars) Financial Statement Information			BPA Analyst Projected Operating Budget	**Grant's[6] Projected Operating Budget**	BPA Analyst Projected Operating Budget
		2002	**2003**	**2004**	**2005**	**2006**	**2007**
Operating Revenues		32,064,057	30,810,541	30,707,299	34,600,000	44,000,000	46,000,000
Operating Expenses - See Notes 1, 2, and 4 below:							
Generation		11,636,471	10,122,746	10,402,512	10,579,355	7,243,491	7,395,604
Transmission		889,319	850,426	838,216	852,466	795,871	812,584
Administrative and General		6,897,861	6,570,905	6,106,684	6,210,498	10,823,737	11,051,035
Maintenance Expenses						5,653,207	5,771,924
Depreciation Expenses		4,613,571	3,681,788	5,078,184	5,157,659	5,334,210	5,513,763
Taxes		856,948	783,116	801,631	815,259	850,000	867,850
Other Operating Costs					1,240,681		
Total Operating Expenses	*	24,894,170	22,008,981	23,227,227	24,855,918	30,700,516	31,412,760
Net Operating Income		7,169,887	8,801,560	7,480,072	9,744,082	13,299,484	14,587,240
Non Operating Revenues and (Expenses)							
Interest Income (Expense)/Gains on Debt Retirements	*	967,727	451,766	338,167	300,000	1,670,598	1,500,000
Interest on Proposed New Debt	*					(3,287,457)	(3,300,000)
Interest on Long-Term Debt - See Note 3	*	(8,253,381)	(8,029,995)	(7,575,817)	(9,050,531)	(8,792,613)	(11,850,662)
Amortization of Debt Expense and Discounts		(614,378)	(695,559)	(694,445)	(693,000)	(691,500)	(700,000)
Total Non Operating Expenses		(7,900,032)	(8,273,788)	(7,932,095)	(9,443,531)	(11,100,972)	(14,350,662)
Excess (Shortfall) of Revenues Over Cost of Services		(730,145)	527,772	(452,023)	300,551	2,198,512	236,578
Operating Costs Before Adjustments (* Sum of numbers asterisks)		32,179,824	29,587,210	30,464,877	33,606,449	41,109,988	45,063,422

Projections of Priest Rapids Hydroelectric Project Annual Operating Costs
BPA's Wholesale Power 2007 Rate Case
Section 7(b)(2) Resource Stack Supporting Documentation

Schedule of Power Costs:	(in whole dollars) Financial Statement Information **2002**	**2003**	**2004**	BPA Analyst Projected Operating Budget **2005**	**Grant's Projected Operating Budget 2006**	BPA Analyst Projected Operating Budget **2007**
Operating Costs Before Adjustments - sum of *	32,179,824	29,587,210	30,464,877	33,606,449	41,109,988	45,063,422
Budget/Operating Cost Adjustments:						
Less Extraordinary maintenance paid by Reserve Funds	(76,008)	(68,630)	0	0	0	0
Less Depreciation Expense	(4,613,571)	(3,681,788)	(5,078,184)	(5,157,659)	(5,334,210)	(5,513,763)
Less 15% of prior year second series debt installments	(1,985,010)	(1,926,646)	(1,952,249)	(1,900,317)	(2,079,116)	(2,899,511)
Plus (less) exclusion of interest on special funds	39,934	(54,716)	(146,826)	(149,322)		(152,458)
Plus capitalized interest	45,928	0	268,747	233,930	0	241,951
Plus Principal and sinking fund payments on debt - See Note 4 below.	4,545,000	4,985,000	5,195,000	5,195,000	7,250,000	7,350,000
Plus 15% of interest and sinking fund installments	1,926,646	1,952,249	1,955,935	2,171,919	2,899,511	2,916,392
Bond issuance costs	1,314	17,861	0	0		0
Net Costs Chargeable to Power Purchasers	32,064,057	30,810,540	30,707,300	34,000,000	43,846,173	47,006,033
Projected Owners Operating Budget escalated for inflation - whole dollars				$34,000,000	$43,846,173	$47,006,033
Average Firm Energy Output (PNW L&R Study #30) (334.45MW) times the number of hours in a year (8760)				2,929,782	2,929,782	2,929,782
Projected Project Cost per MWh using Project Owners Debt Service				**$11.6050**	**$14.9657**	**$16.0442**

Projections of Priest Rapids Hydroelectric Project Annual Operating Costs
BPA's Wholesale Power 2007 Rate Case
Section 7(b)(2) Resource Stack Supporting Documentation

Selected Balance Sheet Items - Priest Rapids Hydroelectric Project:

	(in whole dollars)					
	2002	**2003**	**2004**	**2005**	**2006**	**2007**
Electric Plant Gross (Dam placed in service 1970)	$248,319,424	$250,995,893	$257,882,972	266,710,518	275,688,132	284,818,365
Land and land rights	2,586,576	2,586,576	2,586,576	2,586,576	2,586,576	2,586,576
Construction work in progress - See Note 3	4,381,441	10,183,113	8,827,546	8,977,614	9,130,233	9,321,968
Accum. Deprec. & Amortization (15-95 year lives)	(107,042,152)	(110,725,130)	(115,853,195)	(121,010,854)	(126,345,064)	(131,858,827)
Net Electric Plant (Note 3 of 2003 & 2004 F.S.)	148,245,289	153,040,452	153,443,899	157,263,854	161,059,877	164,868,082
Deferred relicensing costs	15,969,761	21,479,506	25,926,488			
Unamortized debt expense	1,747,505	2,084,600	1,853,557			
Other Deferred Charges and other assets	9,306	0	0			
Total Non Current Assets	165,971,861	176,604,558	181,223,944			
Restricted Assets Current	30,208,013	42,056,984	32,527,571			
Current and Accrued Assets	16,200,038	7,951,490	8,182,286			
Total Current Assets	46,408,051	50,008,474	40,709,857			
Total Assets	$212,379,912	$226,613,032	$221,933,801			
Long-Term Debt-net of discounts	$145,591,449	$172,146,382	$167,414,785			
Current portion of long-term debt	4,545,000	4,985,000	5,195,000			
Current & Accrued Liabilities	22,860,256	9,570,671	9,865,060			
Other Liabilities						
Total Liabilities	172,996,705	186,702,053	182,474,845			
Retained Earnings - restricted for debt service	6,338,804	6,940,349	7,178,763			
Retained Earnings - restricted other	6,000,000	6,000,000	0			
Retained Earnings - unrestricted	27,044,403	26,970,630	32,280,193			
Total Liabilities & Retained Earnings	$212,379,912	$226,613,032	$221,933,801			

Projections of Priest Rapids Hydroelectric Project Annual Operating Costs
BPA's Wholesale Power 2007 Rate Case
Section 7(b)(2) Resource Stack Supporting Documentation

Notes:

1. The financial information for the years 2002, 2003, and 2004 was from Grant County PUD No. 2's audited financial statements, primarily the audited financial statements on the individual developments (enterprise funds), and the Schedules of Power Costs and Allocation to Power Purchasers.

2. The operating cost projections for the years 2005-2007 were based on the 2004 and prior years' audited reports as adjusted for the GNP Price Deflator Inflation Projection obtained from DRI. Specific projections for depreciation expense and debt service were based on the 2004 audited financial statement's notes and other supplementary information.

3. Debt Service Information
The actual interest (a) and principal (b) on the Priest Rapids Bonds for the years 2002-2004 was taken from the Statement of Cash Flows. The projected interest (a) and projected principal (b) for 2005-2007 on the Priest Rapids Revenue Bonds was obtained from Note 5 of the 2004 financial statements (p103), Scheduled debt service requirements. A portion of the information for 2002-2004 was from the Schedules of Power Costs Chargeable to Power Purchasers. The projections for capitalized interest expense for 2005-2007 was computed using an assumed interest rate of 2.65% applied to the balance of construction work in progress at the beginning of the year.

	2002	**2003**	**2004**	**2005**	**2006**	**2007**
Actual/Projected Interest on Priest Rapids Bonds (a)	8,052,724	7,511,045	7,683,777	9,284,461	9,030,520	8,792,613
Less Capitalized interest expenses	(45,928)	0	(268,747)	(233,930)	(237,907)	(241,951)
Adjustment in interest expense	246,585	518,950	160,787	0	0	0
Interest on proposed new debt (a)					3,287,457	3,300,000
Total Interest Expense per operating statement projections	8,253,381	8,029,995	7,575,817	9,050,531	12,080,070	11,850,662
Actual/Projected Principal payments on Priest Rapids Bonds (b)	4,270,000	4,545,000	4,985,000	5,195,000	7,250,000	7,350,000
Total Debt Service (a) + (b)	12,322,724	12,056,045	12,668,777	14,479,461	19,567,977	19,442,613
15% of Debt Service Requirements			1,900,317	2,171,919	2,899,511	2,916,392

4. Under the Power Sales Contracts (See Note 1, accounting policies, revenue recognition), the power purchasers of the project pay all expenses and costs associated with producing and delivering the power, plus 115% of their share of the amounts required for debt service payments. Depreciation, extraordinary maintenance, and other charges are paid by the Reserve and Replacement Fund, Supplemental Repair and Renewal Fund, and Construction Fund and are not considered costs of producing and delivering power for this purpose.

5. Projection of depreciation expense is based on a 2% recovery rate applied to the plant in service balance at the beginning of the year. Electric plant financial information can be found at Note 3 of the Priest Rapids Project's financial segment information (pg. 99 of 2004 F.S.).

6. BPA sent a data request to Grant County PUD #2 dated 5/11/2005 for the projected operating costs of the Priest Rapids Hydroelectric project for the years 2006-2013. Grant County PUD#2 did not respond to the data request. BPA sent a projection of operating costs to Grant County PUD#2 on September 19, 2005, and asked it to please review and make corrections to the projections. Grant County PUD #2 responded in an email on 9/28/05 that its projected operating costs for Priest Rapids project for FY2006 were $43.8 million dollars per year. The projected budget numbers received from Grant for FY2006 are reflected in the spreadsheet.

Priest Rapids Allocation for 2007-2013
Remainder of Data for 2009-2013 is BPA's Table A-20 Priest Rapids Allocation
PNW Loads and Resource Study
2007 - 2013 Fiscal Years
1937 Water Year
[30] 2007 Initial Rate Case

Priest Rapids Energy in Megawatts	2007	2008	2009	2010	2011	2012	2013
Priest Rapids Dam, Project Owner = Grant County PUD, FERC License Exp. 10/31/2005, New Purchaser Agreements became effective 11/01/2005.							
28 Priest Rapids	379.77	379.77	379.77	379.78	379.80	379.85	379.78
29 Priest Rapids Before Encroachment	379.77	379.77	379.77	379.78	379.80	379.85	379.78
Canadian Entitlement Amount	28.90	28.30	28.80	29.95	30.25	29.90	29.55
Priest Rapids							
30 AVWP - Avista Share	10.98	11.00	10.99	13.29	12.91	12.79	12.60
31 COPD - Cowlitz County PUD Share	5.09	5.10	5.09	4.34	4.24	4.21	4.11
32 CWPC - Clear Water PUD Share	0.37	0.37	0.37	0.37	0.37	0.37	0.37
33 EWEB - Eugene Water & Electric Share	3.08	3.09	3.08	3.71	3.60	3.57	3.51
34 FGRV - Forest Grove Share	1.17	1.17	1.17	1.37	1.40	1.40	1.40
35 FREC - Fall River Electric Coop. Share	0.50	0.50	0.50	0.47	0.47	0.47	0.47
36 GCPD - Grant County PUD Share	205.99	206.35	206.08	182.34	186.84	188.48	190.76
37 ICLP - Idaho City Light PUD Share	0.13	0.13	0.13	0.13	0.13	0.13	0.13
38 KITT - Kittitas County PUD Share	0.94	0.94	0.94	0.50	0.47	0.47	0.47
39 KOOT - Kootenai Share	0.64	0.64	0.64	0.63	0.63	0.63	0.64
40 LREC - Lost River Electric Cooperative Share	0.10	0.10	0.10	0.10	0.10	0.10	0.10
41 LVE - Lower Valley Electric Coop. Share	0.84	0.84	0.84	0.83	0.83	0.84	0.84
42 MCMN - McMinnville Share	1.17	1.17	1.17	1.37	1.40	1.40	1.40
43 MTFR - Milton Freewater Share	1.17	1.17	1.17	1.37	1.40	1.40	1.40
44 NLEC - Northern Lights Electric Coop. Share	0.57	0.57	0.57	0.57	0.57	0.57	0.57
45 PGE - Portland General Electric Share	25.05	25.10	25.06	30.28	29.42	29.16	28.72
46 PPL - Pacific Power and Light Share	25.05	25.10	25.06	30.28	29.42	29.16	28.72
47 PSE - Puget Sound Energy Share	14.43	14.46	14.44	17.46	16.95	16.77	16.51
48 RREC - Raft River Electric Coop. Share	0.13	0.13	0.13	0.13	0.13	0.13	0.13
49 SCL - Seattle City Light Share	1.81	1.81	1.81	16.49	15.98	15.80	15.55
50 SLEC -Salmon River Electric Coop. Share	0.10	0.10	0.10	0.10	0.10	0.10	0.10
51 TPU - Tacoma Public Utilities Share	13.56	13.59	13.57	16.49	15.98	15.80	15.55
52 UNEC - United Electric Coop. Share	0.23	0.23	0.23	0.23	0.23	0.23	0.23
53 UNKMKT - Unknown Market Purchaser Share	21.80	21.84	21.81	11.02	10.01	10.02	10.03
54 Priest Rapids After Encroachment	334.90	335.50	335.05	333.87	333.58	334.00	334.31
54 and Canadian Entitlement	334.90	335.50	335.00	333.87	333.58	334.00	334.31
IOU and Market Purchaser Allocations	97.31	97.50	97.36	102.33	98.71	97.90	96.58
Public Power Allocations	237.59	238.00	237.69	231.54	234.87	236.10	237.73
TOTAL	334.90	335.50	335.05	333.87	333.58	334.00	334.31

IOU and Market Purchaser Energy -
Seven Year Average Allocation **98.24**

Priest Rapids Allocation for 2007-2013
Remainder of Data for 2009-2013 is BPA's Table A-20 Priest Rapids Allocation
PNW Loads and Resource Study
2007 - 2013 Fiscal Years
1937 Water Year
[30] 2007 Initial Rate Case

Priest Rapids Allocation Percentages		2007	2008	2009	2010	2011	2012	2013
30 AVWP - Avista Share		3.28%	3.28%	3.28%	3.98%	3.87%	3.83%	3.77%
31 COPD - Cowlitz County PUD Share		1.52%	1.52%	1.52%	1.30%	1.27%	1.26%	1.23%
32 CWPC - Clear Water PUD Share		0.11%	0.11%	0.11%	0.11%	0.11%	0.11%	0.11%
33 EWEB - Eugene Water & Electric Share		0.92%	0.92%	0.92%	1.11%	1.08%	1.07%	1.05%
34 FGRV - Forest Grove Share		0.35%	0.35%	0.35%	0.41%	0.42%	0.42%	0.42%
35 FREC - Fall River Electric Coop. Share		0.15%	0.15%	0.15%	0.14%	0.14%	0.14%	0.14%
36 GCPD - Grant County PUD Share		61.50%	61.50%	61.50%	54.58%	56.01%	56.41%	57.06%
37 ICLP - Idaho City Light PUD Share		0.04%	0.04%	0.04%	0.04%	0.04%	0.04%	0.04%
38 KITT - Kittitas County PUD Share		0.28%	0.28%	0.28%	0.15%	0.14%	0.14%	0.14%
39 KOOT - Kootenai Share		0.19%	0.19%	0.19%	0.19%	0.19%	0.19%	0.19%
40 LREC - Lost River Electric Cooperative Share		0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%
41 LVE - Lower Valley Electric Coop. Share		0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%
42 MCMN - McMinnville Share		0.35%	0.35%	0.35%	0.41%	0.42%	0.42%	0.42%
43 MTFR - Milton Freewater Share		0.35%	0.35%	0.35%	0.41%	0.42%	0.42%	0.42%
44 NLEC - Northern Lights Electric Coop. Share		0.17%	0.17%	0.17%	0.17%	0.17%	0.17%	0.17%
45 PGE - Portland General Electric Share		7.48%	7.48%	7.48%	9.07%	8.82%	8.73%	8.59%
46 PPL - Pacific Power and Light Share		7.48%	7.48%	7.48%	9.07%	8.82%	8.73%	8.59%
47 PSE - Puget Sound Energy Share		4.31%	4.31%	4.31%	5.23%	5.08%	5.02%	4.94%
48 RREC - Raft River Electric Coop. Share		0.04%	0.04%	0.04%	0.04%	0.04%	0.04%	0.04%
49 SCL - Seattle City Light Share		0.54%	0.54%	0.54%	4.94%	4.79%	4.73%	4.65%
50 SLEC -Salmon River Electric Coop. Share		0.03%	0.03%	0.03%	0.03%	0.03%	0.03%	0.03%
51 TPU - Tacoma Public Utilities Share		4.05%	4.05%	4.05%	4.94%	4.79%	4.73%	4.65%
52 UNEC - United Electric Coop. Share		0.07%	0.07%	0.07%	0.07%	0.07%	0.07%	0.07%
53 UNKMKT - Unknown Market Purchaser Share		6.51%	6.51%	6.51%	3.30%	3.00%	3.00%	3.00%
54 Priest Rapids After Encroachment and Canadian Entitlement		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
IOU Percentage of Allocations		29.06%	29.06%	29.06%	30.65%	29.59%	29.31%	28.89%
Public Power Percentage of Allocations		70.94%	70.94%	70.94%	69.35%	70.41%	70.69%	71.11%
TOTAL		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
IOU and Market Purchaser Percentage - Seven Year Average Allocation	**29.37%**							

Projections of Rocky Reach Hydroelectric Project Annual Operating Costs
BPA's Wholesale Power 2007 Rate Case
Section 7(b)(2) Resource Stack Supporting Documentation

GDP Inflation Factors Projections				1.0200	1.017	1.017	1.021
				Amounts in Thousands			
		See Note 1 and 2 below.			2005 Projected Operating Budget[2]	2006 Projected Operating Budget[2]	2007 Projected Operating Budget[2]
		2002	2003	2004			
Operating Revenues		67,488	67,047	64,932	66,036	68,000	70,000
Operating Expenses:							
Maintenance Expenses		9,966	5,508	8,537	8,682	8,830	9,015
Depreciation Expenses		7,324	12,291	14,604	11,131	11,314	11,594
Taxes		1,243	1,147	1,243	1,264	1,285	1,312
Other Expenses		20,894	22,865	23,322	23,718	24,121	24,628
Total Operating Expenses	*	39,427	41,811	47,706	44,795	45,550	46,549
Operating Income		28,061	25,236	17,226	21,241	22,450	23,451
Capital Contributions		15	10	20	0	0	0
Interest Income (Expense)/Gains on Debt Retirements	*	4,931	2,417	1,727	2,400	2,400	2,400
Interest on Long-Term Debt[3]		20,271	22,189	22,084	22,098	23,937	24,663
Other Debt Expense		1,211	888	245	249	253	258
Total Interest & Other Expense	*	21,482	23,077	22,329	22,347	24,190	24,921
Excess of Revenues & Contributions Over Cost of Services		11,525	4,586	(3,356)	1,294	660	930
Operating Costs Before Adjustments (* Sum of numbers asterisks)		55,978	62,471	68,308	64,742	67,340	69,070
Budget/Operating Cost Adjustments							
Less Depreciation Expense		(7,324)	(12,291)	(14,604)	(11,131)	(11,314)	(11,594)
Plus Principal On Debt		20,420	18,250	12,046	14,154	16,655	15,246
Subtotal		69,074	68,430	65,750	67,765	72,681	72,722
Adjustment to reconcile to Project Owner's Projections		(1,801)	(1,622)	(1,013)	(1,652)	(4,681)	(2,722)
Projected Operating Budget		67,273	66,808	64,737	66,113	68,000	70,000
Projected Operating Budget per owner /operator - See Note 6		67,273	66,808	64,737	66,113	N/A	N/A
Projected Project Owners Operating Budget escalated for inflation - whole dollars					$66,113,000	$68,000,000	$70,000,000
Average Firm Energy Output (PNW L&R Study #30) (497.29MW) times the number of hours in a year (8760)					4,356,260	4,356,260	4,356,260
Projected Project Cost per MWh					**$15.1766**	**$15.6097**	**$16.0688**

Projections of Rocky Reach Hydroelectric Project Annual Operating Costs
BPA's Wholesale Power 2007 Rate Case
Section 7(b)(2) Resource Stack Supporting Documentation

Selected Balance Sheet Items - Rocky Reach Hydroelectric Project :

	Amounts in Thousands					
	2002	2003	2004	2005	2006	2007
Electric Plant Gross (Dam placed in service 1970)	417,240	544,722	555,041	556,568	565,711	579,711
Construction work in progress - See Note 5	93,813	4,292	1,527	9,143	14,000	8,252
Accumulated Deprec. & Amortization (15-95 year lives)	(76,153)	(87,613)	(99,697)	(110,828)	(122,142)	(133,736)
Net Electric Plant	434,900	461,401	456,871	454,883	457,569	454,227
Restricted Assets - Non Current	5,158	6,328	4,258			
Deferred Charges and Other Assets	22,607	22,699	21,721			
Restricted Assets Current	80,408	40,576	29,278			
Current and Accrued Assets	9,613	4,048	4,903			
Total Current Assets	90,021	44,624	34,181			
Total Assets	552,686	535,052	517,031			
Long-Term Debt	343,305	337,499	326,265			
Current & Accrued Liabilities	32,564	16,150	12,719			
Total Liabilities	375,869	353,649	338,984			
Deferred Credits						
Unamortized Debt Premium & Gains						
Retained Earnings - restricted for debt service	6,818	9,768	10,092			
Retained Earnings - restricted	8,808	10,129	13,604			
Retained Earnings - unrestricted	161,191	161,506	154,351			
Total Liabilities & Retained Earnings	552,686	535,052	517,031			

Projections of Rocky Reach Hydroelectric Project Annual Operating Costs
BPA's Wholesale Power 2007 Rate Case
Section 7(b)(2) Resource Stack Supporting Documentation

Notes:

1. The financial information for the years 2002, 2003, and 2004 was from Chelan County PUD No. 1's audited financials, Note 6: Segment Disclosure information, Combining Schedules 1-3, and other portions of the reports.

2. Some of the operating costs for the years 2005-2007 were based on the 2004 audited number adjusted for the GNP Price Deflator Inflation Projection obtained from DRI. Other projections were based on the trends present in the 2002, 2003 and 2004 audited financials.

3. Portions of the following schedule were trended based on the Schedule of Power Cost and Net Power Delivered in the financial statements together with the information presented in Note 3 - Long-term Debt, together with the information on capital improvements and financing in other portions of the 2004 annual report.

	2002	2003	2004	2005	2006	2007
Debt service per Power Cost and Net Power Delivered Schedule	40,691	40,439	34,130			
Interest on long-term debt	814	767	720	780	732	684
Interest on intersystem loans	19,457	21,422	21,364	21,318	23,205	23,979
Projected Interest Expense	20,271	22,189	22,084	22,098	23,937	24,663
Projected Principle payments	20,420	18,250	12,046	14,154	16,655	15,246
Total Projected Debt Service	40,691	40,439	34,130	36,252	40,592	39,909

4. Under the power sales contracts to the IOUs the power purchasers pay all expenses and costs associated with the project net of depreciation and capitalized items, including debt service whether the project operates or not.

5. The projection of additional plant additions was based on the Projected Capital Requirements (times a factor of two-thirds due to the delay in being placed in service) outlined in the supplemental financial information on page 90 of the 2004 annual report.

6. BPA sent a data request to Chelan County PUD #1 dated 5/11/2005 for the projected operating costs of the Rocky Reach Hydroelectric project for the years 2006-2013. Chelan County PUD #1 responded in a letter dated 5/19/2005, that they projected the power costs to be $66,113,000 million during CY2005. Officials from the utility stated that future costs were unpredictable due to increasing costs for their Habitat Conservation Plan and Relicensing Costs associated with the Rocky Reach and Lake Chelan Hydro Projects.

Rocky Reach Allocation for 2007 - 2013
PNW Loads and Resource Study
2007 - 2016 Fiscal Years
1937 Water Year
[30] 2007 Initial Rate Case

Rocky Reach Dam, Project Owner = Chelan County PUD, FERC License Exp. 2006, Purchaser Agreement Exp. 2011

Energy in Megawatts	2007	2008	2009	2010	2011	2012	2013
Canadian Entitlement Amount	36.3	35.55	36.2	37.7	38.05	37.6	37.2
Rocky Reach							
3 AVWP-Avista Share	14.44	14.46	14.44	14.40	14.39	14.40	14.41
4 CHPD-Chelan County PUD Share	75.34	75.45	75.35	75.12	75.07	75.14	75.20
5 CLKM-Colockum (Alcoa load/Chelan Native Load)	114.53	114.70	114.55	114.21	114.13	114.22	114.33
6 DOPD-Douglas PUD Share	13.79	13.81	13.80	13.75	13.74	13.76	13.77
7 PGE-Portland Gen. Elec. Share	59.75	59.84	59.76	59.58	59.54	59.60	59.64
8 PPL-PacifiCorp Share	26.39	26.43	26.40	26.32	26.30	26.32	26.34
9 PSE-Puget Sound Energy Share	193.69	193.99	193.73	193.15	193.01	193.19	193.34
10 Rocky Reach After Encroachment	497.93	498.68	498.03	496.53	496.18	496.63	497.03
and Canadian Entitlement	497.93	498.68	498.03	496.53	496.18	496.63	497.03
IOU Allocations	294.27	294.72	294.33	293.45	293.24	293.51	293.73
Public Power Allocations	203.66	203.96	203.70	203.08	202.94	203.12	203.30
TOTAL	497.93	498.68	498.03	496.53	496.18	496.63	497.03

Percentage Share	2007	2008	2009	2010	2011	2012	2013
Rocky Reach							
3 AVWP-Avista Share	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%
4 CHPD-Chelan County PUD Share	15.13%	15.13%	15.13%	15.13%	15.13%	15.13%	15.13%
5 CLKM-Colockum (Alcoa load/Chelan Native Load)	23.00%	23.00%	23.00%	23.00%	23.00%	23.00%	23.00%
6 DOPD-Douglas County PUD Share	2.77%	2.77%	2.77%	2.77%	2.77%	2.77%	2.77%
7 PGE-Portland Gen. Elec. Share	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%
8 PPL-PacifiCorp Share	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%	5.30%
9 PSE-Puget Sound Energy Share	38.90%	38.90%	38.90%	38.90%	38.90%	38.90%	38.90%
10 Rocky Reach After Encroachment	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
IOU Allocations	59.10%	59.10%	59.10%	59.10%	59.10%	59.10%	59.10%
Public Power Allocations	40.90%	40.90%	40.90%	40.90%	40.90%	40.90%	40.90%
TOTAL	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Projections of Rock Island Hydroelectric Project Annual Operating Costs
BPA's Wholesale Power 2007 Rate Case
Section 7(b)(2) Resource Stack Supporting Documentation

GDP Inflation Factors Projections				1.0200	1.017	1.017	1.021
				Amounts in thousands			
		See Note 1 and 2 below.			2005 Projected Operating Budget4	2006 Projected Operating Budget4	2007 Projected Operating Budget4
		2002	2003	2004			
Operating Revenues		58,914	62,803	65,992	67,114	68,255	70,500
Operating Expenses:							
Maintenance Expenses		6,468	8,343	8,989	9,142	9,297	9,492
Depreciation Expenses		6,818	6,419	6,757	8,911	9,157	9,674
Taxes		636	565	546	555	564	576
Other Expenses		22,898	22,043	24,761	25,182	25,000	26,818
Reserve Additions (Credits)							
Total Operating Expenses	*	36,820	37,370	41,053	43,790	44,018	46,560
Operating Income		22,094	25,433	24,939	23,324	24,237	23,940
Interest Income (Expense)/Gains on Debt Retirements	*	3,171	3,185	2,708	3,178	3,178	3,178
Interest Expense on Long-Term Debt - See Note 3		25,502	26,890	26,128	25,256	25,697	25,687
Other Debt Expense		505	486	457	500	500	500
Total Interest & Other Expense	*	26,007	27,376	26,585	25,756	26,197	26,187
Excess of Revenues & Contributions							
Over Cost of Services		(742)	1,242	1,062	746	1,218	931
Operating Costs Before Adjustments (* Sum of numbers asterisks)		59,656	61,561	64,930	66,368	67,037	69,569
Budget/Operating Cost Adjustments							
Less Depreciation Expense		(6,818)	(6,419)	(6,757)	(8,911)	(9,157)	(9,674)
Plus Principal On Debt - See Note 3		1,513	8,493	8,950	10,517	12,374	11,327
Subtotal		54,351	63,635	67,123	67,974	70,254	71,222
Adjustment to reconcile to Project Owner's Projections		4,394	(1,157)	(1,247)	(1,955)	(2,254)	(1,222)
Projected Operating Budget		58,745	62,478	65,876	66,019	68,000	70,000
Projected Operating Budget per owner /operator - See Note 6		58,745	62,478	65,876	66,019	N/A	N/A
Projected Owners Operating Budget escalated for inflation - whole dollars					$66,019,000	$68,000,000	$70,000,000
Average Firm Energy Output (PNW L&R Study #30) (280.22MW) times the number of hours in a year (8760)					2,454,727	2,454,727	2,454,727
Projected Project Cost per MWh using Project Owners Debt Service					**$26.8946**	**$27.7017**	**$28.5164**

Projections of Rock Island Hydroelectric Project Annual Operating Costs
BPA's Wholesale Power 2007 Rate Case
Section 7(b)(2) Resource Stack Supporting Documentation

Selected Balance Sheet Items - Rock Island Hydroelectric Project :

	Amounts in thousands					
	2002	**2003**	**2004**	**2005**	**2006**	**2007**
Electric Plant Gross (Dam placed in service 1970)	427,469	434,295	438,571	445,570	457,866	483,690
Construction work in progress - See Note 5	7,587	4,658	6,999	12,296	25,824	22,501
Accum. Deprec. & Amortization (15-95 year lives)	(106,815)	(112,837)	(119,173)	(128,084)	(137,241)	(146,915)
Net Electric Plant	328,241	326,116	326,397	329,782	346,449	359,276
Restricted Assets - Non Current	7,861	7,752	8,761			
Deferred Charges and Other Assets	10,365	8,896	8,164			
Restricted Assets Current	77,621	77,202	68,266			
Current and Accrued Assets	4,065	2,729	4,024			
Total Current Assets	81,686	79,931	72,290			
Total Assets	428,153	422,695	415,612			
Long-Term Debt	411,983	402,310	393,218			
Current & Accrued Liabilities	20,745	23,718	24,549			
Other Liabilities	35	35	151			
Total Liabilities	432,763	426,063	417,918			
Deferred Credits						
Unamort. Debt Premium & Gains						
Retained Earnings - restricted for debt service	15,422	36,193	34,864			
Retained Earnings - restricted other	3,235	8,272	5,340			
Retained Earnings - unrestricted	(23,267)	(47,833)	(42,510)			
Total Liabilities & Retained Earnings	428,153	422,695	415,612			

Projections of Rock Island Hydroelectric Project Annual Operating Costs
BPA's Wholesale Power 2007 Rate Case
Section 7(b)(2) Resource Stack Supporting Documentation

Notes:

1. The financial information for the years 2002, 2003, and 2004 was from Chelan County PUD No. 1's audited financials, Note 6:Segment Disclosure information, and Combining Schedules 1-3, along with other portions of the report.

2. Some of the operating costs for the years 2005-2007 were based on the 2004 audited number adjusted for the GNP Price Deflator Inflation Projection obtained from DRI. Other projections were based on the 2004 audited financial numbers.

3. Portions of the following schedule were trended based on the Schedule of Power Cost and Net Power Delivered in the financial statements together with the information presented in Note 3 - Long-term Debt, together with the information on capital improvements and financing in other portions of the 2004 annual report.

Rock Island Segment:	2002	2003	2004	2005	2006	2007
Debt service per Power Cost and Net Power Delivered Sch.	27,015	35,383	35,078			
Interest on intersystem loans	6,884	8,561	8,151	8,006	8,717	9,007
Interest on long-term debt	18,618	18,329	17,977	17,250	16,980	16,680
Total Interest Expense per 2003 Debt Ser. Req. Sch.	25,502	26,890	26,128	25,256	25,697	25,687
Principle portion of debt service	1,513	8,493	8,950	10,517	12,374	11,327
	27,015	35,383	35,078	35,773	38,071	37,014

4. Under the power sales contracts to the IOUs the power purchasers pay all expenses and costs associated with the project net of depreciation and capitalized items, including debt service whether the project operates or not.

5. The projection of additional plant additions was based on the Projected Capital Requirements (times a factor of two-thirds due to the delay in being placed in service) outlined in the supplemental financial information on page 90 of the 2004 annual report.

6. BPA sent a data request to Chelan County PUD #1 dated 5/11/2005 for the projected operating costs of the Rock Island Hydroelectric project for the years 2006-2013. Chelan County PUD #1 responded in a letter dated 5/19/2005, that they projected the power costs to be $66,019,000 during CY2005. Officials from the utility stated that future costs were unpredictable due to increasing costs for their Habitat Conservation Plan and Relicensing Costs associated with the Rocky Reach and Lake Chelan Hydro Projects.

Rock Island Allocation for 2007 - 2013
PNW Loads and Resource Study
2007 - 2016 Fiscal Years
1937 Water Year
[30] 2007 Initial Rate Case

Rock Island Dam, Project Owner = Chelan County PUD, FERC License Exp. 2029, Purchaser Agreement Exp. 2012

Energy in Megawatts	2007	2008	2009	2010	2011	2012	2013
Canadian Entitlement Amount	10.65	10.45	10.65	11.05	11.15	11.05	10.95
Rock Island PH#1 & PH#2							
13 CHPD-Chelan County PUD Share	140.21	140.31	140.21	140.01	139.96	140.01	140.06
14 PSE-Puget Sound Energy Share	140.21	140.31	140.21	140.01	139.96	140.01	140.06
15 Rock Island PH#1 After Encroachment	280.42	280.62	280.42	280.02	279.92	280.02	280.12
15 and Canadian Entitlement	280.42	280.62	280.42	280.02	279.92	280.02	280.12
IOU Allocations	140.21	140.31	140.21	140.01	139.96	140.01	140.06
Public Power Allocations	140.21	140.31	140.21	140.01	139.96	140.01	140.06
TOTAL	280.42	280.62	280.42	280.02	279.92	280.02	280.12

Percentage Share	2007	2008	2009	2010	2011	2012	2013
Rock Island PH#1 & PH#2							
13 CHPD-Chelan County PUD Share	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
14 PSE-Puget Sound Energy Share	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
15 Rock Island PH#1 After Encroachment	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
IOU Allocations	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Public Power Allocations	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
TOTAL	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

This page intentionally left blank.

APPENDIX D

BPA Programmatic Conservation Resources

Documentation of the Annual Amounts of Conservation Resources Available

AND

Documentation of Acquisition Cost
(Annual Amounts Expensed and Amounts Capitalized and Financed)

This page intentionally left blank.

BPA's Wholesale Power 2007 Rate Case

BPA Programatic Conservation - Historical Savings and Expenditures - Total Gross Amounts

ConMod, C&RD, and Market Transformation aMW Savings and Expenditures Before Adjustments

$ Millions of Dollars[1]

	Conser. Savings aMW[2,]	(D) - (C) Amount Revenue Expensed[3,4]	From (C) Amount Debt Financed[7]	(D) Annual Expenditures[3] Per "Red Book"	Amort. Period Years	(A) BPA Annual Conservation Capitalized[4]	BPA Bonds Issued: Bond Principal Amount[5]	BPA Bonds Issued: Bond Term[5]	(B) Third-Party Financed Conser.[6]	(C) (A) + (B) Total Capitalized/ Debt Financed Conservation[7]
1982 Conser.	32.4	4.974	61.940	66.914	20	61.940			0.000	61.940
1983 Conser.	68.6	2.907	204.092	206.999	20	204.092	140.0	20	0.000	204.092
1984 Conser.	16.6	8.311	66.783	75.094	20	66.783	150.0	20	0.000	66.783
1985 Conser.	17.0	24.680	103.067	127.747	20	103.067	50.0	5	0.000	103.067
1986 Conser.	23.5	5.256	99.743	104.999	20	97.618	50.0	10	2.125	99.743
							50.0	5		0.000
1987 Conser.	19.7	3.928	71.631	75.559	20	67.381	75.0	20	4.250	71.631
							50.0	5		0.000
1988 Conser.	53.2	8.535	58.570	67.105	20	54.320	90.0	20	4.250	58.570
1989 Conser.	51.7	17.643	46.069	63.712	20	41.819	40.0	20	4.250	46.069
1990 Conser.	38.1	41.859	36.220	78.079	20	34.095			2.125	36.220
1991 Conser.	19.0	43.811	45.714	89.525	20	45.714			0.000	45.714
1992 Conser.	37.4	68.496	62.151	130.647	20	62.151	100.0	15	0.000	62.151
							50.0	20		0.000
1993 Conser.	59.6	59.432	96.717	156.149	20	96.717	90.0	20	0.000	96.717
1994 Conser.	51.3	58.812	121.242	180.054	20	115.030	50.0	20	6.212	121.242
							50.0	4		0.000
1995 Conser.	65.9	50.702	85.252	135.954	20	72.428	85.0	20	12.824	85.252
1996 Conser.	56.3	53.532	52.274	105.806	20	39.450	30.0	15	12.824	52.274
1997 Conser.	54.7	28.023	32.953	60.976	20	20.329	40.0	20	12.624	32.953
1998 Conser.	33.4	32.546	26.331	58.877	20	14.308			12.023	26.331
1999 Conser.	33.1	20.937	19.728	40.665	20	13.716			6.012	19.728
2000 Conser.	18.2	15.377	0.347	15.724	20	0.347	32.0	3	0.000	0.347
2001 Conser.	30.9	29.148	0.057	29.205	20	0.057			0.000	0.057
2002 Conser.	61.0	57.053	28.227	85.280	10	28.227	40.0	3	0.000	28.227
2003 Conser.	53.8	58.725	22.900	81.625	9	22.900			0.000	22.900
2004 Conser.	51.7	48.573	19.431	68.004	8	19.431	30.0	4	0.000	19.431
Adjustments	-1.9									
TOTALS 1982-2004	945.2	743.3	1,361.439	2,104.7		1,281.920	1,292.0		79.5	1,361.439

BPA's Wholesale Power 2007 Rate Case
BPA Programmatic Conservation - Historical Savings and Expenditures
Gross Amounts Before Adjustments

Notes to this Worksheet:

1. Dollar costs are in nominal dollars associated with the year of expenditure.

2. The aMWs of savings acquired and the annual expenditures are gross amounts with no adjustments for degradation of measures over time. The annual savings amounts were obtained from the 2004 Conservation Resource Energy Data, "The Red Book". The annual savings totals for years 1982-2004 were based on Tables A and B using the sub-sector line amounts. The 2004 savings amounts attributable to building codes, market transformation efforts, ConMod, and C&RD ARE included in the savings totals. See the spread sheet titled "Historical Cumulative Conservation Savings aMW." The information in the 2004 Red Book provided greater detail than the 2005 edition for the years 1982-1999. The amounts in the table were updated and reconciled to the February 2005 Red Book addition.

3. Total Annual Expenditures are based on the "Total Cumulative Cost" column, Table C of the 2005 version of the "Red Book." The total expenditures include overhead loadings and indirect costs. Expenditures for building codes, market transformation, ConMod, and C&RD are included in the totals. In addition the amount of conservation investments funded with third-party debt are included in the totals.

4. The annual amount capitalized is based on the additions to Annual Plant in Service based on the 2000 and 2003 Revenue Requirement Study Documentation for the 2000 Rate Case and 2003 SN CRAC 7(i) formal rate proceedings with recent updating by the Plant Accounting data base. This number is consistent with the information in BPA's annual reports after subtracting amortization of prior year investments.

5. The amount of conservation bonds issued and the term of the bonds is based on the 2000 and 2003 Revenue Requirement Study Documentation for the 2000 Rate Case and 2003 SN CRAC 7(i) formal rate proceeding, and from additional information supplied by BPA Corporate Finance and Accounting staff.

6. BPA has agreed to pay the debt service for Conservation and Renewable Energy System (CARES) a joint operating agency (JOA) of the State of Washington, Emerald Public Utility District, City of Tacoma (Tacoma Power), and Eugene Water and Electric Board. The amounts in this column represent the original issue amount (principle) of bonds to finance conservation projects.

7. Total Capitalized/Debt Financed Conservation is comprised of BPA capitalized expenditures that were financed with U.S. Treasury Bonds and the conservation that is capitalized under Nonfederal Projects in BPA's financial statements which consists of third-party funded conservation as outlined in note 6 above.

BPA's Wholesale Power 2007 Rate Case

Total BPA Programatic Conservation - Gross Amounts[1]

	1982	1983	1984	1985	1986	1987	1988
Residential - C&RD	30.0	49.5	10.6	9.0	9.3	5.0	5.0
Adj.	0.0	(0.6)	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	30.0	48.9	10.6	9.0	9.3	5.0	5.0
Commercial - C&RD	2.5	20.8	6.4	8.0	12.4	8.0	1.0
Adj.	(0.1)	(1.1)	(0.4)	(0.4)	(0.7)	(0.4)	(0.1)
Sub TOTAL	2.4	19.7	6.0	7.6	11.7	7.6	0.9
Industrial - C&RD	0.0	0.0	0.0	0.0	0.4	0.9	4.3
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	(0.2)
Sub TOTAL	0.0	0.0	0.0	0.0	0.4	0.9	4.1
Agriculture - C&RD	0.0	0.5	0.5	0.9	0.9	1.3	1.4
Adj.	0.0	(0.5)	(0.5)	(0.9)	(0.9)	(1.3)	(1.4)
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Multi-Sector - C&RD	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Building Codes	0.0	0.0	0.0	0.4	2.1	3.7	5.6
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.4	2.1	3.7	5.6
Con/Mod	0.0	0.0	0.0	0.0	0.0	2.5	37.6
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	2.5	37.6
Market Trans.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
C&RD	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals before Adj.	32.5	70.8	17.5	18.3	25.1	21.4	54.9
Adjustments	(0.1)	(2.2)	(0.9)	(1.3)	(1.6)	(1.7)	(1.7)
Net Annual Amt.	32.4	68.6	16.6	17.0	23.5	19.7	53.2

Note 1 - The aMWs of savings acquired and the annual expenditures are gross amounts with no adjustments for degradation of measures over time. The annual savings amounts were obtained from the June 2005 Conservation Resource Energy Data, "The Red Book".

BPA's Wholesale Power 2007 Rate Case

Total BPA Programatic Conservation - Gross Amounts[1]

	1989	1990	1991	1992	1993	1994	Subtotal 1982-1994
Residential - C&RD	4.0	3.7	4.7	14.4	18.4	9.0	172.6
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	(0.6)
Sub TOTAL	4.0	3.7	4.7	14.4	18.4	9.0	172.0
Commercial - C&RD	0.9	1.0	1.0	5.0	11.4	14.1	92.5
Adj.	0.0	(0.1)	(0.1)	(0.3)	(0.6)	(0.9)	(5.2)
Sub TOTAL	0.9	0.9	0.9	4.7	10.8	13.2	87.3
Industrial - C&RD	6.7	2.2	6.3	6.1	15.2	11.3	53.4
Adj.	(0.4)	(0.1)	(0.3)	(0.3)	(0.9)	(0.6)	(2.8)
Sub TOTAL	6.3	2.1	6.0	5.8	14.3	10.7	50.6
Agriculture - C&RD	1.4	0.1	1.2	0.9	1.7	1.6	12.4
Adj.	(0.1)	0.0	(0.1)	(0.1)	(0.2)	(0.2)	(6.2)
Sub TOTAL	1.3	0.1	1.1	0.8	1.5	1.4	6.2
Multi-Sector - C&RD	0.0	0.0	0.0	0.2	0.7	5.4	6.3
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.2	0.7	5.4	6.3
Building Codes	8.3	6.4	6.3	11.5	13.9	11.6	69.8
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	8.3	6.4	6.3	11.5	13.9	11.6	69.8
Con/Mod	30.9	24.9	0.0	0.0	0.0	0.0	95.9
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	30.9	24.9	0.0	0.0	0.0	0.0	95.9
Market Trans.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
C&RD	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals before Adj.	52.2	38.3	19.5	38.1	61.3	53.0	502.9
Adjustments	(0.5)	(0.2)	(0.5)	(0.7)	(1.7)	(1.7)	(14.8)
Net Annual Amt.	51.7	38.1	19.0	37.4	59.6	51.3	488.1

Note 1 - The aMWs of savings acquired and the annual expenditures are gross amounts with no adjustments for degradation of measures over time. The annual savings amounts were obtained from the June 2005 Conservation Resource Energy Data, "The Red Book".

BPA's Wholesale Power 2007 Rate Case

Total BPA Programatic Conservation - Gross Amounts[1]

	1995	1996	1997	1998	1999	2000
Residential - C&RD	3.4	1.4	0.6	0.7	0.6	0.3
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	3.4	1.4	0.6	0.7	0.6	0.3
Commercial - C&RD	9.3	5.3	4.8	6.8	0.5	0.0
Adj.	(0.5)	(0.2)	(0.2)	(0.3)	0.0	0.0
Sub TOTAL	8.8	5.1	4.6	6.5	0.5	0.0
Industrial - C&RD	18.2	11.8	6.7	0.2	0.2	0.0
Adj.	(1.1)	(0.6)	(0.4)	0.0	0.0	0.0
Sub TOTAL	17.1	11.2	6.3	0.2	0.2	0.0
Agriculture - C&RD	1.8	0.6	0.0	0.0	0.0	0.0
Adj.	(0.2)	(0.2)	0.0	0.0	0.0	0.0
Sub TOTAL	1.6	0.4	0.0	0.0	0.0	0.0
Multi-Sector - C&RD	20.1	23.6	27.9	12.9	13.4	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	20.1	23.6	27.9	12.9	13.4	0.0
Building Codes	14.9	14.6	15.3	13.1	14.4	12.9
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	14.9	14.6	15.3	13.1	14.4	12.9
Con/Mod	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0
Market Trans.	0.0	0.0	0.0	0.0	4.0	5.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	4.0	5.0
C&RD	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0
Totals before Adj.	67.7	57.3	55.3	33.7	33.1	18.2
Adjustments	(1.8)	(1.0)	(0.6)	(0.3)	0.0	0.0
Net Annual Amt.	65.9	56.3	54.7	33.4	33.1	18.2

Note 1 - The aMWs of savings acquired and the annual expenditures are gross amounts with no adjustments for degradation of measures over time. The annual savings amounts were obtained from the June 2005 Conservation Resource Energy Data, "The Red Book".

Page 3 of 4

BPA's Wholesale Power 2007 Rate Case

Total BPA Programatic Conservation - Gross Amounts[1]

	2001	2002	2003	2004	Other Adjust's	FY 1982- FY 2004
Residential - C&RD	2.8	7.3	1.2	9.6		200.5
Adj.	(0.5)	(1.3)	(0.2)	0.0	0.2	(2.4)
Sub TOTAL	2.3	6.0	1.0	9.6	0.2	198.1
Commercial - C&RD	1.7	12.6	13.6	10.4		157.5
Adj.	0.0	0.2	0.2	0.0	(1.6)	(7.6)
Sub TOTAL	1.7	12.8	13.8	10.4	(1.6)	149.9
Industrial - C&RD	0.0	3.5	5.1	3.5		102.6
Adj.	0.0	(0.2)	0.0	0.0	(0.5)	(5.6)
Sub TOTAL	0.0	3.3	5.1	3.5	(0.5)	97.0
Agriculture - C&RD	0.0	0.0	0.0	0.0		14.8
Adj.	0.0	0.0	0.0	0.0		(6.6)
Sub TOTAL	0.0	0.0	0.0	0.0		8.2
Multi-Sector - C&RD	0.0	0.0	0.0	0.0		104.2
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0		104.2
Building Codes	12.4	13.0	4.2	3.9		188.5
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	12.4	13.0	4.2	3.9		188.5
Con/Mod	0.0	0.0	0.0	0.0		95.9
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0		95.9
Market Trans.	7.0	12.0	16.0	14.0		58.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	7.0	12.0	16.0	14.0		58.0
C&RD	9.6	17.7	17.5	13.1		57.9
Adj.	(2.1)	(3.8)	(3.8)	(2.8)	(5.2)	(17.7)
Sub TOTAL	7.5	13.9	13.7	10.3	(5.2)	40.2
Totals before Adj.	33.5	66.1	57.6	54.5		979.9
Adjustments	(2.6)	(5.1)	(3.8)	(2.8)	(1.9)	(34.7)
Net Annual Amt.	30.9	61.0	53.8	51.7	(1.9)	945.2

Total Above	945.2
Less ConMod	(95.9)
Red Book Table A page 5	849.3

BPA's Wholesale Power 2007 Rate Case

BPA 1982-2004 Programatic Conservation - After Adjustments[1]

	1982	1983	1984	1985	1986	1987	1988
Residential - C&RD	30.0	49.5	10.6	9.0	9.3	5.0	5.0
Adj.	0.0	(0.6)	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	30.0	48.9	10.6	9.0	9.3	5.0	5.0
Commercial - C&RD	2.5	20.8	6.4	8.0	12.4	8.0	1.0
Adj.	(0.1)	(1.1)	(0.4)	(0.4)	(0.7)	(0.4)	(0.1)
Sub TOTAL	2.4	19.7	6.0	7.6	11.7	7.6	0.9
Industrial - C&RD	0.0	0.0	0.0	0.0	0.4	0.9	4.3
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	(0.2)
Sub TOTAL	0.0	0.0	0.0	0.0	0.4	0.9	4.1
Agriculture - C&RD	0.0	0.5	0.5	0.9	0.9	1.3	1.4
Adj.	0.0	(0.5)	(0.5)	(0.9)	(0.9)	(1.3)	(1.4)
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Multi-Sector - C&RD	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Building Codes	0.0	0.0	0.0	0.4	2.1	3.7	5.6
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.4	2.1	3.7	5.6
Con/Mod	0.0	0.0	0.0	0.0	0.0	2.5	37.6
Adj.	0.0	0.0	0.0	0.0	0.0	(2.5)	(37.6)
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Market Trans.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
C&RD	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals before Adj.	32.5	70.8	17.5	18.3	25.1	21.4	54.9
Adjustments	(0.1)	(2.2)	(0.9)	(1.3)	(1.6)	(4.2)	(39.3)
Net Annual Amt.	32.4	68.6	16.6	17.0	23.5	17.2	15.6

Note 1 - The aMWs of savings acquired and the annual expenditures are gross amounts with no adjustments for degradation of measures over time. The annual savings amounts were obtained from the April 2004 Conservation Resource Energy Data, "The Red Book."

BPA's Wholesale Power 2007 Rate Case

BPA 1982-2004 Programatic Conservation - After Adjustments[1]

	1989	1990	1991	1992	1993	1994	1982-1994 Totals
Residential - C&RD	4.0	3.7	4.7	14.4	18.4	9.0	172.6
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	(0.6)
Sub TOTAL	4.0	3.7	4.7	14.4	18.4	9.0	172.0
Commercial - C&RD	0.9	1.0	1.0	5.0	11.4	14.1	92.5
Adj.	0.0	(0.1)	(0.1)	(0.3)	(0.6)	(0.9)	(5.2)
Sub TOTAL	0.9	0.9	0.9	4.7	10.8	13.2	87.3
Industrial - C&RD	6.7	2.2	6.3	6.1	15.2	11.3	53.4
Adj.	(0.4)	(0.1)	(0.3)	(0.3)	(0.9)	(0.6)	(2.8)
Sub TOTAL	6.3	2.1	6.0	5.8	14.3	10.7	50.6
Agriculture - C&RD	1.4	0.1	1.2	0.9	1.7	1.6	12.4
Adj.	(0.1)	0.0	(0.1)	(0.1)	(0.2)	(0.2)	(6.2)
Sub TOTAL	1.3	0.1	1.1	0.8	1.5	1.4	6.2
Multi-Sector - C&RD	0.0	0.0	0.0	0.2	0.7	5.4	6.3
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.2	0.7	5.4	6.3
Building Codes	8.3	6.4	6.3	11.5	13.9	11.6	69.8
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	8.3	6.4	6.3	11.5	13.9	11.6	69.8
Con/Mod	30.9	24.9	0.0	0.0	0.0	0.0	95.9
Adj.	(30.9)	(24.9)	0.0	0.0	0.0	0.0	(95.9)
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Market Trans.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
C&RD	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals before Adj.	52.2	38.3	19.5	38.1	61.3	53.0	502.9
Adjustments	(31.4)	(25.1)	(0.5)	(0.7)	(1.7)	(1.7)	(110.7)
Net Annual Amt.	20.8	13.2	19.0	37.4	59.6	51.3	392.2

Note 1 - The aMWs of savings acquired and the annual expenditures are gross amounts with no adjustments for degradation of measures over time. The annual savings amounts were obtained from the April 2004 Conservation Resource Energy Data, "The Red Book."

BPA's Wholesale Power 2007 Rate Case
BPA 1982-2004 Programatic Conservation - After Adjustments[1]

	1995	1996	1997	1998	1999	2000
Residential less C&RD	3.4	1.4	0.6	0.7	0.6	0.3
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	3.4	1.4	0.6	0.7	0.6	0.3
Commercial less C&RD	9.3	5.3	4.8	6.8	0.5	0.0
Adj.	(0.5)	(0.2)	(0.2)	(0.3)	0.0	0.0
Sub TOTAL	8.8	5.1	4.6	6.5	0.5	0.0
Industrial less C&RD	18.2	11.8	6.7	0.2	0.2	0.0
Adj.	(1.1)	(0.6)	(0.4)	0.0	0.0	0.0
Sub TOTAL	17.1	11.2	6.3	0.2	0.2	0.0
Agriculture less C&RD	1.8	0.6	0.0	0.0	0.0	0.0
Adj.	(0.2)	(0.2)	0.0	0.0	0.0	0.0
Sub TOTAL	1.6	0.4	0.0	0.0	0.0	0.0
Multi-Sector less C&RD	20.1	23.6	27.9	12.9	13.4	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	20.1	23.6	27.9	12.9	13.4	0.0
Building Codes[4]	14.9	14.6	15.3	13.1	14.4	12.9
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	14.9	14.6	15.3	13.1	14.4	12.9
Con/Mod	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0
Market Transformation[3]	0.0				4.0	5.0
Adj.	0.0	0.0	0.0	0.0	(2.8)	(3.5)
Sub TOTAL	0.0	0.0	0.0	0.0	1.2	1.5
C&RD[2]	0.0	0.0	0.0	0.0	0.0	0.0
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0	0.0	0.0
Totals before Adj.	67.7	57.3	55.3	33.7	33.1	18.2
Adjustments	(1.8)	(1.0)	(0.6)	(0.3)	(2.8)	(3.5)
Net Annual Amt.	65.9	56.3	54.7	33.4	30.3	14.7

Note 1 - The aMWs of savings acquired and the annual expenditures are gross amounts with no adjustments for degradation of measures over time. The annual savings amounts were obtained from the April 2004 Conservation Resource Energy Data, "The Red Book."

BPA's Wholesale Power 2007 Rate Case

BPA 1982-2004 Programatic Conservation - After Adjustments[1]

	2001	2002	2003	2004	Other Adjust's	TOTALS FY 1982-FY 2004
Residential less C&RD	2.8	7.3	1.2	9.6		200.5
Adj.	(0.5)	(1.3)	(0.2)	0.0	0.2	(2.4)
Sub TOTAL	2.3	6.0	1.0	9.6		198.1
Commercial less C&RD	1.7	12.6	13.6	10.4		157.5
Adj.	0.0	0.2	0.2	0.0	(1.6)	(7.6)
Sub TOTAL	1.7	12.8	13.8	10.4		149.9
Industrial less C&RD	0.0	3.5	5.1	3.5		102.6
Adj.	0.0	(0.2)	0.0	0.0	(0.5)	(5.6)
Sub TOTAL	0.0	3.3	5.1	3.5		97.0
Agriculture less C&RD	0.0	0.0	0.0	0.0		14.8
Adj.	0.0	0.0	0.0	0.0	0.0	(6.6)
Sub TOTAL	0.0	0.0	0.0	0.0		8.2
Multi-Sector less C&RD	0.0	0.0	0.0	0.0		104.2
Adj.	0.0	0.0	0.0	0.0	0.0	0.0
Sub TOTAL	0.0	0.0	0.0	0.0		104.2
Building Codes[4]	12.4	13.0	4.2	3.9		188.5
Adj.	0.0	(13.0)	(4.2)	(3.9)	0.0	(21.1)
Sub TOTAL	12.4	0.0	0.0	0.0		167.4
Con/Mod	0.0	0.0	0.0	0.0		95.9
Adj.	0.0	0.0	0.0	0.0	0.0	(95.9)
Sub TOTAL	0.0	0.0	0.0	0.0		0.0
Market Transformation[3]	7.0	12.0	16.0	14.0		58.0
Adj.	(4.9)	(8.4)	(11.2)	(9.8)	0.0	(40.6)
Sub TOTAL	2.1	3.6	4.8	4.2		17.4
C&RD[2]	7.5	13.9	13.7	10.3		45.4
Adj.	(7.5)	(13.9)	(13.7)	(10.3)	0.0	(45.4)
Sub TOTAL	0.0	0.0	0.0	0.0		0.0
Totals before Adj.	31.4	62.3	53.8	51.7		967.4
Adjustments	(12.9)	(36.6)	(29.1)	(24.0)	3.3	(220.0)
Net Annual Amt.	18.5	25.7	24.7	27.7	3.3	747.4

Total Above	747.4
Plus C&RD Reductions	45.4
Plus Bldg. Code Reductions	21.1
Difference in C&RD	(5.2)
Plus Market Transformation Reductions	40.6
Red Book Table A page 5	849.3

BPA's Wholesale Power 2007 Rate Case
BPA 1982-2004 Programmatic Conservation - After Adjustments[1]
NET BPA Conservation Program - Section 7(b)(2) Amounts

Notes Concerning Conservation Savings Adjustments:

1. The aMWs of savings acquired and the annual expenditures are gross amounts with no adjustments for degradation of measures over time. The annual savings amounts were obtained from the April 2004 Conservation Resource Energy Data, "The Red Book." The annual saving totals for years 1982-1999 were based on Table B2 , pages 7-8, using the sub-sector line amounts. The annual savings for the years 2000-2003 are based on Table B1, page 6 of The 2004 Red Book, using the amounts for ConAug by sector plus the low income residential weatherization amounts. The information in the 2004 Red Book provided greater detail than the 2005 edition of the Red Book concerning the amount of conservation savings for the years 1982-1999. The final results in the tables were updated and reconciled to the February 2005 Red Book. Saving amounts attributable to ConMod and C&RD have been totally removed from the cumulative totals for FY's 1982-2004. See the additional notes below on adjustments made to the Red Book's gross amounts

2. Savings attributable to C&RD were removed in total because there was not adequate compliance efforts in place during those years to have sufficient certainty that the savings were achieved. In addition no reductions to the Administrator's load obligations (contracted power amounts were not decremented) occurred during this period.

3. BPA's market transformation efforts have been achieved through the Northwest Energy Efficiency Alliance (NEEA) for the most part during this period of time. NEEA's market transformation efforts cover the entire Pacific Northwest Region and beyond. BPA paid for approximately one-half of NEEA's operating budgets during the 1999-2005 time frame. BPA plans to continue funding NEEA's efforts through the 2011 time period at the same level of support.

BPA's "Red Book" claims one half of the regional savings attributable to NEEA's efforts commensurate with it's level of funding. The expenditures that BPA pays NEEA however, has only a partial impact on reducing the Administrator's load obligations. The calculation of the amount of benefit that BPA receives is calculated as follows:

Forecasted FY 2007 Regional Loads (No DSI's)	19,964.0	aMW	100%
BPA's Forecasted FY 2007 Loads (No DSI's)	7,189.0	aMW	36%

DSI loads were excluded from both amounts because market transformation efforts do not impact DSI loads. Of the total BPA forecasted loads of 7,189aMW (36%), there is no reduction in contracted power purchases for BPA's non-load following customers. No reduction of purchased power amounts in slice and block power purchase contracts due to NEEA savings were made during this period of time, and no decrements are forecasted for the 2006-2011 time period. The amount of power that BPA provides to load following and non-load following customers is as follows:

Forecasted FY 2007 Total Retail Load:			
Load Following Customers	3,489.0	aMW	40%
Non-Load Following Customers	5,219.0	aMW	60%
	8,708.0	aMW	100%

Notes Concerning Conservation Savings Adjustments Continued:

Note 3 - Continued
For every megawatt of conservation savings that is achieved by NEEA's market transformatior efforts, BPA's load obligations are reduced by approximately 15 percent (36% x 40%). Because the Red Book only claims half of the NEEA savings it is necessary to adjust the calculation below that is based on total regional loads by doubling the final savings amount. The adjustment necessary to reflect just the direct benefit of savings to BPA loads is to reduce the savings in the table by seventy percent (70%). This percentage is derived by doubling the 15% above and subtracting this total from 100% of the gross savings contained in the Red Book (100% -(2 x 15%)) = 70%.

4. Adjustment were made to remove savings attributable to building codes for the years after 2001. BPA's Conservation Program staff are of the opinion that the benefits from earlier BPA expenditures to achieve Model Energy Code standards had largely been achieved by this time. The savings for the 7(b)(2) resource stack should have a high degree of assurance that the conservation savings would be able to reduce 7(b)(2) Case loads.

5. As previously noted in the table of Gross Conservation Savings, The 2005 Red Book totals have excluded the savings form ConMod Conservation investments that were placed primarily with the aluminum reduction industry. Since most of these plants are no longer operating, and since BPA is not planning to meet future power loads from this industry, the conservation savings from these past investments is not available to reduce loads in the 2007-2013 time period of the 7(b)(2) rate test The expenditures for ConMod investments were left in the Red Book to meet the Red Book's objective of accounting for all conservation expenditures. The expenditures for past ConMod investments were removed from the expenditure totals that were included in the 7(b)(2) resource stack.

6. In summary, the following adjustments were made to the 2005 Red Book's conservation savings for the years 1982-2004:

Building Code Savings	21.1	aMW
Market Transformation Saving	40.6	aMW
C&RD Savings	40.2	aMW
	101.9	aMW

The total conservation savings per the Red Book for FY1982-2004 was 849.3 aMW, the total savings included in the 7(b)(2) resource stack for those years was 747.4aMW.

BPA's Wholesale Power 2007 Rate Case

Total Historical Conservation Expenditures -1982-2004, Per Red Book, Adjusted for Plant Accounting Capitalized Conservation Expenditures

($000) [1]

		CAPITALIZED COSTS					EXPENSED CONSERVATION COSTS								
				BPA CAPITALIZED COSTS											
Year	Total Incremental Yearly Costs Table D Red Book	Total Capitalized Costs	Third Party Financing Costs/ Original Issue Amount	Capitalized Conser. Costs	ConAug Costs	Legacy Conser Costs	Total Expense Costs	Support Costs[2]	Market Transform. Costs[5]	Con/Mod Costs[3]	C&RD Total Costs[4]	Energy WEB & New Initiatives	Other Conser. Expense Costs	TOTAL CONSER. COSTS	Gross Conser. Savings per Red Book
1982	66,914	61,940	0	61,940	0	61,940	4,974	4,974	0	0	0	0	0	66,914	32.4
1983	206,999	204,092	0	204,092	0	204,092	2,907	2,907	0	0	0	0	0	206,999	68.6
1984	75,094	66,783	0	66,783	0	66,783	8,311	7,589	0	0	0	0	722	75,094	16.6
1985	127,747	103,067	0	103,067	0	103,067	24,680	20,232	0	0	0	0	4,448	127,747	17.0
1986	104,999	99,743	2,125	97,618	0	97,618	5,256	5,256	0	0	0	0	0	104,999	23.5
1987	75,559	71,631	4,250	67,381	0	67,381	3,928	3,928	0	0	0	0	0	75,559	19.7
1988	67,105	58,570	4,250	54,320	0	54,320	8,535	6,654	0	1,881	0	0	0	67,105	53.2
1989	63,712	46,069	4,250	41,819	0	41,819	17,643	12,917	0	4,726	0	0	0	63,712	51.7
1990	78,079	36,220	2,125	34,095	0	34,095	41,859	5,359	0	6,063	0	0	30,437	78,079	38.1
1991	89,525	45,714	0	45,714	0	45,714	43,811	5,106	0	6,254	0	0	32,451	89,525	19.0
1992	130,647	62,151	0	62,151	0	62,151	68,496	4,134	0	4,553	0	0	59,809	130,647	37.4
1993	156,149	96,717	0	96,717	0	96,717	59,432	8,119	0	4,179	0	0	47,134	156,149	59.6
1994	180,054	121,242	6,212	115,030	0	115,030	58,812	8,210	0	6,462	0	0	44,140	180,054	51.3
1995	135,954	85,252	12,824	72,428	0	72,428	50,702	7,915	0	4,045	0	0	38,742	135,954	65.9
1996	105,806	52,274	12,824	39,450	0	39,450	53,532	7,863	0	4,595	0	0	41,074	105,806	56.3
1997	60,976	32,953	12,624	20,329	0	20,329	28,023	14,800	3,900	2,744	0	0	6,579	60,976	54.7
1998	58,877	26,331	12,023	14,308	0	14,308	32,546	12,200	12,000	2,358	0	0	5,988	58,877	33.4
1999	40,665	19,728	6,012	13,716	0	13,716	20,937	10,571	5,600	280	0	1,400	3,086	40,665	33.1
2000	15,724	347	0	347	0	347	15,377	3,077	12,000	0	0	300	0	15,724	18.2
2001	29,205	57	0	57	3,688	(3,631)	29,148	6,200	9,600	0	9,243	1,450	2,655	29,205	30.9
2002	85,280	28,227	0	28,227	28,201	26	57,053	6,193	7,750	0	39,910	3,200	0	85,280	61.0
2003	81,625	22,900	0	22,900	23,793	(893)	58,725	3,594	9,300	0	41,439	4,392	0	81,625	53.8
2004	68,004	19,431	0	19,431	19,117	314	48,573	5,315	9,700	0	32,752	806	0	68,004	51.7
															(1.9)
	2,104,699	1,361,439	79,519	1,281,920	74,799	1,207,121	743,260	173,113	69,850	48,140	123,344	11,548	317,265	2,104,699	945.2

Page 1 of 4

BPA's Wholesale Power 2007 Rate Case
NET Historical Conservation Savings and Expenditures 1982-2004
With Expenditure Adjustments for ConMod and C&RD
Savings Adjustments for C&RD, Market Transformation and Building Codes
($000) [1]

Year	Total Incremental Costs / Subtotal Cost Allocations	(-) C&RD[4] Cost Adjustments	(-) ConMod[3] Cost Adjustments	(-) Market Trans.[5] Cost Adjustments	Adjusted Net Annual Costs	Net Conser. Savings as Adjusted
1,982	66,914	0	0	0	66,914	32.4
1,983	206,999	0	0	0	206,999	68.6
1,984	75,094	0	0	0	75,094	16.6
1,985	127,747	0	0	0	127,747	17.0
1,986	104,999	0	0	0	104,999	23.5
1,987	75,559	0	0	0	75,559	17.2
1,988	67,105	0	(1,881)	0	65,224	15.6
1,989	63,712	0	(4,726)	0	58,986	20.8
1,990	78,079	0	(6,063)	0	72,016	13.2
1,991	89,525	0	(6,254)	0	83,271	19.0
1,992	130,647	0	(4,553)	0	126,094	37.4
1,993	156,149	0	(4,179)	0	151,970	59.6
1,994	180,054	0	(6,462)	0	173,592	51.3
1,995	135,954	0	(4,045)	0	131,909	65.9
1,996	105,806	0	(4,595)	0	101,211	56.3
1,997	60,976	0	(2,744)	0	58,232	54.7
1,998	58,877	0	(2,358)	0	56,519	33.4
1,999	40,665	0	(280)	0	40,385	30.3
2,000	15,724	0	0	0	15,724	14.7
2,001	29,205	(9,243)	0	0	19,962	18.5
2,002	85,280	(39,910)	0	0	45,370	25.7
2,003	81,625	(41,439)	0	0	40,186	24.7
2,004	68,004	(32,752)	0	0	35,252	27.7
						3.3
	2,104,699	(123,344)	(48,140)	0	1,933,215	747.4

Difference in Costs Conatined in the 7(b)(2) Resource Stack $\boxed{\$171{,}484}$

BPA's Wholesale Power 2007 Rate Case
NET Historical Conservation Savings and Expenditures 1982-2004
With Expenditure Adjustments for ConMod and C&RD
Savings Adjustments for C&RD, Market Transformation and Building Codes

Notes Concerning Expenditure Adjustments:

1. Dollar costs are in nominal dollars associated with the year of expenditure, costs were obtained from Table C of the 2005 Red Book.

2. Support costs are non-sector specific and consist of resource planning costs through FY 1987, Research Development & Demonstration, prior year adjustments, education efforts, and environmental conservation costs.

3. As previously noted in the table of Gross Conservation Savings, The 2005 Red Book totals have excluded the savings form ConMod Conservation investments that were placed primarily with the aluminum reduction industry. Since most of these plants are no longer operating, and since BPA is not planning to meet future power loads from this industry, the conservation savings from these past investments is not available to reduce loads in the 2007-2013 time period of the 7(b)(2) rate test. The expenditures for ConMod investments were left in the Red Book to meet the Red Book's objective of accounting for all the costs of acquiring conservation expenditures. The expenditures for past ConMod investments has been removed from the expenditure totals that were included in the 7(b)(2) resource stack total.

4. The C&RD investments were costs that were not included in BPA's revenue requirement in determining "base" rate levels for years prior to 2007. They were added after the determination of base rates and were credited back to customers as credits on their power bills in return for agreeing to invest the money in conservation efforts or renewable resources. The controls surrounding the achievement of this conservation during the 2002-2006 time period was less than past practices making the savings from these expenditures less assured. The majority of the utilities participating in this program were not "load following" customers and the Administrator's load obligations to these customers was not reduced (no decrementing of contract obligations occurred). For these reasons the savings and expenditures associated with C&RD for 2002-2006 was "netted" out of those years conservation efforts.

Page 3 of 4

BPA's Wholesale Power 2007 Rate Case
NET Historical Conservation Savings and Expenditures 1982-2004
With Expenditure Adjustments for ConMod and C&RD
Savings Adjustments for C&RD, Market Transformation and Building Codes

Notes Concerning Expenditure Adjustments:

5. BPA's market transformation efforts have been achieved through the Northwest Energy Efficiency Alliance (NEEA) for the most part during this period of time. NEEA's market transformation efforts cover the entire Pacific Northwest Region and beyond. BPA paid for approximately one-half of NEEA's operating budgets during the 1997-2004 time frame. The expenditures that BPA pays NEEA has only a partial impact on reducing the Administrator's load obligation. The market transformation savings were reduced by seventy percent, see this calculation at Note 3 to the work sheet "BPA 1982-2004 Programmatic Conservation - After Adjustments." The amount of market transformation expenditures were not reduced. The reason for this is the fact that the amount that BPA paid NEEA was so material in amount, that it was critical in sustaining market transformation efforts in the region. In order to achieve the thirty-percent of savings that were included in the savings total, BPA would have needed to fund the program at approximately the same level.

6. Adjustment were made to remove savings attributable to building codes for the years after 2001. It was thought that the benefits from earlier BPA expenditures to achieve Model Energy Code standards had largely been achieved by this time. The savings for the 7(b)(2) resource stack should be conservatively stated with a high degree of assurance that the conservation savings would be able to reduce loads. No direct expenditures by BPA for building code efforts occurred during FY2002-2006, so no expenditure adjustments are necessary.

7. The historical expenditures reflected in the annual expenditure totals contained in the Red Book contain the direct costs along with indirect and overhead costs that were necessary to acquire the conservation savings reported for the year. The expenditure totals do not contain any costs associated with the financing of conservation efforts. The 2007 rates analysis model (2007RAM) does finance that portion of a year's expenditures that were capitalized, using a 20-year period for investments made during 1982-2001 and 15-years for those investments incurred after 2001. The 2007 RAM uses interest rates of 5.34% and 5.09% for 20 and 15-year financing terms as outlined in the Financing Analysis prepared by Public Financial Management, BPA's financial advisor.

Page 4 of 4

BPA's Wholesale Power 2007 Rate Case
BPA Projected Conservation Program Savings - 2005-2013
Net BPA Conservation Program Savings - Section 7 (b)(2) Amounts
aMW[1]

	2005	2006	2007	2008	2009	2010	2011	2012	2013	Cumulative Totals
Projected Conservation Program - Gross Saving Amounts:										
C&RD - Non-decrement[2]	10.0	5.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	99.0
C&RD - Equivalent-decrement[2]	0.0	0.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	56.0
Conservation Augmentation	18.0	5.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	23.0
Conservation Acquisition - Bi-lateral Contracts	0.0	18.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	172.0
Market Trans.- Non-decrement[3]	8.4	8.4	7.0	7.0	7.0	7.0	7.0	7.0	7.0	65.8
Market Trans.- Equivalent-decrement[3]	3.6	3.6	3.0	3.0	3.0	3.0	3.0	3.0	3.0	28.2
Total Proj. Conservation Savings	40.0	40.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	444.0
Net BPA Conservation Program Savings - Section 7 (b)(2) Amounts:										
Less C&RD Non-Decrement[2]	(10.0)	(5.0)	(12.0)	(12.0)	(12.0)	(12.0)	(12.0)	(12.0)	(12.0)	(99.0)
Less Market Trans.- Non-decrement[3]	(8.4)	(8.4)	(7.0)	(7.0)	(7.0)	(7.0)	(7.0)	(7.0)	(7.0)	(65.8)
Net Conservation Savings for Section 7(b)(2)	21.6	26.6	33.0	33.0	33.0	33.0	33.0	33.0	33.0	279.2

Page 1 of 3

BPA's Wholesale Power 2007 Rate Case
BPA Projected Conservation Program Savings - 2005-2013 -
Net BPA Conservation Program Savings - Section 7 (b)(2) Amounts

Notes - Adjustments Made to BPA's Conservation Program Savings Amounts to Arrive at Savings Available to Reduce Loads per the Section 7 (b)(2) Rate Test

'1. The conservation saving projections for 2005-2006 come from BPA's program budgets for those years. The conservation saving projections for the years 2007-2011 come from BPA's Post -2006 Conservation Program Proposal that were finalized in the Power Function Review sessions held with BPA's customers. The expenditure projections for 2012-2013 were based on the assumption that the conservation program design for 2007-2011 continued during these two years.

2. BPA's post -2006 Conservation Program has provided additional compliance requirements surrounding the C&RD program to help ensure the achievement of conservation savings associated with the granting of C&RD credits. The majority of C&RD expenditures are received by non-load following utilities that purchase the Slice and Flat-Block power products. The Administrator's load obligations to these utilities has not been reduced, (contract power amounts have not been decremented for the conservation savings) thus BPA will not receive a direct benefit from C&RD expenditures associated with non-load following customers during the Section 7(b)(2) rate test period. BPA does receive a direct benefit from load following customers associated with the conservation that occurs in those utility's service territories. Because of the additional controls surrounding the achievement of conservation savings during the post 2006 time period, and because BPA does receive a direct benefit from expenditures that occur in load following utility service territories, the portion of the C&RD savings attributable to load following utilities has been included in the Section 7(b)(2) resource stack.

The reduction in conservation savings attributable to the C&RD program available to the Section 7(b)(2) resource stack is outlined as follows:

a.) The dollar cost for 1 average megawatt of C&RD Savings is estimated at $1.8 Million; total C&RD Program conservation savings is estimated at 20 aMW at a total cost of $36 Million.

b.) Load following BPA customer loads are forecasted at 3,489 aMW for FY 2007, non-load following load is forecasted at 5,219, for a total of 8,708aMW (Total Retail Loads). Nonload following loads represent 60% of total forecasted BPA loads and load following loads represent 40% of BPA's total loads.

c.) Load following savings that reduce the Administrators load obligation =
20.0 aMW times 40% = 8.0 aMW,
Associated cost = 8.0 / 20.0 * $36.0M = $14.4 Million.

BPA's Wholesale Power 2007 Rate Case
BPA Projected Conservation Program Savings - 2005-2013 -
Net BPA Conservation Program Savings - Section 7 (b)(2) Amounts

Notes - Adjustments Made to BPA's Conservation Program Savings Amounts to Arrive at Savings Available to Reduce Loads per the Section 7 (b)(2) Rate Test

Note 2 Continued:

d.) Non-decremental savings benefit to rest of region = 20.0aMW - 8.0aMW = 12.0aMW,
Associated cost = 12.0/ 20.0 * $36.0M = $21.6 Million

Adjustments to the conservation annual savings amounts of 60% for C&RD were made to the Red Book amounts to arrive at the amount of savings available to the resource stack. No adjustment to the annual expenditures have been made as explained by Note 3, "Projected Conservation GROSS and NET EXPENDITURES - 2005-2013 - Net BPA Conservation Program - Section 7 (b)(2) Amounts."

3. BPA's market transformation efforts are being achieved through the Northwest Energy Efficiency Alliance (NEEA) for during the 2007-2013 period of time. NEEA's market transformation efforts cover the entire Pacific Northwest Region and beyond. BPA is projected to pay for approximately one-half of NEEA's operating budgets during this time frame. The expenditures that BPA pays NEEA has only a partial impact on reducing the Administrator's load obligation. The market transformation savings were reduced by seventy percent, see this calculation at Note 3 to the work sheet "BPA 1982-2004 Programmatic Conservation - After Adjustments." This same level of adjustment in annual savings that applied to 2002-2006 also applies to the period 2007-2013.

4. In summary, the following adjustments were made to the conservation savings projected for the years 2005-2013:

Market Transformation Saving	65.8	aMW
C&RD Savings	99.0	aMW
	164.8	aMW

The total conservation savings projected for BPA's Conservation Program for FY's 2005-2013 is 444.0aMW. The total savings included in the 7(b)(2) resource stack for those years was 279.2aMW.

Total BPA Conservation Program
Projected Conservation GROSS EXPENDITURES - 2005-2013
($1,000)[1]

	Energy Efficiency Staffing Costs	Indirect & Overhead Costs	Corporate G&A Costs	Debt Service Other Entities	Total Staffing and Indirect Costs	Market Transform. Costs[4]	Expense Agreements & Grants	C&RD Costs[3]	Infrastructure Support & Evaluation Costs	ConAug/ Cons. Acq. Costs	Total Direct Program Costs[1]	Total Projected Costs Energy Efficiency	Capitalized/ Debt Financed	Expensed	Total Projected Conser. Savings[5] aMW
2005	5,887	20,065	6,720	5,214	37,886	10,000	3,900	37,000	0	22,500	73,400	111,286	22,500	88,786	40.0
2006	6,446	21,579	5,739	5,210	38,974	10,000	4,500	36,000	0	44,000	94,500	133,474	44,000	89,474	40.0
Sub total	12,333	41,644	12,459	10,424	76,860	20,000	8,400	73,000	0	66,500	167,900 #	244,760	66,500	178,260	80.0
2007	6,460	20,151	5,173	5,203	36,987	10,000	5,000	36,000	2,000	32,000	85,000	121,987	32,000	89,987	52.0
2008	6,712	19,123	5,360	5,198	36,393	10,000	5,000	36,000	2,000	32,000	85,000	121,393	32,000	89,393	52.0
2009	6,973	18,665	5,358	5,196	36,192	10,000	5,000	36,000	2,000	32,000	85,000	121,192	32,000	89,192	52.0
2010	7,245	16,606	6,216	4,940	35,007	10,000	5,000	36,000	2,000	40,000	93,000	128,007	40,000	88,007	52.0
2011	7,527	16,310	6,405	4,924	35,166	10,000	5,000	36,000	2,000	40,000	93,000	128,166	40,000	88,166	52.0
2012	7,753	16,855	6,629	4,907	36,144	10,000	5,150	36,000	2,000	40,000	93,150	129,294	40,000	89,294	52.0
2013	7,985	17,419	6,861	4,890	37,155	10,000	5,305	36,000	2,000	40,000	93,305	130,460	40,000	90,460	52.0
Sub total	50,655	125,129	42,002	35,258	253,044	70,000	35,455	252,000	14,000	256,000	627,455 #	880,499	256,000	624,499	364.0
Total	62,988	166,773	54,461	45,682	329,904	90,000	43,855	325,000	14,000	322,500	795,355 #	1,125,259	322,500	802,759	444.0

Gross Expenditures Net of Debt Service Debt Service **$1,079,577**

Net BPA Conservation Program - Section 7 (b)(2)
Projected Conservation NET EXPENDITURES - 2005-2013
($1,000)

	Energy Efficiency Staffing Costs	Indirect & Overhead Costs	Corporate G&A Costs	Debt Service Other Entities[2]	Total Staffing and Indirect Costs	Market Transform. Costs[4]	Expense Agreements & Grants	C&RD Costs[3]	Infrastructure Support & Evaluation Costs	ConAug/ Cons. Acq. Costs	Total Direct Program Costs	NET Projected Costs Energy Efficiency	Capitalized/ Debt Financed	Expensed	Total Projected Conser. Savings[5] aMW
2005	5,887	20,065	6,720	0	32,672	10,000	3,900	0	0	22,500	36,400	69,072	22,500	46,572	21.6
2006	6,446	21,579	5,739	0	33,764	10,000	4,500	0	0	44,000	58,500	92,264	44,000	48,264	26.6
Sub total	12,333	41,644	12,459	0	66,436	20,000	8,400	0	0	66,500	94,900 #	161,336	66,500	94,836	48.2
2007	6,460	20,151	5,173	0	31,784	10,000	5,000	36,000	2,000	32,000	85,000	116,784	32,000	84,784	33.0
2008	6,712	19,123	5,360	0	31,195	10,000	5,000	36,000	2,000	32,000	85,000	116,195	32,000	84,195	33.0
2009	6,973	18,665	5,358	0	30,996	10,000	5,000	36,000	2,000	32,000	85,000	115,996	32,000	83,996	33.0
2010	7,245	16,606	6,216	0	30,067	10,000	5,000	36,000	2,000	40,000	93,000	123,067	40,000	83,067	33.0
2011	7,527	16,310	6,405	0	30,242	10,000	5,000	36,000	2,000	40,000	93,000	123,242	40,000	83,242	33.0
2012	7,753	16,855	6,629	0	31,237	10,000	5,150	36,000	2,000	40,000	93,150	124,387	40,000	84,387	33.0
2013	7,985	17,419	6,861	0	32,265	10,000	5,305	36,000	2,000	40,000	93,305	125,570	40,000	85,570	33.0
Sub total	50,655	125,129	42,002	0	217,786	70,000	35,455	252,000	14,000	256,000	627,455 #	845,241	256,000	589,241	231.0
Total	62,988	166,773	54,461	0	284,222 #	90,000	43,855	252,000	14,000	322,500	722,355 #	**$1,006,577**	322,500	684,077	279.2

Difference in Conservation Expenditures Contained in resource Stacl $\boxed{\$73,000}$

BPA's Wholesale Power 2007 Rate Case
Projected Conservation GROSS and NET EXPENDITURES - 2005-2013 -
Net BPA Conservation Program - Section 7 (b)(2) Amounts

Notes - Adjustments Made to BPA's Conservation Program Expenditure Amounts to Arrive at Section 7 (b)(2) Amounts

1. Dollar costs are in the nominal dollars associated with the year of expenditure. The conservation expenditure projections for 2005-2006 come from BPA's program budgets for those years. The expenditure projections for the years 2007-2011 come from BPA's Post 2006 Conservation Program Proposal that were finalized in the Power Function Review sessions held with BPA's customers. The expenditure projections for 2012-2013 were based on the assumption that the conservation program design for 2007-2011 continued during these two years.

2. Third-party debt service costs are subtracted out of the 7(b)(2) Case amounts so that the expenditure totals reflect only the actual expenditures/costs for acquiring savings for that year. The costs in the resource stack are net of all financing costs. Annual debt service costs are included in the annual revenue requirements for each year by 2007RAM using the interest rate projections provided by BPA's Financial Advisor associated with the hypothetical Joint Operating Agency's funding of all resources in performing the Section 7(b)(2) rate test.

3. No reduction in expenditures for the C&RD program were made. Unlike the FY2002-2006 time period when the C&RD cost were not included in the revenue requirement, the WP-07 revenue requirement includes C&RD costs. The rates charged all BPA customers include C&RD costs. It would be inequitable and not feasible to conduct a C&RD program where only load-following customers were eligible to participate. In order to achieve the conservation savings that occur in the service territories of full-requirements customers, BPA also needs to undertake the C&RD program for BPA's other customers who pay for C&RD costs. In order for BPA and it's customers to meet their portion of the NWPPC's regional targets, the total expenditures for C&RD are required to be incurred.

4. BPA's market transformation efforts are being achieved through the Northwest Energy Efficiency Alliance (NEEA) during the 2007-2013 period of time. NEEA's market transformation efforts cover the entire Pacific Northwest Region and beyond. BPA is projected to pay for approximately one-half of NEEA's operating budgets during this time frame. The expenditures that BPA pays NEEA has only a partial impact on reducing the Administrator's load obligation. The market transformation savings were reduced by seventy percent, see this calculation at Note 3 to the work sheet "BPA 1982-2004 Programmatic Conservation - After Adjustments." This same level of adjustment in annual savings that applied to 2002-2006 also applies to the period 2007-2013. The amount of market transformation expenditures were not reduced. The reason for this is the fact that the amount that BPA is projected to pay NEEA is so material in amount, that it is critical in sustaining market transformation efforts in the region. In order to achieve the thirty-percent of savings that were included in the savings total, BPA would have needed to fund the program at approximately the same level.

5. The Net Conservation Savings for the years 2005-2013 are outlined on the worksheet titled, "BPA Projected Conservation Program Savings - 2005-2013 - Net BPA Conservation Program Savings - Section 7 (b)(2) Amounts."

BPA Programmatic Conservation - Net Historical & Projected Savings and Expenditures
BPA 2007 Rate Case 7(b)(2) Resource Stack - Annual Investments and Savings

($ 000)

	Conser. Savings aMW[2,]		Amount Revenue Expensed	Amount Capitalized & Debt Financed	NET Annual Expenditures	Amort. Period[4] Years
1982 Conser.	32.4		4,974.0	61,940.0	66,914.0	20
1983 Conser.	68.6		2,907.0	204,092.0	206,999.0	20
1984 Conser.	16.6		8,311.0	66,783.0	75,094.0	20
1985 Conser.	17.0		24,680.0	103,067.0	127,747.0	20
1986 Conser.	23.5		5,256.0	99,743.0	104,999.0	20
1987 Conser.	17.2		3,928.0	71,631.0	75,559.0	20
1988 Conser.	15.6		6,654.0	58,570.0	65,224.0	20
1989 Conser.	20.8		12,917.0	46,069.0	58,986.0	20
1990 Conser.	13.2		35,796.0	36,220.0	72,016.0	20
1991 Conser.	19.0		37,557.0	45,714.0	83,271.0	20
1992 Conser.	37.4		63,943.0	62,151.0	126,094.0	20
1993 Conser.	59.6		55,253.0	96,717.0	151,970.0	20
1994 Conser.	51.3		52,350.0	121,242.0	173,592.0	20
1995 Conser.	65.9		46,657.0	85,252.0	131,909.0	20
1996 Conser.	56.3		48,937.0	52,274.0	101,211.0	20
1997 Conser.	54.7		25,279.0	32,953.0	58,232.0	20
1998 Conser.	33.4		30,188.0	26,331.0	56,519.0	20
1999 Conser.	30.3		20,657.0	19,728.0	40,385.0	20
2000 Conser.	14.7		15,377.0	347.0	15,724.0	20
2001 Conser.	18.5		19,905.0	57.0	19,962.0	20
2002 Conser.	25.7		17,143.0	28,227.0	45,370.0	15
2003 Conser.	24.7		17,286.0	22,900.0	40,186.0	15
2004 Conser.	31.0		15,821.0	19,431.0	35,252.0	15
Subtotals	747.4		571,776.0	1,361,439.0	1,933,215.0	
2005 Conser.	21.6		46,572.0	22,500.0	69,072.0	15
2006 Conser.	26.6		48,264.0	44,000.0	92,264.0	15
2007 Conser.	33.0		84,784.0	32,000.0	116,784.0	15
2008 Conser.	33.0		84,195.0	32,000.0	116,195.0	15
2009 Conser.	33.0		83,996.0	32,000.0	115,996.0	15
2010 Conser.	33.0		83,067.0	40,000.0	123,067.0	15
2011 Conser.	33.0		83,242.0	40,000.0	123,242.0	15
2012 Conser.	33.0		84,387.0	40,000.0	124,387.0	15
2013 Conser.	33.0		85,570.0	40,000.0	125,570.0	15
Subtotals	279.2		684,077.0	322,500.0	1,006,577.0	
Cumulative Savings 1982-2013	**1,026.6**	aMW	**$1,255,853.0**	**$1,683,939.0**	**$2,939,792.0**	
Cumulative Savings 1982-2006	**795.6**	aMW	**$666,612.0**	**$1,427,939.0**	**$2,094,551.0**	

2007 Wholesale Power Rate Case Final Proposal

SECTION 7(b)(2) RATE TEST STUDY DOCUMENTATION

July 2006

WP-07-FS-BPA-06A

This page intentionally left blank.

SECTION 7(b)(2) RATE TEST
TABLE OF CONTENTS

Page

This page intentionally left blank.

COMMONLY USED ACRONYMS

AC	Alternating Current
AEP	American Electric Power Company, Inc.
AER	Actual Energy Regulation
AFUDC	Allowance for Funds Used During Construction
AGC	Automatic Generation Control
aMW	Average Megawatt
Alcoa	Alcoa Inc.
AMNR	Accumulated Modified Net Revenues
ANR	Accumulated Net Revenues
AOP	Assured Operating Plan
ASC	Average System Cost
Avista	Avista Corporation
BASC	BPA Average System Cost
BiOp	Biological Opinion
BPA	Bonneville Power Administration
Btu	British thermal unit
C&R Discount	Conservation and Renewables Discount
CAISO	California Independent System Operator
CBFWA	Columbia Basin Fish & Wildlife Authority
CCCT	Combined-Cycle Combustion Turbine
CEC	California Energy Commission
CFAC	Columbia Falls Aluminum Company
Cfs	Cubic feet per second
CGS	Columbia Generating Station
COB	California-Oregon Border
COE	U.S. Army Corps of Engineers
Con Aug	Conservation Augmentation
C/M	Consumers / Mile of Line for Low Density Discount
ConMod	Conservation Modernization Program
COSA	Cost of Service Analysis
Council	Northwest Power Planning 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
CT	Combustion Turbine
CY	Calendar Year (Jan-Dec)
DC	Direct Current
DDC	Dividend Distribution Clause
DJ	Dow Jones
DOE	Department of Energy
DOP	Debt Optimization Program
DROD	Draft Record of Decision

DSI	Direct Service Industrial Customer or Direct Service Industry
ECC	Energy Content Curve
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.
Energy Northwest, Inc.	Formerly Washington Public Power Supply System (Nuclear)
EPA	Environmental Protection Agency
EPP	Environmentally Preferred Power
EQR	Electric Quarterly Report
ESA	Endangered Species Act
EWEB	Eugene Water & Electric Board
F&O	Financial and Operating Reports
FB CRAC	Financial-Based Cost Recovery Adjustment Clause
FBS	Federal Base System
FCCF	Fish Cost Contingency Fund
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FERC	Federal Energy Regulatory Commission
FERC SR	Federal Energy Regulatory Commission Special Rule
FELCC	Firm Energy Load Carrying Capability
Fifth Power Plan	Council's Fifth Northwest Conservation and Electric Power Plan
FPA	Federal Power Act
FPS	Firm Power Products and Services (rate)
FY	Fiscal Year (Oct-Sep)
GAAP	Generally Accepted Accounting Principles
GCPs	General Contract Provisions
GEP	Green Energy Premium
GI	Generation Integration
GSR	Generation Supplied Reactive and Voltage Control
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
ICNU	Industrial Customers of Northwest Utilities
ICUA	Idaho Consumer-Owned Utilities Association, Inc.
IOU	Investor-Owned Utility
IP	Industrial Firm Power (rate)
IP TAC	Industrial Firm Power Targeted Adjustment Charge
IPC	Idaho Power Company
ISO	Independent System Operator
JP	Joint Party

JP1	Cowlitz County Public Utility District, Northwest Requirements Utilities and Members, Western Public Agencies Group and Members, Public Power Council, Industrial Customers of Northwest Utilities
JP2	Grant County Public Utility District No. 2, Benton County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, Western Public Agencies Group and Members, Western Public Agencies Group and Members(Grays Harbor)
JP3	Benton County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, Western Public Agencies Group and Members (Grays Harbor)
JP4	Cowlitz County Public Utility District, Eugene Water & Electric Board, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, Grant County Public Utility District No. 2
JP5	Benton County Public Utility District, Cowlitz County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Northwest Requirements Utilities and Members, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, specified members of WA[1]
JP6	Avista Corporation, Idaho Power Corporation, PacifiCorp, Portland General Electric Company, Puget Sound Energy, Inc.
JP7	NONE
JP8	Northwest Energy Coalition, Save Our *Wild* Salmon
JP9	Alcoa, Inc., Industrial Customers of Northwest Utilities, Public Power Council, Northwest Requirements Utilities and Members, Pacific Northwest Generating Cooperative and Members, PacifiCorp, Western Public Agencies Group and Members, Avista Corporation, Portland General Electric Company
JP10	Alcoa, Inc., Cowlitz County Public Utility District, Industrial Customers of Northwest Utilities

[1] The members of Western Public Agencies Group and Members (WA) that are participating in the JP5 designation include: Benton REA, the cities of Ellensburg and Milton, the towns of Eatonville and Steilacoom, Washington, Alder Mutual Light Co., Elmhurst Mutual Power and Light Co., Lakeview Light and Power Co., Parkland Light and Water Co., Peninsula Light Co., the Public Utility Districts of Grays Harbor, Kittitas, Lewis and Mason Counties, the Public Utility District No. 3 of Mason County, and the Public Utility District No. 2 of Pacific County, Washington.

JP11	Cowlitz County Public Utility District, Eugene Water & Electric Board, Grant County Public Utilities District No. 2, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma
JP12	Alcoa, Inc., Industrial Customers of Northwest Utilities, Public Power Council, Western Public Agencies Group and Members, Northwest Requirements Utilities and Members, Pacific Northwest Generating Cooperative and Members
JP13	Columbia River Inter-Tribal Fish Commission, Confederated Tribes and Bands of the Yakama Nation, Nez Perce Tribe
JP14	Benton County Public Utility District, Cowlitz County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Industrial Customers of Northwest Utilities, Northwest Requirements Utilities and Members , Public Power Council, Seattle City Light, City of Tacoma, Western Public Agencies Group and Members, Springfield Utility Board, Pacific Northwest Generating Cooperative and Members
JP15	Calpine Corporation, Northwest Independent Power Producers Coalition, PPM Energy, Inc., TransAlta Centralia Generation, LLC
kAf	Thousand Acre Feet
kcfs	kilo (thousands) of cubic feet per second
ksfd	thousand second foot day
kV	Kilovolt (1000 volts)
kW	Kilowatt (1000 watts)
kWh	Kilowatt-hour
LB CRAC	Load-Based Cost Recovery Adjustment Clause
LCP	Least-Cost Plan
LDD	Low Density Discount
LLH	Light Load Hour
LOLP	Loss of Load Probability
m/kWh	Mills per kilowatt-hour
MAC	Market Access Coalition Group
MAf	Million Acre Feet
MCA	Marginal Cost Analysis
Mid-C	Mid-Columbia
MIP	Minimum Irrigation Pool
MMBTUMMBtu	Million British Thermal Units
MNR	Modified Net Revenues
MOA	Memorandum of Agreement
MOP	Minimum Operating Pool
MORC	Minimum Operating Reliability Criteria
MT	Market Transmission (rate)

MVAr	Mega Volt Ampere Reactive
MW	Megawatt (1 million watts)
MWh	Megawatt-hour
NCD	Non-coincidental Demand
NWEC	Northwest Energy Coalition
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Council
NF	Nonfirm Energy (rate)
NFB Adjustment	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp) Adjustment
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NOB	Nevada-Oregon Border
NORM	Non-Operating Risk Model
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPA	Northwest Power Act
NPCC	Northwest Power and Conservation Council
NPV	Net Present Value
NR	New Resource
NR (rate)	New Resource Firm Power (rate)
NRU	Northwest Requirements Utilities
NTSA	Non-Treaty Storage Agreement
NUG	Non-Utility Generation
NWPP	Northwest Power Pool
NWPPC	Northwest Power Planning Council
OATT	Open Access Transmission Tariff
O&M	Operation and Maintenance
OMB	Office of Management and Budget
OPUC	Oregon Public Utility Commission
ORC	Operating Reserves Credit
OY	Operating Year (Aug-Jul)
PA	Public Agency
PacifiCorp	PacifiCorp
PBL	Power Business Line
PDP	Proportional Draft Points
PF	Priority Firm Power (rate)
PFR	Power Function Review
PGE	Portland General Electric Company
PGP	Public Generating Pool
PMA	Power Marketing Agencies
PNCA	Pacific Northwest Coordination Agreement
PNGC	Pacific Northwest Generating Cooperative

PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration/Point of Interconnection
POM	Point of Metering
PPC	Public Power Council
PPLM	PP&L Montana, LLC
Project Act	Bonneville Project Act
PSA	Power Sales Agreement
PSC	Power Sales Contract
PSE	Puget Sound Energy
PSW	Pacific Southwest
PTP	Point-to-Point Transmission
PUD	Public or People's Utility District
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
Reclamation	Bureau of Reclamation
Renewable Northwest	Renewable Northwest Project
RD	Regional Dialogue
REP	Residential Exchange Program
RFP	Request for Proposal
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model
RL	Residential Load (rate)
RMS	Remote Metering System
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RTO	Regional Transmission Operator
SCCT	Single-Cycle Combustion Turbine
Slice	Slice of the System (product)
SME	Subject Matter Expert
SN CRAC	Safety-Net Cost Recovery Adjustment Clause
SOS	Save Our *Wild* Salmon
SUB	Springfield Utility Board
SUMY	Stepped-Up Multiyear
SWPA	Southwestern Power Administration
TAC	Targeted Adjustment Charge
TBL	Transmission Business Line
Tcf	Trillion Cubic Feet
TPP	Treasury Payment Probability
Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load
Tribes	Columbia River Inter-Tribal Fish Commission, Nez Perce, Yakama Nation, collectively
UAI Charge	Unauthorized Increase Charge
UAMPS	Utah Associated Municipal Power Systems

UDC	Utility Distribution Company
UP&L	Utah Power & Light
URC	Upper Rule Curve
USBR	U.S. Bureau of Reclamation
USFWS	U.S. Fish and Wildlife Service
VOR	Value of Reserves
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council (formally called WSCC)
WMG&T	Western Montana Electric Generating and Transmission Cooperative
WPAG	Western Public Agencies Group
WPRDS	Wholesale Power Rate Development Study
WSCC	Western Systems Coordination Council (now WECC)
WSPP	Western Systems Power Pool
WUTC	Washington Utilities and Transportation Commission
Yakama	Confederated Tribes and Bands of the Yakama Nation

This page intentionally left blank.

1. PROGRAM CASE RATES ANALYSIS MODEL

This page intentionally left blank.

DESCRIPTION OF RATEMAKING TABLES
7(b)(2) Rate Test Program Case

Sales_01 Forecast of Priority Firm Power (PF) Preference Gigawatthour (GWh) energy sales and peak kilowatt (kW)/mo. demand amounts for each month of the Rate Test Period Fiscal Year (FY) 2007-2013.

Sales_02 Forecast of PF Exchange GWh energy sales and peak kW/mo. demand amounts for each month of the Rate Test Period FY 2007-2013. (Note: While at the start of the 7(b)(2) Rate Test modeling there are data assuming the presence of "potential" exchangers shown in Table Exchange 01 below, after the iterative modeling process some of the "potential" exchangers have dropped out.)

Sales_03 Forecast of IP (industrial rate) GWh energy sales and peak kW/mo. demand amounts for each month of the Rate Test Period FY 2007-2013. (Note: No direct sale to the Direct Service Industry customers 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 0.001 aMW was used.)

Sales_04 Forecast of NR (industrial rate) GWh energy sales and peak kW/mo. demand amounts for each month of the Rate Test Period FY 2007-2013. (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 0.001 aMW was used.)

Exchange_01 Forecast of average residential exchange program (REP) loads and average system costs for those utilities that are the most likely to participate in the REP.

COSA_06 Itemized Revenue Requirements. Power Business Line (PBL) revenue requirements for each FY during the rate test period

COSA_07 Functionalization of Residential Exchange Costs. REP costs are functionalized to generation to comport with other functionalized moving through COSA into the Rate Design Step of the RAM.

COSA_08 Classified Revenue Requirement. Generation costs are classified between energy, demand, and load variance. All costs move through 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.

COSA_09 Functionalized Revenue Credits. 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.

DESCRIPTION OF RATEMAKING TABLES
7(b)(2) Rate Test Program Case

ALLOCATE 01 Energy Allocation Factors (EAF). 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.

ALLOCATE 02 Initial Rate Pool Cost Allocation. Table shows the initial allocation of the revenue requirement costs from the COSA to rate pools using the EAFs from table ALLOCATE 01.

RDS_11 Allocation of Secondary Revenues and Other Revenue Credits. 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.

RDS_17 Surplus Firm Power Revenues Surplus/(Deficiency). Table calculates the firm surplus sale revenue surplus/deficiency. 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.

RDS_19 Summary of Initial Allocations. 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 Preference rate pool.

RDS_21 7(C)(2) Delta Calculation and Allocation of 7(C)(2) Delta. 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.

RDS_23 IP Floor Rate Calculation. 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.

RDS_24 IP Floor Rate Test. 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.

RDS_50 PF Rate Schedule Charge Calculation. Table calculates unbifurcated PF rates. Marginal cost rates are scaled down to produce rates that recover costs allocated to PF energy. Example shown is for FY 2007.

Total PF Load Forecast FY2007-13

		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy GWh	aMW
2007	HLH	2890	3211	3537	3458	3041	3190	2809	2814	2883	2970	3013	2730	60840	6945
	LLH	1925	2141	2408	2281	2069	2117	1892	1872	1878	1974	1919	1818		
	Demand	8167	8932	9322	9285	9159	8507	7655	6959	7262	7540	7361	7083		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2008	HLH	2998	3289	3633	3540	3159	3222	2896	2870	2985	3067	3045	2816	61330	6982
	LLH	1855	2070	2294	2179	2039	2084	1821	1827	1942	1957	1963	1781		
	Demand	8647	9424	9807	9799	9737	8972	7999	7332	7723	7742	7582	7241		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2009	HLH	3042	3277	3715	3569	3125	3254	2928	2807	2984	3112	3072	2829	61568	7028
	LLH	1850	2124	2260	2199	2022	2099	1839	1833	1875	1990	1977	1786		
	Demand	8757	9567	9905	9932	9835	9087	8120	7298	7629	7898	7678	7302		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2010	HLH	3057	3296	3736	3548	3147	3310	2938	2886	3079	3067	3152	2857	62207	7101
	LLH	1855	2130	2266	2248	2025	2067	1849	1880	1932	2058	2025	1800		
	Demand	8837	9655	9999	10028	9930	9171	8192	7529	7899	7963	7731	7396		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2011	HLH	3047	3369	3763	3579	3173	3336	2963	2845	3021	3120	3160	2872	62327	7115
	LLH	1901	2097	2283	2261	2038	2079	1861	1849	1892	2042	1964	1813		
	Demand	8964	9748	10120	10151	10052	9281	8291	7450	7775	8071	7832	7471		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2012	HLH	3045	3383	3768	3564	3233	3348	2922	3030	3296	3201	3235	2866	63183	7213
	LLH	1896	2082	2277	2287	2072	2047	1896	1858	2025	2085	1948	1820		
	Demand	9189	10025	10374	10391	10376	9489	8485	8159	8204	8401	8142	7647		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2013	HLH	3095	3403	3743	3638	3196	3332	2983	2987	3202	3258	3260	2888	63286	7224
	LLH	1867	2086	2327	2258	2091	2100	1870	1828	2019	2066	1959	1830		
	Demand	9270	10113	10467	10514	10436	9598	8581	8068	8084	8488	8226	7729		

Total PF Exchange Load Forecast FY2007-13

		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy GWh	aMW
2007	HLH	1002	1140	1468	1622	1521	1422	1284	851	708	689	917	1126	21851	2494
	LLH	606	655	825	1064	965	859	734	534	385	389	458	626		
	Demand	3331	3525	4472	5072	4900	3576	3477	2385	2013	2296	2713	3319		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2008	HLH	1006	1143	1470	1619	1519	1421	1302	870	732	714	941	1146	22069	2519
	LLH	609	658	827	1063	964	858	746	546	400	405	472	638		
	Demand	3341	3532	4475	5061	4893	3573	3526	2435	2079	2374	2781	3374		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2009	HLH	1024	1160	1485	1641	1512	1450	1350	853	745	728	950	1151	22347	2551
	LLH	621	669	837	1079	960	877	775	536	408	414	478	642		
	Demand	3394	3583	4522	5129	4689	3646	3654	2389	2111	2414	2807	3389		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2010	HLH	1043	1180	1508	1651	1550	1460	1361	861	752	739	967	1162	22646	2585
	LLH	634	681	851	1085	985	884	782	541	412	421	488	648		
	Demand	3454	3644	4588	5158	4990	3671	3682	2409	2132	2449	2855	3419		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2011	HLH	1028	1192	1519	1658	1556	1458	1336	925	793	776	1011	1203	23013	2627
	LLH	626	689	858	1091	990	884	768	583	437	444	513	673		
	Demand	3405	3676	4617	5179	5018	3668	3616	2582	2243	2561	2978	3535		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2012	HLH	1068	1197	1506	1621	1513	1435	1309	972	870	856	1042	1171	23222	2651
	LLH	654	697	855	1068	964	873	756	617	487	496	536	659		
	Demand	3475	3649	4528	5013	4830	3589	3515	2676	2423	2751	3022	3406		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2013	HLH	1090	1222	1536	1658	1530	1469	1340	998	895	880	1068	1197	23743	2710
	LLH	668	712	872	1093	976	894	775	634	501	511	550	674		
	Demand	3545	3723	4617	5127	4705	3672	3605	2749	2493	2827	3095	3480		

Sales 03

Total IP Load Forecast FY2007-13

		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy GWh	aMW
2007	HLH	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.009	0.001
	LLH	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003		
	Demand	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2008	HLH	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.009	0.001
	LLH	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003		
	Demand	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2009	HLH	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.009	0.001
	LLH	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003		
	Demand	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2010	HLH	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.009	0.001
	LLH	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003		
	Demand	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2011	HLH	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.009	0.001
	LLH	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003		
	Demand	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2012	HLH	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.009	0.001
	LLH	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003		
	Demand	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2013	HLH	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.009	0.001
	LLH	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003		
	Demand	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010		

Total NR Load Forecast FY2007-13

		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy GWh	aMW
2007	HLH	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.009	0.001
	LLH	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003		
	Demand	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2008	HLH	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.009	0.001
	LLH	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003		
	Demand	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2009	HLH	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.009	0.001
	LLH	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003		
	Demand	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2010	HLH	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.009	0.001
	LLH	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003		
	Demand	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2011	HLH	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.009	0.001
	LLH	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003		
	Demand	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2012	HLH	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.009	0.001
	LLH	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003		
	Demand	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010		
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2013	HLH	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.009	0.001
	LLH	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003		
	Demand	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010		

Forecast for Traditional Reseidential Exchange Program

Potential Exchanger	Average 07-9 ASC ($/MWh)		Average 07-9 Exchange Load (aMW)
Utility #3	$	63.09	65
Northwester Energy PNWR	$	62.87	132
Puget Sound Energy	$	51.94	1282
Portland General	$	51.89	1041
Utility #5	$	49.81	392
Utilty #2	$	49.55	32
Clark County PUD	$	48.42	288
Avista	$	47.73	479
Pacificorp	$	47.01	1227
Utility #4	$	46.08	37
Utility #1	$	43.92	76
Idaho Power	$	42.49	836

COST OF SERVICE ANALYSIS
Itemized Revenue Requirement
FY 2007

($ 000)

	A	B	C	D	E
	INVEST BASE	**NET INT**	**NET REVS**	**OPER EXP**	**TOTAL (B+C+D)**
1. GENERATION COSTS					
2. FEDERAL BASE SYSTEM					
3. HYDRO	4,955,805	136,816	60,793	370,385	567,994
4. BPA FISH & WILDLIFE PROGRAM	140,228	3,871	1,720	171,903	177,494
5. TROJAN				14,005	14,005
6. WNP #1				148,141	148,141
7. WNP #2				459,359	459,359
8. WNP #3				151,724	151,724
9. SYSTEM AUGMENTATION				169,090	169,090
10. BALANCING POWER PURCHASES				54,017	54,017
11. TOTAL FEDERAL BASE SYSTEM	5,096,033	140,687	62,513	1,538,624	1,741,824
12. NEW RESOURCES					
13. IDAHO FALLS				0	0
14. COWLITZ FALLS				14,089	14,089
15. OTHER NEW RESOURCES PURCHASES				46,764	46,764
16. TOTAL NEW RESOURCES				60,853	60,853
17. RESIDENTIAL EXCHANGE				1,153,300	1,153,300
18. CONSERVATION		21,184	9,413	151,430	182,027
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	43,785	1,209	537	182,192	183,938
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	43,785	1,209	537	182,192	183,938
23. TOTAL GENERATION COSTS	5,139,818	163,080	72,463	3,086,399	3,321,942
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				124,614	124,614
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,300	1,300
27. GENERAL TRANSFER AGREEMENTS				47,000	47,000
28. TOTAL TRANSMISSION COSTS				172,914	172,914
29. TOTAL PBL REVENUE REQUIREMENT		163,080	72,463	3,259,313	3,494,856

COST OF SERVICE ANALYSIS
Itemized Revenue Requirement
FY 2008

($ 000)

	A	B	C	D	E
	INVEST BASE	NET INT	NET REVS	OPER EXP	TOTAL (B+C+D)
1. GENERATION COSTS					
2. FEDERAL BASE SYSTEM					
3. HYDRO	4,971,786	145,229	31,126	380,709	557,064
4. BPA FISH & WILDLIFE PROGRAM	156,170	4,562	978	173,574	179,114
5. TROJAN				12,588	12,588
6. WNP #1				166,116	166,116
7. WNP #2				406,544	406,544
8. WNP #3				160,092	160,092
9. SYSTEM AUGMENTATION				118,024	118,024
10. BALANCING POWER PURCHASES				64,693	64,693
11. TOTAL FEDERAL BASE SYSTEM	5,127,956	149,791	32,104	1,482,340	1,664,235
12. NEW RESOURCES					
13. IDAHO FALLS				0	0
14. COWLITZ FALLS				14,078	14,078
15. OTHER NEW RESOURCES PURCHASES				53,147	53,147
16. TOTAL NEW RESOURCES				67,225	67,225
17. RESIDENTIAL EXCHANGE				1,164,782	1,164,782
18. CONSERVATION		22,354	4,791	154,173	181,318
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	35,876	1,048	224	184,374	185,647
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	35,876	1,048	224	184,374	185,647
23. TOTAL GENERATION COSTS	5,163,832	173,193	37,119	3,052,894	3,263,206
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				126,877	126,877
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,300	1,300
27. GENERAL TRANSFER AGREEMENTS				47,000	47,000
28. TOTAL TRANSMISSION COSTS				175,177	175,177
29. TOTAL PBL REVENUE REQUIREMENT		173,193	37,119	3,228,071	3,438,383

COST OF SERVICE ANALYSIS
Itemized Revenue Requirement
FY 2009

($ 000)

	A	B	C	D	E
	INVEST BASE	**NET INT**	**NET REVS**	**OPER EXP**	**TOTAL (B+C+D)**
1. GENERATION COSTS					
2. FEDERAL BASE SYSTEM					
3. HYDRO	5,028,112	153,037	38,543	391,777	583,357
4. BPA FISH & WILDLIFE PROGRAM	170,827	5,199	1,309	174,856	181,364
5. TROJAN				3,100	3,100
6. WNP #1				163,482	163,482
7. WNP #2				461,669	461,669
8. WNP #3				153,030	153,030
9. SYSTEM AUGMENTATION				169,926	169,926
10. BALANCING POWER PURCHASES				61,570	61,570
11. TOTAL FEDERAL BASE SYSTEM	5,198,939	158,236	39,852	1,579,409	1,777,497
12. NEW RESOURCES					
13. IDAHO FALLS				0	0
14. COWLITZ FALLS				14,089	14,089
15. OTHER NEW RESOURCES PURCHASES				60,110	60,110
16. TOTAL NEW RESOURCES				74,199	74,199
17. RESIDENTIAL EXCHANGE				1,179,360	1,179,360
18. CONSERVATION		23,893	6,018	157,908	187,819
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	26,604	811	204	194,603	195,618
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	26,604	811	204	194,603	195,618
23. TOTAL GENERATION COSTS	5,225,543	182,940	46,074	3,185,479	3,414,493
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				131,515	131,515
26. 3RD PARTY TRANS/ANCILLARY SERVICES				3,000	3,000
27. GENERAL TRANSFER AGREEMENTS				48,000	48,000
28. TOTAL TRANSMISSION COSTS				182,515	182,515
29. TOTAL PBL REVENUE REQUIREMENT		182,940	46,074	3,367,994	3,597,008

COST OF SERVICE ANALYSIS
Itemized Revenue Requirement
FY 2010

($ 000)

	A	B	C	D	E
	INVEST BASE	NET INT	NET REVS	OPER EXP	TOTAL (B+C+D)
1. GENERATION COSTS					
2. FEDERAL BASE SYSTEM					
3. HYDRO	5,111,893	155,360	30,479	404,086	589,925
4. BPA FISH & WILDLIFE PROGRAM	184,568	5,609	1,100	171,224	177,933
5. TROJAN				1,700	1,700
6. WNP #1				159,459	159,459
7. WNP #2				432,093	432,093
8. WNP #3				142,783	142,783
9. SYSTEM AUGMENTATION				0	0
10. BALANCING POWER PURCHASES				61,570	61,570
11. TOTAL FEDERAL BASE SYSTEM	5,296,461	160,969	31,579	1,372,914	1,565,462
12. NEW RESOURCES					
13. IDAHO FALLS				0	0
14. COWLITZ FALLS				14,110	14,110
15. OTHER NEW RESOURCES PURCHASES				81,035	81,035
16. TOTAL NEW RESOURCES				95,145	95,145
17. RESIDENTIAL EXCHANGE				1,262,701	1,262,701
18. CONSERVATION		24,817	4,868	165,478	195,163
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	16,581	505	99	192,866	193,469
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	16,581	505	99	192,866	193,469
23. TOTAL GENERATION COSTS	5,313,042	186,291	36,546	3,089,104	3,311,940
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				135,069	135,069
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,120	1,120
27. GENERAL TRANSFER AGREEMENTS				56,600	56,600
28. TOTAL TRANSMISSION COSTS				192,789	192,789
29. TOTAL PBL REVENUE REQUIREMENT		186,291	36,546	3,281,892	3,504,729

COST OF SERVICE ANALYSIS
Itemized Revenue Requirement
FY 2011

($ 000)

	A	B	C	D	E
	INVEST BASE	NET INT	NET REVS	OPER EXP	TOTAL (B+C+D)
1. GENERATION COSTS					
2. FEDERAL BASE SYSTEM					
3. HYDRO	5,156,309	161,785	23,931	414,565	600,281
4. BPA FISH & WILDLIFE PROGRAM	197,616	6,200	917	172,125	179,242
5. TROJAN				1,700	1,700
6. WNP #1				161,661	161,661
7. WNP #2				458,629	458,629
8. WNP #3				168,250	168,250
9. SYSTEM AUGMENTATION				0	0
10. BALANCING POWER PURCHASES				61,570	61,570
11. TOTAL FEDERAL BASE SYSTEM	5,353,925	167,985	24,848	1,438,500	1,631,333
12. NEW RESOURCES					
13. IDAHO FALLS				0	0
14. COWLITZ FALLS				14,163	14,163
15. OTHER NEW RESOURCES PURCHASES				82,321	82,321
16. TOTAL NEW RESOURCES				96,484	96,484
17. RESIDENTIAL EXCHANGE				1,282,992	1,282,992
18. CONSERVATION		25,127	3,717	162,934	191,778
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	8,422	265	39	190,918	191,222
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	8,422	265	39	190,918	191,222
23. TOTAL GENERATION COSTS	5,362,347	193,377	28,604	3,171,827	3,393,809
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				138,519	138,519
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,150	1,150
27. GENERAL TRANSFER AGREEMENTS				57,800	57,800
28. TOTAL TRANSMISSION COSTS				197,469	197,469
29. TOTAL PBL REVENUE REQUIREMENT		193,377	28,604	3,369,297	3,591,278

COST OF SERVICE ANALYSIS
Itemized Revenue Requirement
FY 2012

($ 000)

	A	B	C	D	E
	INVEST BASE	NET INT	NET REVS	OPER EXP	TOTAL (B+C+D)
1. GENERATION COSTS					
2. FEDERAL BASE SYSTEM					
3. HYDRO	5,253,437	169,619	0	425,954	595,573
4. BPA FISH & WILDLIFE PROGRAM	210,353	6,792	0	176,563	183,355
5. TROJAN				1,751	1,751
6. WNP #1				187,660	187,660
7. WNP #2				504,117	504,117
8. WNP #3				161,778	161,778
9. SYSTEM AUGMENTATION				0	0
10. BALANCING POWER PURCHASES				61,570	61,570
11. TOTAL FEDERAL BASE SYSTEM	5,463,790	176,411	0	1,519,393	1,695,804
12. NEW RESOURCES					
13. IDAHO FALLS				0	0
14. COWLITZ FALLS				14,216	14,216
15. OTHER NEW RESOURCES PURCHASES				83,575	83,575
16. TOTAL NEW RESOURCES				97,791	97,791
17. RESIDENTIAL EXCHANGE				1,353,529	1,353,529
18. CONSERVATION		23,408	0	159,522	182,930
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	5,448	176	0	129,521	129,697
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	5,448	176	0	129,521	129,697
23. TOTAL GENERATION COSTS	5,469,238	199,995	0	3,259,756	3,459,751
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				142,245	142,245
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,185	1,185
27. GENERAL TRANSFER AGREEMENTS				59,534	59,534
28. TOTAL TRANSMISSION COSTS				202,963	202,963
29. TOTAL PBL REVENUE REQUIREMENT		199,995	0	3,462,719	3,662,714

COST OF SERVICE ANALYSIS
Itemized Revenue Requirement
FY 2013

($ 000)

	A INVEST BASE	B NET INT	C NET REVS	D OPER EXP	E TOTAL (B+C+D)
1. GENERATION COSTS					
2. FEDERAL BASE SYSTEM					
3. HYDRO	5,399,067	181,120	36,512	438,787	656,419
4. BPA FISH & WILDLIFE PROGRAM	222,686	7,470	1,506	182,002	190,978
5. TROJAN				1,804	1,804
6. WNP #1				283,394	283,394
7. WNP #2				376,259	376,259
8. WNP #3				176,703	176,703
9. SYSTEM AUGMENTATION				0	0
10. BALANCING POWER PURCHASES				61,570	61,570
11. TOTAL FEDERAL BASE SYSTEM	5,621,753	188,590	38,018	1,520,517	1,747,125
12. NEW RESOURCES					
13. IDAHO FALLS				0	0
14. COWLITZ FALLS				14,262	14,262
15. OTHER NEW RESOURCES PURCHASES				84,836	84,836
16. TOTAL NEW RESOURCES				99,098	99,098
17. RESIDENTIAL EXCHANGE				1,383,604	1,383,604
18. CONSERVATION		23,233	4,684	159,192	187,109
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	5,355	180	36	133,069	133,285
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	5,355	180	36	133,069	133,285
23. TOTAL GENERATION COSTS	5,627,108	212,003	42,738	3,295,480	3,550,221
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				145,978	145,978
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,220	1,220
27. GENERAL TRANSFER AGREEMENTS				61,320	61,320
28. TOTAL TRANSMISSION COSTS				208,518	208,518
29. TOTAL PBL REVENUE REQUIREMENT		212,003	42,738	3,503,998	3,758,739

COSA 07

Functionalization of Residential Exchange Costs

Fiscal Year 2007

($ 000)

Gross Residential Exchange Cost	$ 1,153,300
Residential Exchange Transmission	$ 85,218
Functionalized Residential Exchange Costs	$ 1,068,082

COSA 08

COST OF SERVICE ANALYSIS
Classified Revenue Requirement

	Total Revenue Requirement	Energy Percent	Energy Total	Demand Percent	Demand Total	Load Variance Percent	Load Variance Total
1. GENERATION COSTS							
2. FEDERAL BASE SYSTEM							
3. HYDRO	$ 567,994	92.91%	$ 527,736	6.19%	$ 35,141	0.90%	$ 5,117
4. BPA FISH & WILDLIFE PROGRAM	$ 177,494	93.81%	$ 166,512	6.19%	$ 10,981		
5. TROJAN	$ 14,005	93.81%	$ 13,139	6.19%	$ 866		
6. WNP #1	$ 148,141	93.81%	$ 138,976	6.19%	$ 9,165		
7. WNP #2	$ 459,359	92.91%	$ 426,801	6.19%	$ 28,420	0.90%	$ 4,138
8. WNP #3	$ 151,724	93.81%	$ 142,337	6.19%	$ 9,387		
9. SYSTEM AUGMENTATION	$ 169,090	92.91%	$ 157,105	6.19%	$ 10,461	0.90%	$ 1,523
10. BALANCING POWER PURCHASES	$ 54,017	92.91%	$ 50,188	6.19%	$ 3,342	0.90%	$ 487
11. TOTAL FEDERAL BASE SYSTEM	$ 1,741,824		$ 1,622,793		$ 107,764		$ 11,266
12. NEW RESOURCES							
13. IDAHO FALLS	$ -				$ -		$ -
14. COWLITZ FALLS	$ 14,089	92.91%	$ 13,090	6.19%	$ 872	0.90%	$ 127
15. OTHER NEW RESOURCES PURCHASES	$ 46,764	92.91%	$ 43,449	6.19%	$ 2,893	0.90%	$ 421
16. TOTAL NEW RESOURCES	$ 60,853		$ 56,540		$ 3,765		$ 548
17. RESIDENTIAL EXCHANGE	$ 1,068,082	100.00%	$ 1,068,082				
18. CONSERVATION	$ 182,027	93.81%	$ 170,765	6.19%	$ 11,262		
19. OTHER GENERATION COSTS							
20. BPA PROGRAMS	$ 183,938	92.91%	$ 170,901	6.19%	$ 11,380	0.90%	$ 1,657
21. WNP #3 PLANT	$ -				$ -		
22. TOTAL OTHER GENERATION COSTS	$ 183,938		$ 170,901		$ 11,380		$ 1,657
23. TOTAL GENERATION COSTS	$ 3,236,723		$ 3,089,081		$ 134,171		$ 13,471
			$ -		$ -		$ -
24. TRANSMISSION COSTS							
25. TBL TRANSMISSION/ANCILLARY SERVICES	124,614	100.00%	$ 124,614				
26. 3RD PARTY TRANS/ANCILLARY SERVICES	1,300	100.00%	$ 1,300				
27. GENERAL TRANSFER AGREEMENTS	47,000	100.00%	$ 47,000				
28. TOTAL TRANSMISSION COSTS	172,914		172,914				
29. TOTAL PBL REVENUE REQUIREMENT	$ 3,409,637		$ 3,261,995		$ 147,642		

COST OF SERVICE ANALYSIS
Revenue Credits
Test Period October 2006 - September 2013

($ 000)

	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Colville Credit	$ 4,600	$ 4,600	$ 4,600	$ 4,600	$ 4,600	$ 4,600	$ 4,600
'4(h)(10)(c)	$ 84,707	$ 84,927	$ 84,676	$ 84,676	$ 84,676	$ 84,676	$ 84,676
Ancillary and Reserve Service Revs.	$ 73,131	$ 61,970	$ 62,715	$ 62,715	$ 62,715	$ 62,715	$ 62,715
Energy Efficiency & Misc. Revenues	$ 16,305	$ 16,328	$ 16,353	$ 16,220	$ 16,220	$ 16,220	$ 16,220
Reserve Product Revenue	$ 3,000	$ 3,300	$ 3,630	$ 3,630	$ 3,630	$ 3,630	$ 3,630
Downstream Benefits & Storage	$ 8,921	$ 8,921	$ 8,921	$ 8,921	$ 8,921	$ 8,921	$ 8,921
Green Tags	$ 1,079	$ 1,082	$ 1,082	$ 2,128	$ 2,128	$ 2,128	$ 2,128
Aluminum Hedging	$ 875	$ -	$ -	$ -	$ -	$ -	$ -
TOTALS	$ 192,618	$ 181,129	$ 181,977	$ 182,891	$ 182,891	$ 182,891	$ 182,891

Energy Allocation Factors With Residential Exchange Exchange
Average Megawatts

	2007	2008	2009	2010	2011	2012	2013
Federal Base System							
Total Usage							
Priority Firm...............................	9,714	9,770	9,857	9,967	10,025	10,122	10,223
Industrial Firm............................	0	0	0	0	0	0	0
New Resource Firm....................	0	0	0	0	0	0	0
Surplus Firm Other.....................	1,369	1,359	1,330	1,408	1,361	962	950
Total...	11,082	11,129	11,187	11,375	11,386	11,084	11,173
Federal Base System	0	0	0	0	0	0	0
Priority Firm...............................	8,518	8,550	8,566	8,717	8,685	8,370	8,388
Industrial Firm............................	0	0	0	0	0	0	0
New Resource Firm....................	0	0	0	0	0	0	0
Surplus Firm Other.....................	0	0	0	0	0	0	0
Total...	8,518	8,550	8,566	8,717	8,685	8,370	8,388
Residential Exchange	0	0	0	0	0	0	0
Priority Firm...............................	1,195	1,220	1,292	1,250	1,339	1,752	1,836
Industrial Firm............................	0	0	0	0	0	0	0
New Resource Firm....................	0	0	0	0	0	0	0
Surplus Firm Other.....................	1,372	1,365	1,333	1,410	1,364	969	953
Total...	2,567	2,585	2,625	2,660	2,703	2,720	2,789
New Resource	0	0	0	0	0	0	0
Priority Firm...............................	0	0	0	0	0	0	0
Industrial Firm............................	0	0	0	0	0	0	0
New Resource Firm....................	0	0	0	0	0	0	0
Surplus Firm Other.....................	0	0	0	0	0	0	0
Total...	0	0	0	0	0	0	0
Conservation	0	0	0	0	0	0	0
Priority Firm...............................	9,714	9,770	9,857	9,967	10,025	10,122	10,223
Industrial Firm............................	0	0	0	0	0	0	0
New Resource Firm....................	0	0	0	0	0	0	0
Surplus Firm Other.....................	1,369	1,359	1,330	1,408	1,361	962	950
Total...	11,082	11,129	11,187	11,375	11,386	11,084	11,173

Initial Rate Pool Allocation

($ 000)

	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
CLASSES OF SERVICE:							
Power Rates							
Priority Firm - Preference							
FBS	$ 1,741,824	$ 1,664,235	$ 1,777,497	$ 1,686,280	$ 1,805,095	$ 1,743,527	$ 1,858,566
NR	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Exchange	$ 497,331.2	$ 509,190.2	$ 537,405.3	$ 552,039.4	$ 591,179.0	$ 813,272.6	$ 849,648.9
conservation	$ 159,548	$ 159,173	$ 165,490	$ 171,012	$ 168,854	$ 167,053	$ 171,199
BPA programs	$ 312,784	$ 316,755	$ 333,179	$ 338,459	$ 342,229	$ 303,788	$ 312,740
Total	$ 2,711,486	$ 2,649,353	$ 2,813,571	$ 2,747,790	$ 2,907,357	$ 3,027,640	$ 3,192,153
Industrial Firm Power							
FBS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NR	$ 0.0	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1
Exchange	$ 0.4	$ 0.4	$ 0.4	$ 0.5	$ 0.5	$ 0.5	$ 0.5
conservation	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0
BPA programs	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0
Total	$ 0.5	$ 0.5	$ 0.5	$ 0.6	$ 0.6	$ 0.6	$ 0.6
New Resources Firm							
FBS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NR	$ 0.0	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1
Exchange	$ 0.4	$ 0.4	$ 0.4	$ 0.5	$ 0.5	$ 0.5	$ 0.5
conservation	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0
BPA programs	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0
Total	$ 0.5	$ 0.5	$ 0.5	$ 0.6	$ 0.6	$ 0.6	$ 0.6
Surplus Firm Power							
FBS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NR	$ 60,853	$ 67,225	$ 74,199	$ 95,145	$ 96,484	$ 97,791	$ 99,098
Exchange	$ 570,750	$ 569,521	$ 554,801	$ 622,341	$ 602,062	$ 449,691	$ 441,357
conservation	$ 22,479	$ 22,145	$ 22,329	$ 24,151	$ 22,924	$ 15,877	$ 15,910
BPA programs	$ 44,069	$ 44,069	$ 44,954	$ 47,799	$ 46,462	$ 28,872	$ 29,064
Total	$ 698,150	$ 702,960	$ 696,282	$ 789,436	$ 767,932	$ 592,231	$ 585,429
Total Revenue Requirement	$ 3,409,637	$ 3,352,314	$ 3,509,855	$ 3,537,228	$ 3,675,290	$ 3,619,873	$ 3,777,583

Rate Design Study
Allocation of Secondary and other Revenues
Test Period October 2006 - September 2013

($ 000)

	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Forecast of Secondary Revenues	**$ 600,634**	**$ 582,252**	**$ 566,351**	**$ 566,351**	**$ 566,351**	**$ 566,351**	**$ 566,351**
Additional Secondary Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Gross Secondary Revenues	**$ 600,634**	**$ 582,252**	**$ 566,351**	**$ 566,351**	**$ 566,351**	**$ 566,351**	**$ 566,351**

Allocation of Secondary Revenues Credit							
Priority Firm...	$ (600,634)	$ (582,252)	$ (566,351)	$ (566,351)	$ (566,351)	$ (566,351)	$ (566,351)
Industrial Firm..	$ -	$ -	$ -	$ -	$ -	$ -	$ -
New Resource Firm..	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Surplus Firm Other...	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total..	**$ (600,634)**	**$ (582,252)**	**$ (566,351)**	**$ (566,351)**	**$ (566,351)**	**$ (566,351)**	**$ (566,351)**

Total Other Revenue Credits	**$ 192,618**	**$ 181,129**	**$ 181,977**	**$ 182,891**	**$ 182,891**	**$ 182,891**	**$ 182,891**

Allocation of Other Revenue Credits							
Priority Firm...	$ (192,618)	$ (181,129)	$ (181,977)	$ (182,891)	$ (182,891)	$ (182,891)	$ (182,891)
Industrial Firm..	$ -	$ -	$ -	$ -	$ -	$ -	$ -
New Resource Firm..	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Surplus Firm Other...	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total..	**$ (192,618)**	**$ (181,129)**	**$ (181,977)**	**$ (182,891)**	**$ (182,891)**	**$ (182,891)**	**$ (182,891)**

Rate Design Study
Calculation of FPS (Surplus)/Shortfall
Test Period October 2006 - September 2013

($ 000)

FPS (Surplus)/Shortfall	**FY 2007**	**FY 2008**	**FY 2009**	**FY 2010**	**FY 2011**	**FY 2012**	**FY 2013**
Costs allocated to FPS contract sales	$ 698,150	$ 702,960	$ 696,282	$ 789,436	$ 767,932	$ 592,231	$ 585,429
Expected Revenue from FPS contract sales	$ (69,044)	$ (69,187)	$ (69,044)	$ (69,044)	$ (64,625)	$ (25,283)	$ (25,283)
FPS Pre-Sub Contract Revenue	$ (46,561)	$ (47,781)	$ (41,101)	$ (40,660)	$ (39,784)	$ (5,300)	$ (5,300)
(Surplus)/Shortfall	**$ 582,546**	**$ 585,992**	**$ 586,137**	**$ 679,733**	**$ 663,524**	**$ 561,649**	**$ 554,846**
Secondary Revenues allocated to FPS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Revenue Credits allocated to FPS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
FPS (Surplus)/Shortfall	**$ 582,546**	**$ 585,992**	**$ 586,137**	**$ 679,733**	**$ 663,524**	**$ 561,649**	**$ 554,846**

Rate Design Study
Allocation of FPS (Surplus)/Shortfall
Test Period October 2006 - September 2009

Allocation of FPS (Surplus)/Shortfall							
Priority Firm..	$ 582,546	$ 585,992	$ 586,137	$ 679,733	$ 663,524	$ 561,649	$ 554,846
Industrial Firm..	$ -	$ -	$ -	$ -	$ -	$ -	$ -
New Resource Firm..	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Surplus Firm Other...	$ (582,546)	$ (585,992)	$ (586,137)	$ (679,733)	$ (663,524)	$ (561,649)	$ (554,846)
Total..	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Rate Design Study
Summary of Initial Allocations
Test Period October 2006 - September 2013

($ 000)

	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Allocation of Revenue Requirement							
Priority Firm..	$ 2,711,486	$ 2,649,353	$ 2,813,571	$ 2,747,790	$ 2,907,357	$ 3,027,640	$ 3,192,153
Industrial Firm..	$ 0.52	$ 0.53	$ 0.54	$ 0.58	$ 0.58	$ 0.63	$ 0.63
New Resource Firm..	$ 0.52	$ 0.53	$ 0.54	$ 0.58	$ 0.58	$ 0.63	$ 0.63
Surplus Firm Other...	$ 698,150	$ 702,960	$ 696,282	$ 789,436	$ 767,932	$ 592,231	$ 585,429
Total..	$ 3,409,637	$ 3,352,314	$ 3,509,855	$ 3,537,228	$ 3,675,290	$ 3,619,873	$ 3,777,583
Allocation of Secondary Revenues Credit							
Priority Firm..	$ (600,634)	$ (582,252)	$ (566,351)	$ (566,351)	$ (566,351)	$ (566,351)	$ (566,351)
Industrial Firm..	$ -	$ -	$ -	$ -	$ -	$ -	$ -
New Resource Firm..	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Surplus Firm Other...	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total..	$ (600,634)	$ (582,252)	$ (566,351)	$ (566,351)	$ (566,351)	$ (566,351)	$ (566,351)
Allocation of other Revenues Credits							
Priority Firm..	$ (192,618)	$ (181,129)	$ (181,977)	$ (182,891)	$ (182,891)	$ (182,891)	$ (182,891)
Industrial Firm..	$ -	$ -	$ -	$ -	$ -	$ -	$ -
New Resource Firm..	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Surplus Firm Other...	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total..	$ (192,618)	$ (181,129)	$ (181,977)	$ (182,891)	$ (182,891)	$ (182,891)	$ (182,891)
Allocation of FPS (Surplus)/Shortfall							
Priority Firm..	$ 582,546	$ 585,992	$ 586,137	$ 679,733	$ 663,524	$ 561,649	$ 554,846
Industrial Firm..	$ -	$ -	$ -	$ -	$ -	$ -	$ -
New Resource Firm..	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Surplus Firm Other...	$ (582,546)	$ (585,992)	$ (586,137)	$ (679,733)	$ (663,524)	$ (561,649)	$ (554,846)
Total..	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Low Density Discount							
Priority Firm..	$ 22,289	$ 22,612	$ 22,853	$ 22,853	$ 22,853	$ 22,853	$ 22,853
Irrigation Rate Mitigation.................................							
Priority Firm..	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
Initial Allocation							
Priority Firm..	$ 2,533,069	$ 2,504,576	$ 2,684,233	$ 2,711,134	$ 2,854,492	$ 2,872,900	$ 3,030,610
Industrial Firm..	$ 0.52	$ 0.53	$ 0.54	$ 0.58	$ 0.58	$ 0.63	$ 0.63
New Resource Firm..	$ 0.52	$ 0.53	$ 0.54	$ 0.58	$ 0.58	$ 0.63	$ 0.63
Surplus Firm Other...	$ 115,604	$ 116,968	$ 110,145	$ 109,703	$ 104,408	$ 30,583	$ 30,583
Total..	$ 2,648,674	$ 2,621,545	$ 2,794,379	$ 2,820,839	$ 2,958,901	$ 2,903,484	$ 3,061,194

Rate Design Study
7(c)(2) Delta Calculation
Test Period October 2006 - September 2013

($ 000)

	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
IP Allocated Costs	$ 0.5	$ 0.5	$ 0.5	$ 0.6	$ 0.6	$ 0.6	$ 0.6
IP Revenues @ Net Margin	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0
adjustment	$ (0.0)	$ (0.0)	$ (0.0)	$ (0.0)	$ (0.0)	$ (0.0)	$ (0.0)
IP Marginal Cost Rate Revenues	$ 0.5	$ 0.5	$ 0.5	$ 0.5	$ 0.5	$ 0.5	$ 0.5
PF Marginal Cost Rate Revenues	$ 4,512,192	$ 4,559,432	$ 4,590,838	$ 4,639,804	$ 4,670,049	$ 4,718,817	$ 4,756,096
PF Allocated Energy Costs	$ 2,533,069	$ 2,504,576	$ 2,684,233	$ 2,711,134	$ 2,854,492	$ 2,872,900	$ 3,030,610
Numerator: 1-2-3-((4/5)*6)	0.3	0.3	0.3	0.3	0.3	0.3	0.3
PF Allocation Factor for Delta	9,714	9,770	9,857	9,967	10,025	10,122	10,223
NR Allocation Factor for Delta	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Total Allocation Factors for Delta	9,714	9,770	9,857	9,967	10,025	10,122	10,223
Denominator: 1.0 + ((9/11)*(4/5))	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
DELTA: (7/12)	**0.26**	**0.28**	**0.27**	**0.31**	**0.30**	**0.35**	**0.34**

Rate Design Study
7(c)(2) Delta allocation
Test Period October 2006 - September 2009

IP-PF Linc Allocation..................							
Priority Firm....................................	$ 0.3	$ 0.3	$ 0.3	$ 0.3	$ 0.3	$ 0.3	$ 0.3
Industrial Firm.................................	$ (0.3)	$ (0.3)	$ (0.3)	$ (0.3)	$ (0.3)	$ (0.3)	$ (0.3)
New Resource Firm.........................	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0
Surplus Firm Other..........................	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total..	$ 0.00	$ 0.00	$ 0.00	$ (0.00)	$ (0.00)	$ (0.00)	$ (0.00)

Allocation after Linc.....................							
Priority Firm Preference..................	$ 1,863,711	$ 1,841,813	$ 1,969,407	$ 1,987,571	$ 2,084,750	$ 2,100,799	$ 2,203,811
Priority Firm Exchange...................	$ 669,358	$ 662,764	$ 714,826	$ 723,563	$ 769,742	$ 772,102	$ 826,800
Industrial Firm.................................	$ 0.3	$ 0.3	$ 0.3	$ 0.3	$ 0.3	$ 0.3	$ 0.3
New Resource Firm.........................	$ 0.5	$ 0.5	$ 0.5	$ 0.6	$ 0.6	$ 0.6	$ 0.6
Surplus Firm Other..........................	$ 115,604	$ 116,968	$ 110,145	$ 109,703	$ 104,408	$ 30,583	$ 30,583
Total..	$ 2,648,674	$ 2,621,545	$ 2,794,379	$ 2,820,839	$ 2,958,901	$ 2,903,484	$ 3,061,194

RATE DESIGN STUDY
Industrial Firm Power Floor Rate Calculation
Test Period October 2006 - September 2009

($ 000)

		A	B	C	D	E	F
		DEMAND		**ENERGY**		**Customer**	**Total/**
		Winter	**Summer**	**Winter**	**Summer**	**Charge**	**Average**
		(Dec-Apr)	(May-Nov)	(Sep-Mar)	(Apr-Aug)		
1	IP Billing Determinants	0.015	0.021	0.015	0.011	0.036	0.026
2	IP-83 Rates	4.62	2.21	14.70	12.20	7.34	
3	Revenue	0.069	0.046	0.225	0.134	0.264	0.739
4							
5	Exchange Adj Clause for OY 1985						
6	New ASC Effective Jul 1, 1984						
7	Actual Total Exchange Cost (AEC)	938,442					
8	Actual Exchange Revenue (AER)	772,029					
9	Forecasted Exchange Cost (FEC)	1,088,690					
10	Forecasted Exchange Revenue (FER)	809,201					
11	Total Under/Over-recovery (TAR)						
12	(TAR=(AEC-AER)-(FEC-FER))	(113,076)					
13	Exchange Cost Percentage for IP (ECP)	0.521					
14	Rebate or Surcharge for IP (CCEA=TAR*ECP)	(58,913)					
15	OY 1985 IP Billing Determinants	24,368					
16							
17	OY 1985 DSI Transmission Costs	92,960					
18							
19	Adjustment for Transmission Costs	(3.81)					
20	Adjustment for the Exchange (mills/kWh)	(2.42)					
21	Adjustment for the Deferral (mills/kWh)	(0.90)					
22	IP-83 Average Rate (mills/kWh)	28.10					
23	Floor Rate (mills/kWh)	20.97					

1 Demand billing determinants are the test period DSI load expressed in noncoincidental demand MWs.
15 Billing determinants as forecast in the 1983 Rate Case Final Proposal (WP-83-FS-BPA-07, p. 82).
17 Transmission Costs as forecast in the 1983 Rate Case Final Proposal (WP-83-FS-BPA-07, p. 80).
19 Line 17 / Line 15
20 Line 14 / Line 15
21 1985 Final Rate Proposal (WP-85-FS-BPA-08A, p. 15).
22 Line 3, Col F / Line 1, Col F
23 IP-83 Avg Rate adjusted for the effects of the Exchange and Deferral, Lines 19 + 20 + 21 + 22

RATE DESIGN STUDY
Industrial Firm Power Floor Rate Test
Test Period October 2006 - September 2009

($ 000)

	A	B	C	D	E	F
	Unbundled Requirements Products	**Transmission Total**	**Generation Demand Total**	**Energy Total**	**Total**	**Average Rate**
1 IP Billing Determinants				0.026		
2 Floor Rate (mills/kWh)				20.97		
3 Value of Reserves Credit (mills/kWh)						
4 Revenue at Floor Rate Less VOR Credit				0.552	0.552	20.97
5 IP Revenue Under Proposed Rates	0	0	0.063	1.123	1.186	45.081
6 Difference					0	

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

Rate Design Study
Calculation of PF Preference Rate Components
Fiscal Year 2007

LEVELIZED MARGINAL COSTS OF POWER

Energy Mills/kwh	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
HLH	53.34	63.03	66.13	59.13	59.27	56.85	47.16	41.76	41.17	49.51	54.63	56.83
LLH	46.08	52.01	54.79	50.01	52.39	50.21	40.56	35.55	31.27	41.07	46.87	50.78
MONTHLY DEMAND	1.94	2.08	2.18	1.85	1.88	1.75	1.64	1.36	1.25	1.53	1.79	1.85

PF billing determinants (GWHs)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy GWh
HLH	3,892	4,350	5,005	5,080	4,563	4,612	4,094	3,665	3,592	3,659	3,929	3,857	82691
LLH	2,531	2,796	3,233	3,345	3,034	2,976	2,626	2,405	2,263	2,362	2,378	2,444	
Demand	11,498	12,457	13,794	14,357	14,059	12,083	11,133	9,344	9,275	9,836	10,074	10,401	

Revenue At Marginal Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Maginal Revenues	Allocated Costs	Rate Factor
HLH	$ 207,572	$ 274,197	$ 330,972	$ 300,368	$ 270,409	$ 262,188	$ 193,052	$ 153,056	$ 147,881	$ 181,125	$ 214,656	$ 219,154	$ 4,264,885	$ 2,272,291	53.28%
LLH	$ 116,639	$ 145,426	$ 177,149	$ 167,270	$ 158,966	$ 149,438	$ 106,534	$ 85,506	$ 70,774	$ 97,004	$ 111,452	$ 124,095			
Demand	$ 22,307	$ 25,910	$ 30,071	$ 26,561	$ 26,431	$ 21,146	$ 18,257	$ 12,708	$ 11,593	$ 15,048	$ 18,033	$ 19,243	$ 247,307	$ 247,307	100.00%
												LV Revenue	$ 13,471	$ 13,471	100.00%
													$ 4,525,663	$ 2,533,069	

PF rates	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
HLH	**28.42**	**33.58**	**35.23**	**31.51**	**31.58**	**30.29**	**25.13**	**22.25**	**21.94**	**26.38**	**29.11**	**30.28**
LLH	**24.55**	**27.71**	**29.19**	**26.64**	**27.91**	**26.75**	**21.61**	**18.94**	**16.66**	**21.88**	**24.97**	**27.05**
Demand	**1.94**	**2.08**	**2.18**	**1.85**	**1.88**	**1.75**	**1.64**	**1.36**	**1.25**	**1.53**	**1.79**	**1.85**

Revenues at Proposed Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Totals
HLH	$ 110,602	$ 146,087	$ 176,328	$ 160,058	$ 144,089	$ 139,697	$ 102,873	$ 81,542	$ 78,800	$ 96,515	$ 114,385	$ 116,778	$ 2,272,346
LLH	$ 62,145	$ 77,484	$ 94,370	$ 89,110	$ 84,688	$ 79,613	$ 56,757	$ 45,553	$ 37,709	$ 51,683	$ 59,371	$ 66,109	
Demand	$ 22,307	$ 25,910	$ 30,071	$ 26,561	$ 26,431	$ 21,146	$ 18,257	$ 12,708	$ 11,593	$ 15,048	$ 18,033	$ 19,243	$ 247,307
												LV Revenue	$ 13,471
													$ 2,533,124

Unbifurcated PF Average Rate

Energy Costs	**$ 2,272,291**	**27.48**
Demand Costs	**$ 247,307**	**2.99**
Unbundled Cost	**$ 13,471**	**0.16**
Total	**$ 2,533,069**	**30.63**
Billing Determinants	**82691**	

This page intentionally left blank.

2. 7(B)(2) CASE RATES ANALYSIS MODEL

This page intentionally left blank.

DESCRIPTION OF RATEMAKING TABLES
7(b)(2) Rate Test 7(b)(2) Case

7b2 Sales_01 Forecast of PF Preference GWh energy sales and peak kW/mo. demand amounts for each month of the 7(b)(2) Rate Test Period FY 2007-2013. These billing determinants are used to calculate PF Preference rates and revenues for the rate test period. For the 7(b)(2) Case, PF Preference sales assume no programmatic conservation has been achieved and DSI load within or adjacent to 7(b)(2) customer service areas will be served by those customers.

7B2 Resource_01 7(b)(2) Case Loads/Resources Balance. Table starts with the FBS resource from the Program Case used to serve posted rates load. Transmission losses are subtracted. The amount of Program Case FBS used to serve FPS load for contract not in force at the time of the Regional Power Act is added. The 7(b)(2) Case PF load is then subtracted to yield the amount of resource needed from the 7(b)(2) resource stack.

7B2 Resource_02 7(b)(2) New Resource Sort. Table lists an example of the 7(b)(2) resources in order of least cost first. Resources include those that are owned by 7(b)(2) customers that are not dedicated to serving preference customer loads. Programmatic conservation is also included.

7B2 Resource_03 7(b)(2) New Resource Calculator. Table lists the cumulative 7(b)(2) resources needed for each year of the test period and the last resource taken from the resource stack to satisfy that need. Total aMWs and costs of resources brought on per year are listed. A remainder amount of load from the acquisition of resources is listed along with the extra secondary revenue assumed to be recovered from the sale of the remainder power in the market. The net cost of the additional resources taken from the stack is calculated and is included in the revenue requirement for each year in the rate test period.

7B2 COSA_06 Itemized Revenue Requirements. Power Business Line (PBL) revenue requirements for each FY during the rate test period

7B2 COSA_08 Classified Revenue Requirement. Generation costs are classified between energy, demand, and load variance. All costs move through 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.

7B2 COSA_09 Functionalized Revenue Credits. 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.

DESCRIPTION OF RATEMAKING TABLES
7(b)(2) Rate Test 7(b)(2) Case

7B2 ALLOCATE 01 Energy Allocation Factors (EAF). 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.

7B2 ALLOCATE 02 Initial Rate Pool Cost Allocation. Table shows the initial allocation of the revenue requirement costs from the COSA to rate pools using the EAFs from table ALLOCATE 01.

7B2 RDS_11 Allocation of Secondary Revenues and Other Revenue Credits. 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.

7B2 RDS_17 Surplus Firm Power Revenues Surplus/(Deficiency). Table calculates the firm surplus sale revenue surplus/deficiency. 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.

7B2 RDS_19 Summary of Initial Allocations. 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 Preference rate pool.

7B2 RDS_50 PF Rate Schedule Charge Calculation. Table calculates 7(b)(2) Case PF rates. Marginal cost rates are scaled down to produce rates that recover costs allocated to PF energy. Example shown is for FY 2007.

7(b)(2) Rate Test Table summarizes the results of the rate test.

7(b)(2) Case Load Forecast

(The forecast has been adjusted for conservation resources brought on from resource stack.)

		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy GWh	aMW
2007	HLH	3,192	3,502	3,828	3,761	3,321	3,505	3,101	3,116	3,186	3,261	3,327	3,010	40,109	7,673
	LLH	2,165	2,374	2,658	2,519	2,279	2,344	2,125	2,110	2,100	2,224	2,147	2,063	27,107	
	Demand	8,895	9,659	10,050	10,013	9,887	9,235	8,383	7,687	7,990	8,267	8,089	7,811	105,967	
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2008	HLH	3,299	3,567	3,911	3,829	3,437	3,512	3,185	3,160	3,263	3,356	3,334	3,095	40,949	7,679
	LLH	2,072	2,293	2,534	2,408	2,245	2,311	2,033	2,056	2,165	2,186	2,192	2,004	26,499	
	Demand	9,343	10,121	10,503	10,496	10,434	9,669	8,695	8,029	8,419	8,438	8,279	7,937	110,363	
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2009	HLH	3,357	3,557	4,018	3,872	3,405	3,557	3,231	3,099	3,288	3,415	3,375	3,121	41,297	7,758
	LLH	2,077	2,370	2,499	2,438	2,232	2,337	2,061	2,084	2,096	2,230	2,216	2,020	26,662	
	Demand	9,486	10,297	10,634	10,662	10,565	9,816	8,850	8,028	8,359	8,627	8,407	8,031	111,761	
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2010	HLH	3,386	3,589	4,053	3,853	3,439	3,639	3,256	3,191	3,397	3,384	3,469	3,162	41,817	7,864
	LLH	2,093	2,387	2,516	2,510	2,245	2,304	2,081	2,142	2,163	2,308	2,275	2,044	27,069	
	Demand	9,600	10,418	10,761	10,790	10,692	9,933	8,955	8,291	8,661	8,725	8,493	8,159	113,479	
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2011	HLH	3,378	3,687	4,094	3,897	3,478	3,680	3,294	3,164	3,352	3,438	3,504	3,190	42,155	7,910
	LLH	2,162	2,352	2,544	2,534	2,267	2,326	2,103	2,123	2,134	2,315	2,212	2,068	27,141	
	Demand	9,760	10,543	10,916	10,947	10,848	10,077	9,086	8,245	8,571	8,867	8,627	8,266	114,751	
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2012	HLH	3,402	3,714	4,099	3,908	3,564	3,693	3,267	3,375	3,627	3,546	3,580	3,198	42,973	8,043
	LLH	2,155	2,348	2,562	2,559	2,317	2,318	2,148	2,130	2,290	2,356	2,219	2,085	27,488	
	Demand	10,017	10,854	11,202	11,220	11,204	10,317	9,313	8,987	9,032	9,229	8,970	8,475	118,822	
		Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**		
2013	HLH	3,467	3,734	4,101	3,996	3,526	3,691	3,341	3,332	3,560	3,616	3,618	3,233	43,215	8,086
	LLH	2,136	2,377	2,610	2,541	2,339	2,381	2,132	2,125	2,281	2,349	2,241	2,106	27,617	
	Demand	10,132	10,975	11,329	11,375	11,298	10,459	9,443	8,930	8,946	9,350	9,088	8,590	119,913	

Section 7(b)(2) PF Load includes any within/adjacent DSI Load and additional load due to unrealized conservation programs.

Section 7(b)(2) Load Resource Balance Calculation

	2007	2008	2009	2010	2011	2012	2013
FBS Serving Posted Rates Load in Program Case	6,945	6,982	7,028	7,101	7,115	7,193	7,224
Long-Term Contracts Not in Force at time of Act	61	64	71	71	71	71	71
FBS Available to Serve Load in 7(b)(2) Case (after losses)	7,006	7,046	7,099	7,172	7,186	7,264	7,295
7(b)(2) PF Load	7,791	7,882	7,919	8,046	8,093	8,226	8,268
Resources Needed From Resource Stack w/losses	**807.9**	**860.4**	**843.7**	**899.5**	**933.4**	**990.0**	**1001.3**

All Costs are in 1980 dollars

Example of 7(b)(2) Resource Stack

A		B	C	D	E	F	G	H	I	J	K	L	M	M
Project		Nameplate (MW)	Interest Rate (%)	Capital Investment ($ooo)	Annual O & M ($ooo)	Annual Fuel ($ooo)	Year Available	Capacity Factor	Life	Annual Capital Cost ($ooo)	Total Discounted Capital Cost ($ooo)	Total Discounted O & M and Fuel ($ooo)	Total Cost Dollars per AMW ($)	Total Cost Mills per KWH
BPA & Public resources														
*** The following resources are listed least cost first														
DALLES DAM FISHWAY ND	1992	4.6	0.00	0	228	0	2007	100	30	0	0	3,343	24,226	2.77
WELLS 1967 ND	0	193.90	5.45	0	10,850	0	2007	100	35	0	0	168,625	24,847	2.84
WANAPAM 1963 ND	-	119.50	5.45	0	7,616	0	2007	100	35	0	0	118,364	28,300	3.23
BPA PROG CONS	2001	18.5	5.34	31	10,804	0	2001	100	20	3	31	10,804	29,283	3.34
PRIEST RAPIDS 1959 ND	0	98.20	5.45	0	6,487	0	2007	100	35	0	0	100,818	29,333	3.35
ROCKY REACH 1961 ND	0	293.90	5.45	0	19,437	0	2007	100	35	0	0	302,080	29,367	3.35
BPA PROG CONS	2000	14.7	5.34	191	8,460	0	2000	100	20	16	190	8,460	29,421	3.36
BPA PROG CONS	1997	54.7	5.34	19,030	14,598	0	1997	100	20	1,571	18,903	14,598	30,623	3.50
BPA PROG CONS	1999	30.3	5.34	10,990	11,507	0	1999	100	20	907	10,917	11,507	37,003	4.22
BPA PROG CONS	2004	31.0	5.09	9,932	8,087	0	2004	100	15	963	9,715	8,087	38,283	4.37
BPA PROG CONS	1998	33.4	5.34	14,918	17,104	0	1998	100	20	1,232	14,819	17,104	47,789	5.46
ROCK ISLAND 1933 ND	0	140.10	5.45	0	16,444	0	2007	100	35	0	0	255,565	52,119	5.95
BPA PROG CONS	1996	56.3	5.34	30,813	28,846	0	1996	100	20	2,544	30,608	28,846	52,801	6.03
BPA PROG CONS	2003	24.7	5.09	11,909	8,989	0	2003	100	15	1,154	11,649	8,989	55,702	6.36
BPA PROG CONS	1995	65.9	5.34	51,342	28,098	0	1995	100	20	4,239	51,001	28,098	60,014	6.85
BOARDMAN PUBLIC ND	1980	49	0.00	0	3179	2874	1992	100	30	0	0	88,755	60,378	6.89
BPA PROG CONS	2002	25.7	5.09	15,021	9,122	0	2002	100	15	1,456	14,692	9,122	61,776	7.05
IDAHO FALLS ND	1992	12.6	5.45	0	2,030	0	2007	100	35	0	0	31,549	71,540	8.17
NINE CANYON WIND PROJ.	2002	8.5	5.45	0	1,379	0	2007	100	30	0	0	20,220	79,295	9.05
BPA PROG CONS	1993	59.6	5.34	61,130	34,923	0	1993	100	20	5,048	60,723	34,923	80,240	9.16
BILLING CREDITS	1996	17.5	5.42	28334	699	0	2007	100	25	2,096	28,334	9,450	86,363	9.86
BPA PROG CONS	1982	32.4	5.34	53,020	4,258	0	1982	100	20	4,378	52,667	4,258	87,848	10.03
BPA PROG CONS	1989	20.8	5.34	33,534	9,402	0	1989	100	20	2,769	33,311	9,402	102,675	11.72
BPA PROG CONS	2005	21.6	5.09	10,932	22,627	0	2005	100	15	1,060	10,693	22,627	102,839	11.74
BPA PROG CONS	2013	33.0	5.09	16,438	35,164	0	2013	100	15	1,593	16,078	35,164	103,520	11.82
BPA PROG CONS	1994	51.3	5.34	74,698	32,253	0	1994	100	20	6,168	74,201	32,253	103,757	11.84

7(b)(2) Resource Calculator

Rate Year	AMW needed.	Last Res. Added.	Total New Res.	Cost of New Res.	Remainder	Additional Secondary	Net Cost New Res.
2007	807.9	Resource 09	828.3	$ 201,163	20.4	$ (7,842)	$ 193,322
2008	860.9	Resource 11	892.7	$ 165,323	31.8	$ (10,623)	$ 154,700
2009	843.2	Resource 11	892.7	$ 111,697	49.5	$ (16,487)	$ 95,210
2010	899.5	Resource 12	1032.8	$ 152,292	133.3	$ (45,508)	$ 106,783
2011	933.4	Resource 12	1032.8	$ 155,999	99.4	$ (34,767)	$ 121,232
2012	990.5	Resource 12	1032.8	$ 159,757	42.3	$ (15,165)	$ 144,592
2013	1001.3	Resource 12	1032.8	$ 159,757	31.5	$ (11,563)	$ 148,194

			AMW output	Cum. output	Annual Costs 80$s	Cum. Costs 80$s	Annual Costs 2nd Yr.	Cum. Costs 2nd Yr.
Resource 01	DALLES DAM FISHWAY ND	1992	5	5	$ 228	$ 228	228	$ 228
Resource 02	WELLS 1967 ND	0	194	199	$ 10,850	$ 11,078	10850	$ 11,078
Resource 03	WANAPAM 1963 ND	0	120	318	$ 7,616	$ 18,694	7616	$ 18,694
Resource 04	BPA PROG CONS	2001	19	337	$ 10,807	$ 29,501	3	$ 18,697
Resource 05	PRIEST RAPIDS 1959 ND	0	98	435	$ 6,487	$ 35,988	6487	$ 25,184
Resource 06	ROCKY REACH 1961 ND	0	294	729	$ 19,437	$ 55,425	19437	$ 44,621
Resource 07	BPA PROG CONS	2000	15	743	$ 8,476	$ 63,900	16	$ 44,636
Resource 08	BPA PROG CONS	1997	55	798	$ 16,169	$ 80,070	1571	$ 46,208
Resource 09	BPA PROG CONS	1999	30	828	$ 12,414	$ 92,484	907	$ 47,115
Resource 10	BPA PROG CONS	2004	31	859	$ 9,050	$ 101,534	963	$ 48,078
Resource 11	BPA PROG CONS	1998	33	893	$ 18,336	$ 119,870	1232	$ 49,310
Resource 12	ROCK ISLAND 1933 ND	0	140	1033	$ 16,444	$ 136,314	16444	$ 65,754
Resource 13	BPA PROG CONS	1996	56	1089	$ 31,390	$ 167,704	2544	$ 68,298
Resource 14	BPA PROG CONS	2003	25	1114	$ 10,143	$ 177,847	1154	$ 69,452
Resource 15	BPA PROG CONS	1995	66	1180	$ 32,337	$ 210,185	4239	$ 73,692

COST OF SERVICE ANALYSIS
Itemized Revenue Requirement
FY 2007

($ 000)

	A	B	C	D	E
	INVEST BASE	**NET INT**	**NET REVS**	**OPER EXP**	**TOTAL (B+C+D)**
1. GENERATION COSTS					
2. FEDERAL BASE SYSTEM					
3. HYDRO	4,955,805	140,858	117,648	370,385	628,891
4. BPA FISH & WILDLIFE PROGRAM	140,228	3,986	3,329	171,903	179,218
5. TROJAN				14,005	14,005
6. WNP #1				148,141	148,141
7. WNP #2				459,359	459,359
8. WNP #3				151,724	151,724
9. SYSTEM AUGMENTATION				169,090	169,090
10. BALANCING POWER PURCHASES				54,017	54,017
11. TOTAL FEDERAL BASE SYSTEM	5,096,033	144,844	120,977	1,538,624	1,804,445
12. NEW RESOURCES					
13. IDAHO FALLS				0	0
14. COWLITZ FALLS				0	0
15. OTHER NEW RESOURCES PURCHASES				0	0
16. TOTAL NEW RESOURCES				0	0
17. RESIDENTIAL EXCHANGE SETTLEMENT				0	0
18. CONSERVATION		0	0	0	0
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	43,785	1,244	1,040	182,192	184,476
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	43,785	1,244	1,040	182,192	184,476
23. TOTAL GENERATION COSTS	5,139,818	146,088	122,017	1,720,816	1,988,921
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				124,614	124,614
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,300	1,300
27. GENERAL TRANSFER AGREEMENTS				47,000	47,000
28. TOTAL TRANSMISSION COSTS				172,914	172,914
29. TOTAL PBL REVENUE REQUIREMENT		146,088	122,017	1,893,730	2,161,835

COST OF SERVICE ANALYSIS
Itemized Revenue Requirement
FY 2008

($ 000)

	A	B	C	D	E
	INVEST BASE	**NET INT**	**NET REVS**	**OPER EXP**	**TOTAL (B+C+D)**
1. GENERATION COSTS					
2. FEDERAL BASE SYSTEM					
3. HYDRO	4,971,786	149,041	84,054	380,709	613,804
4. BPA FISH & WILDLIFE PROGRAM	156,170	4,682	2,640	173,574	180,896
5. TROJAN				12,588	12,588
6. WNP #1				166,116	166,116
7. WNP #2				406,544	406,544
8. WNP #3				160,092	160,092
9. SYSTEM AUGMENTATION				118,024	118,024
10. BALANCING POWER PURCHASES				64,693	64,693
11. TOTAL FEDERAL BASE SYSTEM	5,127,956	153,723	86,694	1,482,340	1,722,757
12. NEW RESOURCES					
13. IDAHO FALLS				0	0
14. COWLITZ FALLS				0	0
15. OTHER NEW RESOURCES PURCHASES				0	0
16. TOTAL NEW RESOURCES				0	0
17. RESIDENTIAL EXCHANGE SETTLEMENT				0	0
18. CONSERVATION		0	0	0	0
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	35,876	1,075	607	184,374	186,056
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	35,876	1,075	607	184,374	186,056
23. TOTAL GENERATION COSTS	5,163,832	154,798	87,301	1,666,714	1,908,813
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				126,877	126,877
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,300	1,300
27. GENERAL TRANSFER AGREEMENTS				47,000	47,000
28. TOTAL TRANSMISSION COSTS				175,177	175,177
29. TOTAL PBL REVENUE REQUIREMENT		154,798	87,301	1,841,891	2,083,990

COST OF SERVICE ANALYSIS
Itemized Revenue Requirement
FY 2009

($ 000)

	A	B	C	D	E
	INVEST BASE	NET INT	NET REVS	OPER EXP	TOTAL (B+C+D)
1. GENERATION COSTS					
2. FEDERAL BASE SYSTEM					
3. HYDRO	5,028,112	154,916	99,938	391,777	646,631
4. BPA FISH & WILDLIFE PROGRAM	170,827	5,263	3,395	174,856	183,514
5. TROJAN				3,100	3,100
6. WNP #1				163,482	163,482
7. WNP #2				461,669	461,669
8. WNP #3				153,030	153,030
9. SYSTEM AUGMENTATION				169,926	169,926
10. BALANCING POWER PURCHASES				61,570	61,570
11. TOTAL FEDERAL BASE SYSTEM	5,198,939	160,179	103,333	1,579,409	1,842,921
12. NEW RESOURCES					
13. IDAHO FALLS				0	0
14. COWLITZ FALLS				0	0
15. OTHER NEW RESOURCES PURCHASES				0	0
16. TOTAL NEW RESOURCES				0	0
17. RESIDENTIAL EXCHANGE SETTLEMENT				0	0
18. CONSERVATION		0	0	0	0
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	26,604	820	529	194,603	195,952
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	26,604	820	529	194,603	195,952
23. TOTAL GENERATION COSTS	5,225,543	160,999	103,862	1,774,012	2,038,873
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				131,515	131,515
26. 3RD PARTY TRANS/ANCILLARY SERVICES				3,000	3,000
27. GENERAL TRANSFER AGREEMENTS				48,000	48,000
28. TOTAL TRANSMISSION COSTS				182,515	182,515
29. TOTAL PBL REVENUE REQUIREMENT		160,999	103,862	1,956,527	2,221,388

COST OF SERVICE ANALYSIS
Itemized Revenue Requirement
FY 2010

($ 000)

	A	B	C	D	E
	INVEST BASE	NET INT	NET REVS	OPER EXP	TOTAL (B+C+D)
1. GENERATION COSTS					
2. FEDERAL BASE SYSTEM					
3. HYDRO	5,111,893	156,815	96,051	404,086	656,952
4. BPA FISH & WILDLIFE PROGRAM	184,568	5,662	3,468	171,224	180,354
5. TROJAN				1,700	1,700
6. WNP #1				159,459	159,459
7. WNP #2				432,093	432,093
8. WNP #3				142,783	142,783
9. SYSTEM AUGMENTATION				0	0
10. BALANCING POWER PURCHASES				61,570	61,570
11. TOTAL FEDERAL BASE SYSTEM	5,296,461	162,477	99,519	1,372,914	1,634,910
12. NEW RESOURCES					
13. IDAHO FALLS				0	0
14. COWLITZ FALLS				0	0
15. OTHER NEW RESOURCES PURCHASES				0	0
16. TOTAL NEW RESOURCES				0	0
17. RESIDENTIAL EXCHANGE SETTLEMENT				0	0
18. CONSERVATION		0	0	0	0
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	16,581	509	312	192,866	193,686
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	16,581	509	312	192,866	193,686
23. TOTAL GENERATION COSTS	5,313,042	162,986	99,831	1,565,780	1,828,596
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				135,069	135,069
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,120	1,120
27. GENERAL TRANSFER AGREEMENTS				56,600	56,600
28. TOTAL TRANSMISSION COSTS				192,789	192,789
29. TOTAL PBL REVENUE REQUIREMENT		162,986	99,831	1,758,568	2,021,385

COST OF SERVICE ANALYSIS
Itemized Revenue Requirement
FY 2011

($ 000)

	A	B	C	D	E
	INVEST BASE	NET INT	NET REVS	OPER EXP	TOTAL (B+C+D)
1. GENERATION COSTS					
2. FEDERAL BASE SYSTEM					
3. HYDRO	5,156,309	160,850	83,946	414,565	659,361
4. BPA FISH & WILDLIFE PROGRAM	197,616	6,165	3,217	172,125	181,507
5. TROJAN				1,700	1,700
6. WNP #1				161,661	161,661
7. WNP #2				458,629	458,629
8. WNP #3				168,250	168,250
9. SYSTEM AUGMENTATION				0	0
10. BALANCING POWER PURCHASES				61,570	61,570
11. TOTAL FEDERAL BASE SYSTEM	5,353,925	167,015	87,163	1,438,500	1,692,678
12. NEW RESOURCES					
13. IDAHO FALLS				0	0
14. COWLITZ FALLS				0	0
15. OTHER NEW RESOURCES PURCHASES				0	0
16. TOTAL NEW RESOURCES				0	0
17. RESIDENTIAL EXCHANGE SETTLEMENT				0	0
18. CONSERVATION		0	0	0	0
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	8,422	262	138	190,918	191,318
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	8,422	262	138	190,918	191,318
23. TOTAL GENERATION COSTS	5,362,347	167,277	87,301	1,629,418	1,883,995
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				138,519	138,519
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,150	1,150
27. GENERAL TRANSFER AGREEMENTS				57,800	57,800
28. TOTAL TRANSMISSION COSTS				197,469	197,469
29. TOTAL PBL REVENUE REQUIREMENT		167,277	87,301	1,826,887	2,081,465

COST OF SERVICE ANALYSIS
Itemized Revenue Requirement
FY 2012

($ 000)

	A	B	C	D	E
	INVEST BASE	NET INT	NET REVS	OPER EXP	TOTAL (B+C+D)
1. GENERATION COSTS					
2. FEDERAL BASE SYSTEM					
3. HYDRO	5,253,437	165,416	11,237	425,954	602,607
4. BPA FISH & WILDLIFE PROGRAM	210,353	6,623	450	176,563	183,636
5. TROJAN				1,751	1,751
6. WNP #1				187,660	187,660
7. WNP #2				504,117	504,117
8. WNP #3				161,778	161,778
9. SYSTEM AUGMENTATION				0	0
10. BALANCING POWER PURCHASES				61,570	61,570
11. TOTAL FEDERAL BASE SYSTEM	5,463,790	172,039	11,687	1,519,393	1,703,119
12. NEW RESOURCES					
13. IDAHO FALLS				0	0
14. COWLITZ FALLS				0	0
15. OTHER NEW RESOURCES PURCHASES				0	0
16. TOTAL NEW RESOURCES				0	0
17. RESIDENTIAL EXCHANGE SETTLEMENT				0	0
18. CONSERVATION		0	0	0	0
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	5,448	172	11	129,521	129,704
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	5,448	172	11	129,521	129,704
23. TOTAL GENERATION COSTS	5,469,238	172,211	11,698	1,648,914	1,832,823
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				142,245	142,245
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,185	1,185
27. GENERAL TRANSFER AGREEMENTS				59,534	59,534
28. TOTAL TRANSMISSION COSTS				202,963	202,963
29. TOTAL PBL REVENUE REQUIREMENT		172,211	11,698	1,851,877	2,035,786

COST OF SERVICE ANALYSIS
Itemized Revenue Requirement
FY 2013

($ 000)

	A	B	C	D	E
	INVEST BASE	NET INT	NET REVS	OPER EXP	TOTAL (B+C+D)
1. GENERATION COSTS					
2. FEDERAL BASE SYSTEM					
3. HYDRO	5,399,067	176,256	65,451	438,787	680,494
4. BPA FISH & WILDLIFE PROGRAM	222,686	7,270	2,700	182,002	191,972
5. TROJAN				1,804	1,804
6. WNP #1				283,394	283,394
7. WNP #2				376,259	376,259
8. WNP #3				176,703	176,703
9. SYSTEM AUGMENTATION				0	0
10. BALANCING POWER PURCHASES				61,570	61,570
11. TOTAL FEDERAL BASE SYSTEM	5,621,753	183,526	68,151	1,520,517	1,772,194
12. NEW RESOURCES					
13. IDAHO FALLS				0	0
14. COWLITZ FALLS				0	0
15. OTHER NEW RESOURCES PURCHASES				0	0
16. TOTAL NEW RESOURCES				0	0
17. RESIDENTIAL EXCHANGE SETTLEMENT				0	0
18. CONSERVATION		0	0	0	0
19. OTHER GENERATION COSTS					
20. BPA PROGRAMS	5,355	175	64	133,069	133,308
21. WNP #3 PLANT				0	0
22. TOTAL OTHER GENERATION COSTS	5,355	175	64	133,069	133,308
23. TOTAL GENERATION COSTS	5,627,108	183,701	68,215	1,653,586	1,905,502
24. TRANSMISSION COSTS					
25. TBL TRANSMISSION/ANCILLARY SERVICES				145,978	145,978
26. 3RD PARTY TRANS/ANCILLARY SERVICES				1,220	1,220
27. GENERAL TRANSFER AGREEMENTS				61,320	61,320
28. TOTAL TRANSMISSION COSTS				208,518	208,518
29. TOTAL PBL REVENUE REQUIREMENT		183,701	68,215	1,862,105	2,114,021

COST OF SERVICE ANALYSIS
Classified Revenue Requirement
Fiscal Year 2007

($ 000)

	Total Revenue Requirement	Energy		Demand		Load Variance	
		Percent	Total	Percent	Total	Percent	Total
1. GENERATION COSTS							
2. FEDERAL BASE SYSTEM							
3. HYDRO	$ 628,891	89.55%	$ 563,169	9.47%	$ 59,539	0.98%	$ 6,182
4. BPA FISH & WILDLIFE PROGRAM	$ 179,218	90.53%	$ 162,250	9.47%	$ 16,967		
5. TROJAN	$ 14,005	90.53%	$ 12,679	9.47%	$ 1,326		
6. WNP #1	$ 148,141	90.53%	$ 134,116	9.47%	$ 14,025		
7. WNP #2	$ 459,359	89.55%	$ 411,354	9.47%	$ 43,489	0.98%	$ 4,516
8. WNP #3	$ 151,724	90.53%	$ 137,360	9.47%	$ 14,364		
9. SYSTEM AUGMENTATION	$ 169,090	89.55%	$ 151,419	9.47%	$ 16,008	0.98%	$ 1,662
10. BALANCING POWER PURCHASES	$ 54,017	89.55%	$ 48,372	9.47%	$ 5,114	0.98%	$ 531
11. TOTAL FEDERAL BASE SYSTEM	$ 1,804,445		$ 1,620,719		$ 170,834		$ 12,892
12. NEW RESOURCES							
13. IDAHO FALLS	$ -				$ -		$ -
14. COWLITZ FALLS	$ -		$ -		$ -		$ -
15. OTHER NEW RESOURCES PURCHASES	$ -		$ -		$ -		$ -
16. TOTAL NEW RESOURCES	$ -		$ -		$ -		$ -
17. RESIDENTIAL EXCHANGE	$ -		$ -				
18. CONSERVATION	$ -		$ -		$ -		
19. OTHER GENERATION COSTS							
20. BPA PROGRAMS	$ 184,476	89.55%	$ 165,198	9.47%	$ 17,465	0.98%	$ 1,814
21. WNP #3 PLANT	$ -				$ -		
22. TOTAL OTHER GENERATION COSTS	$ 184,476		$ 165,198		$ 17,465		$ 1,814
23. TOTAL GENERATION COSTS	$ 1,988,921		$ 1,785,917		$ 188,299		$ 14,705
24. TRANSMISSION COSTS							
25. TBL TRANSMISSION/ANCILLARY SERVICES	$ 124,614	100.00%	$ 133,662				
26. 3RD PARTY TRANS/ANCILLARY SERVICES	$ 1,300	100.00%	$ 1,300				
27. GENERAL TRANSFER AGREEMENTS	$ 47,000	100.00%	$ 47,000				
28. TOTAL TRANSMISSION COSTS	172,914		181,962				
29. TOTAL PBL REVENUE REQUIREMENT	$ 2,161,835		$ 1,967,879		$ 203,004		

COST OF SERVICE ANALYSIS
Revenue Credits
Test Period October 2006 - September 2013

	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Colville Credit	$ 4,600	$ 4,600	$ 4,600	$ 4,600	$ 4,600	$ 4,600	$ 4,600
'4(h)(10)(c)	$ 84,707	$ 84,927	$ 84,676	$ 84,676	$ 84,676	$ 84,676	$ 84,676
Ancillary and Reserve Service Revs.	$ 73,131	$ 61,970	$ 62,715	$ 62,715	$ 62,715	$ 62,715	$ 62,715
Energy Efficiency & Misc. Revenues	$ 16,305	$ 16,328	$ 16,353	$ 16,220	$ 16,220	$ 16,220	$ 16,220
Reserve Product Revenue	$ 3,000	$ 3,300	$ 3,630	$ 3,630	$ 3,630	$ 3,630	$ 3,630
Downstream Benefits & Storage	8921	8921	8921	8921	8921	8921	8921
Green Tags	$ 1,079	$ 1,082	$ 1,082	$ 2,128	$ 2,128	$ 2,128	$ 2,128
Aluminum Hedging	$ 875	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ 192,618	$ 181,129	$ 181,977	$ 182,891	$ 182,891	$ 182,891	$ 182,891

Energy Allocation Factors
Average Megawatts

	2007	2008	2009	2010	2011	2012	2013
Federal Base System							
Total Usage							
Priority Firm...............................	8,017	8,111	8,149	8,280	8,328	8,465	8,508
Industrial Firm............................	0	0	0	0	0	0	0
New Resource Firm..................	0	0	0	0	0	0	0
Surplus Firm Other.....................	1,306	1,293	1,257	1,335	1,288	889	877
Total..	9,323	9,404	9,406	9,614	9,616	9,354	9,385
Federal Base System	0	0	0	0	0	0	0
Priority Firm...............................	8,017	8,111	8,149	8,280	8,328	8,465	8,508
Industrial Firm............................	0	0	0	0	0	0	0
New Resource Firm..................	0	0	0	0	0	0	0
Surplus Firm Other.....................	1,306	1,293	1,257	1,600	1,660	989	1,104
Total..	9,323	9,404	9,406	9,880	9,988	9,454	9,613
Residential Exchange	0	0	0	0	0	0	0
Priority Firm...............................	0	0	0	0	0	0	0
Industrial Firm............................	0	0	0	0	0	0	0
New Resource Firm..................	0	0	0	0	0	0	0
Surplus Firm Other.....................	0	0	0	0	0	0	0
Total..	0	0	0	0	0	0	0
New Resource	0	0	0	0	0	0	0
Priority Firm...............................	0	0	0	0	0	0	0
Industrial Firm............................	0	0	0	0	0	0	0
New Resource Firm..................	0	0	0	0	0	0	0
Surplus Firm Other.....................	0	0	0	0	0	0	0
Total..	0	0	0	0	0	0	0
Conservation	0	0	0	0	0	0	0
Priority Firm...............................	0	0	0	0	0	0	0
Industrial Firm............................	0	0	0	0	0	0	0
New Resource Firm..................	0	0	0	0	0	0	0
Surplus Firm Other.....................	0	0	0	0	0	0	0
Total..	9,323	9,404	9,406	9,614	9,616	9,354	9,385

Initial Rate Pool Allocations

	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
CLASSES OF SERVICE:							
Power Rates							
Priority Firm - Preference							
FBS	$ 1,717,963	$ 1,619,246	$ 1,679,136	$ 1,560,872	$ 1,657,247	$ 1,697,188	$ 1,798,394
NR	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Exchange	$ -	$ -	$ -	$ -	$ -	$ -	$ -
conservation	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BPA programs	$ 307,335	$ 311,552	$ 327,892	$ 332,828	$ 336,714	$ 301,052	$ 309,885
Total	$ 2,025,299	$ 1,930,798	$ 2,007,027	$ 1,893,700	$ 1,993,961	$ 1,998,240	$ 2,108,280
Industrial Firm Power							
FBS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NR	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Exchange	$ -	$ -	$ -	$ -	$ -	$ -	$ -
conservation	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BPA programs	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -	$ -	$ -	$ -
New Resources Firm							
FBS	$ -	$ -	$ -	$ -	$ -	$ -	$ -
NR	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Exchange	$ -	$ -	$ -	$ -	$ -	$ -	$ -
conservation	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BPA programs	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Surplus Firm Power							
FBS	$ 279,803	$ 258,211	$ 258,996	$ 301,639	$ 330,424	$ 198,246	$ 233,434
NR	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Exchange	$ -	$ -	$ -	$ -	$ -	$ -	$ -
conservation	$ -	$ -	$ -	$ -	$ -	$ -	$ -
BPA programs	$ 50,055	$ 49,681	$ 50,575	$ 53,647	$ 52,073	$ 31,616	$ 31,941
Total	$ 329,858	$ 307,892	$ 309,571	$ 355,287	$ 382,498	$ 229,862	$ 265,375
Total Revenue Requirement	$ 2,355,156	$ 2,238,691	$ 2,316,598	$ 2,248,987	$ 2,376,459	$ 2,228,102	$ 2,373,655

Rate Design Study
Allocation of Secondary and other Revenues
Test Period October 2006 - September 2013

	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Forecast of Secondary Revenues	**$ 600,634**	**$ 582,252**	**$ 566,351**	**$ 566,351**	**$ 566,351**	**$ 566,351**	**$ 566,351**
Additional Secondary Revenues	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Gross Secondary Revenues	**$ 600,634**	**$ 582,252**	**$ 566,351**	**$ 566,351**	**$ 566,351**	**$ 566,351**	**$ 566,351**

	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Allocation of Secondary Revenues Credit							
Priority Firm..	$ (516,510)	$ (502,173)	$ (490,669)	$ (474,629)	$ (472,203)	$ (507,116)	$ (501,284)
Industrial Firm..	$ -	$ -	$ -	$ -	$ -	$ -	$ -
New Resource Firm..	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Surplus Firm Other...	$ (84,123)	$ (80,078)	$ (75,682)	$ (91,722)	$ (94,148)	$ (59,236)	$ (65,067)
Total...	**$ (600,634)**	**$ (582,252)**	**$ (566,351)**	**$ (566,351)**	**$ (566,351)**	**$ (566,351)**	**$ (566,351)**

	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Total Other Revenue Credits	**$ 192,618**	**$ 181,129**	**$ 181,977**	**$ 182,891**	**$ 182,891**	**$ 182,891**	**$ 182,891**

	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Allocation of Other Revenue Credits							
Priority Firm..	$ (165,641)	$ (156,218)	$ (157,659)	$ (153,271)	$ (152,488)	$ (163,762)	$ (161,879)
Industrial Firm..	$ -	$ -	$ -	$ -	$ -	$ -	$ -
New Resource Firm..	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Surplus Firm Other...	$ (26,978)	$ (24,911)	$ (24,318)	$ (29,620)	$ (30,403)	$ (19,129)	$ (21,012)
Total...	**$ (192,618)**	**$ (181,129)**	**$ (181,977)**	**$ (182,891)**	**$ (182,891)**	**$ (182,891)**	**$ (182,891)**

Rate Design Study
Calculation of FPS (Surplus)/Shortfall
Test Period October 2006 - September 2013

FPS (Surplus)/Shortfall	**FY 2007**	**FY 2008**	**FY 2009**	**FY 2010**	**FY 2011**	**FY 2012**	**FY 2013**
Costs allocated to FPS contract sales	$ 329,858	$ 307,892	$ 309,571	$ 355,287	$ 382,498	$ 229,862	$ 265,375
Expected Revenue from FPS contract sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -
FPS Pre-Sub Contract Revenue	$ (46,561)	$ (47,781)	$ (41,101)	$ (40,660)	$ (39,784)	$ (5,300)	$ (5,300)
(Surplus)/Shortfall	**$ 283,297**	**$ 260,111**	**$ 268,469**	**$ 314,627**	**$ 342,714**	**$ 224,562**	**$ 260,075**
Secondary Revenues allocated to FPS	$ (84,123)	$ (80,078)	$ (75,682)	$ (91,722)	$ (94,148)	$ (59,236)	$ (65,067)
Revenue Credits allocated to FPS	$ (26,978)	$ (24,911)	$ (24,318)	$ (29,620)	$ (30,403)	$ (19,129)	$ (21,012)
FPS (Surplus)/Shortfall	**$ 172,196**	**$ 155,122**	**$ 168,469**	**$ 193,285**	**$ 218,162**	**$ 146,198**	**$ 173,996**

Rate Design Study
Allocation of FPS (Surplus)/Shortfall
Test Period October 2006 - September 2009

Allocation of FPS (Surplus)/Shortfall							
Priority Firm..	$ 172,196	$ 155,122	$ 168,469	$ 193,285	$ 218,162	$ 146,198	$ 173,996
Industrial Firm..	$ -	$ -	$ -	$ -	$ -	$ -	$ -
New Resource Firm.......................................	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Surplus Firm Other..	$ (172,196)	$ (155,122)	$ (168,469)	$ (193,285)	$ (218,162)	$ (146,198)	$ (173,996)
Total...	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Rate Design Study
Summary of Initial Allocations
Test Period October 2006 - September 2013

	FY 2007	FY 2008	FY 2009	FY 2010	FY 2011	FY 2012	FY 2013
Allocation of Revenue Requirement							
Priority Firm.......................................	$ 2,025,299	$ 1,930,798	$ 2,007,027	$ 1,893,700	$ 1,993,961	$ 1,998,240	$ 2,108,280
Industrial Firm....................................	$ -	$ -	$ -	$ -	$ -	$ -	$ -
New Resource Firm............................	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Surplus Firm Other.............................	$ 329,858	$ 307,892	$ 309,571	$ 355,287	$ 382,498	$ 229,862	$ 265,375
Total...	$ 2,355,156	$ 2,238,691	$ 2,316,598	$ 2,248,987	$ 2,376,459	$ 2,228,102	$ 2,373,655
Allocation of Secondary Revenues Credit							
Priority Firm.......................................	$ (516,510)	$ (502,173)	$ (490,669)	$ (474,629)	$ (472,203)	$ (507,116)	$ (501,284)
Industrial Firm....................................	$ -	$ -	$ -	$ -	$ -	$ -	$ -
New Resource Firm............................	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Surplus Firm Other.............................	$ (84,123)	$ (80,078)	$ (75,682)	$ (91,722)	$ (94,148)	$ (59,236)	$ (65,067)
Total...	$ (600,634)	$ (582,252)	$ (566,351)	$ (566,351)	$ (566,351)	$ (566,351)	$ (566,351)
Allocation of other Revenues Credits							
Priority Firm.......................................	$ (165,641)	$ (156,218)	$ (157,659)	$ (153,271)	$ (152,488)	$ (163,762)	$ (161,879)
Industrial Firm....................................	$ -	$ -	$ -	$ -	$ -	$ -	$ -
New Resource Firm............................	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Surplus Firm Other.............................	$ (26,978)	$ (24,911)	$ (24,318)	$ (29,620)	$ (30,403)	$ (19,129)	$ (21,012)
Total...	$ (192,618)	$ (181,129)	$ (181,977)	$ (182,891)	$ (182,891)	$ (182,891)	$ (182,891)
Allocation of FPS (Surplus)/Shortfall							
Priority Firm.......................................	$ 172,196	$ 155,122	$ 168,469	$ 193,285	$ 218,162	$ 146,198	$ 173,996
Industrial Firm....................................	$ -	$ -	$ -	$ -	$ -	$ -	$ -
New Resource Firm............................	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Surplus Firm Other.............................	$ (172,196)	$ (155,122)	$ (168,469)	$ (193,285)	$ (218,162)	$ (146,198)	$ (173,996)
Total...	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Low Density Discount							
Priority Firm.......................................	$ 22,289	$ 22,612	$ 22,853	$ 22,853	$ 22,853	$ 22,853	$ 22,853
Irrigation Rate Mitigation............							
Priority Firm.......................................	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
Initial Allocation							
Priority Firm.......................................	$ 1,547,633	$ 1,460,141	$ 1,560,021	$ 1,491,938	$ 1,620,286	$ 1,506,413	$ 1,651,966
Industrial Firm....................................	$ -	$ -	$ -	$ -	$ -	$ -	$ -
New Resource Firm............................	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Surplus Firm Other.............................	$ 46,561	$ 47,781	$ 41,101	$ 40,660	$ 39,784	$ 5,300	$ 5,300
Total...	$ 1,594,193	$ 1,507,922	$ 1,601,123	$ 1,532,598	$ 1,660,070	$ 1,511,713	$ 1,657,266

Rate Design Study
Calculation of 7(b)(2) Case PF Preference Rate Components
Fiscal Year 2007

LEVELIZED MARGINAL COSTS OF POWER

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Energy Mills/kwh												
HLH	53.34	63.03	66.13	59.13	59.27	56.85	47.16	41.76	41.17	49.51	54.63	56.83
LLH	46.08	52.01	54.79	50.01	52.39	50.21	40.56	35.55	31.27	41.07	46.87	50.78
MONTHLY DEMAND	1.94	2.08	2.18	1.85	1.88	1.75	1.64	1.36	1.25	1.53	1.79	1.85

PF billing determinants (GWhs)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total Energy (GWhs)		
HLH	3,192	3,502	3,828	3,761	3,321	3,505	3,101	3,116	3,186	3,261	3,327	3,010	67,216	67,216	7,673
LLH	2,165	2,374	2,658	2,519	2,279	2,344	2,125	2,110	2,100	2,224	2,147	2,063			
Demand	8,895	9,659	10,050	10,013	9,887	9,235	8,383	7,687	7,990	8,267	8,089	7,811			

Revenue At Marginal Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Maginal Revenues	Allocated Costs	Rate Factor
HLH	$ 170,275	$ 220,707	$ 253,141	$ 222,379	$ 196,808	$ 199,229	$ 146,221	$ 130,155	$ 131,178	$ 161,449	$ 181,755	$ 171,031	$ 3,439,809	$ 1,344,629	39.09%
LLH	$ 99,744	$ 123,457	$ 145,647	$ 125,983	$ 119,389	$ 117,688	$ 86,203	$ 75,026	$ 65,649	$ 91,332	$ 100,620	$ 104,743			
Demand	$ 17,256	$ 20,092	$ 21,909	$ 18,525	$ 18,588	$ 16,161	$ 13,748	$ 10,454	$ 9,987	$ 12,649	$ 14,479	$ 14,450	$ 188,299	$ 188,299	100.00%
												LV Revenue	$ 14,705	$ 14,705.1	100.00%
													$ 3,642,812	$ 1,547,633	

PF rates	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
HLH	**20.85**	**24.64**	**25.85**	**23.11**	**23.17**	**22.22**	**18.43**	**16.33**	**16.10**	**19.35**	**21.35**	**22.21**
LLH	**18.01**	**20.33**	**21.42**	**19.55**	**20.48**	**19.63**	**15.86**	**13.90**	**12.22**	**16.05**	**18.32**	**19.85**
Demand	**1.94**	**2.08**	**2.18**	**1.85**	**1.88**	**1.75**	**1.64**	**1.36**	**1.25**	**1.53**	**1.79**	**1.85**

Revenues at Proposed Rates

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Totals
HLH	$ 66,562	$ 86,282	$ 98,955	$ 86,910	$ 76,942	$ 77,870	$ 57,144	$ 50,892	$ 51,293	$ 63,104	$ 71,034	$ 66,846	$ 1,344,617
LLH	$ 38,987	$ 48,260	$ 56,935	$ 49,253	$ 46,672	$ 46,010	$ 33,705	$ 29,334	$ 25,656	$ 35,695	$ 39,326	$ 40,947	
Demand	$ 17,256	$ 20,092	$ 21,909	$ 18,525	$ 18,588	$ 16,161	$ 13,748	$ 10,454	$ 9,987	$ 12,649	$ 14,479	$ 14,450	$ 188,299
												LV Revenue	$ 14,705
													$ 1,547,621

Unbifurcated PF Average Rate

Energy Costs	**$ 1,344,629**	**20.00**
Demand Costs	**$ 188,299**	**2.80**
Unbundled Cost	**$ 14,705**	**0.22**
Total	**$ 1,547,633**	**23.02**
Billing Determinants	**67216**	

This page intentionally left blank.

3. 7(B)(2) RATE TEST RESULTS

This page intentionally left blank.

7(b)(2) Rate Test

Nominal mills/kWh

	Program Case PF Rate	Program Case 7(g) costs	Adjusted Program Case PF Rate	7(b)(2) Case PF Rate
2007	30.63	1.93	28.70	23.02
2008	30.11	1.91	28.20	21.65
2009	31.90	1.97	29.93	23.02
2010	31.95	2.02	29.94	21.66
2011	33.45	1.98	31.47	23.38
2012	33.34	1.94	31.40	21.38
2013	34.82	1.97	32.86	23.32

Discounted 2007 mills/kWh

	Adjusted Program Case PF Rate	7(b)(2) Case PF Rate
2007	26.91	21.59
2008	24.71	18.97
2009	24.46	18.81
2010	22.75	16.46
2011	22.23	16.52
2012	20.62	14.04
2013	20.07	14.24

Average Discounted Program Case Rate	23.1
Average Discounted 7(b)(2) Case Rate	17.2
Rate Test Result (Triggers if Positive)	5.90

This page intentionally left blank.